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Susan Frank
Vice President and Chief Regulatory Officer
Regulatory Affairs

BY COURIER

June 25, 2008

Ms. Kirsten Walli
Secretary
Ontario Energy Board
Suite 2700, 2300 Yonge Street
P.O. Box 2319
Toronto, ON.
M4P 1E4

Dear Ms. Walli:

EB-2007-0681 – Hydro One Networks' 2008 Distribution Rate Application – Evidence Update Filing

Hydro One Networks Inc. is updating the evidence filed to date with the Board with the addition of two new exhibits, Exhibit A-19-1 Witness List and Exhibit A-19-2 Curriculum Vitae.

An electronic copy of the complete application, including the attached updates, has been filed using the Board's Regulatory Electronic Submission System (RESS) and the proof of successful submission slip is attached.

Hydro One Networks will post electronic copies of the update on the Hydro One Networks' website for public access. In addition, one copy is being provided for public access at each of the following Hydro One Networks' offices –

Hydro One Networks Head Office, 8th Floor, South Tower, 483 Bay Street, Toronto, Ontario

Hydro One Networks Barrie Field Business Centre, 45 Sarjeant Drive, Barrie, Ontario

Hydro One Networks Peterborough Field Business Centre, 913 Crawford Drive, Peterborough, Ontario

Hydro One Networks Sudbury Field Business Centre, 957 Falconbridge Road, Sudbury, Ontario

Hydro One Networks Merivale Service Centre, 31 Woodfield Drive, Ottawa, Ontario

Hydro One Networks Dundas Field Business Centre, 40 Olympic Drive, Dundas, Ontario

Hydro One Networks Beachville Field Business Centre, 56 Embro Street, Beachville, Ontario

Hydro One Networks Thunder Bay Field Business Centre, 255 Burwood Road, Thunder Bay, Ontario

Hydro One Networks' point of contact for service of documents associated with this Application is listed in Exhibit A, Tab 1, Schedule 1.

Sincerely,

ORIGINAL SIGNED BY SUSAN FRANK

Susan Frank

Attach.

cc: Intervenors of EB-2007-0681

ONTARIO ENERGY BOARD

IN THE MATTER OF *the Ontario Energy Board Act, 1998*;

AND IN THE MATTER OF an Application by Hydro One Networks Inc. For an Order or Orders approving rates for the distribution of electricity.

APPLICATION

1. The Applicant is Hydro One Networks Inc. ("Hydro One Networks"), a subsidiary of Hydro One Inc. Hydro One Networks is an Ontario corporation with its head office in Toronto. The Applicant carries on the business, among other things, of owning and operating transmission and distribution facilities in Ontario. The distribution business of Hydro One Networks will be referred to as "Hydro One Distribution".

2. Hydro One Networks hereby applies to the Ontario Energy Board (the "Board"), pursuant to section 78 of the *Ontario Energy Board Act, 1998,* for an Order or Orders approving the 2008 revenue requirement and customer rates for the distribution of electricity.

3. Hydro One Networks seeks approval of a revenue requirement of $1,067 million for the test year 2008. As part of the application, Hydro One Networks seeks approval to refund regulatory assets with a net balance of $(49) million, to be refunded over a four-year period at $(12) million per year. As a result of the expiry of historical rate riders to recover costs associated with a prior period as well as interim costs for smart meters, the resulting distribution rate increase for the average customer, relative to 2007 rates set by the Board under the Incentive Regulation Mechanism, would be on average less than 2.5% on the distribution

portion of the average customer total bill. This amounts to an average increase of less than 1% on the average customer total bill.

4. Hydro One Networks requests approval for electricity distribution rates that reflect the harmonization of rates for its acquired LDC and legacy customers and for a cost allocation and rate design that begins the process of establishing cost based rates.

5. Hydro One Networks also seeks approval for variance accounts related to incremental OEB costs, variances in actual pension costs, and bill impact mitigation.

6. Hydro One Networks will work within the framework of the Board established process for developing a third generation Incentive Regulation Model. Hydro One Networks anticipates that it will apply the Board’s third generation Incentive Regulation Model to adjust approved revenue requirement components to determine annual revenue requirements in 2009 and 2010.

7. The evidence to be filed with the Board will include a full description of all costs common to the Applicant’s distribution and transmission activities, but the revenue requirement and rates are based only upon those costs appropriately allocated to the distribution business.

8. The written evidence filed with the Board may be amended from time to time prior to the Board’s final decision on the Application. Further, the Applicant may seek meetings with Board staff and intervenors in an attempt to identify and reach agreements to settle issues arising out of this Application.

9. The persons affected by this Application are the ratepayers of Hydro One's distribution business. It is impractical to set out their names and addresses because they are too numerous.

10. Hydro One Networks requests that a copy of all documents filed with the Board by each party to this Application be served on the Applicant and the Applicant's counsel as follows:

a) The Applicant:

Mr. Glen MacDonald
Senior Advisor – Regulatory Affairs
Hydro One Networks Inc.

Address for personal service:	8th Floor, South Tower 483 Bay Street Toronto, ON M5G 2P5
Mailing Address:	8th Floor, South Tower 483 Bay Street Toronto, ON M5G 2P5
Telephone:	(416) 345-5913
Fax:	(416) 345-5866
Electronic access:	glen.e.macdonald@HydroOne.com

b) The Applicant's counsel:

Mr. D.H. Rogers, Q.C.
Rogers Partners LLP

Address for personal service:	181 University Avenue Suite 1900, P.O. Box 97 Toronto, ON M5H 3M7

Mailing Address:	181 University Avenue Suite 1900, P.O. Box 97 Toronto, ON M5H 3M7
Telephone:	(416) 594-4500
Fax:	(416) 594-9100
Electronic access:	don.rogers@rogersmoore.com

DATED at Toronto, Ontario, this 15th day of August, 2007.

HYDRO ONE NETWORKS INC.

By its counsel,

____

D.H. Rogers, Q.C.

SUMMARY OF APPLICATION

Hydro One Networks Inc. ("Hydro One" or "Hydro One Distribution" or "the Company") is applying for an Order approving the revenue requirement, cost allocation and rates for Hydro One's Distribution Business for the year 2008 ("test year") in accordance with the memorandum dated May 4, 2007, provided by the Ontario Energy Board (the "Board" or "OEB"), under Docket Number EB-2006-0330. This summary provides a brief description of the approvals being sought through this Application and a summary of reasons for the increase in revenue requirement.

1.0 SCOPE OF APPLICATION

The scope of this Application includes:

- the review of Hydro One's evidence in support of Distribution revenue requirements for 2008,
- the review of revised Distribution rates to be implemented in 2008, and
- the review of Hydro One's proposal for harmonizing acquired LDC and legacy customers' distribution rates into a reduced number of new rate classes over a 4 years period.

In its December 20, 2006 Cost of Capital report under Proceeding EB-2006-0088/EB-2006-0089, the Board determined that a deemed capital structure of 60% debt and 40% common equity was appropriate for all distributors in determining their revenue requirements. Hydro One has applied the Board's deemed capital structure of 60% debt and 40% common equity in determining its 2008 revenue requirements. For the 2008 test year, as per the Board's formulaic approach in Appendix B of the Cost of Capital Report, Hydro One has applied an equity return of 8.64% using the May 2007 Consensus

Forecast. The Company assumes that when the Board reaches its decision in this Application, Hydro One will be instructed to recalculate its 2008 test year equity return using a more current 2008 Consensus Forecast.

The Board's Decision on Hydro One's Distribution rates for 2006 under Proceeding RP-2005-0020/EB-2005-0378 approved methodologies to establish common corporate cost allocation, working capital and depreciation. The same methodologies were applied for and approved by the Board in their Decision on Hydro One Transmission's application under Proceeding EB-2006-0501, which included a 2008 test year. To ensure consistency is maintained for the 2008 test year, which is common to both the Distribution and Transmission Businesses, Hydro One has utilized these same methodologies. The interest rate used for construction work in progress (CWIP), also referred to as Allowance for Funds Used During Construction (AFUDC), reflects the Board's decision in EB-2006-0117, effective November 28, 2006. This decision prescribed that the interest rate to use for CWIP, effective May 1, 2006, would be the Scotia Capital All-Corporates Mid-Term Yield, as published on the Bank of Canada website and updated quarterly.

Hydro One assesses the condition of its Distribution assets on an ongoing basis, and the resulting Asset Condition Assessment has been used to shape the Sustainment OM&A and Capital plans set out in Exhibits C and D. Hydro One also undertook a stakeholder consultation process to increase understanding of the issues in this Application and to provide a forum for early identification of stakeholder concerns.

As discussed in Exhibit A, Tab 5, Schedule 1, this application by Hydro One Distribution is substantively consistent with the 2006 Electricity Distribution Rate Handbook ("the Handbook") issued by the Board on May 11, 2005, and with the Filing Requirements for Transmission and Distribution Applications (the "Filing Requirements") issued by the

Board on November 14, 2006. The evidence filed with this application is also consistent with Hydro One's Application for 2006 Distribution rates, and its Application for 2007 and 2008 Transmission rates, both of which were approved by the Board.

This application also fully reflects the impact of the Board's recent Decision with Reasons in EB-2007-0063, "OEB Combined Proceeding re: Smart Meters", issued on August 8, 2007. The smart meters decision is reflected and discussed in Exhibit F, Regulatory Assets.

Hydro One addresses through this Application all outstanding Board directives with respect to its Distribution Business. A listing of all relevant directives and the corresponding exhibit or a statement of status is provided in Exhibit A, Tab 17, Schedule 1.

In addition, over the next year, Hydro One will work within the framework of the Board established process for developing a third generation Incentive Regulation Model ("IRM"). Hydro One anticipates that it will apply the Board's third generation IRM to adjust revenue requirement components to determine annual revenue requirements in 2009 and 2010.

2.0 APPROVALS REQUESTED

2.1 Revenue Requirement

Respecting Hydro One's revenue requirement in the year 2008 for its Distribution Business, the Company is seeking approvals for:

1. A revenue requirement of $1,067 million for the 2008 test year, as set out in Exhibit E2, Tab 1, Schedule 1 on the basis of the methodology described in Exhibit E1, Tab 1, Schedule 1.
2. An OM&A cost expenditure level of $478 million in 2008 for the Distribution Business, as summarized in Exhibit C1, Tab 2, Schedule 1. Hydro One's request for this approval is supported by detailed evidence in various schedules in Exhibit C.
3. Other components of the "Cost of Service", as summarized in Exhibit C1, Tab 6, Schedule 1 and Exhibit C1, Tab 7, Schedule 1. These include Hydro One's depreciation and amortization rates and Payments in Lieu of corporate income taxes ("PILs") for the Distribution Business for 2008.
4. A Distribution business rate base of $4,382 million in 2008 as summarized in Exhibit D1, Tab 1, Schedule 1. Hydro One's request for this approval is supported by a discussion of the assets and the capital expenditures forecast for 2008 as found in Exhibit D.
5. Regulatory assets with a total balance of $(49) million to April 30, 2008, which would be refunded over a four-year period, as summarized in Exhibits F1, Tab 1, Schedule 1 and F1, Tab 2, Schedule 1.

Approval of the revenue requirement of $1,067 million for the 2008 test year and the regulatory assets with a total balance of $(49) million, combined with the expiry of rate riders, established under Proceeding RP-2004-0117/0118, and expiry of smart meters interim costs, result in a net distribution rate increase of less than 2.5%, relative to 2007 rates set by the OEB under the Incentive Regulation Mechanism. This distribution rate increase represents an increase of less than 1% on the average customer's total bill.

2.2 Cost Allocation and Rates

With respect to cost allocation and rates, Hydro One is seeking approvals of:

1. The 2008 rate schedules including terms and conditions of service as set out in Schedule 1 of Exhibit G2, Tab 4 to Exhibit G2, Tab 94. These schedules reflect the Company's proposed Retail Transmission Service Rates and loss factors.
2. The charges for the provision of miscellaneous services as set out in Exhibit G2, Tab 95, Schedule 1.
3. Hydro One Distribution's proposed cost allocation and rate design methodology, as described in Exhibit G1, Tab 1, Schedule 1 and supported by the remainder of the G Exhibit.
4. Hydro One Distribution's proposal for harmonizing acquired LDC and legacy customers' distribution rates into a reduced number of new rate classes over a 4 year period, as described in Exhibits G1, Tab 2, Schedule 5 and Exhibit G2, Tab 2, Schedule 1.
5. The modifications to the OEB cost allocation model as discussed in Exhibit G2, Tab 1, Schedule 1.
6. The disposition of the balances accumulated in Regulatory Accounts as shown in Exhibit F1, Tab 2, Schedule 1.

<u>Other</u>

7. Hydro One also seeks approval of variance accounts to track the impact of incremental OEB costs, variances between Hydro One's planned and actual pension costs, and the deferred revenue as a result of mitigation to limit customer's total bill impacts as described in Exhibit F1, Tab 3, Schedule 1.

3.0 CAUSES OF THE INCREASE IN REVENUE REQUIREMENT

Hydro One's revenue requirement of $1,067 million for 2008 is provided in Exhibit E2, Tab 1, Schedule 1. The main contributions to the increase in revenue requirement in 2008 are:

- Growth of about $660 million in the installed asset base since rates were established in the year 2006. This expansion was required to install smart meters, meet growth in customer demand, replace assets damaged by storms, resolve trouble calls, and replace end-of-life assets.
- Increases in OM&A requirements, largely precipitated by a planned increase in vegetation management, support of smart meters, lower overheads capitalized and the effects of escalation in replacement parts, materials and labour rates.
- The increase to the Hydro One Distribution Business common equity component from 36% to 40%. This deemed capital structure was determined by the Ontario Energy Board as being appropriate for all distributors in its December 20, 2006, Cost of Capital report.

These increases are offset by lower statutory tax rates, sales growth, a reduced return on equity, a decrease in asset removal costs, and lower interest rates. The increased revenue requirement combined with the expiry of rate riders, established under Proceeding RP-2004-0117/0118, and the expiry of smart meters interim costs, result in a net distribution rate increase of less than 2.5% relative to 2007 rates set by the OEB under the Incentive Regulation Mechanism, which represents an increase of less than 1% on the average customer's total bill.

The increases identified within the Application will ensure that customers within the Province will continue to be supplied in a secure and reliable manner, thereby contributing to the health and competitiveness of the Province's economy.

FINANCIAL SUMMARY

1.0 INTRODUCTION

Hydro One Distribution is making this application in accordance with the requirements of the Ontario Energy Board *Filing Requirements for Transmission and Distribution Applications* issued November 14, 2006. The proposed revenue requirement and rates included in this application have been prepared on the basis of a forward-looking 2008 test year. This submission also includes information for a 2007 bridge year, historical information for 2004, 2005 and 2006, and historic Board approved 2006 year.

Hydro One is proposing to recover a total revenue requirement of $1,067 million from its customers for the 2008 test year. Calculation of the revenue requirement appears in the evidence at Exhibit E2, Tab 1, Schedule 1.

Hydro One has not conducted a Cost of Capital or Rate of Return study in support of its current submission. Hydro One's submission is based on the capital structure, debt rates and return on equity formulas prescribed in the 'Report of the Board on Cost of Capital and 2nd Generation Incentive Regulation (December 20, 2006). The requested return on common equity is 8.64%, as specified by the formula in the report above. Hydro One Distribution's evidence in support of its Cost of Third Party Long Term Debt appears at Exhibit B1, Tab 1, Schedule 1 and Exhibit B1, Tab 2, Schedule 1, respectively.

Hydro One Distribution's OM&A expenditures have been determined on the basis of an examination of required work programs to ensure the most appropriate, cost-effective solutions to respond to corporate objectives. A description of Hydro One's planning process is provided at Exhibit A, Tab 14, Schedule 1. The proposed OM&A expenditures are $478 million, driven by such factors as the need to meet customer, regulatory and statutory requirements regarding service and reliability. These expenditures are itemized at Exhibit C2, Tab 2, Schedule 1 and discussed in written direct evidence at Exhibit C1, Tabs 1 and 2. Hydro One has used the Corporate Cost Allocation Methodology, approved in RP-2005-0020/EB-2005-0378, to allocate the costs of shared services OM&A and capital expenses between Transmission and Distribution.

Depreciation and amortization expense of $239 million for 2008 has been determined based on the results of Hydro One's depreciation policy. These costs are described in written evidence at Exhibit C1, Tab 6, Schedule 1 and shown in detail in C2, Tab 5, Schedule 1. Depreciation was calculated using the Depreciation Study methodology submitted as part of the 2006 Distribution rate filing (RP-2005-0020/EB-2005-0378). The Board accepted the methodology and resulting cost flows from the Depreciation Study for the purpose of setting rates.

In addition to the Depreciation Study, Hydro One has incorporated the methodologies of the Lead Lag study, submitted and accepted by the Board in RP-2005-0020/EB2005-0378, into the 2008 revenue requirement. The calculation of working capital, filed at Exhibit D1, Tab 1, Schedule 3, incorporates the methodologies of the Lead Lag study.

Hydro One Distribution's proposed Rate Base of $4,382 million is discussed at Exhibit D1, Tab 1, Schedule 1.

This submission reflects Hydro One Distribution's plan to invest in distribution assets to meet its objectives regarding public and employee safety; regulatory and legislative compliance; service quality and reliability; and meeting system growth requirements. The capital project and program approval and control policy is presented at Exhibit A, Tab 14, Schedule 4. Hydro One is forecasting total capital expenditures of $566 million. Details of Hydro One Distribution's capital budget are illustrated in schedules filed at Exhibit D2, Tab 2 and discussed in detail at Exhibit D1, Tab 3.

Hydro One Distribution earns approximately 4% of its revenues from sources other than its distribution tariff. As the costs incurred to generate these revenues are included in Hydro One's cost of service, these external revenues of $42 million in 2008 are recorded as an offset to the revenue requirement. External revenues are discussed at Exhibit E3, Tab 1, Schedule 1 and illustrated in Exhibit E3, Tab 2, Schedule 1.

In accordance with standard regulatory practice, Hydro One Distribution has incurred prior costs for which it is requesting approval in this submission. A total of $(49) million will be recorded as at April 30, 2008 in a series of regulatory assets. Hydro One is proposing to recover the $(49) million over four years, $(12) million per year starting in the 2008 test year. Hydro One's submissions regarding this account balance and proposed disposition appears at Exhibit F1, Tab 1, Schedule 1 and Exhibit F1, Tab 2, Schedule 1 respectively.

Hydro One Networks received OEB approval on October 10, 2007 to purchase the distribution system of Terrace Bay Superior Wires and amend its Distribution Licence to include in its service area the area previously served by Terrace Bay Superior Wires. The assets of Terrace Bay have subsequently been integrated into Hydro One Distribution's operations. The Terrace Bay acquisition adds $1.1 million to rate base and $0.3 million to revenue requirement. The customer forecast has been updated to reflect the Terrace Bay acquisition, as noted in Exhibit A, Tab 14, Schedule 3. Given the relatively minor impact on Hydro One Distribution's rate base and revenue requirement, these numbers have not been changed throughout the evidence. The distribution rates for Terrace Bay customers have been provided as part of Exhibit G2, Tab 82.

The following tables summarize the financial highlights for the 2008 Test Year.

Cost of Capital

Line No.		*Deemed* Capital Structure ($ millions)*	*Total Rate Base Percent*	*Cost Rate (%)*	*Exhibit*
		(a)	(b)	(c)	(d)
1	Total Debt	2,629.2	60.0%	5.65%	B2-1-1
2	Common Equity	1,752.8	40.0%	8.64%	B2-1-1
3	Total Rate Base	4,382.0	100.0%	6.84%	B1-1-1

* As per Board direction, Preferred Shares deemed to be $0 for regulatory purposes.

Financial Highlights

Line No.		*$ millions*	*Exhibit*
1	Total OM&A Expense	477.7	C2-1-1
2	Capital Expenditures	566.2	D2-2-1
3	Rate Base	4,382.0	D2-1-1
4	Revenue Requirement	1,066.8	E2-1-1
5	External Revenues	42.0	E3-2-1
6	Return on Capital	299.9	E2-1-1
7	Regulatory Assets Recovery	(12.2)	F2-2-1

2.0 2006 BOARD APPROVED VS. 2006 ACTUALS VARIANCE EXPLANATIONS

2.1 Operations, Maintenance & Administration

The following table compares 2006 actual costs versus 2006 Board approved costs for OM&A.

OM&A Cost Categories ($ million)	**2006 Actuals** ($ million)	**2006 Board Approved** ($ million)	**Variance** ($ million)
Sustaining	$255.6	$230.3	$25.3
Development	4.2	4.9	(0.7)
Operations	14.9	14.3	0.6
Customer Care	103.7	101.1	2.6
Shared Services & Other Costs	21.2	67.9	(46.7)
Taxes other than Income Taxes	4.5	4.6	(0.1)
Total OM&A	$404.1	$423.1	$(18.9)

Hydro One Distribution's OM&A costs were $404 million compared to $423 million approved by the Board in the RP-2005-0020/EB-2005-0378 Decision with Reasons, a decrease of $19 million. The majority of this differential comes from a decrease in Shared Services and Other Costs, ($47 million) offset by increases in Sustaining OM&A, $25 million, and Customer Care, $3 million.

Shared Services and Other Costs were $47 million below the $68 million approved by the OEB, primarily due to deferred pension expenses ($30 million), increased capitalized overhead credit ($11 million) and smart meter expenses ($5 million).

Corporate capitalized overhead was negative $59.8 million versus the approved negative $48.4 million. This reflects higher capital expenditures than planned which results in more overhead costs capitalized. OM&A expense is reduced by the amount of overhead capitalized. Hydro One will be adjusting the Overhead Capitalization rate in 2008 to return this amount to customers (see Exhibit C1, Tab 5, Schedule 2).

Sustaining OM&A actual 2006 costs was $25 million over the $230 million approved by the OEB. This was primarily due to work efforts required associated with system restoration and forestry work due to the unusually high number of major storms. In addition, smart meter expense was reclassified to sustaining from shared services, increasing sustaining by $5 million.

2.2 Capital Expenditures

Capital Expenditures ($ million)	**2006 Actuals** ($ million)	**2006 Board Approved** ($ million)	**Variance** ($ million)
Sustaining	$186.3	$119.6	$66.7
Development	146.8	137.2	9.6
Operations	2.1	3.5	(1.4)
Shared Services	57.4	72.7	(15.3)
Total	$392.6	$333.0	$59.6

Hydro One Distribution's capital expenditures in 2006 were $393 million compared to $333 million approved by the Board in the EB-2005-0378/RP-2005-0020 Distribution Decision, an increase of $60 million.

A number of factors resulted in capital spending above Board approved levels. The primary factors were the unusually high number of damaging storms in 2006 and an increased need for unplanned equipment replacement, which together contributed to $48 million of additional Sustaining capital. Smart Meters resulted in $14 million of additional Sustaining capital. As well, equipment and material cost escalation rose significantly above forecast levels between the completion of the 2006 business plan and the actual commencement of work. These equipment and material cost increases had a significant impact upon Sustaining and Development program investments. Development capital also increased as a result of Hydro One experiencing a higher than expected volume of more costly sub-division work and with the Company introducing new protection standards for subdivision connections in 2006.

2.3 Rate Base

Rate Base Component ($M)	2006 Actuals	2006 Board Approved	Variance
Gross Plant	$5,679.6	$5,550.0	$ 129.6
Accumulated Depreciation	(2,252.3)	(2,126.7)	(125.5)
Net Plant	**3,427.3**	**3,423.3**	**4.0**
Cash Working Capital[1]	265.6	265.6	-
Materials & Supplies Inventory	22.6	22.9	(0.3)
Total Rate Base	$3,715.4	$3,711.7	$ 3.7

Hydro One Distribution does not calculate actual cash working capital, thus the 2006 approved amount was used for illustrative purposes.

Total rate base was $3.7 million above the board approved amount, a variance of less than 1%.

SUMMARY OF DISTRIBUTION BUSINESS

1.0 INTRODUCTION

Hydro One Networks Inc. is licensed by the Ontario Energy Board (the "OEB" or the "Board") to own, operate and maintain electricity distribution facilities in the Province of Ontario. Hydro One's distribution system is one of the largest systems in North America and serves predominately rural Ontario along with several urban centres.

Hydro One Distribution is driven by Hydro One's corporate mission and business values. Together, they provide the basis to deliver on targeted performance objectives.

1.1 Corporate Mission

> ***"Our mission is to be an efficient transmission and distribution company that is best in North America in the areas of safety, customer service and reliability, while focusing on the development and retention of our employees and creating shareholder value."***

1.2 Strategic Goals and Performance Targets

The company's strategic goals as represented by its business values and performance targets are shown in Table 1 below. The performance targets shown are for 2010. The 2008 investments and expenditures described in this filing are consistent with achieving these 2010 targets and consistent with meeting the business values described in Exhibit A, Tab 14, Schedule 5.

Table 1:
Strategic Goals

Business Value	2010 Performance Target
Safety Focus on cultural change to create and maintain an injury-free workplace.	Zero serious injuries and zero serious near misses
Customer Service Become a more customer-focused company. Improve customer satisfaction. Build relationships with large and mid-size customers that reflect their commercial requirements.	90% customer satisfaction in all major segments
Reliability Maintain or improve reliability and service standards in the distribution system while expanding the system to meet Ontario's future needs.	First quartile distribution reliability (like with like comparison)
Employees Manage the challenges of labour demographics, productivity improvement, development of skills And retention of critical staff.	Attract, develop and retain productive employees
Shareholder Maintain an effective borrowing capability through stable credit quality, and deliver stable financial returns.	Maintain “A” credit rating Allowed regulated return on equity Top quartile capital/operating efficiency Top quartile employee productivity

2.0 SYSTEM BACKGROUND

The Hydro One Distribution system has evolved over almost 100 years. At Dec. 31, 2006, Hydro One Distribution managed $3.5 billion in fixed assets supplying electricity to customers across the province of Ontario. The assets consist of about 119,900 circuit kilometers of distribution line and 1006 distributing and regulating stations. The system delivers electricity at voltages below 50 kV from Ontario's transmission and generation systems to 34 Local Distribution Companies, approximately 1.2 million Retail Customers and 44 directly connected large users. The system is also likely to be used increasingly to serve distributed generators. As of the end of June, 2007, the Ontario Power Authority's (OPA's) Renewable Energy Standard Offer Program had resulted in about 1,000 projects exploring the feasibility of developing new renewable generation up to 10 MW connecting to Hydro One's distribution system. It is expected that many of these will go forward and connect to the system.

The Hydro One Distribution system is mainly radial in design, with very little redundancy in supply to customers, which is consistent with other rural systems. Because of this configuration, most component failures require immediate repair to restore service. To effectively manage the response to trouble calls from customers, initial problem assessment and dispatching of a response is handled through the single Ontario Grid Control Centre (OGCC).

The Hydro One Distribution system typically operates in a service territory characterized by low customer densities. To cost-effectively provide operating, maintenance and restoration services there are a number of Service Centers located throughout the Province. These Service Centers provide base locations for field crews and related materials, tools and equipment.

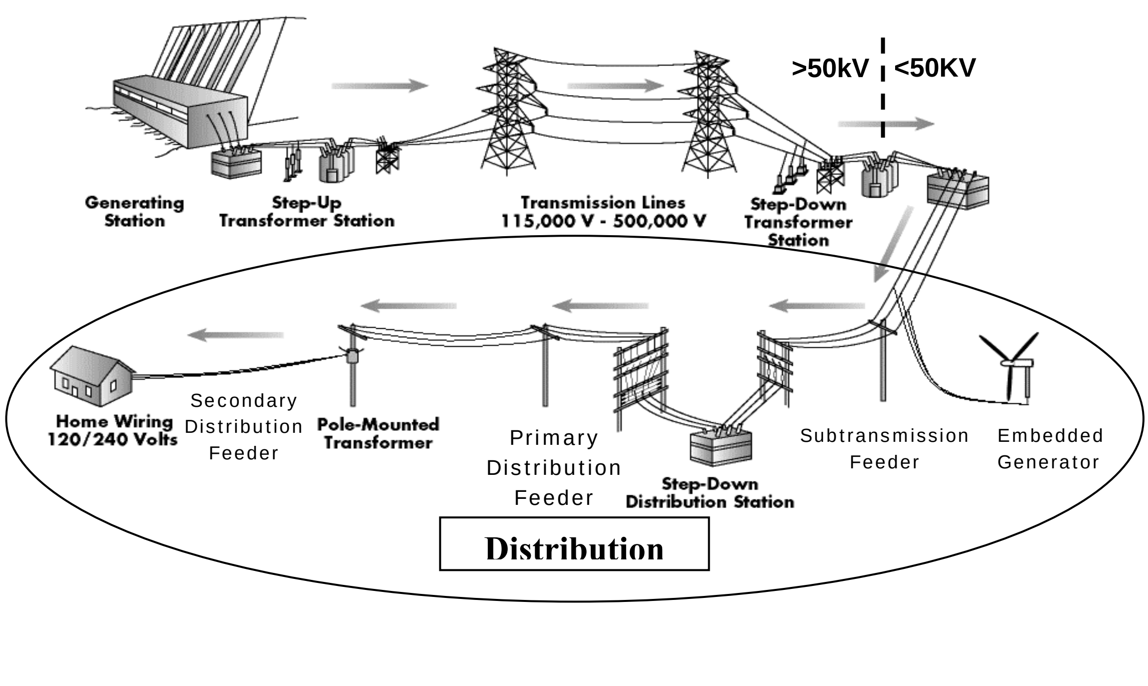
3.0 DISTRIBUTION SYSTEM COMPONENTS

The Hydro One Distribution system receives wholesale electricity from the transmission system and delivers it to consumers at lower voltages through a series of radial assets. It is also used to take electricity from smaller distributed generators connected directly to the distribution system, or connected to load customer systems which are connected to the distribution system. The system consists primarily of the following assets:

- Subtransmission feeders
- Distribution Stations
- Primary Distribution Feeders
- Pole top and pad mounted transformers
- Secondary distribution feeder

Figure 1 provides a simplified illustration of Hydro One Networks' distribution system.

Figure 1: Hydro One Networks' Distribution System [1]



[1] For illustrative purposes only, actual configuration may vary from case to case.

3.1 Subtransmission Feeders

Hydro One's 24,800 circuit kilometers of subtransmission feeders predominately originate at transmission transformer stations and in a some cases at distribution stations and provide a link between Hydro One Networks' system and large distribution connected customers, (e.g. generators, distribution LDCs) and other end use customers. Typically, subtransmission feeders supply service at 44 kV, 27.6 kV, 25 kV, 22 kV and 13.8 kV directly to end-use customers or deliver service to distribution stations owned by either LDCs or Hydro One Distribution where further voltage transformation takes place.

In some cases, regulating stations are used to maintain subtransmission feeder voltages within the prescribed limits. This is needed because the line voltage increases or decreases depending on the loading variations at the distribution stations supplied by the sub-transmission feeders.

3.2 Distribution Stations

Distribution stations step down voltage from transmission or sub-transmission levels to primary distribution voltage for distribution to commercial, industrial, farm, year-round residential and seasonal residential customers. In future, where the output of distributed generation served from a distribution station exceeds the demand of load customers served by that station, the distribution station will also be required to step up voltages as the flow reverses from the normal direction of serving load.

Distribution stations typically consist of one or two transformers, depending on the load that needs to be supplied. A loss of any one element (such as a transformer or a feeder) at a distribution station will normally result in the interruption of service to all customers served from that station until the failed component is repaired or replaced, or until an alternate service is enabled.

3.3 Primary Distribution Feeders

Hydro One Distribution has 95,100 circuit kilometers of primary distribution feeders operating from 4 kV to 13.8 kV. These feeders are radial circuits that deliver power from distribution stations to individual customers via pole top and pad mounted transformers and include overhead circuits, underground cables and submarine cables. These feeders are also likely to be used to serve increasing numbers of smaller new generators in future.

3.4 Pole Top and Pad Mounted Transformers

Hydro One Distribution's 435,000 pole top transformers are used to step down primary distribution voltages to secondary voltage level, the voltage level used by residential and small commercial customers. Hydro One's system also has 40,000 pad mounted transformers which perform the same function when power is supplied by underground feeders.

Depending on the proximity of adjacent customers, each single-phase pole top or pad mounted transformer may supply several customers at 240/120 volts whereas a three-phase pole top or pad mounted transformer supplies a single customer at 600/347 volts or 208/120 volts.

3.5 Secondary Distribution Feeders

Hydro One Distribution's system has approximately 48,000 kilometers of secondary distribution feeders connect pole top or pad mounted transformers with individual customers at the secondary voltage levels described in the previous section. These feeders could be either underground or overhead when originating from a pole top transformer and underground only when originating from a pad mounted transformer.

4.0 WORK PLANNING AND SYSTEM OPERATIONS

Hydro One Distribution's investment plans and work needs are based on a long-term planning cycle which takes into account various factors such as asset condition assessment studies, historical performance data, asset criticality, availability of spare equipment and material, asset demographics, load growth and future capacity requirements. Program and project needs are evaluated using the prioritization approach described in Exhibit A, Tab 14, Schedule 5. The prioritization approach uses business values reflecting Hydro One Distribution's mission and strategic objectives to develop a ranked list of projects and programs. The annual work plan is then refined to a more detailed level, scheduled and implemented. The work plan also includes provision for unplanned work necessitated by storm damage, equipment failures and other unforeseeable events.

The annual work plan is broadly grouped into Sustaining, Development and Operations categories, as further described below.

4.1 Sustaining

Asset sustaining work is defined as the work required to maintain existing infrastructure and facilities such that they operate at their required performance level. Hydro One Distribution plans and executes asset sustainment work to maintain customer delivery reliability system-wide while meeting applicable legislative, regulatory, safety and environmental requirements. The capital component of sustaining work deals primarily with refurbishment or replacement of end of life components or systems. The OM&A component of sustaining work addresses preventive and breakdown (corrective) maintenance within the useful life span of the asset.

The Sustainment OM&A and Capital components of the investment plan are described in Exhibit C1, Tab 2, Schedule 2 and Exhibit D1, Tab 3, Schedule 2 respectively.

4.2 Development

Hydro One Distribution plans and executes development work on the distribution system to connect new load customers and generators, and to ensure that the system has sufficient capability to supply existing and forecast loads. Included in the Development category is work to improve the reliability of service to customers, ensure that service is within acceptable utility standards, and in some cases mitigate risks associated with deteriorated assets, where a different network configuration is preferable to like-for-like asset replacement. The work is largely driven by customer demand and involves both short-term and long-term system reinforcement projects. Funding levels are based on meeting requirements of the Distribution System Code and Hydro One Distribution's Conditions of Service, and addressing the most critical system reinforcement needs.

The Development OM&A and Capital components of the investment plan are described in Exhibit C1, Tab 2, Schedule 3 and Exhibit D1, Tab 3, Schedule 3 respectively.

4.3 Operations

The Operations category primarily includes work to operate the distribution system on a day-to-day basis. As noted above, the distribution system is operated through a combination of central control and dispatch via the OGCC, and local response by field crews operating from service centers across Hydro One Distribution's service territory. This approach allows for efficient problem-identification and dispatch of personnel as well as timely customer notification. Currently the Hydro One Distribution system relies on power-off calls by customers to identify interruptions except at locations where a sub-transmission feeder originates at a transformer station. Real time monitoring exists at these transformer stations, but not on other locations on the distribution system.

The Hydro One Distribution system covers an extensive geographic area and its customer base is both urban and rural resulting in large density differences. The company's response capability is dependent on service center location, fault location and terrain. In general, high-density areas are served within 2 hours and in rural areas response times can be up to 4 hours due to travel requirements. This scale and diversity in the distribution system has a direct impact on Hydro One Distribution's costs and system-average interruption measures for both frequency and duration.

The Operations OM&A and Capital components of the investment plan are described in Exhibit C1, Tab 2, Schedule 4 and Exhibit D1, Tab 3, Schedule 4,

5.0 ASSET MANAGEMENT MODEL

Hydro One has adopted an Asset Management model in designing the processes used to plan, approve and implement work. The key principles include having functions primarily responsible for defining the work requirements (Asset Management functions) and functions primarily responsible for delivering asset and customer based services in accordance with the defined work (Work Execution functions). Primary responsibility for planning and decision making associated with the management of distribution assets falls under the Asset Management functions, whereas primary responsibility for providing engineering, design, estimating, construction, maintenance, operating, and customer care services falls under the Work Execution functions.

Both components of the business actively participate in all phases of work planning and implementation. However, the focus created by this approach allows Hydro One Distribution to better create the competencies and cost-efficiencies to effectively plan and implement the work.

5.1 Asset Management Functions

Hydro One manages its distribution assets using two main processes, Strategy Development and System Investment.

5.1.1 Strategy Development

The Strategy Development function provides a managed approach for developing strategies, policies, and standards associated with the operation, maintenance and expansion of the distribution system. This function is specifically responsible for designing programs to:

- Ensure compliance with regulatory requirements;
- Achieve business objectives such as public and employee safety, reliability, productivity and customer service;
- Provide feedback for continually improving process effectiveness and asset/business performance; and
- Incorporate new methodologies and refining existing methodologies to improve effectiveness and productivity of processes in place.

The Strategy Development function provides the strategies and framework used by the System Investment function to develop programs and investments for Hydro One's distribution assets.

5.1.2 System Investment

Hydro One's distribution business strives to continually improve the efficiency and effectiveness of the regulated wires assets. This involves asset management processes and practices to ensure that the asset related decisions are consistent, cost-efficient and effective. These decisions are aimed at developing a prioritized and rationalized investment plan for the operation, maintenance and upgrade of existing assets, and the addition of new assets.

Hydro One utilizes a Life Cycle Planning concept which recognizes that the distribution business encompasses a portfolio of assets that must be managed over the long term and reflects the fact that not all assets have the same life cycle characteristics or the same criticality with respect to achieving business values and performance.

In preparing investment plans, the planning function utilizes Asset Condition Assessment information (described in Exhibit D1, Tab 2, Schedule 1), historical performance data, asset criticality, availability of spares and asset demographics to develop a detailed list of specific work needs.

Each specific work need is evaluated against the business values, described in Exhibit A, Tab 14, Schedule 5, to establish the benefit of the work and the associated risks of not conducting it. Solutions are developed to mitigate these risks on a program-by-program basis. For each program a prioritization index (cost versus benefit) is developed and all investments are then prioritized in accordance with the process described in Exhibit A, Tab 14, Schedule 5. This prioritized list of programs is then detailed, scheduled and implemented by the work execution functions.

Substantial new generation appears likely to connect to Hydro One's distribution system over the next few years. At present, generators are connected on a completely user pay basis. As such, the distribution system is not being developed proactively to accommodate potential new generation. However, there is a need to evolve the distribution planning function to deal with issues related to such things as distribution system limits on generation capacity, maintaining reliability and power quality for other customers, and ensuring the necessary operational and planning flexibility to respond to changing system needs. As a result, the addition of new generators will lead to an expanded scope for distribution system planning going forward

5.2 Work Execution Functions

The work execution functions provide engineering, design, estimating, construction, maintenance, and operating services. Customer relationship management and support services and supporting research, environmental, and public/employee health and safety programs are also provided by these functions. These activities are performed by a multi-disciplined workforce capable of performing tasks related to operating, maintaining and expanding the distribution business. There are three primary work execution functions within Hydro One: Customer Operations, Grid Operations and Engineering and Construction.

5.2.1 Customer Operations

The Customer Operations function is responsible for the design, estimating, scheduling and completion of line construction and maintenance work for lines, including forestry and customer care support services. As well, the Customer Operations function has accountability for planning and connecting new retail customers to the distribution system and to address local system planning issues. The work activities are managed through the following core processes:

- Estimating Process,
- Planning and Scheduling Process,
- Project Management Process,
- Customer Connection Process,
- Condition Assessment, Line Maintenance, and Lines Sustaining Capital work execution,
- Lines Trouble Response and Correction Action Process,
- Lines Development Capital work execution,
- Work Program Management, and
- Work Reporting Processes.

Lines and Forestry services provide for the maintenance of overhead and underground distribution lines and for vegetation management. The vegetation management program is necessary to ensure that clearances to energized equipment are maintained and that these clearances provide a sustainable level of reliability.

Customer care services may be divided into the following high-level functions: meter reading; billing; settlements; customer contact handling; and collections.

5.2.2 Grid Operations

The Grid Operations function provides maintenance and technical services for stations and protection and control. This function also provides central operations and services for distribution which includes distribution system operation from the OGCC. The work activities are managed through the following core processes:

- Estimating Process,
- Planning and Scheduling Processes,
- Condition Assessment, Station Maintenance, and Station Sustaining Capital work execution,
- Trouble Response and Corrective Action Process,
- Work Program Management, and
- Work Reporting Processes.

The OGCC coordinates an extensive outage program with various internal stakeholders and external customers to support Hydro One's distribution expansion and maintenance programs. Required outages are assessed and coordinated to minimize their impact on reliability and customer operation.

Grid Operations also maintains back-up operating facilities which serve as a fully redundant back-up to the OGCC.

5.2.3 Engineering and Construction

The Engineering and Construction function provides services ranging from engineering and design to the construction and commissioning of new or enhanced facilities. These projects include the engineering, estimating, project management, and construction of stations, system protection and control, as well as engineering services as required. The work activities are managed through the following core processes:

- •• Estimating Process,
- •• Planning and Scheduling Process,
- •• Project Management Process, and
- •• Project/Program Controls Process.

6.0 RELIABILITY

The reliability of the distribution system and its ability to delivery power to customers without interruption is measured using the following two industry standard metrics:

- •• System Average Interruption Duration Index (SAIDI)
- •• System Average Interruption Frequency Index (SAIFI)

SAIDI is a measure that indicates the amount of time without power that an average customer on Hydro One Distribution's system experienced in a given year. SAIFI is a measure that indicates the number of times that an average customer on Hydro One Distribution's system was interrupted in a given year.

Reliability performance is affected by the level of equipment maintenance and replacement programs, which ensure assets remain in good operating condition, and by the level of vegetation management, which ensures that outages caused by tree contacts are minimized. In addition, the time required to respond to a power interruption has a direct impact on restoration time and therefore impacts the SAIDI measure.

Spending levels for vegetation management and other maintenance programs are determined by balancing the benefits achieved through a reduction in the number of incidents and reduced future costs (such as lower unit costs to remove less vegetation), against the cost of additional spending to achieve the longer term reductions. Costs and reliability are derived using life-cycle analysis and these are ranked against other investment plans using the prioritization methodology described in Exhibit A, Tab 14, Schedule 5 to arrive at the optimum spending levels.

The following two figures illustrate Hydro One Distribution's reliability performance over the 2003 to 2006 period. Note that an event is considered *force majeure* when it impacts more that 10% of customers serviced by Hydro One Distribution.

Figure 2: Yearly SAIDI Performance

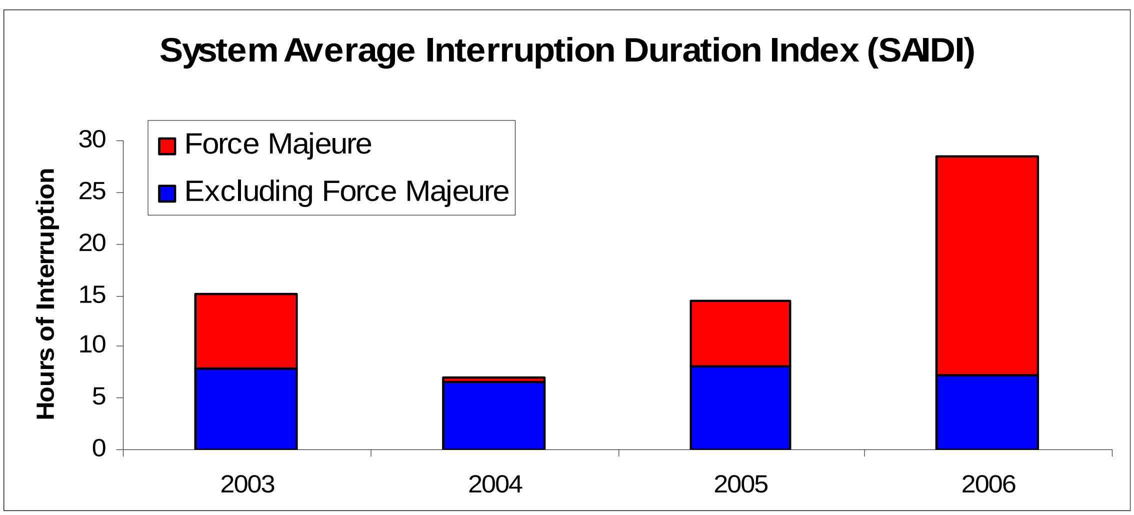
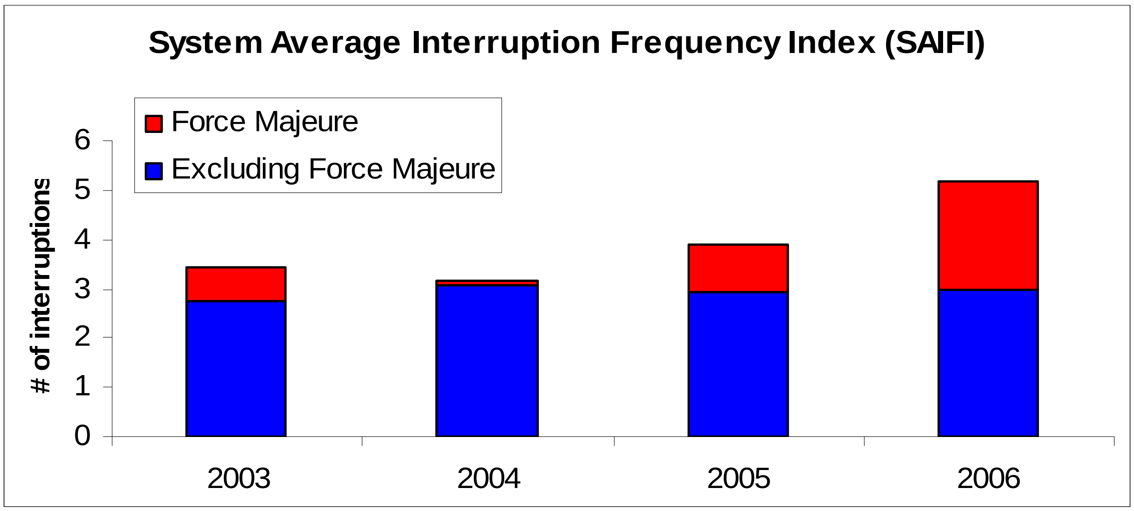


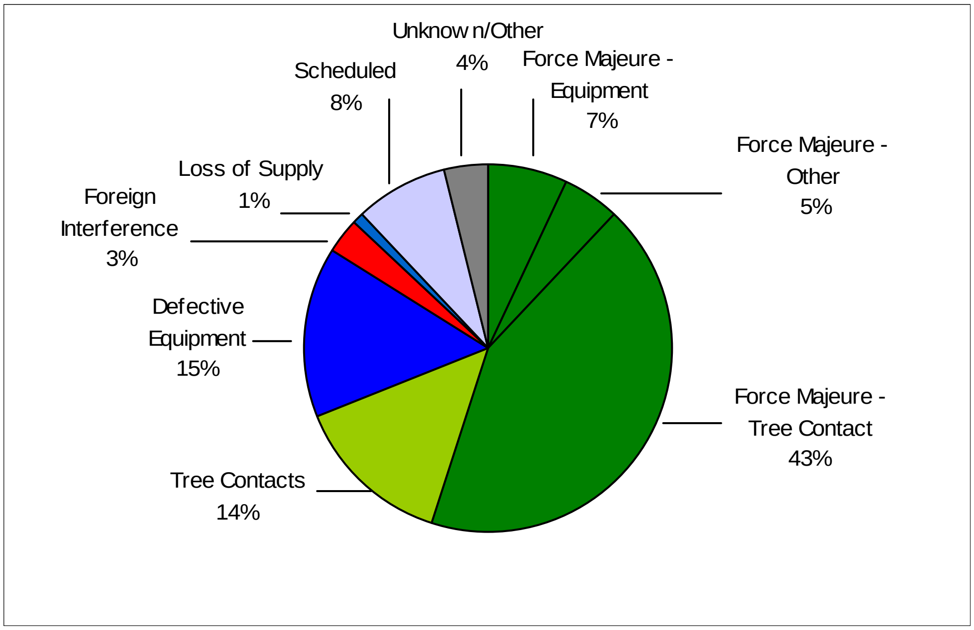
Figure 3: Yearly SAIFI Performance



Excluding *force majeure* events, performance for both SAIDI and SAIFI has remained relatively consistent during the 2003 to 2006 period, with performance in 2006 remaining stable or improving relative to 2005. Including *force majeure* events, performance has varied significantly from year to year due to variations in the number and severity of storms that have affected the Hydro One Distribution system in a given year.

Figure 4 below illustrates the factors that contributed to the SAIDI performance over the 2003 to 2006 period.

Figure 4: Contributions to SAIDI - Four Year Average 2003 - 2006

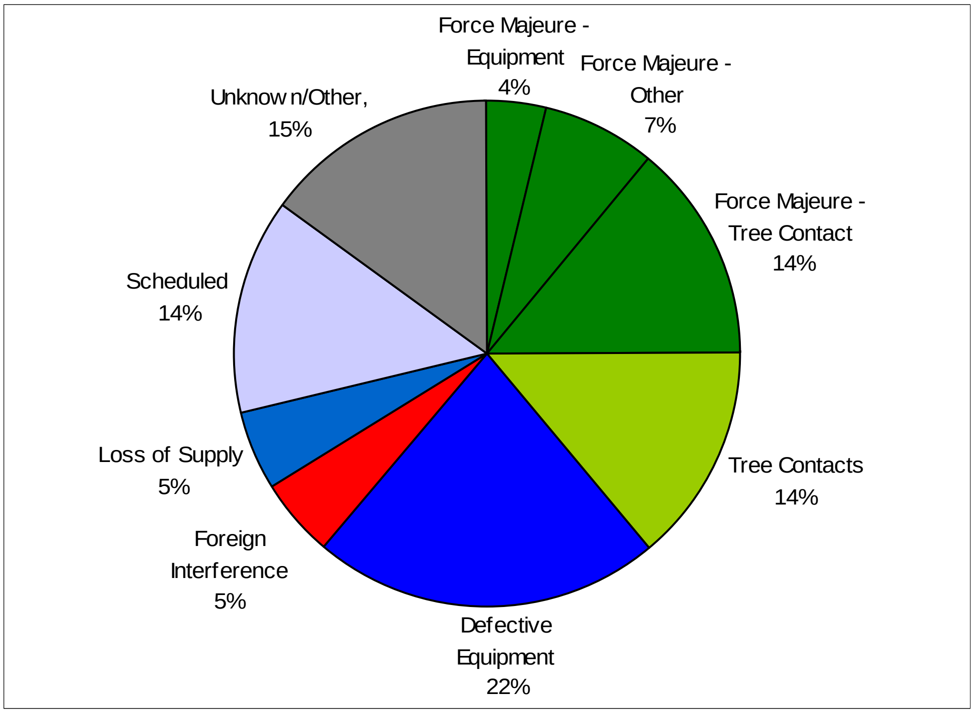


* Excludes Aug 14, 2003 blackout

Outages attributed *to Force majeure* events (e.g. high winds, ice or snow) contributed to 55% of SAIDI. With a focus on specific causes, it is noted that tree contacts account for 57% of total SAIDI (43% *force majeure* and a further 14% excluding *force majeure*). The next largest contributor to SAIDI was defective equipment at 15%.

Figure 5 below illustrates the factors that contributed to the SAIFI performance over the 2003 to 2006 period.

Figure 5: Contributions to SAIFI - Four Year Average 2003 - 2006



* Excludes Aug 14, 2003 blackout

Tree contact was the main contributor to SAIFI totaling 28% (i.e. 14% *force majeure* and a further 14% excluding *force majeure*). The other significant contributor was defective equipment at 22%.

NOTICES OF MOTION

To be filed behind this tab as and when Notices are filed.

COMPLIANCE WITH OEB FILING REQUIREMENTS FOR ELECTRICITY DISTRIBUTORS

1.0 INTRODUCTION

This application by Hydro One Distribution is substantially consistent with the requirements of the 2006 Electricity Distribution Rate Handbook ("the Handbook") issued by the Board on May 11, 2005 and with the Filing Requirements for Transmission and Distribution Applications (the "Filing Requirements") issued by the Board on November 14, 2006.

Hydro One Distribution's Application follows the format used in the previous Distribution Rates proceeding, which was well received by the Board and intervenors, and incorporates improvements made to the filing format as part of the recent Transmission Application. Hydro One's Application substantially satisfies the Filing Requirements and Handbook requirements except where it was not practical or appropriate to do so based on previous comments and direction from the Board, or as a result of specific government regulation.

2.0 TEST YEAR AND HISTORICAL PERIOD

The Filing Requirements indicate that a forward test-year methodology is to be utilized when a distributor is seeking the Board's approval for rebasing its rates. Hydro One Distribution's application has been filed using a forward test year and provides three years of historical data, consistent with the approach used in the two prior main rate cases for Distribution and Transmission rates. As such, this Application includes written evidence and supporting schedules for the following:

- 2008 test year;
- 2007 bridge year;
- 2004, 2005 and 2006 historical years;
- 2006 Board-approved historical year.

3.0 RATE BASE

The Filing Requirements, past direction from the Board, and a number of specific government regulations influence the determination of Hydro One Distribution's rate base and associated capital costs, as well as influencing the rate base information provided in the Application.

3.1 Sentinel Lighting

Hydro One Distribution includes sentinel lighting as a regulated activity by virtue of Regulation 116/02 dated March 22, 2002, made under the *Electricity Act, 1998*. This regulation allows Hydro One Distribution to include in its regulated rate base the assets and OM&A directly related to the provision of sentinel light services. As such, all costs and external revenues associated with sentinel lights have been included in the determination of the 2008 revenue requirement.

3.2 Generation Assets

Assets necessary to provide back up generation on Pelee Island continue to be included in the rate base. Hydro One is allowed to provide back-up generation on Pelee Island by virtue of an exemption granted to it by Ontario Regulation 71/02, made under the *Electricity Act, 1998,* and gazetted March 30, 2002, which amended Ontario regulation 160/99.

3.3 High Voltage Distribution Stations

Pursuant to the Board's RP-1998-0001 Decision, Hydro One Distribution is allowed to include the assets at its 88 High Voltage Distribution Stations (HVDSs) in the Company's distribution rate base.

The functionality of Hydro One Distribution's HVDSs was subsequently reviewed at the 2002 OEB proceeding RP-2000-0023 and the OEB reaffirmed the designation of HVDSs as distribution assets. This treatment of HVDS assets is also consistent with the Company's transmission rate base proposed in EB-2006-0501, which excluded HVDS assets.

3.4 Amortization Rates

Hydro One Distribution's 2008 Revenue Requirement reflects the adoption of the amortization rates approved by the Board in EB-2005-0378, based on the depreciation study by Foster Associates accepted by the Board in that proceeding.

3.5 Working Capital Allowance

Hydro One Distribution's 2008 Revenue Requirement reflects the cash working capital requirements using the methodology from the lead-lag study by Navigant Consulting Inc. approved by the Board in EB-2005-0378.

3.6 Interest Rates for Construction Work in Progress

The interest rate used for construction work in progress (CWIP), also referred to as Allowance for Funds Used During Construction (AFUDC), reflects the Board's decision in EB-2006-0017, effective November 28, 2006. This decision prescribed that the interest rate to use for CWIP would be the Scotia Capital All-Corporates Mid-Term Yield, as published on the Bank of Canada website and updated quarterly. As a result, 2007 bridge and 2008 test years reflect the prescribed CWIP rate on a forecast basis, while the historical years reflect CWIP at Hydro One Distribution's previously approved embedded cost of debt.

3.7 Capital Projects and Programs

Details for all capital projects and programs that exceed $1 million in net capital costs are provided in Investment Justification Documents (IJDs). The IJDs for these projects and programs are filed at Exhibit D2, Tab 2, Schedule 3.

3.8 In-Service Additions

Hydro One Distribution continues to plan, manage and perform its internal and external reporting on a work basis using its general ledger accounts, as these are reflective of the way in which Hydro One Distribution manages its operations. The evidence has been filed on the basis of Hydro One Distribution's accounting systems, but a schedule showing distribution in-service additions by OEB-specified USofA accounts for the 2008 test year, 2007 bridge year and 2006 historical year is filed at Exhibit D2, Tab 2, Schedule 4.

4.0 COST OF CAPITAL

Hydro One Distribution's filing reflects the direction provided in the Report of the Board on Cost of Capital and Second Generation Incentive Regulation, issued December 20, 2006, with respect to the Company's deemed capital structure, forecast debt costs and a common equity return.

5.0 COST OF SERVICE

5.1 Operating (OM&A) Costs

Hydro One Distribution continues to plan, manage and perform its internal and external reporting on a work basis using its general ledger accounts, as these are reflective of the way in which Hydro One Distribution manages its operations. The evidence has been filed on the basis of Hydro One Distribution's accounting systems but a schedule showing distribution OM&A expenditures by OEB-specified USofA accounts for the 2008 test year, 2007 bridge year and 2006 historical year is filed at Exhibit C2, Tab 2, Schedule 2.

5.2 Taxes / Payments-in-Lieu (PILs)

Hydro One Distribution will not be using the OEB Tax Model since it is filing on a forward test year basis. However, the equivalent level of detail has been filed for the 2008 test year at Exhibit C2, Tab 6, Schedule 1.

The Filing Requirements require an applicant to file the taxes it actually paid for the historic years (in this case 2004, 2005 and 2006) with respect to the distribution business of the applicant. Hydro One Distribution is not a legal entity and therefore does not file income tax returns at the distribution level. Corporate tax returns are filed at the Hydro One Networks Inc. level which includes transmission operations. The audited financial statements filed as Attachments to Exhibit A, Tab 9, Schedule 1 do, however, provide

PILs information for the 2004 – 2006 period on a GAAP basis at Note 6 for the 2004 and 2006 historic years and at Note 7 for the 2005 historic year.

6.0 OPERATING REVENUE AND REVENUE SUFFICIENCY/DEFICIENCY

The revenue sufficiency/deficiency for 2008, including operating revenue, is provided as Attachment A to Exhibit E1, Tab 1, Schedule 1. In addition, this Application provides customers and the Board with the impact on current rates resulting from the requested 2008 Revenue Requirement and proposed rate design changes, as detailed in Exhibit G1, Tab 7. Hydro One Distribution believes the detailed description of revenue requirement, in a form consistent to what it has filed in its last two main rate cases, combined with the assessment of rate impacts resulting from the proposals in this Application, provides customers and the Board with the necessary information to fully assess the merits of the Application.

DISTRIBUTION LICENCE

The Ontario Energy Board Act requires any entity that distributes electricity to obtain a Distributor's licence. The Hydro One Networks Inc distribution licence is attached. The licence identifies Hydro One's service territory, and addresses various obligations common to all Distributors, such as the obligation to connect, to provide non-discriminatory access to the distribution system, and to comply with Market rules.

Hydro One is providing its current Distribution Licence, which reflect the Board's approval of the purchase of Terrace Bay Superior Wires. Hydro One is also currently working with Board staff as part of proceeding EB-2007-0933 for an amendment to Hydro One's Electricity Distribution Licence to reflect past decisions of the Board.

The Company confirms that, as with all its licences, its Distributor's licence is being complied with in all material respects and is in good standing

Electricity Distribution Licence

ED-2003-0043

Hydro One Networks Inc.

Valid Until

September 28, 2024

Kirsten Walli
Board Secretary
Ontario Energy Board
Date of Issuance: September 29, 2004
Date of Amendment: October 12, 2005
Date of Amendment: November 26, 2007

Ontario Energy Board	Commission de l'énergie de l'Ontario
P.O. Box 2319	C.P. 2319
2300 Yonge Street	2300, rue Yonge
27th. Floor	27e étage
Toronto, ON M4P 1E4	Toronto ON M4P 1E4

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1 Definitions

In this Licence:

"**Accounting Procedures Handbook**" means the handbook, approved by the Board which specifies the accounting records, accounting principles and accounting separation standards to be followed by the Licensee;

"**Act**" means the *Ontario Energy Board Act, 1998*, S.O. 1998, c. 15, Schedule B;

"**Affiliate Relationships Code for Electricity Distributors and Transmitters**" means the code, approved by the Board which, among other things, establishes the standards and conditions for the interaction between electricity distributors or transmitters and their respective affiliated companies;

"**distribution services**" means services related to the distribution of electricity and the services the Board has required distributors to carry out, including the sales of electricity to consumers under section 29 of the Act, for which a charge or rate has been established in the Rate Order;

"**Distribution System Code**" means the code approved by the Board which, among other things, establishes the obligations of the distributor with respect to the services and terms of service to be offered to customers and retailers and provides minimum, technical operating standards of distribution systems;

"**Electricity Act**" means the *Electricity Act, 1998*, S.O. 1998, c. 15, Schedule A;

"**Licensee**" means Hydro One Networks Inc.

"**Market Rules**" means the rules made under section 32 of the Electricity Act;

"**Performance Standards**" means the performance targets for the distribution and connection activities of the Licensee as established by the Board in accordance with section 83 of the Act;

"**Rate Order**" means an Order or Orders of the Board establishing rates the Licensee is permitted to charge;

"**regulation**" means a regulation made under the Act or the Electricity Act;

"**Retail Settlement Code**" means the code approved by the Board which, among other things, establishes a distributor's obligations and responsibilities associated with financial settlement among retailers and consumers and provides for tracking and facilitating consumer transfers among competitive retailers;

"**service area**" with respect to a distributor, means the area in which the distributor is authorized by its licence to distribute electricity;

"**Standard Supply Service Code**" means the code approved by the Board which, among other things, establishes the minimum conditions that a distributor must meet in carrying out its obligations to sell electricity under section 29 of the Electricity Act;

"**wholesaler**" means a person that purchases electricity or ancillary services in the IESO administered markets or directly from a generator or, a person who sells electricity or ancillary services through the IESO-administered markets or directly to another person other than a consumer.

2 Interpretation

2.1 In this Licence, words and phrases shall have the meaning ascribed to them in the Act or the Electricity Act. Words or phrases importing the singular shall include the plural and vice versa. Headings are for convenience only and shall not affect the interpretation of the Licence. Any reference to a document or a provision of a document includes an amendment or supplement to, or a replacement of, that document or that provision of that document. In the computation of time under this Licence, where there is a reference to a number of days between two events, they shall be counted by excluding the day on which the first event happens and including the day on which the second event happens and where the time for doing an act expires on a holiday, the act may be done on the next day that is not a holiday.

3 Authorization

3.1 The Licensee is authorized, under Part V of the Act and subject to the terms and conditions set out in this Licence:

a) to own and operate a distribution system in the service area described in Schedule 1 of this Licence;

b) to retail electricity for the purposes of fulfilling its obligation under section 29 of the Electricity Act in the manner specified in Schedule 2 of this Licence; and

c) to act as a wholesaler for the purposes of fulfilling its obligations under the Retail Settlement Code or under section 29 of the Electricity Act.

4 Obligation to Comply with Legislation, Regulations and Market Rules

4.1 The Licensee shall comply with all applicable provisions of the Act and the Electricity Act and regulations under these Acts, except where the Licensee has been exempted from such compliance by regulation.

4.2 The Licensee shall comply with all applicable Market Rules.

5 Obligation to Comply with Codes

5.1 The Licensee shall at all times comply with the following Codes (collectively the "Codes") approved by the Board, except where the Licensee has been specifically exempted from such compliance by the Board. Any exemptions granted to the licensee are set out in Schedule 3 of this Licence. The following Codes apply to this Licence:

a) the Affiliate Relationships Code for Electricity Distributors and Transmitters;

b) the Distribution System Code;

c) the Retail Settlement Code; and

d) the Standard Supply Service Code.

5.2 The Licensee shall:

a) make a copy of the Codes available for inspection by members of the public at its head office and regional offices during normal business hours; and

b) provide a copy of the Codes to any person who requests it. The Licensee may impose a fair and reasonable charge for the cost of providing copies.

6 Obligation to Provide Non-discriminatory Access

6.1 The Licensee shall, upon the request of a consumer, generator or retailer, provide such consumer, generator or retailer with access to the Licensee's distribution system and shall convey electricity on behalf of such consumer, generator or retailer in accordance with the terms of this Licence.

7 Obligation to Connect

7.1 The Licensee shall connect a building to its distribution system if:

a) the building lies along any of the lines of the distributor's distribution system; and

b) the owner, occupant or other person in charge of the building requests the connection in writing.

7.2 The Licensee shall make an offer to connect a building to its distribution system if:

a) the building is within the Licensee's service area as described in Schedule 1; and

b) the owner, occupant or other person in charge of the building requests the connection in writing.

7.3 The terms of such connection or offer to connect shall be fair and reasonable and made in accordance with the Distribution System Code, and the Licensee's Rate Order as approved by the Board.

7.4 The Licensee shall not refuse to connect or refuse to make an offer to connect unless it is permitted to do so by the Act or a regulation or any Codes to which the Licensee is obligated to comply with as a condition of this Licence.

8 Obligation to Sell Electricity

8.1 The Licensee shall fulfill its obligation under section 29 of the Electricity Act to sell electricity in accordance with the requirements established in the Standard Supply Service Code, the Retail Settlement Code and the Licensee's Rate Order as approved by the Board.

9 Obligation to Maintain System Integrity

9.1 The Licensee shall maintain its distribution system in accordance with the standards established in the Distribution System Code and Market Rules, and have regard to any other recognized industry operating or planning standards adopted by the Board.

10 Market Power Mitigation Rebates

10.1 The Licensee shall comply with the pass through of Ontario Power Generation rebate conditions set out in Appendix A of this Licence.

11 Distribution Rates

11.1 The Licensee shall not charge for connection to the distribution system, the distribution of electricity or the retailing of electricity to meet its obligation under section 29 of the Electricity Act except in accordance with a Rate Order of the Board.

12 Separation of Business Activities

12.1 The Licensee shall keep financial records associated with distributing electricity separate from its financial records associated with transmitting electricity or other activities in accordance with the Accounting Procedures Handbook and as otherwise required by the Board.

13 Expansion of Distribution System

13.1 The Licensee shall not construct, expand or reinforce an electricity distribution system or make an interconnection except in accordance with the Act and Regulations, the Distribution System Code and applicable provisions of the Market Rules.

13.2 In order to ensure and maintain system integrity or reliable and adequate capacity and supply of electricity, the Board may order the Licensee to expand or reinforce its distribution system in accordance with Market Rules and the Distribution System Code, or in such a manner as the Board may determine.

14 Provision of Information to the Board

14.1 The Licensee shall maintain records of and provide, in the manner and form determined by the Board, such information as the Board may require from time to time.

14.2 Without limiting the generality of paragraph 14.1, the Licensee shall notify the Board of any material change in circumstances that adversely affects or is likely to adversely affect the business, operations or assets of the Licensee as soon as practicable, but in any event no more than twenty (20) days past the date upon which such change occurs.

14.3 The Licensee shall:

a) immediately notify the Board in writing of the notice; and

b) provide a plan to the Board as soon as possible, but no later than ten (10) days after the receipt of the notice, as to how the affected distribution services will be maintained in compliance with the terms of this licence.

15 Restrictions on Provision of Information

15.1 The Licensee shall not use information regarding a consumer, retailer, wholesaler or generator obtained for one purpose for any other purpose without the written consent of the consumer, retailer, wholesaler or generator.

15.2 The Licensee shall not disclose information regarding a consumer, retailer, wholesaler or generator to any other party without the written consent of the consumer, retailer, wholesaler or generator, except where such information is required to be disclosed:

a) to comply with any legislative or regulatory requirements, including the conditions of this Licence;

b) for billing, settlement or market operations purposes;

c) for law enforcement purposes; or

d) to a debt collection agency for the processing of past due accounts of the consumer, retailer, wholesaler or generator.

15.3 The Licensee may disclose information regarding consumers, retailers, wholesalers or generators where the information has been sufficiently aggregated such that their particular information cannot reasonably be identified.

15.4 The Licensee shall inform consumers, retailers, wholesalers and generators of the conditions under which their information may be released to a third party without their consent.

15.5 If the Licensee discloses information under this section, the Licensee shall ensure that the information provided will not be used for any other purpose except the purpose for which it was disclosed.

16 Customer Complaint and Dispute Resolution

16.1 The Licensee shall:

a) have a process for resolving disputes with customers that deals with disputes in a fair, reasonable and timely manner;

b) publish information which will make its customers aware of and help them to use its dispute resolution process;

c) make a copy of the dispute resolution process available for inspection by members of the public at each of the Licensee’s premises during normal business hours;

d) give or send free of charge a copy of the process to any person who reasonably requests it; and

e) subscribe to and refer unresolved complaints to an independent third party complaints resolution service provider selected by the Board. This condition will become effective on a date to be determined by the Board. The Board will provide reasonable notice to the Licensee of the date this condition becomes effective.

17 Term of Licence

17.1 This Licence shall take effect on September 29, 2004 and expire on September 28, 2024. The term of this Licence may be extended by the Board.

18 Fees and Assessments

18.1 The Licensee shall pay all fees charged and amounts assessed by the Board.

19 Communication

19.1 The Licensee shall designate a person that will act as a primary contact with the Board on matters related to this Licence. The Licensee shall notify the Board promptly should the contact details change.

19.2 All official communication relating to this Licence shall be in writing.

19.3 All written communication is to be regarded as having been given by the sender and received by the addressee:

a) when delivered in person to the addressee by hand, by registered mail or by courier;

b) ten (10) business days after the date of posting if the communication is sent by regular mail; and

c) when received by facsimile transmission by the addressee, according to the sender's transmission report.

20 Copies of the Licence

20.1 The Licensee shall:

a) make a copy of this Licence available for inspection by members of the public at its head office and regional offices during normal business hours; and

b) provide a copy of this Licence to any person who requests it. The Licensee may impose a fair and reasonable charge for the cost of providing copies.

SCHEDULE 1 DEFINITION OF DISTRIBUTION SERVICE AREA

This Schedule specifies the area in which the Licensee is authorized to distribute and sell electricity in accordance with paragraph 8.1 of this Licence.

1. Municipalities as set out in Appendix B – Tab 1.

2. First Nation Reserves as set out in Appendix B – Tab 2.

3. Unorganized Townships as set out in Appendix B – Tab 3.

4. Municipalities where areas are served by the Licensee and other distributors as set out in Appendix B – Tab 4.

5. Consumers located outside the municipalities served by the Licensee as set out in Appendix B – Tab 5.

SCHEDULE 2 PROVISION OF STANDARD SUPPLY SERVICE

This Schedule specifies the manner in which the Licensee is authorized to retail electricity for the purposes of fulfilling its obligation under section 29 of the Electricity Act.

The Licensee is authorized to retail electricity directly to consumers within its service area in accordance with paragraph 8.1 of this Licence, any applicable exemptions to this Licence, and at the rates set out in the Rate Orders.

SCHEDULE 3 LIST OF CODE EXEMPTIONS

This Schedule specifies any specific Code requirements from which the Licensee has been exempted.

The Licensee is exempt from the requirements of section 2.4.28 of the Distribution System Code until November 30, 2005.

APPENDIX A

MARKET POWER MITIGATION REBATES

1. Definitions and Interpretations

In this Licence

"embedded distributor" means a distributor who is not a market participant and to whom a host distributor distributes electricity;

"embedded generator" means a generator who is not a market participant and whose generation facility is connected to a distribution system of a distributor, but does not include a generator who consumes more electricity than it generates;

"host distributor" means a distributor who is a market participant and who distributes electricity to another distributor who is not a market participant.

In this Licence, a reference to the payment of a rebate amount by the IESO includes interim payments made by the IESO.

2. Information Given to IESO

a Prior to the payment of a rebate amount by the IESO to a distributor, the distributor shall provide the IESO, in the form specified by the IESO and before the expiry of the period specified by the IESO, with information in respect of the volumes of electricity withdrawn by the distributor from the IESO-controlled grid during the rebate period and distributed by the distributor in the distributor's service area to:

i consumers served by a retailer where a service transaction request as defined in the Retail Settlement Code has been implemented; and

ii consumers other than consumers referred to in clause (i) who are not receiving the fixed price under sections 79.4, 79.5 and 79.16 of the *Ontario Energy Board Act, 1998.*

b Prior to the payment of a rebate amount by the IESO to a distributor which relates to electricity consumed in the service area of an embedded distributor, the embedded distributor shall provide the host distributor, in the form specified by the IESO and before the expiry of the period specified in the Retail Settlement Code, with the volumes of electricity distributed during the rebate period by the embedded distributor's host distributor to the embedded distributor net of any electricity distributed to the embedded distributor which is attributable to embedded generation and distributed by the embedded distributor in the embedded distributor's service area to:

i consumers served by a retailer where a service transaction request as defined in the Retail Settlement Code has been implemented; and

ii consumers other than consumers referred to in clause (i) who are not receiving the fixed price under sections 79.4, 79.5 and 79.16 of the *Ontario Energy Board Act, 1998*.

c Prior to the payment of a rebate amount by the IESO to a distributor which relates to electricity consumed in the service area of an embedded distributor, the host distributor shall provide the IESO, in the form specified by the IESO and before the expiry of the period specified by the IESO, with the information provided to the host distributor by the embedded distributor in accordance with section 2.

The IESO may issue instructions or directions providing for any information to be given under this section. The IESO shall rely on the information provided to it by distributors and there shall be no opportunity to correct any such information or provide any additional information and all amounts paid shall be final and binding and not subject to any adjustment.

For the purposes of attributing electricity distributed to an embedded distributor to embedded generation, the volume of electricity distributed by a host distributor to an embedded distributor shall be deemed to consist of electricity withdrawn from the IESO-controlled grid or supplied to the host distributor by an embedded generator in the same proportion as the total volume of electricity withdrawn from the IESO-controlled grid by the distributor in the rebate period bears to the total volume of electricity supplied to the distributor by embedded generators during the rebate period.

3. Pass Through of Rebate

A distributor shall promptly pass through, with the next regular bill or settlement statement after the rebate amount is received, any rebate received from the IESO, together with interest at the Prime Rate, calculated and accrued daily, on such amount from the date of receipt, to:

a retailers who serve one or more consumers in the distributor’s service area where a service transaction request as defined in the Retail Settlement Code has been implemented;

b consumers who are not receiving the fixed price under sections 79.4, 79.5 and 79.16 of the *Ontario Energy Board Act, 1998* and who are not served by a retailer where a service transaction request as defined in the Retail Settlement Code has been implemented; and

c embedded distributors to whom the distributor distributes electricity.

The amounts paid out to the recipients listed above shall be based on energy consumed and calculated in accordance with the rules set out in the Retail Settlement Code. These payments may be made by way of set off at the option of the distributor.

If requested in writing by OPGI, the distributor shall ensure that all rebates are identified as coming from OPGI in the following form on or with each applicable bill or settlement statement:

“ONTARIO POWER GENERATION INC. rebate”

Any rebate amount which cannot be distributed as provided above or which is returned by a retailer to the distributor in accordance with its licence shall be promptly returned to the host distributor or IESO as applicable, together with interest at the Prime Rate, calculated and accrued daily, on such amount from the date of receipt.

Nothing shall preclude an agreement whereby a consumer assigns the benefit of a rebate payment to a retailer or another party.

Pending pass-through or return to the IESO of any rebate received, the distributor shall hold the funds received in trust for the beneficiaries thereof in a segregated account.

ONTARIO POWER GENERATION INC. REBATES

For the payments that relate to the period from May 1, 2006 to April 30, 2009, the rules set out below shall apply.

1. Definitions and Interpretations

In this Licence

"embedded distributor" means a distributor who is not a market participant and to whom a host distributor distributes electricity;

"embedded generator" means a generator who is not a market participant and whose generation facility is connected to a distribution system of a distributor, but does not include a generator who consumes more electricity than it generates;

"host distributor" means a distributor who is a market participant and who distributes electricity to another distributor who is not a market participant.

In this Licence, a reference to the payment of a rebate amount by the IESO includes interim payments made by the IESO.

2. Information Given to IESO

a Prior to the payment of a rebate amount by the IESO to a distributor, the distributor shall provide the IESO, in the form specified by the IESO and before the expiry of the period specified by the IESO, with information in respect of the volumes of electricity withdrawn by the distributor from the IESO-controlled grid during the rebate period and distributed by the distributor in the distributor's service area to:

i consumers served by a retailer where a service transaction request as defined in the Retail Settlement Code has been implemented and the consumer is not receiving the prices established under sections 79.4, 79.5 and 79.16 of the *Ontario Energy Board Act, 1998*; and

ii consumers other than consumers referred to in clause (i) who are not receiving the fixed price under sections 79.4, 79.5 and 79.16 of the *Ontario Energy Board Act, 1998*.

b Prior to the payment of a rebate amount by the IESO to a distributor which relates to electricity consumed in the service area of an embedded distributor, the embedded distributor shall provide the host distributor, in the form specified by the IESO and before the expiry of the period specified in the Retail Settlement Code, with the volumes of electricity distributed during the rebate period by the embedded distributor's host distributor to the embedded distributor net of any electricity distributed to the embedded distributor which is attributable to embedded generation and distributed by the embedded distributor in the embedded distributor's service area to:

i consumers served by a retailer where a service transaction request as defined in the Retail Settlement Code has been implemented; and

ii consumers other than consumers referred to in clause (i) who are not receiving the fixed price under sections 79.4, 79.5 and 79.16 of the *Ontario Energy Board Act, 1998*.

c Prior to the payment of a rebate amount by the IESO to a distributor which relates to electricity consumed in the service area of an embedded distributor, the host distributor shall provide the IESO, in the form specified by the IESO and before the expiry of the period specified by the IESO, with the information provided to the host distributor by the embedded distributor in accordance with section 2.

The IESO may issue instructions or directions providing for any information to be given under this section. The IESO shall rely on the information provided to it by distributors and there shall be no opportunity to correct any such information or provide any additional information and all amounts paid shall be final and binding and not subject to any adjustment.

For the purposes of attributing electricity distributed to an embedded distributor to embedded generation, the volume of electricity distributed by a host distributor to an embedded distributor shall be deemed to consist of electricity withdrawn from the IESO-controlled grid or supplied to the host distributor by an embedded generator in the same proportion as the total volume of electricity withdrawn from the IESO-controlled grid by the distributor in the rebate period bears to the total volume of electricity supplied to the distributor by embedded generators during the rebate period.

3. Pass Through of Rebate

A distributor shall promptly pass through, with the next regular bill or settlement statement after the rebate amount is received, any rebate received from the IESO, together with interest at the Prime Rate, calculated and accrued daily, on such amount from the date of receipt, to:

a retailers who serve one or more consumers in the distributor's service area where a service transaction request as defined in the Retail Settlement Code has been implemented and the consumer is not receiving the prices established under sections 79.4, 79.5 and 79.16 of the *Ontario Energy Board Act, 1998*;

b consumers who are not receiving the fixed price under sections 79.4, 79.5 and 79.16 of the *Ontario Energy Board Act, 1998* and who are not served by a retailer where a service transaction request as defined in the Retail Settlement Code has been implemented; and

c embedded distributors to whom the distributor distributes electricity.

The amounts paid out to the recipients listed above shall be based on energy consumed and calculated in accordance with the rules set out in the Retail Settlement Code. These payments may be made by way of set off at the option of the distributor.

If requested in writing by OPGI, the distributor shall ensure that all rebates are identified as coming from OPGI in the following form on or with each applicable bill or settlement statement:

"ONTARIO POWER GENERATION INC. rebate"

Any rebate amount which cannot be distributed as provided above or which is returned by a retailer to the distributor in accordance with its licence shall be promptly returned to the host distributor or IESO as applicable, together with interest at the Prime Rate, calculated and accrued daily, on such amount from the date of receipt.

Nothing shall preclude an agreement whereby a consumer assigns the benefit of a rebate payment to a retailer or another party.

Pending pass-through or return to the IESO of any rebate received, the distributor shall hold the funds received in trust for the beneficiaries thereof in a segregated account.

Tab 1 MUNICIPALITIES

Name of Municipality:	Township of Addington Highlands
Formerly Known as:	Township of Denbign, Abinger and Ashby, Township of Anglesea and Effingham, Kaladar, as at December 31. 1999.

Name of Municipality:	Township of Adelaide Metcalfe
Formerly Known As:	Township of Adelaide, Township of Metcalfe, as at December 31, 2000.

Name of Municipality:	Township of Adjala-Tosorontio
Formerly Known As:	Portions of the Township of Adjala, Township of Tosorontio, Township of Sunnidale, as at December 31, 1993.

Name of Municipality:	Township of Admaston/Bromley
Formerly Known As:	Township of Admaston, Township of Bromley, as at December 31, 1999.

Name of Municipality:	Township of Alberton as at March 31, 1999.
Formerly Known As:	Same

Name of Municipality:	Township of Algonquin Highlands, (Formerly known as Township of Sherborne, Stanhope, McClintock, Livingstone, Lawrence and Nightingale)
Formerly Known As:	Township of Sherborne et al,Township of Stanhope, as at December 31, 2000.

Name of Municipality: Township of Alnwick/Haldimand
Formerly Known As: Township of Alnwick, Township of Haldimand, as at December 31, 2000.

Name of Municipality: Township of Amaranth as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Township of The Archipelago as at March 31, 1999.
Formerly Known As: Conger, Cowper, Harrison, Henvey, Wallbridge plus geographic/unorganized townships and unsurveyed areas

Name of Municipality: Township of Armour as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Township of Armstrong as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Town of Arnprior as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Municipality of Arran-Elderslie
Formerly Known As: Township of Arran, Township of Elderslie, Town of Chesley, Village of Tara, Village of Paisley, as at December 31, 1998.

Name of Municipality: Township of Ashfield-Colborne-Wawanosh
Formerly Known As: Township of Ashfield, Township of West Wananosh, Township of Colborne, as at December 31, 2000.

Name of Municipality: Township of Assiginack as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Township of Athens
Formerly Known As: Township of Rear of Young and Escott, Village of Athens, as at December 31, 2000.

Name of Municipality: Township of Augusta as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Township of Baldwin as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Town of Bancroft
Formerly Known As: Town of Bancroft, Township of Dungannon, as at December 31, 1998.

Name of Municipality: Township of Barrie Island as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Municipality of Bayham
Formerly Known As: Township of Baymen, Village of Port Burwell, Village of Vienna, as at December 31, 1997.

Name of Municipality: Township of Beckwith as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Township of Billings as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Township of Black River-Matheson as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Township of Blandford-Blenheim as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Town of Blind River as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Township of Bonfield as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Township of Bonnechere Valley
Formerly Known As: Village of Eganville, Township of Grattan, Township of Sebastopol, Township of South Algona, as at December 31, 2000.

Name of Municipality: Township of Brethour as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Municipality of Brighton
Formerly Known As: Town of Brighton, Township of Brighton, as at December 31, 2001.

Name of Municipality: City of Brockville as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Township of Brudenell, Lyndoch and Raglan
Formerly Known As: Township of Brudenell and Lyndoch, Township of Raglan, as at December 31, 1998.

Name of Municipality: Township of Burpee and Mills
Formerly Known As: Township of Burpee, Unorganized Twp of Mills, as at December 31, 1997.

Name of Municipality: Town of Caledon
Formerly Known As: Township of Albion, Township of Caledon, Village of Bolton, Village of Caledon East, Township of Chinguacousy (part), as at December 31, 1973.

Name of Municipality: Township of Calvin as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Town of Carleton Place as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Township of Carling as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Township of Carlow/Mayo
Formerly Known As: Township of Carlow, Township of Mayo, as at December 31, 2000.

Name of Municipality: Township of Casey as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Township of Cavan-Millbrook-North Monoghan
Formerly Known As: Township of Cavan, Township of North Monaghan, Village of Millbrook, as at December 31, 1997.

Name of Municipality: Township of Central Frontenac
Formerly Known As: Township of Hinchinbrooke, Township of Kennebec, Township of Olden, Township of Oso, as at December 31, 1997.

Name of Municipality: Township of Central Manitoulin
Formerly Known As: Twp. Of Carnarvon, Unorganized Twp of Sandfield, as at April 30, 1997.

Name of Municipality: Municipality of Centre Hastings
Formerly Known As: Village of Madoc, Township of Huntingdon, as at December 31, 1997.

Name of Municipality: Township of Chamberlain as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Township of Champlain
Formerly Known As: Village of L'Orignal, Township of West Hawkesbury, Township of Longueuil, Town of Vankleek Hill, as at December 31, 1997.

Name of Municipality: Township of Chapple as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Municipality of Charlton and Dack
Formerly Known As: Town of Charlton, Township of Dack, as at December 31, 2002.

Name of Municipality: Township of Chatsworth
Formerly Known As: Village of Chatsworth, Township of Holland, Township of Sullivan, as at December 31, 1999.

Name of Municipality: Township of Chisolm as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: City of Clarence-Rockland
Formerly Known As: Town of Rockland, Township of Clarence, as at December 31, 1997.

Name of Municipality: Town of Cobalt as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Township of Cockburn Island as at March 31, 1999
Formerly Known As: Same

Name of Municipality: Township of Coleman as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Township of Conmee as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Township of Dawn-Euphemia
Formerly Known As: Township of Dawn, Township of Euphemia, as at December 31, 1997.

Name of Municipality: Township of Dawson
Formerly Known As: Township of Atwood, Township of Blue, Township of Worthington, Township of Dilke, as at December 31, 1996.

Name of Municipality: Town of Deep River as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Town of Deseronto as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Township of Dorion as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Township of Douro-Dummer
Formerly Known As: Township of Douro, Township of Dummer, as at December 31, 1997.

Name of Municipality: Township of Drummond/North Elmsley
Formerly Known As: Township of Drummond, Township of North Elmsley, as at December 31, 1997.

Name of Municipality: City of Dryden
Formerly Known As: Town of Dryden, Township of Barclay

Name of Municipality: Township of Dysart et al as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Municipality of Ear Falls as at March 31, 1999.
Formerly Known As: Same

Name of Municipality:	Township of East Ferris as at March 31, 1999.
Formerly Known As:	Same
Name of Municipality:	Township of East Garafraxa as at March 31, 1999.
Formerly Known As:	Same
Name of Municipality:	Township of East Hawkesbury as at March 31, 1999.
Formerly Known As:	Same
Name of Municipality:	Township of Elizabethtown-Kitley
Formerly Known As:	Township of Kitley, Township of Elizabethtown as at December 31, 2000.
Name of Municipality:	City of Elliott Lake as at March 31, 1999.
Formerly Known As:	Same
Name of Municipality:	Township of Emo, as at March 31, 1999.
Formerly Known As:	Same
Name of Municipality:	Township of Englehart as at March 31, 1999.
Formerly Known As:	Same
Name of Municipality:	Township of Enniskillen as at March 31, 1999.
Formerly Known As:	Same
Name of Municipality:	Town of Erin
Formerly Known As:	Township of Erin, Village of Erin, as at December 31, 1997.

Name of Municipality: Township of Evantural as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Township of Faraday as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Township of Township of Fauquier-Strickland as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Municipality of French River
Formerly Known As: Township of Cosby, Township of Mason, Township of Martland, geographic/unorganized townships of Delamere, Hoskin and Scollard in whole and Bigwood, Cherriman and Haddo in part, as at December 31, 1998.

Name of Municipality: Township of Front of Young as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Township of Frontenac Islands
Formerly Known As: Township of Howe Island, Township of Wolfe Island, as at December 31, 1997.

Name of Municipality: Township of Galway-Cavendish and Harvey
Formerly Known As: Township of Galway and Cavandish, Township of Harvey, as at December 31, 1997.

Name of Municipality: Township of Gauthier as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Township of Georgian Bay as at March 31, 1999.
Formerly Known As: Township of Freeman, Township of Gibson, Township of Baxter.

Name of Municipality: Township of Georgian Bluffs
Formerly Known As: Township of Derby, Township of Keppel, Township of Sarawak, as at December 31, 2000.

Name of Municipality: Town of Georgina as at March 31, 1999.
Formerly Known As: Township of North Gwillimbury, Township of Georgina.

Name of Municipality: Township of Gillies as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Township of Gordon as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Town of Gore Bay as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Township of Greater Madawaska
Formerly Known As: Township of Bagot, Blythfield and Brougham, Township of Griffith, and Matawatchan, (Jan 1998: Township of Bagot and Blythfield, Township of Brougham amalgamated into Township of Bagot, Blythfield and Brougham), as at December 31, 2000.

Name of Municipality: Town of Greater Napanee
Formerly Known As: Township of Adolphustown, Township of North Fredericksburgh, Township of South Fredericksburgh, Township of Richmond, Town of Napanee, as at December 31, 1997.

Name of Municipality: Municipality of Greenstone
Formerly Known As: Town of Geraldton, Town of Longlac, Township of Beardmore, Township of Nakina, as at December 31, 2000.

Name of Municipality: Municipality of Grey Highlands
Formerly Known As: Township of Artemesia, Township of Euphrasia Village of Markdale, Township of Osprey, as at December 31, 2000.

Name of Municipality: Township of Hamilton as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Township of Harley as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Township of Harris as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Municipality of Hastings Highlands
Formerly Known As: Township of Bangor, Wicklow and McClure, Township of Herschel, Township of Monteagle, as at December 31, 2000.

Name of Municipality: Township of Havelock-Belmont-Methuen
Formerly Known As: Township of Belmont and Methuen, Village of Havelock, as at December 31, 1997.

Name of Municipality: Township of Head, Clara and Maria, as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Municipality of Highland East
Formerly Known As: Township of Bicroft, Township Cardiff, Township of Glamorgan, Township of Monmouth, as at December 31, 2000.

Name of Municipality: Township of Hilliard as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Township of Hornpayne as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Township of Horton as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: The Township of Howick as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Township of Hudson as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Township of Ignace as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Township of James as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Township of Joly as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: The City of Kawartha Lakes
Formerly Known As: County of Victoria, Town of Lindsay, Municipality of Bobcaygeon/ Verulam, Village of Fenelon Falls, Village of Omemee, Village of Sturgeon Point, Village of Woodville, Township of Bexley, Township of Carden/Dalton, Township of Eldon, Township of Emily, Township of Fenelon, Township of Laxton, Digby and Longford, Township Manvers, Township of Mariposa, Township of Ops, Township of Somerville, (Jan 2000: Township of Carden , Township of Dalton amalgamated into Township of Carden/Dalton), (Jan 2000; Village of Bobcaygeon/Township of Verulam amalgamated into the Municipality of Bobcaygeon/Verulam), as at December 31, 2000.

Name of Municipality: Town of Kearney as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Township of Kerns as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Municipality of Killarney
Formerly Known As: Townships of Rutherford and George Island and the geographic/unorganized townships of, Allen, Atlee, Goschen, Hansen, Killarney, Kilpatrick, Sale, Struthers, Travers, and portions of the geographic/unorganized townships of Bigwood, Carlyle, Humboldt, Mowat, and unsurveyed territory and islands, as at Deember 31, 1998.

Name of Municipality: Township of King as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Town of Kirkland Lake as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Township of La Vallee as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Township of Lake of Bays as at March 31, 1999.
Formerly Known As: Township of McLean, Township of Ridout, Township of Franklin, Township of Sinclair, Township of Finlayson.

Name of Municipality: Township of Lake of the Woods
Formerly Known As: Township of McCrosson and Tovell, Township of of Morson, unorganized islands in Kenora District and Rainy River District, as at December 31, 1998.

Name of Municipality: Municipality of Lambton Shores
Formerly Known As: Village of Arkona, Town of Bosanquet, Town of Forest, Village of Grand Bend, Village of Thedford, as at December 31, 2000.

Name of Municipality:	Township of Lanark Highlands
Formerly Known As:	Township of Darling, Township of North West Lanark, (May 1997: Lavant, Dalhousie and North Sherbrook Township/Township Lanark/Village Lanark amalgamated into Township of North West Lanark), as at June 30, 1996.
Name of Municipality:	Township of Larder Lake as at March 31, 1999.
Formerly Known As:	Same
Name of Municipality:	Town of Latchford as at March 31, 1999.
Formerly Known As:	Same
Name of Municipality:	Town of Laurentian Hills
Formerly Known As:	Township of Rolph, Township of Wylie and McKay, Village of Chalk River, as at December 31, 1999.
Name of Municipality:	Township of Laurentian Valley
Formerly Known As:	Township of Stafford and Pembroke, Township of Alice and Fraser, as at December 31, 1999.
Name of Municipality:	Township of Limerick as at March 31, 1999.
Formerly Known As:	Same
Name of Municipality:	Township of Loyalist
Formerly Known As:	Township of Amherst Island, Township of Ernestown, Village of Bath, as at December 31, 1997.
Name of Municipality:	Township of Lucan Biddulph
Formerly Known As:	Village of Lucan, Township of Biddulph, Police Village of Granton, as at December 31, 1998.

Name of Municipality: Township of Machar as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Township of Machin as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Township of Madawaska Valley
Formerly Known As: Village of Barry's Bay, Township of Radcliffe, Township of Sherwood, Jones and Burns, as at December 31, 2000.

Name of Municipality: Township of Madoc as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Township of Malahide
Formerly Known As: Township of Malahide, Township of Dorchester, Village of Springfield, as at December 31, 1997.

Name of Municipality: Township of Manitouwadge as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Township of Mapleton
Formerly Known As: Township of Mapleton, Township of Maryborough, (Jan 1998-Village of Drayton, Township of Peel amalgamated into the Township of Mapleton), as at December 31, 1998.

Name of Municipality: Town of Marathon as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Municipality of Markstay-Warren
Formerly Known As: Township of Hagar, Township of Ratter and Dunnet, geographic/unorganized township of Awrey and portions of the geographic/unorganized townships of Hawley, Henry, Loughrin, Street, as at December 31, 1998.

Name of Municipality: Municipality of Marmora and Lake
Formerly Known As: Township of Marmora and Lake, Village of Marmora, (Jan 1998: Village of Deloro, Township of Marmora and Lake amalgamated into the Township of Marmora and Lake, as at December 31, 1997.

Name of Municipality: Township of Matachewan as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Town of Mattawa as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Township of Mattawan as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Township of Mattice-Val Cote as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Township of McDougall
Formerly Known As: Township of McDougall, geographic/unorganized township of Ferguson, as at December 31, 1999.

Name of Municipality: Township of McGarry as at March 31, 1999.
Formerly Known As: Same

Name of Municipality:	Township of McKellar as at March 31, 1999.
Formerly Known As:	Same

Name of Municipality:	Township of McMurrich/Monteith
Formerly Known As:	Township of McMurrich, geographic/unorganized township of Monteith (eastern portion), as at December 31, 1997.

Name of Municipality:	Township of McNab/Braeside
Formerly Known As:	Township of McNab, Village Braeside, as at December 31, 1997

Name of Municipality:	Municipality of Meaford (formerly known as Town of Georgian Highlands)
Formerly Known As:	Township of St. Vincent, Township of Sydenham, Town of Meaford, as at December 31, 2000.

Name of Municipality:	Township of Melancthon as at March 31, 1999.
Formerly Known As:	Same

Name of Municipality:	Village of Merrickville-Wolford
Formerly Known As:	Township of Wolford, Village of Merrickville, as at December 31, 1997.

Name of Municipality:	Township of Middlesex Centre
Formerly Known As:	Township of Lobo, Township of London, Township of Delaware, Police Village of Delaware, as at December 31, 1998.

Name of Municipality: Township of Minden Hills
Formerly Known As: Township of Anson, Hindon and Minden, Township of Lutterworth, Township of Snowdon, as at December 31, 2000.

Name of Municipality: Town of Mono as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Township of Montague as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Township of Moonbeam as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Town of Moosonee as at March 31, 1999.
Formerly Known As: Moosonee Development Board

Name of Municipality: Township of Morley
Formerly Known As: Township of Morley, geographic/unorganized townships Twp's of Dewart and Sifton, as at December 31, 2003.

Name of Municipality: Municipality of Morris-Turnberry
Formerly Known As: Township of Morris, Township of Turnberry, as at December 31, 2000.

Name of Municipality: Township of Mulmar as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Township of Muskoka Lakes as at March 31, 1999.
Formerly Known As: Township of Cardwell, Township of Watt, Township of Medora, Township of Monck, Township of Wood.

Name of Municipality: Township of Nairn and Hyman
Formerly Known As: Township of Nairn, Unorganized Township of Hyman, as at December 31, 1997.

Name of Municipality: The Nation Municipality
Formerly Known As: Township of Cambridge, Township of South Plantagenet, Village of St. Isidore, Township of Caledonia, as December 31, 1997.

Name of Municipality: Municipality of Neebing as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Municipality of New Liskeard-Haileybury-Dymond
Formerly Known As: Town of New Liskeard, Town of Haileybury, Township of Dymond, as at December 31, 2003.

Name of Municipality: Township of Nipigon as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Township of Nipissing as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Township of North Algona-Wilberforce
Formerly Known As: Township of North Algona, Township of Wilberforce, as at December 31, 1998.

Name of Municipality: Municipality of Northern Bruce Peninsula
Formerly Known As: Township of St. Edmunds, Township of Lindsay, Township of Eastnor, Village of Lion's Head, as at December 31, 1998.

Name of Municipality: Township of North Dundas
Formerly Known As: Township of Mountain, Township of Winchester, Village of Chesterville, Village of Winchester, as at December 31, 1997.

Name of Municipality: Township of North Frontenac
Formerly Known As: Township of Barrie, Township of Clarendon, Township of Miller, Township of Palmerston, Township of North Canonto, Township of South Canonto, as at December 31, 1997.

Name of Municipality: Township of North Glengarry
Formerly Known As: Township of Kenyon, Township of Lochiel, Town of Alexandria, Village of Maxville, Police Village of Apple Hill, as at December 31, 1997.

Name of Municipality: Township of North Grenville
Formerly Known As: Township of Oxford-on-Rideau, Town of Kemptville, Township of South Gower, as at December 31, 1997.

Name of Municipality: Township of North Himsworth as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Township of North Kawartha
Formerly Known As: Township of Burleigh and Anstruther, Township of Chandos, as at December 31, 1997.

Name of Municipality: Town of North Perth
Formerly Known As: Township of Wallace, Township of Elma, Town of Listowel, as at December 31, 1997.

Name of Municipality: Township of The North Shore as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Township of North Stormont
Formerly Known As: Township of Finch, Township of Roxborough, Village of Finch, Police Village of Avonmore (in the Township of Roxborough), as at December 31, 1997.

Name of Municipality: Town of Northeastern Manitoulin and the Islands
Formerly Known As: Township of Howland, Town of Little Current, all islands not part of other municipalities on Manitoulin Island, as at December 31, 1997.

Name of Municipality: Township of O'Conner as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Township of Oliver Paipoonge
Formerly Known As: Township of Oliver, Township of Paipoonge, as at December 31, 1997.

Name of Municipality: Township of Opasatika as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Township of Oro-Medonte
Formerly Known As: Portions of the Township of Medonte, Township of Oro, Township of Orillia, Township of Tay, Township of Flos, Township of Vespra, as at December 31, 1993.

Name of Municipality: Township of Otonabee-South Monaghan
Formerly Known As: Township of Otonabee, Township of South Monaghan, as at December 1, 1999.

Name of Municipality: City of Owen Sound as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Township of Papineau-Cameron as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Township of Perry as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Township of Pelee as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Township of Perth East
Formerly Known As: Township of Mornington, Township of Ellice, Township of North Easthope, Township of South Easthope, Village of Milverton, as at December 31, 1997.

Name of Municipality: The Township of Perth South
Formerly Known As: Township of Downie, Township of Blanshard, as at December 31, 1997.

Name of Municipality: Town of Perth as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Town of Petawawa
Formerly Known As: Village of Petawawa, Township of Petawawa, as at June 30, 1996.

Name of Municipality: Township of Pickle Lake as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Town of Plympton-Wyoming
Formerly Known As: Township of Plympton, Village of Wyoming, as at December 31, 2000.

Name of Municipality: Municipality of Powassan
Formerly Known As: Town of Powassan, Township of Himsworth South, Town of Trout Creek, as at December 31, 2000.

Name of Municipality: County of Prince Edward
Formerly Known As: County of Prince Edward, Town of Picton, Village of Bloomfield, Village of Wellington, Township of Ameliasburgh, Township of Athol, Township of Hallowell, Township of Hillier, Township of North Marysburgh, Township of South Marysburgh, Township of Sophiasburgh, as at December 31, 1997.

Name of Municipality: Township of Puslinch as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: City of Quinte West
Formerly Known As: City of Trenton, Village of Frankford, Township of Sidney, Township of Murray, as at December 31, 1997.

Name of Municipality: Town of Rainy River as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Township of Ramara
Formerly Known As: Township of Mara, Township of Rama , as at December 31, 1993.

Name of Municipality: Township of Red Rock as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Township of Rideau Lakes
Formerly Known As: Village of Newboro, Township of Bastard and South Burgess, Township of North Crosby, Township of South Crosby, Township of South Elmsley, as at December 31, 1997.

Name of Municipality: Township of Ryerson as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Township of Schreiber as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Township of Seguin
Formerly Known As: Township of Humphrey, Township of Foley, Township of Christie, geographic/unorganized Township of Monteith (western portion), Village of Rosseau, as at December 31, 1997.

Name of Municipality: Township of Severn
Formerly Known As: Portions of Village of Coldwater, Township of Matchedash, Township of Medonte, Township of Orillia, Township of Tay, as at December 31, 1993.

Name of Municipality: Township of Shedden as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Town of Shelburne as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Township of Shuniah as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Township of Sioux Narrows-Nestor Falls
Formerly Known As: Township of Sioux Narrows, all of the geographic/unorganized townships of Code, Devonshire, Godson, Manross, MacQuarrie, Phillips, Tweedsmuir, and Work, portions of the geographic/unorganized townships of LeMay, McKeekin in Kenora District, and the geographic/unorganized townships of Claxton, Croome, and Mathieu in the Rainy River District, as at December 31, 2000.

Name of Municipality: Separated Town of Smiths Falls as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Town of Smooth Rock Falls as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Township of South Algonquin
Formerly Known As: Township of Airy and geographic/unincorporated townships of Dickens, Lyell, Murchison and Sabine, as at May 31, 1997.

Name of Municipality: Town of South Bruce Peninsula
Formerly Known As: Township of Albemarle, Township of Amabel, Town of Wiarton, Village of Hepworth, as at December 31, 1998.

Name of Municipality: Township of South Frontenac
Formerly Known As: Township of Bedford, Township of Loughborough, Township of Portland, Township of Storrington, as at December 31, 1997.

Name of Municipality: Village of South River as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Municipality of Southwest Middlesex
Formerly Known As: Township of Ekfrid, Township of Mosa, Village of Glencoe, Village of Wardsville, as at December 31, 2000.

Name of Municipality: Township of Southwold as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Township of Springwater
Formerly Known As: Portions of the former Village of Elmvale, Township of Flos, Township of Medonte, Township of Vespra, Town of Wasaga Beach, as at December 31, 1993.

Name of Municipality: Municipality of St. Charles
Formerly Known As: Township of Casimir, Jennings & Appleby and the geographic/unorganized townships of Cherriman and Haddo, as at December 31, 1998.

Name of Municipality: Township of St. Clair
Formerly Known As: Township of Sombra, Township of Moore, as at December 31, 2000.

Name of Municipality: Township of Stirling-Rawdon
Formerly Known As: Village of Stirling, Township of Rawdon, as at December 31, 1997.

Name of Municipality: Township of Stone Mills
Formerly Known As: Township of Camden East, Township of Sheffield, Village of Newburgh, as at December 31, 1997.

Name of Municipality: Township of Strong as at March 31, 1996.
Formerly Known As: Same

Name of Municipality: Township of Tay Valley
Formerly Known As: Township of South Sherbrooke, Township of Bathurst, Township of North Burgess, as at December 31, 1997.

Name of Municipality: Township of Tehkummah as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Municipality of Temagami as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Township of Terrace Bay as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Municipality of Thames Centre
Formerly Known As: Township of North Dorchester, Township of West Nissouri, Village of Dorchester, Police Village of Thorndale, as at December 31, 2000.

Name of Municipality: Town of Thessalon as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Village of Thornloe as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: City of Thorold as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: City of Timmins as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Township of Tiny as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Municipality of Trent Hills
Formerly Known As: Municipality of Campbellford/Seymour, Township of Percy, Village of Hastings, Police Village of Warkworth (Jan 1998-Town of Campbellford, Township of Seymour amalgamated into the Municipality of Campbellford/Seymour), as at December 31, 2000.

Name of Municipality: Township of Tudor and Cashel as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Municipality of Tweed
Formerly Known As: Village of Tweed, Township of Hungerford, Township of Elzevir and Gromsthorpe, as at December 31, 1997.

Name of Municipality: Township of Tyendinaga as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Township of Val Rita-Harty as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Township of Wainfleet as at March 31, 1999.
Formerly Known As: Same

Name of Municipality: Municipality of West Elgin
Formerly Known As: Township of Aldborough, Village of West Lorne, Police Village of Rodney, as at December 31, 1997.

Name of Municipality: Town of Whitchurch-Stouffville as at March 31, 1999.
Formerly Known As: Village of Stouffville and portions of the Township of Whitchurch and the Township of Markham.

Name of Municipality: Township of White River as at March 31, 1999.

Formerly Known As: Same

Name of Municipality: Municipality of Whitestone

Formerly Known As: Township Hagerman, and the geographic/unorganized townships of Ferrie, McKenzie, East Burpee, and a portion of the Township of Magnetawan, as at December 31, 1999.

Name of Municipality: Township of Wollaston as at March 31, 1999.

Formerly Known As: Same

TAB 2

FIRST NATION RESERVES

Reserve Name: Abitibi I.R. No. 70
Band Name: Wahgoshig First Nation

Reserve Name: Alderville I.R No. 37
Band Name: Alderville First Nation

Reserve Name: Aroland Indian Settlement
Band Name: Aroland

Reserve Name: Big Grassy River I.R. No. 35G
Band Name: Big Grassy First Nation

Reserve Name: Big Island Mainland 93
Band Name: Anishnaabeg of Naongashiing

Reserve Name: Cape Croker Island I.R. No. 27, Neyaashiinigmiing Reserve
Band Name: Chippewas of Nawash First Nation

Reserve Name: Chippewas of the Thames
Band Name: Chippewas of the Thames First Nation

Reserve Name: Chapleau I.R. No. 74A
Band Name: Chapleau Ojibway First Nation

Reserve Name: Christian Island I.R. No.30
Band Name: Beausoleil First Nation

Reserve Name: Cockburn Island 19, 19A
Band Name: Zhiibaahaasing First Nation

Reserve Name: Constance Lake I.R. 92
Band Name: Constance Lake First Nations

Reserve Name: Couchiching I.R. No. 16A
Band Name: Couchiching First Nation

Reserve Name: Curve Lake I.R. No. 35
Band Name: Curve Lake First Nation

Reserve Name: Dalles I.R. No. 38C
Band Name: Ochiichagwe'babigo'ining First Nation

Reserve Name: Duck Lake R.R. No. 76B
Band Name: Brunswick House First Nation

Reserve Name: Dokis I.R. No. 9
Band Name: Dokis First Nation

Reserve Name: Eagle Lake I.R. No. 27
Band Name: Eagle Lake First Nation

Reserve Name: English River I.R. No.21
Band Name: Grassy Narrows First Nation

Reserve Name: Factory Island I.R. No. 1
Band Name: Moose Factory First Nation

Reserve Name: Georgina Island I.R. No. 33
Band Name: Chippewas of Georgina Island First Nation

Reserve Name: Gibson I.R. No. 31 Wahta mohawk
Band Name: Mohawks of Gibson

Reserve Name: Golden Lake No. 39
Band Name: Algonquins Golden Lake First Nation

Reserve Name: Henvey Inlet I.R. No. 2 French River I.R. 13
Band Name: Henvey Inlet First Nation

Reserve Name: Hiawatha I.R. No.36
Band Name: Ojibways of Hiawatha First Nation

Reserve Name: Islington I.R No. 29
Band Name: Wabasemoong Independent Nations

Reserve Name: Kenora I.R. No. 38B
Band Name: Wauzhushk Onigum Nation

Reserve Name: Kettle Point I.R. No. 44
Band Name: Chippewas of Kettle and Stony Point First Nation

Reserve Name: Lac des Milles Lacs I.R. 22A1, Seine River I.R. 22A2
Band Name: Lac des Milles Lacs

Reserve Name: Lac Suel I.R. No. 28
Band Name: Lac Suel Nation

Reserve Name: Lake Helen I.R. No. 53A
Band Name: Red Rock Band

Reserve Name: Long Lake I.R. No. 77
Band Name: Ginoogaming First Nation

Reserve Name: Long Lake I.R. No. 58
Band Name: Long Lake No. 58 First Nation

Reserve Name: Magnetewan I.R No. 1
Band Name: Magnetewan First Nation

Reserve Name: Manitou Rapids I.R. No. 11
Band Name: Rainy River First Nation

Reserve Name: Matachewan I.R 72
Band Name: Matachewan First Nation

Reserve Name: Mattagami I.R No.71
Band Name: Mattagami First Nation

Reserve Name: Mississagi River I.R No.8
Band Name: Mississauga First Nation

Reserve Name: Mobert I.R No. 82
Band Name: Pic Mobert First Nation

Reserve Name: Moose Point I.R No. 79
Band Name: Moose Deer Point First Nation

Reserve Name: Moravian I.R. No. 47
Band Name: Delaware First Nation

Reserve Name: Muncey Delaware Nation No. 1
Band Name: Munsee-Delaware First Nation

Reserve Name: Neguaguon Lake I.R No. 25d
Band Name: Lac La Croix First Nation

Reserve Name: New Credit I.R 40A
Band Name: Mississaugas of the New Credit First Nation

Reserve Name: New Post 69, 69a
Band Name: New Post First Nation

Reserve Name: Nipissing I.R No. 10
Band Name: Nipissing First Nation

Reserve Name: Northwest Angle I.R No. 33B and Whitefish Bay I.R. No. 33a
Band Name: Northwest Angle No. 33 First Nation

Reserve Name: Oneida I.R No. 41
Band Name: ONA YO TE'A:KA

Reserve Name: Osnaburgh I.R No. 63A, 63B
Band Name: Osnaburgh First Nation

Reserve Name: Parry Island I.R No. 16
Band Name: Wasauksing First Nation

Reserve Name: Pays Plat I.R. No. 51
Band Name: Pays Plat First Nation

Reserve Name: Pic River I..R. No. 50
Band Name: Ojibways of Pic River No. 50 First Nation

Reserve Name: Rainy Lake I.R No. 17A, 17B
Band Name: Naicatchewenin First Nation

Reserve Name: Rainy Lake I.R. 26A
Band Name: ` Nicickousemenecaning First Nation

Reserve Name: Rainy Lake I.R. No. 18c
Band Name: Stanjikoming First Nation

Reserve Name: Rama I.R. No. 32
Band Name: Chippewas of Mnjikaning First Nation

Reserve Name: Rat Portage I.R No. 38A
Band Name: Washagamis Bay First Nation

Reserve Name: Rocky Bay I.R. No. 1
Band Name: Rocky Bay First Nation

Reserve Name: Sabaskong Bay 32c, Whitefish Bay 32a, Yellow Girl Bay 32b
Band Name: Naotkamegwanning Anishnabe First Nation

Reserve Name: Sabaskong Bay I.R 35D
Band Name: Ojibways of Onegaming First Nation

Reserve Name: Sarnia I.R.No.45
Band Name: Chippewas of Sarnia

Reserve Name: Saug-A-Gaw-Sing I.R. No. 1
Band Name: Big Island First Nation

Reserve Name: Saugeen I.R. No. 29
Band Name: Chippewas of Saugeen First Nation

Reserve Name: Savant Lake Indian Settlement
Band Name: Saugeen Nation

Reserve Name: Scugog I.R No. 34
Band Name: Mississauga of Scugog First Nation

Reserve Name: Seine River I.R. No. 23A, 23B, Sturgeon Falls No. 23
Band Name: Seine River First Nation

Reserve Name: Serpent River I.R. No. 7
Band Name: Serpent River First Nation

Reserve Name: Shawanaga I.R. No. 17
Band Name: Shawanaga First Nation

Reserve Name: Sheguiandah I.R. No. 24
Band Name: Sheguiandah First Nation

Reserve Name: Sheshegwaning I.R. No. 20
Band Name: Sheshegwaning First Nation

Reserve Name: Shoal Lake I.R. No 39A
Band Name: Shoal Lake No. 39 First Nation

Reserve Name: Shoal Lake I.R. No 40
Band Name: Shoal Lake No. 40 First Nation

Reserve Name: Six Nations I.R. No. 40
Band Name: Six Nations of the Grand River Territory

Reserve Name: Slate Falls Indian Settlement
Band Name: Slate Falls Nation

Reserve Name: Spanish River I.R. No. 5
Band Name: Sagamok Anishnawbek

Reserve Name: Sucker Creek I.R NO. 23
Band Name: Sucker Creek First Nation

Reserve Name: Thessalon I.R. No. 12
Band Name: Thessalon First Nation

Reserve Name: Tyendinaga Mohawk Territory
Band Name: Mohawks of the Bay of Quinte

Reserve Name: Wabauskang 21
Band Name: Wabauskang First Nation

Reserve Name: Wabigoon Lake I.R No. 27
Band Name: Wabigoon Lake Ojibway Nation

Reserve Name: Wahnapitae 11
Band Name: Wahnapitae First Nation

Reserve Name: Walpole Island I.R. No.46
Band Name: Walpole Island First Nation

Reserve Name: West Bay I.R. No. 22
Band Name: West Bay First Nation

Reserve Name: Whitefish Bay I.R No. 32A
Band Name: Whitefish Bay First Nation

Reserve Name: Whitefish Bay I.R No. 34A and Lake of the Woods I.R No. 37
Band Name: Northwest Angle No. 37 First Nation

Reserve Name: Whitefish Lake I.R. No. 6
Band Name: Whitefish Lake First Nation

Reserve Name: Whitefish River I.R. No. 4
Band Name: Whitefish River First Nation

Reserve Name: Wikewemikong I.R. No. 26
Band Name: Wikwemikong Unceded First Nation

TAB 3 UNORGANIZED TOWNSHIPS

Networks provides service to numerous Unorganized geographic townships. These townships are not incorporated as municipalities.

TAB 4 MUNICIPALITIES WHERE AREAS ARE SERVICED BY THE LICENSEE AND OTHER LOCAL DISTRIBUTION COMPANIES

Name of Municipality:	Township of Alfred and Plantagenet
Formerly Known As:	Township of Alfred, Village of Alfred, Township of North Plantagenet, Village of Plantagenet, as at December 31, 1996.
Area Not Served By Networks:	The area served by Hydro 2000 Inc. described as the former Villages of Alfred and Plantagenet as more particularly set out in Licence No. ED-2002-0542.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No

Name of Municipality:	Town of Amherstburg
Formerly Known As:	Town of Amherstburg, Township of Anderdon, Township of Malden, as at December 31, 1997.
Area Not Served By Networks:	The area served by Essex Powerlines Corporation described as the former Town of Amherstburg as more particularly set out in Licence No. ED-2002-0499.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	Two industrial (former Direct Class) customers

	located at 381 Front Road North, Amherstburg ON, and 99 Thomas Road, Amherstburg ON

Name of Municipality:	Township of Asphodel-Norwood
Formerly Known As:	Township of Asphodel, Village of Norwood, as at December 31, 1997.
Area Not Served By Networks:	The area served by Asphodel/Norwood Distribution Inc. described as the former Village of Norwood as more particularly set out in Licence No. ED-2002-0506.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No

Name of Municipality:	Town of Aylmer as at January 1, 1998.
Formerly Known As:	Same
Area Not Served By Networks:	The area served by Erie Thames Powerlines Corporation described as the Town of Aylmer as more particularly set out in Licence No. ED-2002-0156.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No

Name of Municipality:	City of Belleville
Formerly Known As:	City of Belleville, Township of Thurlow, City of Quinte West, as at December 31, 1997.
Area Not Served By Networks:	The area served by Veridian Connections Inc. described as the former City of Belleville as more particularly set out in Licence No. ED-2002-0503.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No

Name of Municipality:	Town of the Blue Mountains
Formerly Known As:	Town of Thornbury, Township of Collingwood, as at December 31**,** 1997.
Area Not Served By Networks:	The area served by Collingwood Utility Services Corporation (COLLUS) described as the former Town of Thornbury as more particularly set out in Licence No. ED-2002-0518.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No

Name of Municipality:	Municipality of Bluewater
Formerly Known As:	Township of Hay, Township of Stanley, Village of Bayfield, Village of Hensall, Village of Zurich, as at December 31,2000.

Area Not Served By Networks:	The area served by Festival Hydro Inc. described as the former Village of Hensall, and the former Village of Zurich as more particularly set out in Licence No. ED-2002-0513.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No

Name of Municipality:	Town of Bracebridge
Formerly Known As:	Townships of Macaulay, Draper, Monck, Oakely, Town of Bracebridge, as at December 31, 1970.
Area Not Served By Networks:	The area served by Lakeland Power Distribution Ltd. described as the former Town of Bracebridge, as more particularly set out in Licence No. ED-2002-0540.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	One industrial customer located at 154 Beaumont Drive, Bracebridge, ON.

Name of Municipality:	Town of Bradford-West Gwillimbury
Formerly Known As:	Town of Bradford, Township of West Gwillimbury, as at December 31, 1990.
Area Not Served By Networks:	The area served by Barrie Hydro Distribution Inc. described as the former Town of Bradford as more

	particularly set out in Licence No. ED-2002-0534.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No

Name of Municipality:	County of Brant (Initially known as City of Brant-on-the-Grand)
Formerly Known As:	County of Brant, Town of Paris, Township of Brantford, Township of Burford, Township of Oakland, Township of Onondaga, Township of South Dumfries, as at December 31, 1998.
Area Not Served By Networks:	The area served by Brant County Power Inc. described as the former Village of Burford, the former Town of Paris, the former Township of Brantford and the former Police Village of St. George (in the former Township of South Dumfries) as more particularly set out in Licence No. ED-2002-0522.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No

Name of Municipality:	Township of Brock
Formerly Known As:	Village of Beaverton, Village of Cannington, Township of Brock, Township of Thorah, as at

	December 31, 1973.
Area Not Served By Networks:	The area served by Veridian Connections Inc. described as the former Villages of Beaverton and Cannington and the former Police Village of Sunderland (in the former Township of Brock) as more particularly set out in Licence No. ED-2002-0503.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No

Name of Municipality:	Municipality of Brockton
Formerly Known As:	Township of Greenock, Township of Brant, Town of Walkerton, as at December 31, 1998.
Area Not Served By Networks:	The area served by Westario Power Inc. described as the former Town of Walkerton and the portion of the former Police Village of Elmwood (in the former Township of Brant) as more particularly set out in Licence No. ED-2002-0515.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No

Name of Municipality:	Township of Brooke-Alvinston
Formerly Known As:	Township of Brooke, Village of Alvinston

Area Not Served By Networks:	The area served by Bluewater Power Distribution Corp. described as the former Village of Alvinston as more particularly set out in Licence No. ED-2002-0517.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No

Name of Municipality:	Municipality of Central Elgin
Formerly Known As:	Township of Yarmouth, Village of Belmont, Village of Port Stanley, as at December 31, 1997.
Area Not Served By Networks:	The area served by Erie Thames Powerlines Corporation described as the former Villages of Belmont and Port Stanley as more particularly set out in Licence No. ED-2002-0516.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No

Name of Municipality:	Municipality of Central Huron
Formerly Known As:	Township of Goderich, Township of Hullett, Town of Clinton, as at December 31, 2000.
Area Not Served By Networks:	The area served by Clinton Power Corporation described as the former Town of Clinton as more particularly set out in Licence No. ED-20025-2000.

Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No

Name of Municipality:	Township of Centre Wellington
Formerly Known As:	Town of Fergus, Village of Elora, Township of West Garafraxa, Township of Nichol, Township of Pilkington, as at December 31, 1998.
Area Not Served By Networks:	The area served by Centre Wellington Hydro Ltd. described as the former Town of Fergus and the former Village of Elora as more particularly set out in Licence No. ED-2002-0498.
Networks Assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No

Name of Municipality:	Municipality of Chatham-Kent
Formerly Known As:	City of Chatham, County of Kent, Town of Blenheim, Town of Bothwell, Town of Dresden, Town of Ridgetown, Town of Tilbury, Town of Wallaceburg, Village of Erie Beach, Village of Erieau, Village of Highgate, Village of Thamesville, Village of Wheatley, Township of Camden, Township of Chatham, Township of

	Dover, Township of Harwich, Township of Howard, Township of Orford, Township of Raleigh, Township of Rodney, Township of Tilbury East, Township of Zone, as at December 31, 1997.
Area Not Served By Networks:	The area served by Chatham-Kent Hydro Inc. described as the former City of Chatham, former Police Village of Merlin (straddling the former townships of Raleigh and Tilbury East), former Village of Erieau, former Village of Thamesville, former Town of Bothwell, former Village of Wheatley, former Town of Dresden, former Town of Blenheim, former Town of Tilbury, former Town of Ridgetown, and the former Town of Wallaceburg as more particularly set out in Licence No. ED-2002-0563.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No

Name of Municipality:	Municipality of Clarington
Formerly Known As:	Town of Bowmanville, Village of Newcastle, Township of Clarke, Township of Darlington, as at December 31, 1973.
Area Not Served By Networks:	The area served by Veridian Connections Inc. described as the former Town of Bowmanville, the former Police Village of Orono (in the former Township of Clarke), the former Town of

	Newcastle as more particularly set out in Licence No. ED-2002-0503
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	1 Industrial customer located at 410 Wavely Road, Bowmanville ON.

Name of Municipality:	Township of Clearview
Formerly Known As:	Town of Stayner, Village of Creemore, Township of Nottawasaga, Township of Sunnidale, as at December 31, 1993.
Area Not Served By Networks:	The area served by Collingwood Utility Services Corp. described as the former Town of Stayner and the former Village of Creemore as more particularly set out in Licence No. ED-2002-0518.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No

Name of Municipality:	Town of Cochrane
Formerly Known As:	Town of Cochrane, Township of Glackmeyer, Unorganized Twp. of Lamarche, as at December 31, 1999.
Area Not Served By Networks:	The area served by Northern Ontario Wires Inc. described as the former Town of Cochrane as more

	particularly set out in Licence No. ED-2002-0018
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No

Name of Municipality:	Township of Cramahe
Formerly Known As:	Village of Colborne, Township of Cramahe, as at December 31, 2000.
Area Not Served By Networks:	The area served by Lakefront Utilities Inc. described as the former Village of Colborne as more particularly set out in Licence No. ED-2002-0545.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No

Name of Municipality:	Municipality of Dutton/Dunwich
Formerly Known As:	Township of Dunwich, Village of Dutton, as at December 31, 1997.
Area Not Served By Networks:	The area served by Dutton Hydro Ltd. described as the former Village of Dutton as more particularly set out in Licence No. ED-2003-0025.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No

Name of Municipality:	Town of East Gwillimbury as at March 31, 1999.
Formerly Known As:	Same
Area Not Served By Networks:	The area served by Newmarket Hydro Ltd. as particularly set out in Licence No. ED- 2002–0553.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No

Name of Municipality:	Township of East Luther Grand Valley
Formerly Known As:	Township of East Luther, Village of Grand Valley, as at December 31, 1994.
Area Not Served By Networks:	The area served by Grand Valley Energy Inc. described as the former Village of Grand Valley as more particularly set out in Licence No. ED-2002-0512.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No

Name of Municipality:	The Township of East Zorra-Tavistock
Formerly Known As:	Township of East Zorra, Town of Tavistock, as at December 31, 1997.
Area Not Served By Networks:	The area served by Erie Thames Powerlines Corp. described as the former Town of Tavistock as more

	particularly set out in Licence No. ED-2002-0516.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No

Name of Municipality:	Township of Edwardsburgh/Cardinal
Formerly Known As:	Village of Cardinal, Township of Edwardsburgh, as at December 31, 2000.
Area Not Served By Networks:	The area served by Rideau St. Lawrence Distribution Inc. described as the former Village of Cardinal as more particularly set out in Licence No. ED-2003-0003.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No

Name of Municipality:	Township of Essa as at March 31, 1999.
Formerly Known As:	Same
Area Not Served By Networks:	The area served by Barrie Hydro Distribution Inc. described as the former Police Village of Thorton as more particularly set out in Licence No. ED-2002-0534.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not	

served by Networks:	No

Name of Municipality:	Town of Essex
Formerly Known As:	Town of Essex, Town of Harrow, Township of North Colchester, Township of South Colchester, as at December 31, 1998.
Area Not Served By Networks:	The area served by E.L.K. Energy Inc. described as the former Town of Essex and the former Town of Harrow as more particularly set out in Licence No. ED-2003-0015.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No

Name of Municipality:	Town of Gravenhurst
Formerly Known As:	Formerly the Township of Morrison, the United Townships of Medora and Wood, the Township of Muskoka, the Township of Ryde, the Town of Gravenhurst, as at December 31, 1970.
Area Not Served By Networks:	The area served by Gravenhurst Hydro Electric Inc. described as the former urban boundary of the Town of Gravenhurst as more particularly set out in Licence No. ED-2002-0576.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not	

served by Networks:	No

Name of Municipality:	City of Greater Sudbury
Formerly Known As:	Region of Sudbury, City of Sudbury, City of Valley East, Town of Capreol, Town of Nickel Centre, Town of Onaping Falls, Town of Rayside-Balfour, Town of Walden, as at December 31, 2000.
Area Not Served By Networks:	The area served by Greater Sudbury Hydro Inc. described as the former City of Sudbury, the former townsite of the former Town of Capreol, and the former Town of Conniston (part of former Town of Nickel Centre) as more particularly set out in Licence No. ED-2002-0559.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No

Name of Municipality:	Township of Guelph/Eramosa
Formerly Known As:	Township of Guelph, Township of Eramosa, as at December 31, 1998.
Area Not Served By Networks:	The area served by Wellington Electric Distribution Inc. described as the former Police Village of Rockwood (in the former Township of Eramosa) as more particularly set out in Licence No. ED-2002-0564.
Networks assets within area	

not served by Networks:	Yes
Customer(s) within area not served by Networks:	No

Name of Municipality:	City of Hamilton
Formerly Known As:	Region of Hamilton-Wentworth, City of Hamiton, City of Stoney Creek, Town of Ancaster, Town of Dundas, Town of Flamborough, Township of Glanbrook, as at December 31, 2000.
Area Not Served By Networks:	The area served by Hamilton Hydro Inc. described as the former City of Hamilton, the former Police Village of Ancaster, former Town of Dundas, the former Police Village of Lynden (straddling the former Town of Flamborough and Town of Ancaster), the former Village of Waterdown, and the former City of Stoney Creek as more particularly set out in Licence No. ED-2002-0566.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No

Name of Municipality:	Town of Hawkesbury as at March 31, 1999.
Formerly Known As:	Same
Area Not Served By Networks:	The area served by Hydro Hawkesbury Inc. described as the Town of Hawkesbury prior to annexation or amalgamation pursuant to the Minister's Order or Restructuring Act as more

	particularly set out in Licence No. ED-2003-0027.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No

Name of Municipality:	Town of Huntsville
Formerly Known As:	Township of Brunel, Village of Port Sydney, Town of Chaffey, Township of Stephenson, Township of of Stisted, Town of Huntsville, as at December 31, 1970.
Area Not Served By Networks:	The area served by Lakeland Power Distribution Ltd. described as the former Town of Huntsville as more particularly set out in Licence No. ED-2002-0540.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	One Industrial customer located at 61 Domtar Road, Huntsville ON.

Name of Municipality:	Municipality of Huron East
Formerly Known As:	Village of Brussels, Township of Grey, Township of McKillop, Town of Seaforth, Township of Tuckersmith, as at December 31, 2000.
Area Not Served By Networks:	The area served by Festival Hydro Inc. described as

	the former Village of Brussels and the former Town of Seaforth as more particularly set out in Licence No. ED-2002-0513.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No

Name of Municipality:	Township of Huron-Kinloss
Formerly Known As:	Township of Huron (former Police Village of Ripley amalgamated with twp in 1995), Township of Kinloss, Village of Lucknow, as at December 31, 1998.
Area Not Served By Networks:	The area served by Westario Power Inc. described as the former Police Village of Ripley (in the former Township of Huron) and the former Village of Lucknow as more particularly set out in Licence No. ED-2002-0515.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No

Name of Municipality:	Municipality of Huron Shores

Formerly Known As:	Township of Day & Bright Add'l, Township of Thessalon, Village of Iron Bridge, as at December 31, 1998.
Area Not Served By Networks:	The area served by Great Lakes Power Limited described as part of the former Township of Thessalon or as more particularly set out in Licence No. ED-1999-0227
Networks assets within area not served by Networks:	No
Customer(s) within area not served by Networks:	No

Name of Municipality:	Town of Ingersoll
Formerly Known As:	Same
Area Not Served By Networks:	The area served by Erie Thames Powerlines Corporation described as the Town of Ingersoll as more particularly set out in Licence No. ED-2002-0516.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No

Name of Municipality:	Town of Iroquois Falls as at March 31, 1999.
Formerly Known As:	Same
Area Not Served By Networks:	The area served by Northern Ontario Wires Inc. described as the Town of Iroquois Falls as more particularly set out in Licence No. ED-2002-0018.
Networks assets within area not served by Networks:	Yes

Customer(s) within area not served by Networks:	No

Name of Municipality:	City of Kenora
Formerly Known As:	Town of Kenora, Town of Keewatin, Town of Jaffray Melick, as at December 31,1999.
Area Not Served By Networks:	The area served by Kenora Hydro Electric Distribution Inc. described as the former Town of Kenora and part of the former Town of Keewatin as more particularly set out in Licence No. ED-2003-0030.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No

Name of Municipality:	Township of Killaloe, Hagarty and Richards
Formerly Known As:	Township of Hagarty and Richards, Village of Killaloe, as at June 30, 1999
Area Not Served By Networks:	The area served by Ottawa River Power Corp. described as the former Village of Killaloe as more particularly set out in Licence No. ED-2002-0033.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not	

served by Networks:	No

Name of Municipality:	Municipality of Kincardine
Formerly Known As:	Town of Kincardine, Township of Bruce (Village of Tiverton, Township of Bruce amalgamation), Township of Kincardine, as at December 31, 1998.
Area Not Served By Networks:	The area served by Westario Power Inc. described as the former Town of Kincardine as more particularly set out in Licence No. ED-2002-0515.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No

Name of Municipality:	City of Kingston
Formerly Known As:	City of Kingston, Township of Kingston, Township of Pittsburgh, as at December 31, December 31, 1997.
Area Not Served By Networks:	The area served by Kingston Electricity Distribution Ltd. described as the former City of Kingston, the former Township of Kingston, and part of the former Township of Pittsburgh as more particularly set out in Licence No. ED-2003-0057.
	The area served by Eastern Ontario Power Inc. described as part of the former Township of Pittsburgh as more particularly set out in Licence

	No. ED-2003-0116.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No

Name of Municipality:	Town of Kingsville
Formerly Known As:	Town of Kingsville, Township of Gosfield North, Township of Gosfield South, as at December 31, 1997.
Area Not Served By Networks:	The area served by E.L.K. Energy Inc. described as the former Town of Kingsville and the former Police Village of Cottam (in the former Township of Gosfield North) as more particularly set out in Licence No. ED-2003-0015.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No

Name of Municipality:	Town of Lakeshore
Formerly Known As:	Township of Lakeshore, (Jan 1998: Town of Belle River, Township of Maidstone amalgamated into Lakeshore Township), Township of Rochester, Township of Tillbury North, Township of Tillbury West, as at December 31, 1998.
Area Not Served By Networks:	The area served by E.L.K. Energy Inc. described as

	the former Police Village of Comber (in the former Township of Tillbury West) and the former Town of Belle River as more particularly set out in Licence No. ED-2003-0015.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No

Name of Municipality:	Municipality of Leamington
Formerly Known As:	Town of Leamington, Township of Mersea, as at December 31, 1998.
Area Not Served By Networks:	The area served by Essex Powerlines Ltd. described as the former Town of Leamington as more particularly set out in Licence No. ED-2002-0499.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No

Name of Municipality:	Township of Leeds and the Thousand Islands
Formerly Known As:	Township of Front of Leeds and Lansdowne, Township of Rear of Leeds and Lansdowne, Township of Front of Escott, as at December 31, 2000.
Area Not Served By Networks:	The area served by Eastern Ontario Power Inc. described as part of the former Township of the

	Front of Leeds and Lansdowne as more particularly set out in Licence No. ED-2003-0116.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No

Name of Municipality:	Municipality of Magnetawan
Formerly Known As:	Township of Chapman, Village of Magnetawan, Unorganized Township of Croft, as at December 31, 1997.
Area Not Served By Networks:	The area served by Lakeland Power Distribution Ltd. described as the former Village of Magnetawan as more particularly set out in Licence No. ED-2002-0540.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No

Name of Municipality:	Town of Minto
Formerly Known As:	Township of Minto, Town of Palmerston, Town of Harriston, Village of Clifford, Township of Minto, as at December 31, 1998.
Area Not Served By Networks:	The area served by Westario Power Inc. described as the former Town of Harriston, the former Town of Palmerston, and the former Village of Clifford as

	more particularly set out in Licence No. ED-2002-0515.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No

Name of Municipality:	The Corporation of the Town of Mississippi Mills
Formerly Known As:	Town of Almonte, Township of Pakenham, Township of Ramsay, as at December 31, 1998.
Area Not Served By Networks:	The area served by Ottawa River Power Corp. described as the former Town of Almonte as more particularly set out in Licence No. ED-2003-0033.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No

Name of Municipality:	Town of New Tecumseth
Formerly Known As:	Town of Alliston, the Village of Beeton, the Village of Tottenham and the portion of the Township of Tecumseth, as at December 31, 1991.
Area Not Served By Networks:	The area served by Barrie Hydro Distribution Inc. described as the former Town of Alliston, the former Village of Beeton and the former Village of Tottenham (all in the former Township of Tecumseth) as more particularly set out in Licence

	No. ED-2002-0534.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	1 Industrial customer located in the former Town of Alliston.

Name of Municipality:	The Corporation of Norfolk County
Formerly Known As:	Township of Norfolk, Township of Delhi, Town of Simcoe, City of Nanticoke (westerly 'half' only), as at December 31, 2000.
Area Not Served By Networks:	The area served by Norfolk Power Distribution Co. Ltd. described as the former Town of Delhi (in the former Township of Delhi), the westerly half of the former City of Nanticoke, the former Village of Port Rowan (in former Township of Norfolk), and the former Town of Simcoe as more particularly set out in Licence No. ED-2002-0521.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	1 Industrial customer located at Lake Erie and Regional Rd.. 3, Nanticoke, ON.

Name of Municipality:	Township of North Huron
Formerly Known As:	Town of Wingham, Village of Blyth, Township of East Wawnosh, as at December 31, 2000.

Area Not Served By Networks: The area served by Westario Power Inc. described as the former Town of Wingham as more particularly set out in Licence No. ED-2002-0515.

Networks assets within area not served by Networks: Yes

Customer(s) within area not served by Networks: 2 Industrial customers located at 40621 Amberly Rd., and 200 Water Street Wingham, ON.

Name of Municipality: Municipality of North Middlesex

Formerly Known As: Township of McGillivray, Township of East Williams, Township of West Williams, Town of Parkhill, Village of Ailsa Craig, as at December 31, 2000.

Area Not Served By Networks: The area served by Middlesex Power Distribution Corp. described as the former Town of Parkhill as more particularly set out in Licence No. ED-2003-0059.

Networks assets within area not served by Networks: Yes

Customer(s) within area not served by Networks: No

Name of Municipality: The Township of Norwich as at March 31, 1999.

Formerly Known As: Township of North Norwich, Township of South Norwich, Township of East Oxford, Village of Norwich, Village of Burgessville, and Police

	Village of Otterville, as at
Area Not Served By Networks:	The area served by Erie Thames Powerlines Corp. described as the former Village of Norwich, the former Village of Burgessville, and the former Police Village of Otterville as more particularly set out in Licence No. ED-2002-0516.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No

Name of Municipality:	City of Ottawa
Formerly Known As:	Region of Ottawa-Carleton, City of Gloucester, City of Kanata, City of Nepean, City of Ottawa, City of Vanier, Township of Cumberland, Township of Goulbourn, Township of Osgoode, Township of Rideau, Township of West Carleton, Village of Rockcliffe Park, as at December 31, 2000.
Area Not Served By Networks:	The area served by Hydro Ottawa Limited. described as the former City of Gloucester, the former City of Kanata, the former City of Nepean, the former City of Ottawa, the former City of Vanier, the former Township of Goulbourn, the former Village of Rockcliffe Park, and the portion of the former Township of Rideau on Long Island, North of Bridge Street, as more particularly set out in Licence No. ED-2002-0556.
Networks assets within area	

not served by Networks:	Yes
Customer(s) within area not served by Networks:	No.

Name of Municipality:	Town of Pelham
Formerly Known As:	Township of Pelham, Village of Fonthill, as at December 31, 1969.
Area Not Served By Networks:	The area served by Peninsula West Utilities Ltd. described as the former Village of Fonthill as more particularly set out in Licence No. ED-2002-0555.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No

Name of Municipality:	City of Peterborough as at March 31, 1999.
Formerly Known As:	Same
Area Not Served By Networks:	The area served by Peterborough Distribution Inc. described as the City of Peterborough as more particularly set out in Licence No. ED-2002-0504.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No

Name of Municipality:	Municipality of Port Hope

Formerly Known As:	Town of Port Hope, Township of Hope (initially restructured as Municipality of Port Hope and Hope), as at December 31, 2000.
Area Not Served By Networks:	The area served by Veridian Connections Inc. described as the former Town of Port Hope as more particularly set out in Licence No. ED-2002-0503.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No

Name of Municipality:	Municipality of Red Lake
Formerly Known As:	Township of Red Lake, Township of Golden, as at June 30, 1997.
Area Not Served By Networks:	The area served by Gold Corp Inc. described as part of the former Improvement District of Balmertown.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No

Name of Municipality:	Township of Russell as at March 31, 1999.
Formerly Known As:	Same
Area Not Served By Networks:	The area served by Cooperative Hydro Embrun Inc. described as the former Police Village of Embrum as more particularly set out in Licence No. ED-2002-0493.

Networks assets within area not served by Networks:	No
Customer(s) within area not served by Networks:	No

Name of Municipality:	Township of Sables-Spanish Rivers
Formerly Known As:	Town of Massey, Town of Webbwood, Town of Spanish River, as at June 30, 1997.
Area Not Served By Networks:	The area served by Espanola Regional Hydro Distribution Corp. described as the former Town of Massey and the former Town of Webbwood as more particularly set out in Licence No. ED-2002-0502.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No

Name of Municipality:	Township of Saugeen Shores
Formerly Known As:	Town of Saugeen, Town of Southampton, Town of Port Elgin, as at December 31, 1998.
Area Not Served By Networks:	The area served by Westario Power Inc. described as the former Town of Southampton and the former Town of Port Elgin as more particularly set out in Licence No. ED-2002-0515.
Networks assets within area not served by Networks:	Yes

Customer(s) within area not served by Networks:	No

Name of Municipality:	City of St. Thomas as at March 31, 1999.
Formerly Known As:	Same
Area Not Served By Networks:	The area served by St. Thomas Energy Inc. described as the City of St. Thomas as more particularly set out in Licence No. ED-2002-0523.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	1 Industrial customer located at 1 Cosma Court

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Name of Municipality:	Township of Scugog
Formerly Known As:	Township of Scugog, Township of Cartwright, Township of Reach, Village of Port Perry, as at December 31. 1973.
Area Not Served By Networks:	The area served by Scugog Hydro Electric Corp. described as the former Village of Port Perry as more particularly set out in Licence No. ED-2002-0570.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No

Name of Municipality: Municipality of Sioux Lookout as at March 31, 1999.

Formerly Known As: Same

Area Not Served By Networks: The area served by Sioux Lookout Hydro Inc. described as the Municipality of Sioux Lookout as more particularly set out in Licence No. ED-2002-0514.

Networks assets within area not served by Networks: Yes

Customer(s) within area not served by Networks: No

Name of Municipality: Township of Smith-Ennismore-Lakefield

Formerly Known As*:* Village of Lakefield, Township of Smith-Ennismore (formerly Township of Smith and Township of Ennismore), as at December 31, 2000.

Area Not Served By Networks: The area served by Lakefield Distribution Inc. described as the former Village of Lakefield as more particularly set out in Licence No. ED-2002-0505.

Networks assets within area not served by Networks: Yes

Customer(s) within area not served by Networks: No

Name of Municipality: Municipality of South Bruce

Formerly Known As*:* Township of Mildmay-Carrick, Township of

	Teeswater-Culross, (Jan 1998: Village of Teeswater, Township of Culross amalgamated into the Township of Teeswater-Culross. Village of Mildmay, Township of Carrick amalgamated into the Township of Mildmay-Carrick), as at December 31, 1997.
Area Not Served By Networks:	The area served by Westario Power Inc. described as the former Village of Mildmay and the former Village of Teeswater as more particularly set out in Licence No. ED-2002-0515.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No

Name of Municipality:	Township of South Dundas
Formerly Known As:	Township of Matilda, Township of Williamsburg, Village of Iroquois, Village of Morrisburg, as at December 31, 1997.
Area Not Served By Networks:	The area served by Rideau St. Lawrence Distribution Ltd. described as the former Police Village of Williamsburg, the former Village of Morrisburg, and the former Village of Iroquois as more particularly set out in Licence No. ED-2003-0003.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not	

served by Networks: No

Name of Municipality: Township of South Glengarry

Formerly Known As*:* Township of Charlottenburgh, Township of Lancaster, Village of Lancaster, Police Village of Martintown, as at December 31, 1997.

Area Not Served By Networks: The area served by the Cornwall Street Railway Light and Power Company Ltd. described as part of the former Township of Charlottenburgh as more particularly set out in Licence No. ED-1999-0273.

Networks assets within area not served by Networks: Yes

Customer(s) within area not served by Networks: No

Name of Municipality: Municipality of South Huron

Formerly Known As: Township of Stephen, Township of Usborne, Town of Exeter, as at December 31, 2000.

Area Not Served By Networks: The area served by Festival Hydro Inc. described as the former Police Village of Dashwood as more particularly set out in Licence No. ED-2002-0513.

Networks assets within area not served by Networks: Yes

Customer(s) within area not served by Networks: No

Name of Municipality:	Township of South Stormont
Formerly Known As:	Township of Osnabruck, Township of Cornwall, as at December 31, 1997
Area Not Served By Networks:	The area served by Cornwall Street Railway Light and Power Company Ltd. described as part of the former Township of Cornwall and part of the former Township of Osnabruk as more particularly set out in Licence No. ED-1999-0273.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No

Name of Municipality:	Township of Southgate
Formerly Known As:	Village of Dundalk, Township of Egremont, Township of Proton, Police Village of Holstein, as at December 31, 1999.
Area Not Served By Networks:	The area served by Wellington North Power Inc. described as the former Police Village of Holstein as more particularly set out in Licence No. ED-2002-0511.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No

Name of Municipality:	The Township of South-West Oxford

Formerly Known As*:*	Township of West Oxford, Township of Dereham, Village of Beachville, as at December 31,. 1974.
Area Not Served By Networks:	The area served by Erie Thames Powerlines Corp. described as the former Village of Beachville as more particularly set out in Licence No. ED-2002-0516.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No

Name of Municipality:	Township of Strathroy-Caradoc
Formerly Known As*:*	Town of Strathroy, Township of Caradoc**,** as at December 31, 2000.
Area Not Served By Networks:	The area served by Middlesex Power Distribution Corp. described as the former Police Village of Mount Brydges (in the former Township of Caradoc) and the former Town of Strathroy as more particularly set out in Licence No. ED-2003-0059.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No

Name of Municipality:	Township of Tay
Formerly Known As*:*	Village of Port NcNicoll, Village of Victoria Harbour, the Township of Medonte, Township of

	Tay, Township of Tiny, Township of Flos, Police Village of Waubaushene, as at December 31, 1996.
Area Not Served By Networks:	The area served by Tay Hydro Electric Distribution Company Inc. described as the former Village of Port NcNicoll, the former Village of Victoria Harbour, the former Police Village of Waubaushene and part of the former Township of Tay as more particularly set out in Licence No. ED-2002-0519.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No

Name of Municipality:	Town of Tecumseh
Formerly Known As*:*	Town of Tecumseh, Village of St. Clair Beach, Township of Sandwich South, as at December 31, 1998.
Area Not Served By Networks:	The area served by Essex Powerlines Corporation described as the former Town of Tecumseh and the former Village of St. Clair Beach as more particularly set out in Licence No. ED-2002-0499.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No

Name of Municipality:	Township of Uxbridge

Formerly Known As*:*	Town of Uxbridge, Township of Scott, Township of Uxbridge, as at December 31. 1973.
Area Not Served By Networks:	The area served by Veridian Connections Inc. described as the former Town of Uxbridge as more particularly set out in Licence No. ED-2002-0503.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No

Name of Municipality:	Town of Warwick
Formerly Known As*:*	Village of Watford, Township of Warwick, as at December 31, 1997.
Area Not Served By Networks:	The area served by Bluewater Power Distribution Corp. described as the former Village of Watford as more particularly set out in Licence No. ED-2002-0517.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No

Name of Municipality:	Township of Wellington North
Formerly Known As*:*	Town of Mount Forest, Village of Arthur, Township of Arthur, Township of West Luther, as at December 31, 1998.
Area Not Served By Networks:	The area served by Wellington North Power Inc.

	described as the former Village of Arthur and the former Town of Mount Forest as more particularly set out in Licence No. ED-2002-0511.
Networks assets within area not served by Networks:	No
Customer(s) within area not served by Networks:	No

Name of Municipality:	Township of West Grey
Formerly Known As*:*	Township of West Grey, Town of Durham (Jan 2000 Township Bentinck, Township of Glenelg, Town Normanby, Village of Neustadt amalgamated into the Township of West Grey), as at December 31, 1999.
Area Not Served By Networks:	The area served by Westario Power Inc. described as the former Village of Neustadt and a portion of the former Police Village of Elmwood (in the former Township of Bentinck) as more particularly set out in Licence No. ED-2002-0515.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No

Name of Municipality:	Municipality of West Nipissing
Formerly Known As*:*	Town of Cache Bay, Town of Sturgeon Falls, Township of Caldwell, Township of Field,

	Township of Springer, as at December 31, 1998.
Area Not Served By Networks:	The area served by West Nipissing Energy Services Ltd. described as the former Town of Cache Bay and the former Town of Sturgeon Falls as more particularly set out in Licence No. ED-2002-0562.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No

Name of Municipality:	Municipality of West Perth
Formerly Known As*:*	Township of Logan, Township of Fullarton, Town of Mitchell, Police Village of Dublin, as at December 31, 1997.
Area Not Served By Networks:	The area served by West Perth Power Inc. described as the former Town of Mitchell and the former Police Village of Dublin as more particularly set out in Licence No. ED-2002-0508.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No

Name of Municipality:	Township of Whitewater Region
Formerly Known As*:*	Township of Ross, Township of Westmeath, Village of Beachburg, Village of Cobden, as at December 31, 2000.

Area Not Served By Networks: The area served by Ottawa River Power Distribution Corp. described as the former Village of Beachburg as more particularly set out in Licence No. ED-2003-0033.

Networks assets within area not served by Networks: Yes

Customer(s) within area not served by Networks: No

Name of Municipality: City of Woodstock as at March 31, 1999.

Formerly Known As*:* Same

Area Not Served By Networks: The area served by Woodstock Hydro Services Inc. described as the City of Woodstock as more particularly set out in Licence No. ED-2003-0011.

Networks assets within area not served by Networks: Yes

Customer(s) within area not served by Networks: No

Name of Municipality: Township of Zorra

Formerly Known As: Township of West Zorra, Township of East Nissouri, Township of North Oxford, Village of Embro, Village of Thamesford , as at December 31, 1997.

Area Not Served By Networks: The area served by Erie Thames Powerlines Corp. described as the former Village of Embro and the former Village of Thamesford as more particularly

	set out in Licence No. ED-2002-0516.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No

Name of Municipality:	Town of East Gwillimbury as at March 31, 1999
Formerly Known As:	Same
Area Not Served By Networks:	The area served by Newmarket Hydro Ltd. described as part of the south side of Green Lane as more particularly set out in Licence No. ED-2002-0553.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No

Name of Municipality:	The Towns of Penetanguishene as at March 31, 1999
Formerly Known As:	Same
Area Not Served By Networks:	The area served by Barrie described as part of the Town of Penetanguishene as more particularly set out in Licence No. ED-2002-0534.
Networks assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	No

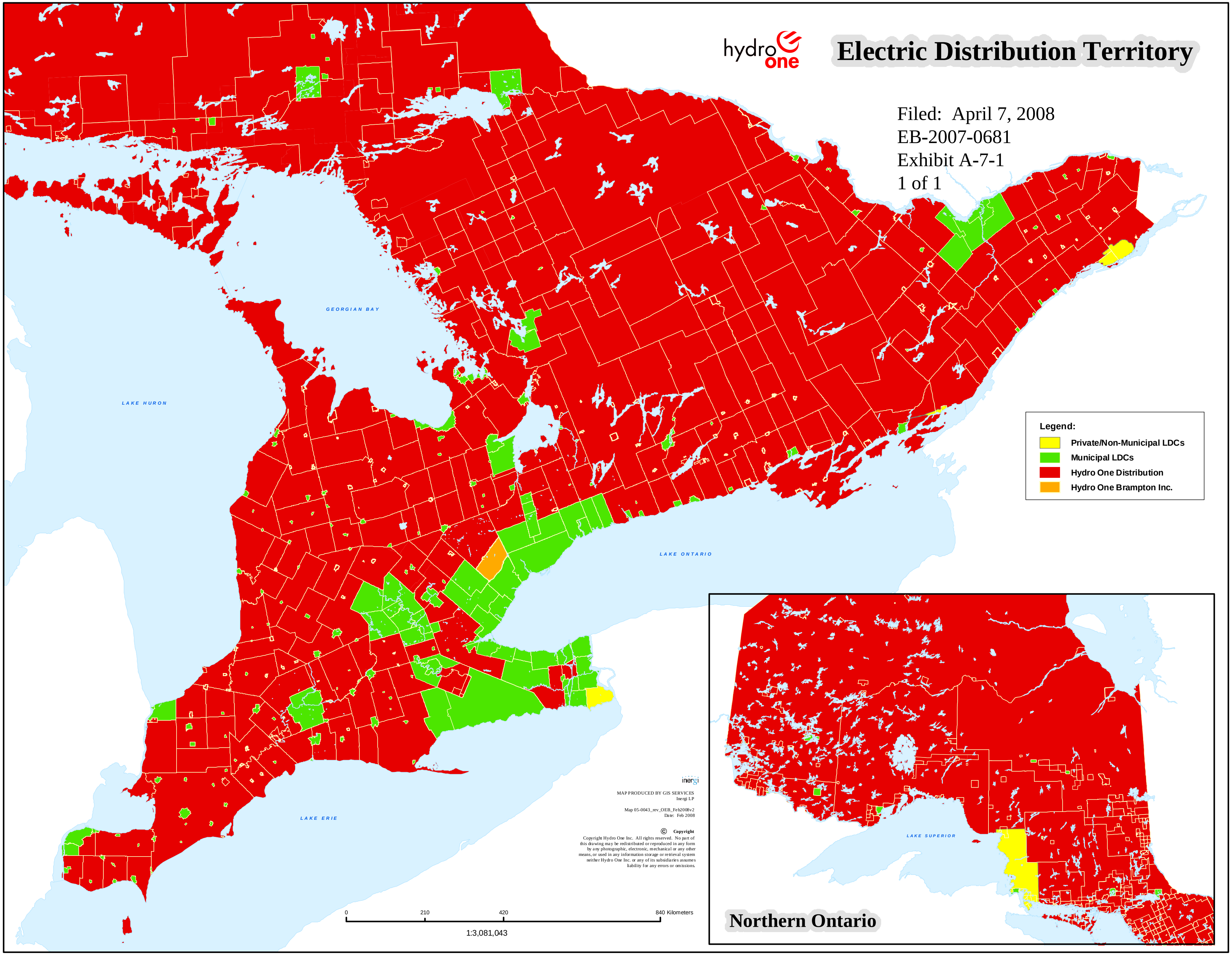
TAB 5

CONSUMERS LOCATED OUTSIDE THE MUNICIPALITIES SERVICED BY THE LICENSEE

Name of Municipality:	City of Cornwall
Assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	1 Industrial customer located at 800 Second Street W
Name of Municipality:	County of Haldimand
Assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	I customer located in Caledonia, Ont.
Name of Municipality:	City of Niagara Falls
Assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	Three customers located at 8001 Daly Street, 7780 Stanley Ave, 6225 Progress Street
Name of Municipality:	City of St. Thomas
Assets within area not served by Networks:	Yes
Customer(s) within area not served by Networks:	1 Cosma Court.

SERVICE AREA MAP

The attached map is a representation of Hydro One Distribution's service territory. It is not a substitute for the written description in the licence. The map is accurate where LDC boundaries conform to existing or former municipal boundaries, but is only a best-effort representation in locations where there have been annexations or for other reasons the LDC boundaries are different from current or former municipal boundaries. Please note that Hydro One Distribution does not assume it will supply to areas of Ontario that currently do not have electrical service.


hydro one
Electric Distribution Territory
Filed: April 7, 2008
EB-2007-0681
Exhibit A-7-1
1 of 1
GEORGIAN BAY
LAKE HURON
LAKE ONTARIO
LAKE ERIE
Legend:
Private/Non-Municipal LDCs
Municipal LDCs
Hydro One Distribution
Hydro One Brampton Inc.
inergi
MAP PRODUCED BY GIS SERVICES
Inergi LP
Map 05-0043_rev_OEB_Feb2008v2
Date: Feb 2008
Copyright
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0
210
420
840 Kilometers
1:3,081,043
LAKE SUPERIOR
Northern Ontario

CORPORATE ORGANIZATION CHARTS

1.0 INTRODUCTION

Hydro One Networks Inc. ("Hydro One") is the electricity transmission and distribution successor company to the original Hydro-Electric Power Commission of Ontario, which became Ontario Hydro in 1974.

This schedule describes the current organization of Hydro One's electricity distribution business, beginning with an overview of the parent company (Hydro One Inc.), a discussion about Hydro One's distribution business, and a brief summary of Hydro One's affiliates and related parties.

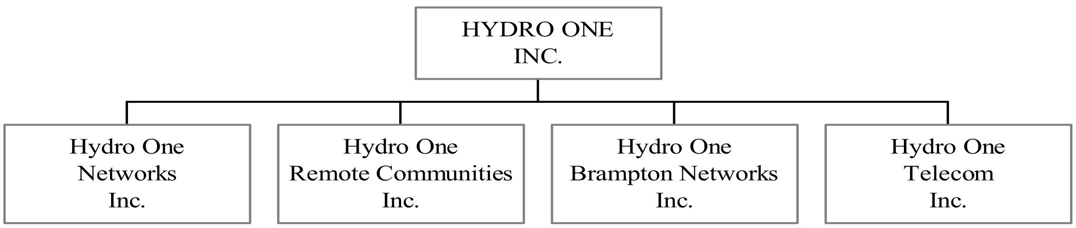
2.0 A BRIEF OVERVIEW OF HYDRO ONE INC.

Following the enactment of the *Electricity Act, 1998* and the anticipated restructuring of the former Ontario Hydro, Hydro One Inc. was incorporated under Ontario's *Business Corporations Act* on December 1, 1998 as Ontario Hydro Services Company Inc. and commenced carrying on business on May 1, 1999. On May 1, 2000, the company's name was changed to Hydro One Inc. In accordance with Section 48.1 of the *Electricity Act, 1998*, as amended, Hydro One Inc. is a holding company operating through its subsidiaries. Its principal subsidiary, Hydro One Networks Inc. (Hydro One) is the largest electricity transmitter and distributor to customers within Ontario.

Figure 1 below shows Hydro One Inc.'s principal subsidiaries, all of which are wholly-owned subsidiaries incorporated under Ontario's *Business Corporations Act*. The business functions of Hydro One and its subsidiaries are discussed in sections 3.0 and 5.0 of this Exhibit, respectively.

Figure 1

Hydro One Inc.



3.0 HYDRO ONE NETWORKS INC.

Hydro One is the primary subsidiary of Hydro One Inc. Its principal mandate is established by Section 48 (1) of the *Electricity Act, 1998,* which states:

> "The objects of Hydro One Inc. include, in addition to any other objects, owning and operating transmission systems and distribution systems through one or more subsidiaries."

Accordingly, Hydro One, as a subsidiary of Hydro One Inc., is permitted to carry on business related to the ownership, operation and management of both electricity transmission and distribution systems and facilities, under a separate Board-approved licence for each of its transmission and distribution businesses. A copy of Hydro One's distribution licence is provided in Exhibit A, Tab 6, Schedule 1.

Hydro One's businesses are carried out by four operating divisions (Customer Operations, Asset Management, Engineering and Construction Services and Grid Operations). There are also four service groups (Law, Finance, Corporate Services and Corporate and Regulatory Affairs). An organization chart indicating these divisions and the main functions of each is provided in Figure 2.

Figure 2

Hydro One Networks Inc. Organization

President and Chief Executive Officer
L. Formusa

Customer Operations M. D'Arcey	• Provincial Lines • Forestry Services • Remote Operations • Customer Service • Call Centre & Billing • Health, Safety & Environment	• Work Management • Business Processes & Quality Assurance • Field Administrative Services • Work Force Acquisition • Smart Metering (when on-going)
Asset Management G. Ogram	• Investment & Sustainment Planning • Strategy Development	• Business Transformation • Program Integration • Telecom Services
Engineering & Construction Services N. McQueen	• Engineering Services • Supply Chain Management • Construction Services • Inergi Contract Management	• Strategic Design Development • Work Planning & Management • Project Management • Injury-Free Program
Grid Operations W. Smith	• Large Customer & Generator Relations • Program Management • Stations Maintenance • Central Metering & P&C Support	• Central Operations & Support • Operating and Outage Management • Fleet Management • Ground & Site Maintenance
General Counsel & Secretariat J. Agostino (General Counsel, Acting) M. Wareham (Secretary to the Board, Acting)	• Law	• Corporate Secretariat
Corporate Projects Carmine Marcello	• Oversight and Delivery of Corporate-wide Projects	
Corporate Services T. Goldie	• Human Resources • Labour Relations	• Business IT • Security
Corporate & Regulatory Affairs P. Gregg	• Aboriginal Affairs • Regulatory Affairs & Pricing • Communications	• Internal Audit • Facilities & Real Estate Services • Executive Office Services • Culture Champion

4.0 HYDRO ONE'S DISTRIBUTION BUSINESS

As stated earlier, Hydro One is mandated and licensed to provide both the transmission and distribution of electricity to customers in Ontario. Operating both businesses from the one corporation has enabled Hydro One to take advantage of a multi-skilled work force. Efficiencies have been realized through the sharing of certain facilities and equipment, where possible. For example, in 2004, the rationalization and amalgamation of a number of facilities (the Transmission and the Distribution Operations Management Centres and twelve transmission operating centres) were completed. This has enabled the monitoring, control and operation of all of the Company's transmission and much of the distribution assets from one location – the Ontario Grid Control Centre ("OGCC").

Although staff, equipment and facilities may be shared, the definition of work specific to the Distribution Business is undertaken annually and appropriate systems, processes and models provide for the isolation of costs related to this work. High level descriptions of the work to be performed by Hydro One in 2008 in relation to Hydro One's Distribution Business or on distribution assets can be found in the Summary of OM&A Expenses and Summary of Capital Budget Exhibits (Exhibit C1, Tab 2, Schedule 1 and Exhibit D1, Tab 3, Schedule 1, respectively), followed by their companion exhibits that provide details of the costs for Sustainment, Development, Operations, Customer Care and Shared Services.

Hydro One utilizes a centralized shared services model to deliver its common services. This serves as the most economic approach. Accordingly, common services are provided to the Transmission and Distribution businesses of Hydro One and to other subsidiaries of Hydro One Inc. on a centralized basis.

The costs of these services and assets are assigned to business units on the basis of cost causation. These costs and assets are directly assigned where it is possible to do so. All other costs are allocated based on cost drivers, direct benefits or other methods as appropriate. The series of exhibits in Exhibit C1, Tab 5, describe these allocation methods, as well as the derivation of the overhead capitalization rate, which determine the assignment of overhead costs to capital expenditures.

Hydro One commissioned R.J. Rudden Associates to conduct studies to recommend appropriate allocation methods for the assignment of these costs (the "Rudden Study"). The Rudden Study was presented for examination during Hydro One's 2006 Distribution Rates proceeding, RP-2005-0020/EB-2005-0378 and was accepted by the Board as an appropriate methodology for allocating costs among the subsidiaries. R.J. Rudden was retained in 2006 to update the cost allocation report, specific to the Transmission business, based on the same methodology as used in Hydro One's 2006 Distribution Rates proceeding. The Rudden methodology has been used to derive the 2008 common cost allocation to the Distribution business as discussed in Exhibit C1, Tab 5, Schedule 1.

5.0 AFFILIATES AND RELATED PARTIES

5.1 Other Subsidiaries of Hydro One Inc.

As noted in section 2.0 of this Exhibit, Hydro One Inc. owns three other subsidiaries - Hydro One Remote Communities Inc., Hydro One Brampton Networks Inc. and Hydro One Telecom Inc. The business function of each is provided below.

a) Hydro One Remote Communities Inc. carries on all business relating to ownership, operation, maintenance and construction of generation and distribution assets used in the supply of electricity to remote communities throughout northern Ontario that are not connected to the transmission grid.
b) Hydro One Brampton Networks Inc. carries on all business relating to the ownership, operation and management of electricity distribution systems and facilities in Brampton, Ontario.

c) Hydro One Telecom Inc. carries on all business relating to leasing dark fibre and providing lit capacity to other telecommunications carriers, large corporations, government, health care and education institutions.

5.2 Related Parties

Ontario Electricity Financial Corporation ("OEFC"), the Independent Electricity System Operator (the "IESO"), the Ontario Power Authority (the "OPA") and Ontario Power Generation Inc. ("OPG") are related parties of Hydro One Inc., due to their ownership by the Province. Each is described below.

a) OEFC is the financial successor corporation of Ontario Hydro, established under Section 54 of the *Electricity Act, 1998*. Among its primary responsibilities is the management and retirement of Ontario Hydro's outstanding debt and other financial obligations.
b) The IESO is the centralized independent electricity system operator responsible for maintaining the security and reliability of electricity supply in Ontario and for directing the operations of the IESO-controlled grid. The Ontario Energy Board approves the licence, business plan and fees of the IESO.
c) The OPA is mandated to ensure the adequacy and efficiency of electricity supply in the Province through planning of electricity supply and demand.
d) OPG's principal business is the generation and sale of electricity to customers in Ontario and in inter-connected markets. OPG is licensed by the Ontario Energy Board.

HYDRO ONE GOVERNANCE FRAMEWORK

1.0 OVERVIEW

The corporate governance structure and Internal Control Framework of Hydro One Inc. provide reasonable assurance regarding Hydro One Distribution's effective and efficient operations, reliable financial reporting and compliance with applicable laws and regulations. In the past few years, federal and provincial governments and regulators have moved decisively to increase the robustness and transparency of corporate governance, as well as expand the requirements for internal control and disclosure. Although the majority of Hydro One Distribution's practices already conform to these requirements, special projects have been undertaken to ensure full compliance. In 2006, the focus was on documenting and testing the controls over financial reporting. Tests of operational effectiveness will continue each year.

2.0 CORPORATE GOVERNANCE

Corporate governance is the mechanism by which a corporation ensures independent oversight of management activities on behalf of the shareholder(s). For Hydro One Inc., the Board of Directors and its associated committees fulfill this role, and provide direction to management through precepts such as ethical management (as established through our Code of Business Conduct), review and/or approval of a stated mission, goals and business objectives, organizational authorities, and business plans.

The company's corporate governance structure is illustrated in Figure 1. Hydro One's Board and Senior Management committees are also described in detail below.

Hydro One Corporate Governance

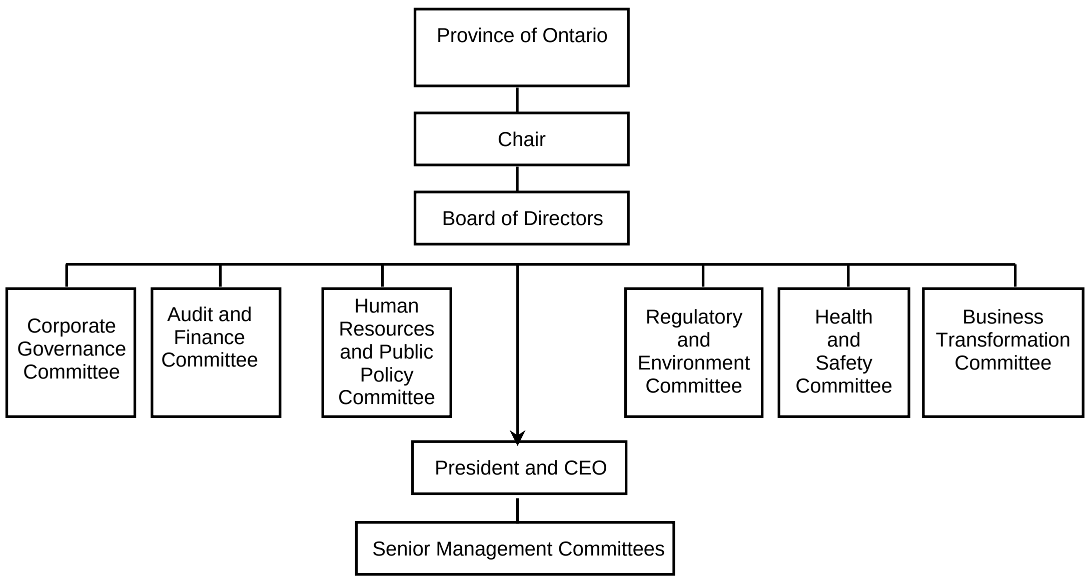


Figure 1

2.1 The Corporate Governance Committee is the Board governance committee of Hydro One Inc. and its subsidiaries. The committee is primarily responsible for carrying out an annual review of the mandates of the Board and each committee of the Board or subsidiary Boards. Other obligations include recommending issues for discussion at Board meetings, monitoring the quality of management's relationship with the Board, recommending suitable nominees to the Board of Directors, conducting the annual Board and individual Director effectiveness evaluations and reviewing all Director compensation.

2.2 The Audit and Finance Committee is mainly responsible for overseeing the accounting, financial reporting and auditing practices for Hydro One Inc. and its subsidiaries. Specifically, the committee makes recommendations regarding financial objectives and plans, and risk management strategies of the company. It is also accountable for reviewing and recommending to the Board for approval the interim and annual consolidated financial statements, management discussion and analysis disclosures, and financial statements in debt securities offering documents. In addition, the Audit and Finance Committee reviews the internal audit procedures of the company and advises the Board on its auditing practices and procedures, selects and oversees the work of external auditors and obtains assurance that internal controls are adequate. The committee also reviews, at least annually but more frequently if necessary, complaints brought forward under the Code of Business Conduct that relate specifically to inappropriate accounting, internal control or auditing matters. All members of the committee are independent and financially literate as per applicable Canadian securities legislation.

2.3 The Human Resources and Public Policy Committee is responsible for reviewing the appropriateness of current and future organization structures, succession plans for corporate and divisional officers, the appropriateness of the Code of Business Conduct (including any breaches for the preceding year), and the performance and remuneration of senior executives. Also, the committee identifies, assesses and provides advice to the Board on public affairs issues that have significant impact on the company.

2.4 The Regulatory and Environment Committee maintains an up-to-date understanding of regulatory and environmental compliance risks and seeks to ensure that management is effectively managing those risks. The committee is also responsible for reviewing management's regulatory strategy and proposals for transmission and distribution rate applications, as well as the status of outstanding applications. It also plays an advisory role with respect to changes or additions to environmental policies, standards, accountabilities and programs, and recommends such to the Board for approval.

2.5 The Health and Safety Committee is responsible for reviewing and ensuring compliance with occupational health and safety legislation, policies, standards, and programs. They annually review the company's state of readiness to respond to crisis situations, as well as reports of any occupational accidents. They may also review such other health and safety matters, including public health and safety, as appropriate.

2.6 The Business Transformation Committee is responsible for assisting the Board of Directors in its oversight responsibility on matters related to the Enterprise Application Systems Replacement Strategy. The strategy addresses the replacement of existing customized business applications with commercially available software system applications to simplify the information technology infrastructure and improve functionality in business processes.

3.0 SENIOR MANAGEMENT COMMITTEES

Prudent decision-making, operational effectiveness and business transparency are supported by four key senior management committees: Executive Committee, Operations Committee, Pension Committee and Disclosure Committee.

3.1 Executive Committee

This committee is a decision-making body established to review and approve business plans and strategies, capital projects and investments, key operating decisions, regulatory filings, labour strategy, financial and operational performance indicators and other items as required. The Executive Committee also reviews all project approvals prior to going to the Board.

3.2 Operations Committee

This committee provides business coordination between lines of business, including resourcing strategy, alignment of business plans, health and safety policy, support for regulatory filings and implementation of corporate strategies. They also review and coordinate operational issues and review project and program expenditures. Any required changes to project or program schedules are coordinated across all lines of business.

3.3 Pension Committee

The Pension Committee is responsible for approving appropriate pension policies, standards and programs. It is also responsible for ensuring compliance with legislation, policies and standards.

3.4 Disclosure Committee

The Disclosure Committee operates under the principal that communications to the public should be timely, factual and accurate and broadly disseminated in accordance with all applicable legal and regulatory requirements in Canada. The committee meets quarterly to review financial statements and management's discussion and analysis disclosures, offering documents for debt securities, as well as risk assessments prepared for credit rating agencies and government.

4.0 INTERNAL CONTROL FRAMEWORK

Internal controls ensure the company achieves its mission and goals, by enabling management to deal with rapidly changing economic and competitive environments, customer demands and priorities, and restructuring for future growth. Internal controls promote efficiency, reduce risk of asset loss, and help ensure the reliability of financial statements and compliance with laws and regulations.

Hydro One Inc.'s Internal Control Framework has five components, including: the Control Environment, Risk Assessment, Control Activities, Information and Communication, and Monitoring. The framework further addresses the appropriate elements of each component at the entity (Board) level, corporate (senior management) level and operational (local) level. The framework is consistent with accepted external standards and control criteria set out by such standard setting bodies as the Canadian Institute of Chartered Accountants and the US Committee of Sponsoring Organizations (COSO criteria, Internal Control-Integrated Framework). Key components of the framework are described in more detail below:

The "Control Environment" refers to direction and oversight from the top of the organization. The control environment component in the framework captures the notion of ethical and prudent financial management as established by the Board of Directors and senior management (see Section 2.0 above), and sets the tone for all financial and project management policies and practices established at lower levels. Regular education sessions on policies, processes and practices/procedures are also provided.

Hydro One Inc. has a formal Code of Business Conduct and a Disclosure Policy which have been issued to all staff. The Code of Business Conduct requires all management employees at the director level and above to sign an annual compliance form to document that they have read, understood, and complied with the Code, and that all conflicts or potential conflicts of interest have been disclosed. The Corporate Ethics Officer ensures that this process is performed on a timely basis and that a compliance register is maintained and submitted to the President and CEO of Hydro One Inc. And lastly, individual performance contracts capture the understanding between a manager and a direct report as to the results expected and the means by which such results will be achieved.

"Risk Assessment" involves the identification and analysis by management of the key risks to achieving the company's business objectives. Such an assessment is performed, at minimum, annually, and provides the basis for business planning decisions. Programs that mitigate existing risks to acceptable residual levels, or provide mitigation for emerging risks, are captured in business plans. Risk assessment extends to individual investment decisions through the Work Program Prioritization process (see Exhibit A, Tab 14, Schedule 5). This process assesses whether any proposed solutions for a specific operational need will achieve a level of residual risk acceptable to senior management and our shareholder. Projects and programs underway are regularly assessed for new and changing risks. Moreover, at the operational level, extensive emergency and contingency plans exist and are regularly tested and updated.

"Control Activities" refers to the systems, policies and procedures that ensure management's objectives are achieved and risk mitigation plans are carried out. Sets of policies and procedures exist to govern annual, monthly and day to day operations at the business unit and local levels. Many of these policies were imported from Ontario Hydro, and revised to focus on the core activities of transmission and distribution. Each revised policy has an issue date and expected review date. In many locations, policies and procedures are available on internal web sites. More information on Hydro One's policies may be found in Exhibit A, Tab 12, Schedule 1.

One of the foundations of good control is the establishment of appropriate levels of authority for spending and other business decisions. The delegation and exercise of all authorities are governed by 'Guiding Principles', the Code of Business Conduct, and policies and procedures. Authorities are reviewed by Audit and Finance Committee. Business plans, budgets and business cases establish overall spending of the company.

The budgeting and business planning process is also a critical element of effective internal controls. Annually a budget and business plan are prepared and submitted to the Board for approval. The budget and business plan sets the parameters of the company's activities for a specific fiscal period. More information on our planning process may be found in Exhibit A, Tab 14, Schedule 1. Information on our Project and Program approval process and our Work Program Prioritization process may be found in Exhibit A, Tab 14, Schedule 4 and Exhibit A, Tab 14, Schedule 5, respectively.

The Executive Authorities Register (EAR) delegates authorities from the Board to senior management. Organizational Authority Registers (OAR's) exist at subsidiary and business unit levels to delegate authorities from senior management to business unit and local levels.

The Inergi outsourcing agreement further provides approvals assigned by Hydro One to Inergi LP for specific transactions and levels of spending.

"Information and Communication" supports all other control components. Pertinent information must be identified, captured and communicated in a form and timeframe that enables staff to carry out their responsibilities. Regular communication occurs to all staff from the Chief Financial Officer and from the Corporate Controller with respect to new or changed policies and procedures. Presentations on various internal control matters also occur regularly. And, as noted previously, policies and procedures can be found in many locations on internal websites.

"Monitoring" covers the oversight of internal controls by management or independent parties outside the process; or the application of independent methodologies, such as customized procedures or standard checklists, by employees within a process. Monitoring also includes assessing the quality of internal controls over time and implementing required changes.

Quarterly letters of representation and disclosure prepared and submitted by Vice-Presidents provide both assurance and communication with respect to internal controls and validity of financial statements. The Letter of Disclosure addresses issues such as legal claims; changes in accounting policies, practices, systems, and procedures that have occurred in the period; and financial accounting matters that could have a significant impact on financial statements. The Letter of Representation provides assurance that internal control systems, policies and procedures are in place and functioning properly and financial statements are a true representation of the business.

Every month, each line of business is required to conduct a detailed review of financial results by comparing operating results to budgets and responding to discrepancies. Project details with major accounts are reconciled monthly to source sub-systems and suspense accounts are also explained and reconciled. Monthly control reports related to key aspects of operations financial and project activity are prepared centrally and delivered to managers for review and follow-up action as appropriate. A month-end close schedule is established to ensure timely production of financial statements. In addition, annual compliance testing of key financial activities are performed locally by line of business staff.

Compliance monitoring with respect to codes and policies is performed by multiple groups. Regulatory compliance is monitored by Regulatory Affairs (e.g. Affiliate Relationships Code; see Exhibit A, Tab 8, Schedule 3). Internal Audit performs compliance audits and uses a risk-based audit approach for prioritizing such audits. Internal controls are reviewed on a recurring cycle, again linked to level of risk. Furthermore, regular review of all outstanding items from past audits is performed. Annual year-end audits are also conducted by the external auditor.

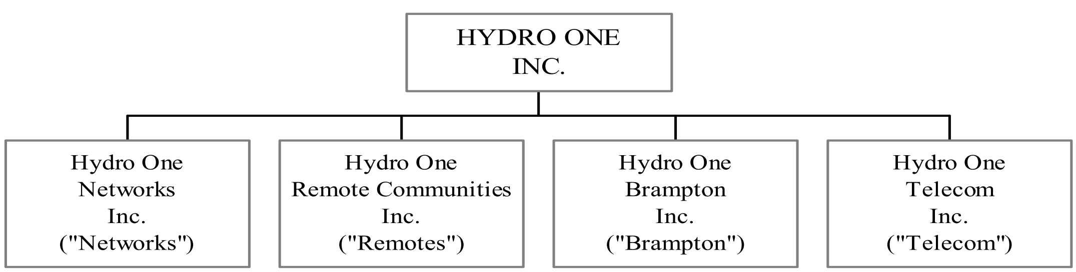
The outsourcing contract with Inergi LP requires that Inergi conduct an independent confirmation of the integrity of financial controls for all Hydro One transactions, and allows for auditing of processes and systems by Hydro One Internal Audit. Such audits are designed to assess the appropriate occurrence, proper measurement, completeness and accuracy of transactions and whether they were classified, described and disclosed in accordance with generally accepted accounting principles.

AFFILIATE SERVICE AGREEMENTS

1.0 INTRODUCTION

In accordance with the Affiliate Relationships Code ("ARC"), when Hydro One Distribution, as a business within Hydro One Networks ("Networks"), provides services to or purchases services from affiliates, it does so in accordance with service agreements. This Exhibit discusses the current agreements between Networks and its active affiliates. Networks and its active affiliates are displayed originally in the corporate organization chart in Exhibit A, Tab 8, Schedule 1 and repeated in Figure 1.0 below for convenience.

Figure 1
Hydro One Inc.



2.0 THE DEVELOPMENT OF THE SERVICE AGREEMENTS

As discussed in Exhibit A, Tab 8, Schedule 1, Hydro One's primary distribution business is "housed" within Networks. Accordingly, representatives from Networks and the various affiliates identify and negotiate the nature of the services being provided or purchased, any specific terms and the prices (or, alternatively, the pricing formula) for these services. This information is incorporated into legal agreements with commercial terms and conditions, then reviewed and approved by each company's CEO or other accountable officer. Two agreements, which focus on the provision of common administrative services from Hydro One Inc. to its subsidiaries and from Networks to its affiliates, are structured as multi-party agreements and accordingly, are reviewed and signed by all parties.

The current agreements between Networks and its affiliates are listed below, in Table 1, which identifies the service provider, the recipient and a brief description of the services.

Table 1
Networks' Service Agreements – 2007

Service Provider	***Recipient(s)***	***Description of Services***
Hydro One Inc. (Appendix A)	Networks Telecom Remotes Brampton Networks	***a) General Counsel and Secretary services*** – Professional legal advice and input as well as guidance on business ethics and support in the form of a business code of conduct. ***b) President / CEO / Chairman services*** – Strategic direction and management. ***c) Chief Financial Office services*** – Review of policies and procedures, investment decisions, treasury operations and tax planning, financial control and reporting.
Networks (Appendix B)	Hydro One Inc. Remotes Telecom Inc. Brampton Networks	***a) General Counsel and Secretary services*** – Professional legal advice and input and services regarding the protection of assets and management of security risks. ***b) Financial services*** -- Financial information, business planning, budgeting and financial reporting as well as other financial services such as treasury/pension/investor relations, taxation, internal audit and risk management, insurance, financial systems and services, cost and inventory accounting, decision support, transaction processing (accounts payable and receivable), and fixed asset and general accounting. ***c) Corporate services*** -- Facility management and support services, human resource services and corporate communications. ***d) Telecommunications-related services*** – Field and engineering, logistics, corporate, construction, telecommunication and information technology services. ***e) Other services*** – Supply procurement, customer services operation and information management.
Networks (Appendix C)	Remotes	***Utility Operations services*** – Provincial lines, forestry, drafting, environmental land assessment and remediation, fleet management, flight safety, training, safety, station maintenance, meter services, approval of plans, drawings and specification of installation work,

Service Provider	*Recipient(s)*	*Description of Services*
		joint use services and engineering and construction services.
Networks (Appendix D)	Remotes	***CEO / President services*** -- Administrative oversight, provision of strategic direction and advice and advocacy of the service recipient's position regarding operational and budgetary issues.
Telecom (Appendix E)	Networks	***Telecommunication services*** -- Monitoring of power system teleprotection, including analogue and digital microwave, PLC, fibre optic, radio and other systems. Monitoring, management and operation of business system telecom services. Provision of alarm based services, coordinated network management services, systems analysis services and carrier/vendor management services.
Remotes (Appendix F)	Networks	***Metering and Lines Services*** -Lines Apprenticeship program instruction services, update, install, reverify and sample meter changes and maintain the services recipient's distribution system.

3.0 TERMS AND CONDITIONS

In accordance with the ARC, the agreements describe the nature of, and the fees payable for, the services and they contain confidentiality, liability and indemnification provisions. They also describe a dispute resolution process to which the parties must adhere in resolving disputes under the agreements. More details on the key clauses are provided below.

3.1 Description of Services

The agreements address Networks' provision of certain common administrative and corporate services and utility operation and maintenance services to its affiliates as well as the receipt by Networks of operating, certain common administrative and corporate and telecommunications services from them. The services are described in detail as a schedule to the agreements.

3.2 Fees Payable

Pursuant to the ARC, where a utility provides a service, resource or product to an affiliate, the utility shall ensure that the sale price is no less than the fair market value of the service, resource or product. In purchasing a service, resource or product, from an affiliate, a utility shall pay no more than the fair market value. Where no fair market value is available for any product, resource or service, a utility shall charge no less than a cost-based price, and shall pay not more than a cost-based price.

Each services agreement specifies the price payable for the specific services described in the agreement and generally, the price is cost-based since no fair market value is available for the said services.

The annual fees payable to Networks by its affiliates for certain common administrative and corporate services for the years 2006, 2007 and 2008 are as specified in the following table. Service agreements are provided for 2007. The amounts for 2008 are planned amounts consistent with the revenue requirements in this Application.

Table 2
Fees Payable to Networks for Services Provided

FEES PAYABLE BY AFFILIATES TO NETWORKS FOR SERVICES TO BE PROVIDED BY NETWORKS:
(in $Thousands)

Services	Hydro One Inc.	Remotes	Telecom	Brampton
General Counsel and Secretary Services				
•• **2006**	65	187	65	131
•• **2007**	68	198	68	136
•• **2008**	75	220	75	150
Financial Services				
•• **2006**	29	230	370	457
•• **2007**	112	201	389	240
•• **2008**	57	308	354	236
Corporate Services				
•• **2006**	0	56	92	18
•• **2007**	0	79	106	45
•• **2008**	0	89	146	28
Telecommunication Services				
•• **2006**	0	163	286	0
•• **2007**	0	126	202	0
•• **2008**	0	118	195	0
Other Services				
•• **2006**	0	547	1,033	0
•• **2007**	0	481	920	0
•• **2008**	0	479	1,086	0

FEES PAYABLE BY AFFILIATES TO NETWORKS FOR SERVICES TO BE PROVIDED BY NETWORKS: (in $Thousands)				
Services	**Hydro One Inc.**	**Remotes**	**Telecom**	**Brampton**
CEO/President Services				
•• **2006**	0	80	0	0
•• **2007**	0	80	0	0
•• **2008**	0	80	0	0
Utility Operation Services				
•• **2006**	0	725	0	0
•• **2007**	0	325	0	0
•• **2008**	0	325	0	0
Totals				
•• **2006**	94	1,988	1,846	606
•• **2007**	180	1,490	1,685	421
•• **2008**	132	1,619	1,856	414

The annual fees payable by Networks to Hydro One Inc. for certain common administrative and corporate services and payable by Networks to Hydro One Telecom Inc. for telecommunications services, for the years 2006, 2007 and 2008 are as specified in the following table. Service agreements are provided for 2007. The amounts for 2008 are planned amounts consistent with the revenue requirements in this Application.

Table 3
Fees Payable by Networks for Services Received

FEES PAYABLE BY NETWORKS FOR SERVICES TO BE RECEIVED FROM HYDRO ONE INC AND TELECOM: (in $Thousands)			
Services provided by Hydro One Inc.	**2006**	**2007**	**2008**
General Counsel & Secretary	955	916	907
President / CEO / Chairman Services	4,242	4,080	3,366
Chief Financial Office Services	1,055	953	804
Totals	6,252	5,949	5,077
Services provided by Telecom			
Telecommunication Services	6,361	8,656	9,000
Totals	6,361	8,656	9,000

3.3 Dispute Resolution Procedure

If the parties have a dispute under the agreement that cannot be resolved by a director or manager from each party, the dispute will be passed to the parties' respective presidents. If, after five days after receipt of notice of the dispute, the dispute is still unresolved, the matter proceeds to the President of Hydro One Inc. for final resolution.

3.4 Confidentiality

Except as required by law and in certain other circumstances (which exceptions are typical in a confidentiality agreement), each party is to maintain in strict confidence the Agreement and all information received from the other party and shall not copy or disclose the information to any third party without the prior written consent of the disclosing party. No such consent is required for disclosure to the receiving party's representatives who have a need to know. Such information includes personal information and information regarding a consumer, retailer, wholesale buyer, wholesale supplier, or a generator. The agreements also include security safeguards to be adhered to by the party receiving confidential information.

3.5 Intellectual Property

All rights, title and interests, including copyright ownership, to any reports and any other deliverable that is to be produced and delivered to the service recipient by the service provider vests with the service recipient and the recipient may use, disclose or modify such reports or deliverable in any manner it deems appropriate.

3.6 Indemnification

Each party (the "indemnifying party") shall be liable for and shall indemnify the other party from and against all costs or damages attributable to the indemnifying party's performance and/or non-performance of its obligations under the agreement, whether arising from or based on breach of contract, tort, negligence, strict liability or otherwise. Notwithstanding any other provision of the agreement, neither party shall be liable for any economic loss, loss of goodwill, loss of profit or for any special, indirect or consequential damages where the said losses or damages are incurred by the other party or by any third party claiming through or under the other party. The obligation to indemnify survives the termination or expiry of the agreement.

4.0 COST-BASED PRICING

As noted above, the fees payable for services delivered between affiliates are cost-based. Such costs may be billed directly, and if this is done, the individual agreement will specify these fees. An alternative is to allocate costs across a number of affiliates, based on the proportion of a given service used by the affiliates or the benefit derived. Where this is done, a cost allocation model is used. The Hydro One cost allocation model is described in Exhibit C1, Tab 5, Schedule 1.

AFFILIATE SERVICE AGREEMENTS

Appendix A

Hydro One Inc.

Service Provision to:

Hydro One Networks Inc.
Hydro One Telecom Inc.
Hydro One Remote Communities Inc.
Hydro One Brampton Networks Inc.

2007

(Legal advice, financial services, strategic direction and management)

THIS AGREEMENT made in duplicate this 1st day of January, 2007 (the "Effective Date").

BETWEEN:

HYDRO ONE INC.
(the "Services Provider")

- and -

HYDRO ONE REMOTE COMMUNITIES INC., HYDRO ONE NETWORKS INC., HYDRO ONE TELECOM INC. and HYDRO ONE BRAMPTON NETWORKS INC.
(individually, the "Services Recipient" and collectively, the "Services Recipients")

1.0 PREFACE

This Agreement is intended to identify the services that are to be provided to each of the Services Recipients by the Services Provider in accordance with the terms and conditions herein. Except as otherwise specified, the term of this Agreement shall be for a period of 1year commencing on the Effective Date.

2.0 SERVICES

The Services Provider shall provide to each of the Services Recipients (as may be required by each of them respectively from time to time during the term of this Agreement) the following services (the "**Services**"), which Services are more particularly described in Schedule "A" attached hereto:

- General Counsel & Secretary (including Corporate Executive Office) services
- President / CEO / Chairman services
- Chief Financial Office services (including Strategic Financial services)
- Use of certain assets by Hydro One Networks Inc.

3.0 FEES PAYABLE

(a) The price for the performance of the Services for each of the Services Recipients shall be as identified in Schedule "A" attached hereto, exclusive of any sales and use taxes, as may be applicable. The relevant price for the Services shall be paid by each of the Services Recipients to the Services Provider by means of monthly electronic journal transfers which shall be reflected in the applicable books and records of each party. In addition, each Services Recipient shall pay for any material costs which the Services Provider, acting reasonably, incurs as a result of resources, services and products that the Services Provider must purchase and that are in addition to the Services Provider's existing resources, services and products, in order to provide the said Services Recipient with specific services it requires and requests.

(b) If at any time during the performance of the Services, a Services Recipient is of the opinion that there are deficiencies in the Services provided to it and/or that the price payable is in any way inaccurate, the said Services Recipient shall pay the entire relevant price payable by it in full and its sole remedy shall be to follow the dispute resolution procedures outlined in Section 6.0 herein to determine what amount, if any, shall be refunded to the said Services Recipient and/or what Services, if any, shall be rectified or redone by the Services Provider.

(c) The parties acknowledge and agree that they qualify as specified members of a closely related group under subsection 156(1) of the Excise Tax Act (Canada), as amended (the "Act") and have jointly executed a Form GST 25, to make an election under subsection 156(2) of the Act to deem the purchase and sale of the Services to be made for nil consideration for Goods and Services Tax purposes.

4.0 REPRESENTATIONS AND WARRANTIES

(a) The Services Provider represents and warrants that:
   (i) it has all the necessary authority and capacity to enter into this Agreement and to perform its obligations hereunder;
   (ii) the execution of this Agreement and compliance with and performance of the terms, conditions, and covenants contemplated herein have been duly authorized by all necessary corporate action on the part of the Services Provider; and
   (iii) all staff employed in the performance of the Services shall have the qualifications, expertise and experience which could reasonably be expected of staff of a services provider performing work similar to the Services.

(b) Each Services Recipient represents and warrants that:
   (i) it has all the necessary authority and capacity to enter into this Agreement and to perform its obligations hereunder; and
   (ii) the execution of this Agreement and compliance with and performance of the terms, conditions, and covenants contemplated herein have been duly authorized by all necessary corporate action on the part of the Services Recipient.

5.0 PERFORMANCE OF THE SERVICES

(a) **Compliance with Standards and Applicable Law:** The Services Provider shall perform the Services in a diligent and professional manner and shall comply with the Services Recipient's computer data management and data access protocols contained in the Services Recipient's documents entitled "Corporate Security Standard 600-3 – Information Security Policy" and "Corporate Security Policy 600 – Information Security Policy", both of which are dated January 17, 2000" and any amendments thereto which may be made from time to time by the Services Recipient. The Services Provider shall comply at all times with the statutes, regulations, by-laws, standards and codes, as amended, as may be applicable to the Services Provider in respect of the Services and the performance of its obligations hereunder and it shall, at its own expense, obtain and maintain in good standing all permits and licences required by any authorities having jurisdiction to perform the Services.

(b) **<u>Safety and Security Measures</u>**: When any part of the Services is to be performed at any of the Services Recipients' premises, all of the Services Provider's staff engaged in the performance of the Services at the said premises shall comply with the safety and security requirements and measures in effect at the said premises.

(c) **<u>Meetings</u>**: Each of the Services Recipient and the Services Provider shall, after the Effective Date, meet at least twice during the term of this Agreement to review performance, quality and timeliness of the Services provided by the Services Provider pursuant to this Agreement.

6.0 DISPUTE RESOLUTION PROCEDURES

Any controversy, dispute, difference, question or claim arising between any of the parties in connection with the interpretation, performance, construction or implementation of this Agreement that cannot be resolved by a director or manager from each of the said parties (collectively "Dispute") shall be settled in accordance with this Section. The aggrieved party shall send the other affected party(ies) written notice identifying the Dispute, the amount involved, if any, and the remedy sought, and invoking the procedures of this Section. The Presidents of each affected party shall confer in an effort to resolve the Dispute. If the Presidents are unable to resolve the Dispute within 5 business days after receipt of the written notice of the Dispute, then the affected parties shall submit the Dispute to the President of Hydro One Inc. for resolution.

7.0 CONFIDENTIALITY AND INTELLECTUAL PROPERTY

(a) Confidentiality:

Each party (the "Receiving Party") shall maintain in strict confidence this Agreement and the existence and contents thereof and all information, analysis, conclusions, drawings, reports, specifications or other information, proprietary or otherwise, whether transmitted orally, electronically or in written form, and received in furtherance of this Agreement from any of the other parties (the "Disclosing Party") or any of the Disclosing Party's directors, officers, employees, consultants, agents or legal and other advisors (the "Disclosing Party Representatives") (collectively the "Confidential Information"). Except as permitted herein, the Receiving Party shall not publish, reproduce, or disclose, either directly or indirectly, the said Confidential Information to any third party and shall not use the said Confidential Information for any purpose other than for purposes of this Agreement without the prior written consent of the Disclosing Party. The Receiving Party may disclose the Confidential Information only to its shareholder, directors, officers, employees, consultants, agents or professional advisors (the "Receiving Party Representatives") having a need to know same and who have undertaken a like obligation to maintain its confidentiality.

For greater certainty, Confidential Information includes any and all personal information (as that term is defined in the *Freedom of Information and Protection of Privacy Act* (Ontario) and the *Personal Information Protection and Electronic Documents Act* (Canada), as they may be amended, and any and all information regarding a consumer, retailer, wholesale buyer, wholesale supplier, or a generator, provided by the Disclosing Party to the Receiving Party for purposes of this Agreement, whether or not such information was initially provided prior to the Effective Date.

The Receiving Party undertakes to protect and safeguard all Confidential Information in its possession or under its control and received by the Disclosing Party, in the manner described in Schedule "B" attached hereto. The Disclosing Party may, on reasonable notice, and during regular business hours, audit the information management practices of the Receiving Party to confirm compliance with the terms and conditions of this Section 7.0 and all applicable statutes, regulations, by-laws, standards and codes, as amended.

The Receiving Party undertakes to notify the Disclosing Party immediately upon discovery of any unauthorized use and/or disclosure of any of the Disclosing Party's Confidential Information, to co-operate with the Disclosing Party to help regain possession of such Confidential Information, and to prevent its further unauthorized use and/or disclosure.

The foregoing obligations with respect to confidentiality, use, reproduction, dissemination, publication and non-disclosure herein shall not apply to any information that:

(i) is previously known to or lawfully in the possession of the Receiving Party prior to the date of disclosure as evidenced by the Receiving Party's written record;

(ii) is independently known to or discovered by the Receiving Party, without any reference to the information or material;

(iii) is obtained by the Receiving Party from an arm's length third party having a bona fide right to disclose same and who was not otherwise under an obligation of confidence or fiduciary duty to the Disclosing Party or the Disclosing Party Representatives;

(iv) is or becomes public knowledge through no fault or omission of, or breach of this Agreement by the Receiving Party or the Receiving Party Representatives; or

(iv) is required to be disclosed pursuant to a final judicial or governmental order or other legal process.

Confidential Information (other than this Agreement which shall be jointly owned by the parties) shall remain the sole and exclusive property of the Disclosing Party that has disclosed the Confidential Information, and the Disclosing Party shall retain all right, title and interest in and to the said Confidential Information.

The Receiving Party shall keep a record of written Confidential Information furnished to it by the Disclosing Party in a location separate from those locations where the Receiving Party has stored information in respect of other third parties for which it performs work and it shall advise the Disclosing Party of such location.

All Confidential Information furnished by the Disclosing Party (other than this Agreement), including that portion of the Confidential Information which is contained in analyses, compilations, studies or other documents prepared by the Receiving Party or by the Receiving Party Representatives, is the Disclosing Party's property and will be returned immediately to the Disclosing Party upon its request.

(b) Intellectual Property:

Each of the Services Recipients shall obtain all rights, title and interests, including copyright ownership, to any reports and any other deliverable that is to be produced and delivered to it by the Services Provider and, subject to applicable legislation and notwithstanding clause 7.0(a) above, the said Services Recipient may use, disclose or modify such reports or deliverable in any manner it deems appropriate. The Services Provider shall not do any act which may compromise or diminish the said Services Recipient's interest as aforesaid.

(c) Survival of Obligations:

This Section 7.0 shall forever survive the termination or expiration of this Agreement.

8.0 LIABILITY

The Services Provider shall indemnify each of the Services Recipients and the Services Recipient's respective successors and assigns, directors, officers, employees, contractors and agents from and against all costs or damages attributable to the Services Provider's performance and/or non-performance of its obligations under this Agreement and any amendments thereto, whether arising from or based upon breach of contract, tort, negligence, strict liability or otherwise. Each Services Recipient shall indemnify the Services Provider and the Services Provider's successors and assigns, directors, officers, employees, contractors and agents from and against all costs or damages attributable to the said Services Recipient's performance and/or non-performance of its obligations under this Agreement and any amendments thereto, whether arising from or based upon breach of contract, tort, negligence, strict liability or otherwise. Notwithstanding any other provision of this Agreement, no party hereto shall be liable for any economic loss, loss of goodwill, loss of profit or for any special, indirect or consequential damages, where the said losses or damages are incurred by the other parties or any of them or by any third party claiming through or under the other parties or any of them.

This Section 8.0 shall forever survive the termination or expiration of this Agreement.

9.0 AUTHORIZED REPRESENTATIVES

The authorized representatives of the parties hereto for purposes of this Agreement are the following:

HYDRO ONE TELECOM INC.
65 Kelfield Street,
Rexdale, Ontario M9W 5A3

Attention: **Cliff Truax**
Telephone: 416-240-6713
Telecopier: 416-240-6802

HYDRO ONE REMOTE COMMUNITIES INC.
483 Bay Street,
Toronto, Ontario M5G 2P5

Attention: **Una O'Reilly**
TCT14
Telephone: 416-345-6698
Telecopier: 416-345-6356

HYDRO ONE NETWORKS INC.
483 Bay Street,
Toronto, Ontario M5G 2P5

Attention:	**George Carleton**
	TCT14
Telephone:	416-345-5733
Telecopier:	416-345-5405

HYDRO ONE INC.
483 Bay Street,
Toronto, Ontario M5G 2P5

Attention:	**Beth Summers**
	TCT15
Telephone:	416-345-4008
Telecopier:	416-345-6058

HYDRO ONE BRAMPTON NETWORKS INC.
175 Sandalwood Parkway West,
Brampton, Ontario
L7A 1E8

Attention:	**James Gribbon**
Telephone:	(905) 840-6300 ext. 205
Telecopier:	(905) 840-0967

All correspondence, reports, documents and/or other communication concerning this Agreement and the Schedule attached hereto shall be directed to the attention of the authorized representatives noted above and shall be deemed to be sufficiently given if delivered personally, mailed or transmitted by fax to the attention of the authorized representatives at the addresses above, and any notice so given shall be deemed to have been made and received on the date of delivery or on the 5th business day following the day of mailing of same or on the day of transmission if transmitted during normal business hours, otherwise on the next business day, as the case may be.

10.0 CHANGE OF CONTROL

In the event of a change of control of any of the Services Recipients, this Agreement shall immediately terminate as between the said Services Recipient and the Services Provider only. A change of control shall mean, as applicable, a purchase of more than fifty (50) percent of the outstanding capital by a non-affiliate third party.

11.0 ASSIGNMENT

Neither this Agreement nor any rights and obligations shall be assigned by any of the Services Recipients without the prior written consent of the Services Provider and by the Services Provider without the prior written consent of the affected Services Recipient, in either case which consent shall not be unreasonably withheld. Subject to the foregoing, this Agreement shall enure to the benefit of the parties hereto and their respective successors and permitted assigns.

12.0 SCHEDULES

Schedules "A" and "B" attached hereto are to be read with and form part of this Agreement.

13.0 COUNTERPARTS

This Agreement may be executed in counterparts and the counterparts together shall constitute an original.

IN WITNESS THEREOF the parties hereto have caused this Agreement to be executed by their respective representatives duly authorized in that behalf.

HYDRO ONE TELECOM INC.

Name: Paul Marchant
Title: President and CEO
I have authority to bind the corporation.

HYDRO ONE REMOTE COMMUNITIES INC.

Name: Myles D'Arcey
Title: President and CEO
I have authority to bind the corporation.

HYDRO ONE NETWORKS INC.

Maureen Wareham

Name: Maureen Wareham
Title: Acting Secretary
I have authority to bind the corporation.

HYDRO ONE INC.

Name: Beth Summers
Title: Chief Financial Officer
I have authority to bind the corporation.

HYDRO ONE BRAMPTON NETWORKS INC.

Roger a. albert

Name: Roger A. Albert
Title: President and CEO
I have authority to bind the corporation.

Schedule "A"

The annual cost for the performance of the Services to be delivered is summarized as follows:

Services	SERVICES TO BE PROVIDED BY HYDRO ONE INC. TO: (in $Thousands)			
	Hydro One Networks Inc.	Hydro One Remote Communities Inc.	Hydro One Telecom Inc.	Hydro One Brampton Networks Inc.
General Counsel & Secretary (including Corporate Executive Office)	916	25	10	20
President / CEO / Chairman Services	4,080	21	30	43
Chief Financial Office Services (including Strategic Financial services)	953	8	33	45
Totals	5,949	54	73	108

DESCRIPTION OF SERVICES:

General Counsel and Secretary

The Services Provider shall provide the Services Recipient with professional legal advice and input. This advice shall include, but shall not be limited to, interpretation and analysis of legislation and regulations, advice concerning corporate structure and governance, development of regulatory instruments (licences), contracts, and environmental and health and safety issues. The Services Provider will also provide guidance on business ethics and support in the form of a business code of conduct.

President / CEO / Chairman services

The Services Provider shall provide the Services Recipient with strategic direction and management in an attempt to ensure that the Services Recipient's corporate goals are achieved.

Chief Financial Office services (including Strategic Financial services)

The Services Provider shall provide the Services Recipient with strategic direction and management in an attempt to ensure that the Services Recipient's corporate financial goals are achieved.

The Services Provider shall provide the Services Recipient with strategic approval with respect to investment decisions. Services relating to the review of policies and procedures, treasury operations and tax planning, financial control and reporting will also be provided by the Services Provider to the Services Recipient as required by the Services Recipient.

Schedule "B"

Receiving Party Security Safeguards Regarding Confidential Information Received from the Disclosing Party

The Receiving Party shall protect the Confidential Information by security safeguards appropriate to the sensitivity of the information.

1) The Receiving Party shall protect the Confidential Information against such risks as loss or theft, unauthorized access, disclosure, copying, use, modification or destruction, through appropriate security measures, regardless of the format in which it is held.

2) All of the Receiving Party's Representatives with access to the Confidential Information shall be contractually required to respect the confidentiality of that information.

3) The Receiving Party acknowledges and agrees that the nature of the safeguards will vary depending on the sensitivity, amount, distribution and format of the information, and the method of storage. The Receiving Party shall ensure that more sensitive information will be safeguarded by a higher level of protection.

4) The Receiving Party shall ensure that methods of protection will include:

(a) physical measures, for example, locked filing cabinets and restricted access to offices;

(b) organizational measures, for example, controlling entry to data centers and limiting access to information on a "need-to-know" basis;

(c) technological measures, for example, the use of passwords and encryption; and

(d) investigative measures, in cases where the Receiving Party has reasonable grounds to believe that the Confidential Information is being inappropriately collected, used or disclosed by anyone whom in law the Receiving Party is responsible.

AFFILIATE SERVICE AGREEMENTS

Appendix B

Hydro One Networks Inc.

Service Provision to:

Hydro One Inc.
Hydro One Telecom Inc.
Hydro One Remote Communities Inc.
Hydro One Brampton Networks Inc.

2007

(General Counsel/Secretary Services, Financial services, Corporate services, telecommunications services, supply procurement, customer services operation and information management)

THIS AGREEMENT made in duplicate this 1st day of January, 2007 (the "Effective Date").

BETWEEN:

HYDRO ONE NETWORKS INC.
(the "Services Provider")

- and -

HYDRO ONE REMOTE COMMUNITIES INC, HYDRO ONE INC.
HYDRO ONE TELECOM INC., and HYDRO ONE BRAMPTON NETWORKS INC.

(individually, the "Services Recipient" and collectively, the "Services Recipients")

1.0 PREFACE

This Agreement is intended to identify the services that are to be provided to each of the Services Recipients by the Services Provider in accordance with the terms and conditions herein. Except as otherwise specified, the term of this Agreement shall be for a period of 1 year commencing on the Effective Date.

2.0 SERVICES

The Services Provider shall provide to each of the Services Recipients (as may be required by each of them respectively from time to time during the term of this Agreement) the following services (the "**Services**"), which Services are more particularly described in Schedule "A" attached hereto:

- General Counsel and Secretary services
- Financial services
- Corporate services
- Telecommunications Services
- Other services

3.0 FEES PAYABLE

(a) The price for the performance of the Services for each of the Services Recipients shall be as identified in Schedule "A" attached hereto, exclusive of any sales and use taxes, as may be applicable. The relevant price for the Services shall be paid by each of the Services Recipients to the Services Provider by means of monthly electronic journal transfers which shall be reflected in the applicable books and records of each party. In addition, each Services Recipient shall pay for any material costs which the Services Provider, acting reasonably, incurs as a result of resources, services and products that the Services Provider must purchase and that are in addition to the

Services Provider's existing resources, services and products, in order to provide the said Services Recipient with specific services it requires and requests.

(b) If at any time during the performance of the Services, a Services Recipient is of the opinion that there are deficiencies in the Services provided to it and/or that the price payable is in any way inaccurate, the said Services Recipient shall pay the entire relevant price payable by it in full and its sole remedy shall be to follow the dispute resolution procedures outlined in Section 6.0 herein to determine what amount, if any, shall be refunded to the said Services Recipient and/or what Services, if any, shall be rectified or redone by the Services Provider.

c) The parties acknowledge and agree that they qualify as specified members of a closely related group under subsection 156(1) of the Excise Tax Act (Canada), as amended (the "Act") and have jointly executed a Form GST25, to make an election under subsection 156(2) of the Act to deem the purchase and sale of the Services to be made for nil consideration for Goods and Services Tax purposes.

4.0 REPRESENTATIONS AND WARRANTIES

(a) The Services Provider represents and warrants that:
- (i) it has all the necessary authority and capacity to enter into this Agreement and to perform its obligations hereunder;
- (ii) the execution of this Agreement and compliance with and performance of the terms, conditions, and covenants contemplated herein have been duly authorized by all necessary corporate action on the part of the Services Provider; and
- (iii) all staff employed in the performance of the Services shall have the qualifications, expertise and experience which could reasonably be expected of staff of a services provider performing work similar to the Services.

(b) Each Services Recipient represents and warrants that:
- (i) it has all the necessary authority and capacity to enter into this Agreement and to perform its obligations hereunder; and
- (ii) the execution of this Agreement and compliance with and performance of the terms, conditions, and covenants contemplated herein have been duly authorized by all necessary corporate action on the part of the Services Recipient.

5.0 PERFORMANCE OF THE SERVICES

(a) **Compliance with Standards and Applicable Law:** The Services Provider shall perform the Services in a diligent and professional manner and shall comply with the Services Recipient's computer data management and data access protocols contained in the Services Recipient's documents entitled "Corporate Security Standard 600-3 – Information Security Policy" and "Corporate Security Policy 600 – Information Security Policy", both of which are dated January 17, 2000 and any amendments thereto which may be made from time to time by the Services Recipient. The Services Provider shall comply at all times with the statutes, regulations, by-laws, standards and codes, as amended, as may be applicable to the Services Provider in respect of the Services and the performance of its obligations hereunder and it shall, at its own expense, obtain and maintain in good standing all permits and licences required by any authorities having jurisdiction to perform the Services.

(b) **Safety and Security Measures**: When any part of the Services is to be performed at any of the Services Recipients' premises, all of the Services Provider's staff engaged in the performance of the Services at the said premises shall comply with the safety and security requirements and measures in effect at the said premises.

(c) **Meetings**: Each of the Services Recipient and the Services Provider shall, after the Effective Date, meet at least twice during the term of this Agreement to review performance, quality and timeliness of the Services provided by the Services Provider pursuant to this Agreement.

6.0 DISPUTE RESOLUTION PROCEDURES

Any controversy, dispute, difference, question or claim arising between any of the parties in connection with the interpretation, performance, construction or implementation of this Agreement that cannot be resolved by a director or manager from each of the said parties (collectively "Dispute") shall be settled in accordance with this Section. The aggrieved party shall send the other affected party(ies) written notice identifying the Dispute, the amount involved, if any, and the remedy sought, and invoking the procedures of this Section. The Presidents of each affected party shall confer in an effort to resolve the Dispute. If the Presidents are unable to resolve the Dispute within 5 business days after receipt of the written notice of the Dispute, then the affected parties shall submit the Dispute to the President of Hydro One Inc. for resolution.

7.0 CONFIDENTIALITY AND INTELLECTUAL PROPERTY

(a) Confidentiality:

Each party (the "Receiving Party") shall maintain in strict confidence this Agreement and the existence and contents thereof and all information, analysis, conclusions, drawings, reports, specifications or other information, proprietary or otherwise, whether transmitted orally, electronically or in written form, and received in furtherance of this Agreement from any of the other parties (the "Disclosing Party") or any of the Disclosing Party's directors, officers, employees, consultants, agents or legal and other advisors (the "Disclosing Party Representatives") (collectively the "Confidential Information"). Except as permitted herein, the Receiving Party shall not publish, reproduce, or disclose, either directly or indirectly, the said Confidential Information to any third party and shall not use the said Confidential Information for any purpose other than for purposes of this Agreement without the prior written consent of the Disclosing Party. The Receiving Party may disclose the Confidential Information only to its shareholder, directors, officers, employees, consultants, agents or professional advisors (the "Receiving Party Representatives") having a need to know same and who have undertaken a like obligation to maintain its confidentiality.

For greater certainty, Confidential Information includes any and all personal information (as that term is defined in the *Freedom of Information and Protection of Privacy Act* (Ontario) and the *Personal Information Protection and Electronic Documents Act* (Canada), as they may be amended, and any and all information regarding a consumer, retailer, wholesale buyer, wholesale supplier, or a generator provided by the Disclosing Party to the Receiving Party for purposes of this Agreement, whether or not such information was initially provided prior to the Effective Date.

The Receiving Party undertakes to protect and safeguard all Confidential Information in its possession or under its control and received by the Disclosing Party, in the manner described in Schedule "B" attached hereto. The Disclosing Party may, on reasonable notice, and during regular business hours, audit the information management practices of the Receiving Party to confirm compliance with the terms and conditions of this Section 7.0 and all applicable statutes, regulations, by-laws, standards and codes, as amended.

The Receiving Party undertakes to notify the Disclosing Party immediately upon discovery of any unauthorized use and/or disclosure of any of the Disclosing Party's Confidential Information, to co-operate with the Disclosing Party to help regain possession of such Confidential Information, and to prevent its further unauthorized use and/or disclosure.

The foregoing obligations with respect to confidentiality, use, reproduction, dissemination, publication and non-disclosure herein shall not apply to any information that:

(i) is previously known to or lawfully in the possession of the Receiving Party prior to the date of disclosure as evidenced by the Receiving Party's written record;
(ii) is independently known to or discovered by the Receiving Party, without any reference to the information or material;
(iii) is obtained by the Receiving Party from an arm's length third party having a bona fide right to disclose same and who was not otherwise under an obligation of confidence or fiduciary duty to the Disclosing Party or the Disclosing Party Representatives;
(iv) is or becomes public knowledge through no fault or omission of, or breach of this Agreement by the Receiving Party or the Receiving Party Representatives; or
(v) is required to be disclosed pursuant to a final judicial or governmental order or other legal process.

Confidential Information (other than this Agreement which shall be jointly owned by the parties) shall remain the sole and exclusive property of the Disclosing Party that has disclosed the Confidential Information, and the Disclosing Party shall retain all right, title and interest in and to the said Confidential Information.

The Receiving Party shall keep a record of written Confidential Information furnished to it by the Disclosing Party in a location separate from those locations where the Receiving Party has stored information in respect of other third parties for which it performs work and it shall advise the Disclosing Party of such location.

All Confidential Information furnished by the Disclosing Party (other than this Agreement), including that portion of the Confidential Information which is contained in analyses, compilations, studies or other documents prepared by the Receiving Party or by the Receiving Party Representatives, is the Disclosing Party's property and will be returned immediately to the Disclosing Party upon its request.

(b) Intellectual Property:

Each of the Services Recipients shall obtain all rights, title and interests, including copyright ownership, to any reports and any other deliverable that is to be produced and delivered to it by the Services Provider and, subject to applicable legislation and notwithstanding clause 7.0(a) above, the said Services Recipient may use, disclose or modify such reports or deliverable in any manner it deems appropriate. The Services Provider shall not do any act which may compromise or diminish the said Services Recipient's interest as aforesaid.

(c) Survival of Obligations:

The obligations in this Section 7.0 shall forever survive the termination or expiration of this Agreement.

8.0 LIABILITY

The Services Provider shall indemnify each of the Services Recipients and the Services Recipient's respective successors and assigns, directors, officers, employees, contractors and agents from and against all costs or damages attributable to the Services Provider's performance and/or non-performance of its obligations under this Agreement and any amendments thereto, whether arising from or based upon breach of contract, tort, negligence, strict liability or otherwise. Each Services Recipient shall indemnify the Services Provider and the Services Provider's successors and assigns, directors, officers, employees, contractors and agents from and against all costs or damages attributable to the said Services Recipient's performance and/or non-performance of its obligations under this Agreement and any amendments thereto, whether arising from or based upon breach of contract, tort, negligence, strict liability or otherwise. Notwithstanding any other provision of this Agreement, no party hereto shall be liable for any economic loss, loss of goodwill, loss of profit or for any special, indirect or consequential damages, where the said losses or damages are incurred by the other parties or any of them or by any third party claiming through or under the other parties or any of them.

This Section 8.0 shall forever survive the termination or expiration of this Agreement.

9.0 AUTHORIZED REPRESENTATIVES

The authorized representatives of the parties hereto for purposes of this Agreement are the following:

HYDRO ONE TELECOM INC.
65 Kelfield Street,
Rexdale, Ontario M9W 5A3

Attention:	**Cliff Truax**
Telephone:	416-240-6713
Telecopier:	416-240-6802

HYDRO ONE REMOTE COMMUNITIES INC.
483 Bay Street,
Toronto, Ontario M5G 2P5

Attention:	**Una O'Reilly**
	TCT 14
Telephone:	416-345-6698
Telecopier:	416-345-6356

HYDRO ONE NETWORKS INC.
483 Bay Street,
Toronto, Ontario M5G 2P5

Attention:	**George Carleton**
	TCT 14
Telephone:	416-345-5733
Telecopier:	416-345-5405

HYDRO ONE INC.
483 Bay Street,
Toronto, Ontario M5G 2P5

Attention:	**Beth Summers**
	TCT 15
Telephone:	416-345-4008
Telecopier:	416-345-6285

HYDRO ONE BRAMPTON NETWORKS INC.
175 Sandalwood Parkway West,
Brampton, Ontario
L7A 1E8

Attention:	**James Gribbon**
Telephone:	(905) 840-6300 ext. 205
Telecopier:	(905) 840-0967

All correspondence, reports, documents and/or other communication concerning this Agreement and the Schedule attached hereto shall be directed to the attention of the authorized representatives noted above and shall be deemed to be sufficiently given if delivered personally, mailed or transmitted by fax to the attention of the authorized representatives at the addresses above, and any notice so given shall be deemed to have been made and received on the date of delivery or on the 5th business day following the day of mailing of same or on the day of transmission if transmitted during normal business hours, otherwise on the next business day, as the case may be.

10.0 CHANGE OF CONTROL

In the event of a change of control of the Services Provider, this Agreement shall immediately terminate as between each of the Services Recipients and the Services Provider. A change of control shall mean, as applicable, a purchase of more than fifty (50) percent of the outstanding capital by a non-affiliate third party.

11.0 ASSIGNMENT

Neither this Agreement nor any rights and obligations shall be assigned by any of the Services Recipients without the prior written consent of the Services Provider and by the Services Provider without the prior written consent of the affected Services Recipient, in either case which consent shall not be unreasonably withheld. Subject to the foregoing, this Agreement shall enure to the benefit of the parties hereto and their respective successors and permitted assigns.

12.0 SCHEDULES

Schedules “A” and “B” attached hereto are to be read with and form part of this Agreement.

13.0 COUNTERPARTS

This Agreement may be executed in counterparts and the counterparts together shall constitute an original.

IN WITNESS THEREOF the parties hereto have caused this Agreement to be executed by their respective representatives duly authorized in that behalf.

HYDRO ONE TELECOM INC.

Name: Paul Marchant
Title: President and CEO
I have authority to bind the corporation

HYDRO ONE REMOTE COMMUNITIES INC.

Name: Myles D'Arcey
Title: President and CEO
have authority to bind the corporation.

HYDRO ONE NETWORKS INC.

Maureen Wareham

Name: Maureen Wareham
Title: Acting Secretary
I have authority to bind the corporation.

HYDRO ONE INC.

Name: Beth Summers
Title: Chief Financial Officer
I have authority to bind the corporation.

HYDRO ONE BRAMPTON NETWORKS INC.

Roger A. Albert

Name: Roger A. Albert
Title: President and CEO
I have authority to bind the corporation.

Schedule "A"

The annual cost for the performance of the Services to be delivered is summarized as follows:

	SERVICES TO BE PROVIDED BY HYDRO ONE NETWORKS INC. TO: (in $Thousands)			
SERVICES	**Hydro One Inc.**	**Hydro One Remote Communities Inc.**	**Hydro One Telecom Inc.**	**Hydro One Brampton Networks Inc.**
General Counsel and Secretary Services	68	198	68	136
Financial Services	112	201	389	240
Corporate Services		79	106	45
Telecommunication Services		126	202	
Other Services		481	920	
Totals	180	1085	1685	421

DESCRIPTION OF SERVICES:

The following provides a generic description of all Services to be provided by the Services Provider.

GENERAL COUNSEL AND SECRETARY SERVICES

The Services Provider shall provide the Services Recipient with professional legal advice and input which shall include, but not be limited to, interpretation and analysis of legislation and regulations, advice concerning corporate structure and governance, development of regulatory instruments (licenses), contracts, and environmental and health and safety issues. The Services Provider will also provide services regarding the protection of assets and management of security risks.

FINANCIAL SERVICES

The Services Provider shall provide financial services support to the Services Recipient by providing timely and reliable financial information. The Services Provider will also provide services relating to business planning, budgeting and financial reporting. As required, services relating to treasury/pension/investor relations, taxation, internal audit and risk management, insurance, financial systems and services, cost and inventory accounting and decision support will also be provided. Other financial services such as transaction processing (accounts payable and receivable), and fixed asset and general accounting will also be provided.

CORPORATE SERVICES

The Services Provider shall provide corporate services in three main areas:

- facility management and support services – management services related to acquisition, maintenance, protection and disposal of the Services Recipient's portfolio of land holdings as well as facilities and buildings management, including office accommodation and all related support and services; services related to the appraisal, negotiation and acquisition of real estate rights including: full ownership, easements, leases, licenses, and permits, as well as special projects.
- human resource services – provision of human resource policy, strategy and standards to meet legal and other requirements. This includes staff planning, leadership development, succession planning and change management, as well as labour relations services, pay equity, diversity, health services and performance management, compensation, health and benefits programs and administration of payroll, benefits plans and incentive programs.
- corporate communications – provision of strategy, program and support for corporate communications, public affairs and media relations, as well as corporate and shareholder relations and strategy and programs related to internal communications.

TELECOMMUNICATIONS SERVICES

The Services Provider shall provide the Services Recipient with various telecommunications-related services including field and engineering, logistics, corporate, construction, telecommunication and information technology services.

OTHER SERVICES

The Services Provider shall provide the Services Recipient with:

- Supply Procurement – provision of demand planning, management and procurement, vendor and inventory management, process development, data management, warehousing, waste management and investment recovery.
- Customer Services Operation – provision of bill production and dispatch and settlements service, as well as data services related to field-based service orders.
- Information Management – provision of infrastructure operations, including a variety of activities such as system testing and integration, Internet and database management services, as well as services related to mainframe infrastructure operations, end user and desk-top support.

Schedule "B"

Receiving Party Security Safeguards Regarding Confidential Information Received from the Disclosing Party

The Receiving Party shall protect the Confidential Information by security safeguards appropriate to the sensitivity of the information.

1) The Receiving Party shall protect the Confidential Information against such risks as loss or theft, unauthorized access, disclosure, copying, use, modification or destruction, through appropriate security measures, regardless of the format in which it is held.

2) All of the Receiving Party's Representatives with access to the Confidential Information shall be contractually required to respect the confidentiality of that information.

3) The Receiving Party acknowledges and agrees that the nature of the safeguards will vary depending on the sensitivity, amount, distribution and format of the information, and the method of storage. The Receiving Party shall ensure that more sensitive information will be safeguarded by a higher level of protection.

4) The Receiving Party shall ensure that methods of protection will include:

(a) physical measures, for example, locked filing cabinets and restricted access to offices;

(b) organizational measures, for example, controlling entry to data centers and limiting access to information on a "need-to-know" basis;

(c) technological measures, for example, the use of passwords and encryption; and

(d) investigative measures, in cases where the Receiving Party has reasonable grounds to believe that the Confidential Information is being inappropriately collected, used or disclosed by anyone whom in law the Receiving Party is responsible.

AFFILIATE SERVICE AGREEMENTS

Appendix C

Hydro One Networks Inc.

Service Provision to:

Hydro One Remote Communities Inc.

2007

(Utility operations services, including line maintenance, forestry, station maintenance, meter services, safety and environment, etc.)

THIS MASTER AGREEMENT made in duplicate as of the 1st day of January, 2007 (the "Effective Date").

BETWEEN:

HYDRO ONE NETWORKS INC.

- and -

HYDRO ONE REMOTE COMMUNITIES INC.

1.0 PREFACE

This Master Agreement and the subsequent individual contracts hereunder are intended to identify the services (collectively, the "Services") that are to be provided to Hydro One Remote Communities Inc. (hereinafter referred to as the "Services Recipient") by Hydro One Networks Inc. (hereinafter referred to as the "Services Provider") in accordance with the terms and conditions herein.

This Master Agreement serves to provide the general commercial terms and conditions that will govern each individual contract (the "Contract") to be agreed upon and executed by the Services Recipient and the Services Provider. Each Contract shall be uniquely numbered, shall specifically describe the individual Services that shall be provided by the Services Provider to the Services Recipient, reference performance targets and reporting requirements and may specify supplementary or different commercial terms and conditions, such as remedies for default, that take precedence over the terms and conditions of this Master Agreement.

Subject to the termination rights in the immediately following paragraph and in Section 6.0 herein, this Master Agreement and the Contracts executed hereunder (except as may be otherwise provided in any of the said Contracts) shall be effective as of the Effective Date and shall continue in full force and effect for a period of 2 years thereafter. In the event that the parties agree to extend the term of a Contract beyond the 2-year period contemplated herein, this Master Agreement shall continue to be in full force and effect for such extended period for purposes of the said Contract.

In the event that either party decides to cease carrying on the business of performing the type of work activities that constitute any portion of the Services under any Contract, it shall provide the other party with 6 months' prior written notice and on the first business day after expiry of the said 6-month period, all Contracts pertaining to the type of work activities which the said party has decided to cease carrying on shall be deemed to be terminated and the Services Recipient shall have no further obligation to the Services Provider other than to pay the Services Provider any monies then due and owing to the Services Provider because of any performance of the Services Provider's obligations completed up to the effective date of such termination plus reasonable costs incurred by the Services Provider as may be agreed upon by the parties, provided that the Services Recipient's liability under this paragraph shall not exceed the price to be paid for the Services as stipulated in the said Contract.

2.0 DEFINITIONS

In the Contracts and this Master Agreement, including the recitals and Schedules hereto, in addition to terms defined elsewhere in this Master Agreement or the Contracts, unless there is something in the subject matter or context inconsistent therewith, the following words shall have the following meanings:

(a) **"Contract Time"** means the time stipulated in any Contract from commencement of the Services to Substantial Performance of the Services.

(b) **"Substantial Performance of the Services"** means the point at which the Services are ready for use or are being used by the Services Recipient for the purpose intended.

(c) **"Total Performance"** means the point at which all of the following have occurred, where applicable:
- Project Completion Report has been received by the Services Recipient from the Services Provider;
- Test Certificate and Permits have been provided by the Services Provider to the Services Recipient;
- the Services Provider has updated the drawings for the Services to "AS BUILT" and has provided the said updated drawings to the Services Recipient.

3.0 SERVICES

The Services Provider shall provide the Services Recipient with the following Services as may be required by the Services Recipient from time to time and as may be agreed upon by both parties in a Contract, which Contract shall be in the form attached hereto as Schedule "C":

- Provincial Lines services
- Forestry services
- Drafting services
- Environmental Land Assessment and Remediation services
- Fleet services
- Flight Safety services
- Safety services
- Training services
- Meter services
- Station Maintenance: Technical Support services
- Approval of plans, drawings and specification of installation work
- Engineering and Construction Services
- Joint Use services

4.0 FEES PAYABLE

(a) The price for the performance of the Services described in each Contract shall be as specified in the relevant Contract and shall include any sales and use taxes as may be applicable, which taxes shall be shown separately in the said Contract. In the event that the parties agree that the Services Recipient shall pay the Services Provider for the Services on a time and materials basis, such time and materials basis shall be in accordance with the Services Provider's 2007-2008 hourly rates by job category and fleet rates, which hourly rates and fleet rates may be amended from time to time by mutual agreement of the parties. The parties acknowledge and agree that the Services Recipient has received the Services Provider's 2007-2008 hourly and fleet rates from the Services Provider.

The parties agree that the price for the Services described in each Contract shall be paid by the Services Recipient to the Services Provider by means of monthly electronic journal transfers which shall be reflected in the applicable books and records of each party or by direct time reporting through Hydro One Inc.'s payroll system.

The parties acknowledge and agree that some Contracts may contain holdback provisions that may be based upon performance or other criteria as may be agreed upon, as well as provisions dealing with bonuses and/or penalties.

(b) The parties acknowledge and agree that they qualify as specified members of a closely related group under subsection 156(1) of the *Excise Tax Act (Canada)*, as amended (the "Act") and have jointly executed a Form GST25, to make an election under subsection 156(2) of the Act to deem the purchase and sale of the Services under the Contracts to be made for nil consideration for Goods and Services Tax purposes.

5.0 REPRESENTATIONS AND WARRANTIES

(a) The Services Provider represents and warrants that:

(i) it has all the necessary corporate power, authority and capacity to enter into this Master Agreement and to perform its obligations hereunder;

(ii) the execution of this Master Agreement and compliance with and performance of the terms, conditions, and covenants contemplated herein have been duly authorized by all necessary corporate action on the part of the Services Provider;

(iii) all staff employed in the performance of the Services shall have the qualifications, expertise and experience which could reasonably be expected of staff of a services provider performing work similar to the Services; and

(iv) all material, tools, machinery and equipment provided by the Services Provider to the Services Recipient as part of the Services shall be new and of a quality best suited to the purpose required and their use subject to the approval of the Services Recipient.

(b) The Services Recipient represents and warrants that:

(i) it has all the necessary corporate power, authority and capacity to enter into this Master Agreement and to perform its obligations hereunder; and

(ii) the execution of this Master Agreement and compliance with and performance of the terms, conditions, and covenants contemplated herein have been duly authorized by all necessary corporate action on the part of the Services Recipient.

6.0 PERFORMANCE OF THE SERVICES

(a) **Access to Site:** The Services Recipient shall provide the Services Provider with an opportunity to visit and examine the site at which the Services are to be performed prior to the execution of any Contract for the said Services. Upon execution of any Contract, the Services Provider shall be deemed to have represented and warranted, along with the representations and warranties in Section 5.0(a) above, that the Services Provider has visited and examined the site at which the Services are to be performed under the said Contract and that the Services Provider has satisfied itself as to the form and nature of the site, the quantities and nature of the Services to be performed, the labour conditions existing in the area for the Services involved, facilities present on site, access to the site, the seasonal conditions limiting access to the site, the materials necessary for the performance of the Services, and any restrictions or barriers present at the site that would impact the performance of the Services and which the Services Provider was able to reasonably detect upon examination of the site.

(b) **Compliance with Standards, Specifications and Applicable Law:** The Services Provider shall perform the Services in a diligent and professional manner and shall comply with the Services Recipient's computer data management and data access protocols contained in the Services Recipient's documents entitled "Corporate Security Standard 600-3 – Information Security Policy" and "Corporate Security Policy 600 – Information Security Policy", both of which are dated January 17, 2000 and any amendments thereto which may be made from time to time by the Services Recipient. The Services Provider shall comply at all times with all statutes, regulations, by-laws, standards and codes as may be applicable to the Services Provider in respect of the Services and the performance of its obligations hereunder and it shall, at its own expense, obtain and maintain in good standing all permits and licences required by any authorities having jurisdiction to perform the Services identified in each Contract.

The Services Provider shall also comply with the General Standards and Specifications set out in Schedule "A" attached hereto in its performance of the Services, as may be applicable.

The Services Provider shall be responsible for coordinating all related work activities to be performed under all the Contracts.

(c) **Input from Services Recipient:** The Services Recipient shall cooperate and provide any required input as might be requested by the Services Provider, on a timely basis, to facilitate the performance of the Services by the Services Provider. In addition, the Services Recipient shall disclose to the Services Provider on a timely basis any information within the Services Recipient's possession or control which may reasonably affect the ability of the Services Provider to meet its obligations under this Master Agreement and the Contracts.

(d) **Constructor:** Unless otherwise specified in any executed Contract, the parties acknowledge and agree that the Services Provider shall be the "Constructor" of the Services performed under any executed Contract within the meaning of the Occupational Health and Safety Act, R.S.O. 1990, c. 0.1, as amended and the regulations thereunder and shall have all of the responsibilities and liabilities of a "Constructor".

(e) **Safety and Security Measures:** When any part of the Services under any Contract is to be performed at the Services Recipient's premises, all of the Services Provider's staff engaged in the performance of the Services at the said premises shall comply with the safety and security requirements and measures in effect at the said premises.

(f) **Cleanup:** The Services Provider shall maintain the location at which the Services are performed in a tidy condition and free from the accumulation of waste products and debris, other than that caused by the Services Recipient, its contractors or their respective employees. Upon completion of the Services, the Services Provider shall remove the material, tools, machinery and equipment and waste products and debris, other than those resulting from the work of the Services Recipient, its contractors and their respective employees.

(g) **Review and Inspection of the Services:** The Services Recipient shall have access to the Services at all times. The Services Provider shall provide sufficient, safe, and proper facilities at all times for the review of the Services by the Services Recipient. The Services Recipient may order any portion or portions of the Services to be examined to confirm that such work is in accordance with the requirements of this Master Agreement and the relevant Contract. If the work is not in accordance with the requirements of this Master Agreement and the relevant Contract, the Services Provider shall correct the work and pay the cost of examination and correction. If the work is in accordance with the requirements of this Master Agreement and the relevant Contract, the Services Recipient shall pay the cost of examination and restoration. No payment by the Services Recipient under the relevant Contract shall constitute an acceptance of any portion of the Services which are not in accordance with the requirements of this Master Agreement and the relevant Contract.

(h) **Defective Services:** The Services Provider shall promptly remove from the site at which the Services have been performed and replace or re-execute defective work that has been rejected by the Services Recipient as failing to conform to this Master Agreement and/or the relevant Contract whether or not the defective work has been incorporated in the Services and whether or not the defect is the result of poor workmanship, use of defective products, or damage through carelessness or other act or omission of the Services Provider. The Services Provider shall promptly make good other contractors' work destroyed or damaged by such removals or replacements at the Services Provider's expense. If, in the reasonable opinion of the Services Recipient it is not expedient to correct defective work or work not performed as provided in this Master Agreement and/or the relevant Contract, the Services Recipient may deduct from the amount otherwise due to the Services Provider the difference in value between the work as performed and that called for by this Master Agreement and the relevant Contract. If the Services Provider and Services Recipient do not agree on the difference in value, they shall follow the dispute resolution procedures outlined in Section 8.0 herein.

(i) **Meetings:** The parties agree to meet quarterly after the Effective Date to review performance, quality and timeliness of the Services provided by the Services Provider pursuant to each Contract.

(j) **Right to Terminate Contract:** The Services Recipient may terminate any Contract, without cause and without any penalty to it, at any time by providing written notice to the Services Provider. Upon termination in accordance with this clause, the Services Recipient shall have no further obligation to the Services Provider other than to pay the Services Provider any monies then due and owing to the Services Provider because of any performance of the Services Provider's obligations completed up to the effective date of such termination plus reasonable costs incurred by the Services Provider as may be agreed upon by the parties, provided that the Services Recipient's liability under this clause shall not exceed the price to be paid for the Services as stipulated in the said Contract.

(k) **Emergency Priority:** Upon determination by the Services Recipient that the Services Recipient is in an emergency situation, the Services Provider shall give first priority to responding to the said emergency, in priority over any emergency response commitments that the Services Provider may have to a third party.

7.0 CHANGES TO SERVICES

Either party may request a change to the scope of work specified in each Contract including work already in progress in accordance with this Section.

If either party desires a change in the work described in any individual Contract, it shall complete and submit to the other party's Contract manager identified in the relevant Contract, a Contract Change Notification Form (the "CCNF") in the form attached hereto as Schedule "B". The CCNF shall identify the reasons and impact (cost and schedule) of the change. The other party shall respond to the CCNF no later than 10 business days after receipt thereof. In the event that the parties agree with the change in the scope of work, price and/or time for completion, the parties shall execute the CCNF and the executed CCNF shall be attached to the relevant Contract as a schedule thereto.

In the event that the parties agree on the change in the scope of work but do not agree on a revised price for the changed scope of work, the price shall be fixed on a time and materials basis in accordance with the Services Provider's 2007-2008 hourly rates and fleet rates as may be amended pursuant to this Agreement and the CCNF shall be executed by the parties accordingly. The Services Provider shall provide the Services Recipient with an invoice for the said changed scope of work that is payable on a time and materials basis and the invoice shall include a description of the work performed, a breakdown of the number of hours worked and applicable hourly rates. The Services Provider shall also provide to the Services Recipient such other information and supporting documentation as the Services Recipient may reasonably require. Such invoices, information and supporting documentation shall at all reasonable times be open to audit, inspection and copying by the Services Recipient and shall be preserved and kept available by the Services Provider for audit by the Services Recipient until the expiration of two years from the completion date of the changed scope of work.

Unless otherwise specified in the relevant Contract, the Services Provider shall not be obligated to carry out any change in the scope of work and the Services Recipient shall not be obligated to pay for any change in the scope of work unless and until the relevant CCNF has been executed.

8.0 DISPUTE RESOLUTION PROCEDURES

Any controversy, dispute, difference, question or claim arising between the parties in connection with the interpretation, performance, construction or implementation of this Master Agreement or any Contract that cannot be resolved by a Director from each party (collectively "Dispute"), other than a Dispute regarding any change to the scope of work activities processed under Section 7.0 above, shall be settled in accordance with this Section. The aggrieved party shall send the other party written notice identifying the Dispute, the amount involved, if any, and the remedy sought, and invoking the procedures of this Section. The Presidents from each party shall confer in an effort to resolve the Dispute. If the Presidents are unable to resolve the Dispute within 5 business days after receipt of the written notice of the Dispute, then the parties shall submit the Dispute in writing to the President of Hydro One Inc. for resolution.

9.0 CONFIDENTIALITY AND INTELLECTUAL PROPERTY

(a) **Confidentiality**: Each party (the "Receiving Party") shall maintain in strict confidence this Master Agreement, the Contracts and the existence and contents thereof respectively and all information, analysis, conclusions, drawings, reports, specifications or other information, proprietary or otherwise, whether transmitted orally, electronically or in written form, and received in furtherance of this Master Agreement and/or the Contracts from the other party (the "Disclosing Party") or any of the Disclosing Party's directors, officers, employees, consultants, agents or legal, financial or professional advisors (the "Disclosing Party Representatives") (collectively the "Confidential Information"). Except as permitted herein, the Receiving Party shall not publish, reproduce, or disclose, either directly or indirectly, the said Confidential Information to any third party and shall not use the said Confidential Information for any purpose other than for purposes of this Agreement without the prior written consent of the Disclosing Party. The Receiving Party may disclose the Confidential Information only to its shareholder, directors, officers, employees, consultants, agents or professional advisors (the "Receiving Party Representatives") having a need to know same and who have undertaken a like obligation to maintain its confidentiality.

For greater certainty, Confidential Information includes any and all personal information (as that term is defined in the Freedom of Information and Protection of Privacy Act (Ontario) and the Personal Information Protection and Electronic Documents Act (Canada), as they may be amended) and any and all information regarding a consumer, retailer, wholesale buyer, wholesale supplier, or a generator, provided by the Disclosing Party to the Receiving Party for purposes of this Agreement, whether or not such information was initially provided prior to the Effective Date.

The Receiving Party undertakes to protect and safeguard all Confidential Information in its possession or under its control and received by the Disclosing Party, in the manner described in Schedule "F" attached hereto. The Disclosing Party may, on reasonable notice, and during regular business hours, audit the information management practices of the Receiving Party to confirm compliance with the terms and conditions of this Section 9.0 and all applicable statutes, regulations, by-laws, standards and codes, as amended. The Receiving Party undertakes to notify the Disclosing Party immediately upon discovery of any unauthorized use and/or disclosure of any of the Disclosing Party's Confidential Information, to co-operate with the Disclosing Party to help regain possession of such Confidential Information, and to prevent its further unauthorized use and/or disclosure.

The foregoing obligations with respect to confidentiality, use, reproduction, dissemination, publication and non-disclosure herein shall not apply to any information that:

(i) is previously known to or lawfully in the possession of the Receiving Party prior to the date of disclosure as evidenced by the Receiving Party's written record;

(ii) is independently known to or discovered by the Receiving Party, without any reference to the information or material;

(iii) is obtained by the Receiving Party from an arm's length third party having a bona fide right to disclose same and who was not otherwise under an obligation of confidence or fiduciary duty to the Disclosing Party or the Disclosing Party Representatives;

(iv) is or becomes public knowledge through no fault or omission of, or breach of this Master Agreement or the Contracts by, the Receiving Party or the Receiving Party Representatives; or

(v) is required to be disclosed pursuant to a final judicial or governmental order or other legal process, including, without limitation, an order of or legal process involving a regulatory authority such as the Ontario Energy Board.

The parties acknowledge and agree that the Confidential Information (other than this Master Agreement and the Contracts which shall be jointly owned by the parties) shall remain the sole and exclusive property of the Disclosing Party that has disclosed the Confidential Information, and the Disclosing Party shall retain all right, title and interest in and to the Confidential Information it has disclosed to the Receiving Party.

The Receiving Party agrees that it shall keep a record of written Confidential Information furnished to it by the Disclosing Party in a location separate from those locations where the Receiving Party has stored information in respect of other third parties for which it performs work and it shall advise the Disclosing Party of such location.

All Confidential Information furnished by the Disclosing Party (other than this Master Agreement and the Contracts), including that portion of the Confidential Information which is contained in analyses, compilations, studies or other documents prepared by the Receiving Party or by the Receiving Party Representatives, is the Disclosing Party's property and will be returned immediately to the Disclosing Party upon its request.

(b) **Intellectual Property:** Unless otherwise agreed, the Services Recipient shall obtain all rights, title and interests, including copyright ownership, to any reports and any other deliverable that is to be produced and delivered to the Services Recipient by the Services Provider in accordance with any Contract and, subject to applicable legislation, and notwithstanding clause 9.0(a) above, the Services Recipient may use, disclose or modify such reports or deliverable in any manner it deems appropriate. The Services Provider shall not do any act which may compromise or diminish the Services Recipient's interest as aforesaid.

(c) **Survival of Obligations:** The obligations in this Section 9.0 shall forever survive the termination or expiration of this Master Agreement and the Contracts.

10.0 INSURANCE

The Services Provider shall maintain in full force and effect during the term of any executed Contract and with financially responsible insurance carriers, the following insurance coverage and the insurance coverage specified in Schedule "E" attached hereto as may be applicable for any Services and as shall be specified in the relevant Contract for the said Services:

(i) Workers Compensation as required by *the Ontario Workplace Safety and Insurance Act, 1997,* S.O. 1997, c.16, Schedule A, as amended or similar applicable legislation covering all persons employed by the Services Provider for the Services performed under any executed Contract. For U.S. employees, appropriate State Workers Compensation must be carried including Employer's Liability for a minimum limit of $5,000,000 U.S., with a Foreign Coverage Endorsement and, to the extent applicable, Jones Act and U.S. Longshoreman's and Harbor Workers coverage and FELA. To achieve the desired limit, umbrella or excess liability insurance may be used. A waiver of subrogation shall be provided by the insurers to the Services Recipient.

(ii) Automobile Liability Insurance, covering all licensed motor vehicles owned, rented or leased and used in connection with the Services to be performed by the Services Provider under any executed Contract covering Bodily Injury and Property Damage Liability to a combined inclusive minimum limit of $5,000,000 and mandatory Accident Benefits. To achieve the desired limit, umbrella or excess liability insurance may be used.

(iii) Commercial General and Excess Liability Insurance with limits of $5,000,000 inclusive for both bodily injury, including death, personal injury and damage to property, including loss of use thereof, for each occurrence. To achieve the desired limit, umbrella or excess liability insurance may be used. This coverage shall specifically include, but not be limited to, the following:

a. Blanket Contractual Liability;
b. Damage to property of the Owner including loss of use thereof;
c. Pollution Liability coverage on at least a Sudden and Accidental basis;
d. Products & Completed Operations to be continuously maintained through the operational liability insurance.
e. Employer's Liability;
f. Non-Owned Automobile Liability; and,
g. Broad Form Property Damage

Prior to the commencement of the performance of the Services under any executed Contract, the Services Provider shall provide to the Services Recipient's representative and address noted immediately below, evidence of the minimum coverages required under this Section 10.0 in the form attached hereto as Schedule "D", noting the policy number and term and executed by a duly authorized representative of their respective insurers.

Manager, Risk and Insurance, Hydro One Networks Inc. 483 Bay Street, South
Tower TCT 08, Toronto, Ontario M5G 2P5

With the exception of subparagraph (ii) above, all insurance coverages noted above shall specify that it is primary coverage and not contributory with or in excess of any other insurance that may be maintained by the Services Recipient.

The Services Recipient shall be included as a Named Insured subject to the Sole Agent provision under coverages noted in subparagraph (iii) above, but only to the extent to which the Services Provider is liable to the Services Recipient for breach of its obligations under the relevant

Contract. In addition, the parties acknowledge and agree that the insurance coverages noted in subparagraph (iii) above shall contain a cross liability clause and a severability of interests clause.

The parties further acknowledge and agree that the Insurance coverage described in this Section and provided for the Services Provider shall not be invalidated by actions or inactions of others.

11.0 LIABILITY

Unless otherwise agreed in writing, each party shall indemnify the other party and that other party's successors and assigns, directors, officers, employees, contractors and agents from and against all direct costs or damages attributable to the indemnifying party's performance and/or non-performance of its obligations under this Master Agreement and the Contracts and any amendments or additions thereto that are mutually agreed to in writing, whether arising from or based on breach of contract, tort, negligence, strict liability or otherwise. Notwithstanding any other provision of this Master Agreement, neither party shall be liable for any special, indirect or consequential damages or for economic loss, incurred by the other or by any third party claiming through or under the other.

The foregoing paragraph shall forever survive the termination or expiration of this Master Agreement and the Contracts.

12.0 AUTHORIZED REPRESENTATIVES

The authorized representatives of the parties hereto for purposes of this Master Agreement are the following:

HYDRO ONE REMOTE COMMUNITIES INC.
483 Bay St.
North Tower, 14th Floor, A8
Toronto, Ontario
M5G 2P5
Attention: Una O'Reilly
Telephone: (416) 345-6698
Telecopier: (416) 345-6356

HYDRO ONE NETWORKS INC.
483 Bay St.
South Tower, 8th Floor, G3
Toronto, Ontario
M5G 2P5
Attention: Greg Van Dusen
Telephone: (416) 345-5722
Telecopier: (416) 345-6833

All correspondence, reports, documents and/or other communication concerning this Master Agreement and the Schedules attached hereto shall be directed to the attention of the authorized representatives noted above and all correspondence, reports, documents and/or other communication concerning any Contract and the Services to be performed thereunder shall be directed to the attention of the Contract Managers specified in the relevant Contract. Any notice permitted or required to be given hereunder and/or pursuant to any Contract shall be deemed to be sufficiently given if delivered personally, mailed or transmitted by fax to the attention of the authorized representatives at the addresses above, and any notice so given shall be deemed to have been made and received on the date of delivery or on the 5th business day following the day of mailing of same or on the day of transmission if transmitted during normal business hours, otherwise on the next business day, as the case may be.

13.0 FORCE MAJEURE

Except for the payment of any monies required hereunder, neither party shall be deemed to be in default of this Master Agreement or any Contract where the failure to perform or the delay in performing any obligation is due to a cause beyond its reasonable control, including, but not limited to, an act of God, act of any federal, provincial, municipal or government action, or order of court or administrative or regulatory authority, civil commotion, strikes, lockouts and other labour disputes, fires, floods, sabotage, earthquakes, storms, ice storms and epidemics. As soon as a party anticipates that a force majeure event may occur which will delay or prevent it from performing any of its obligations under this Master Agreement or any Contract, it shall promptly notify the other party and shall exercise all reasonable efforts to mitigate or limit the effect on the other party.

Once a party becomes subject to such an event of force majeure, it shall promptly notify the other party of its inability to perform, or of any delay in performing, due to an event of force majeure and shall provide an estimate, as soon as practicable, as to when the obligation will be performed. The party subject to the force majeure event shall also continue to furnish timely reports to the other party with respect to the force majeure event during the continuation of the said event and the said party shall exercise all reasonable efforts to mitigate or limit damages to the other party. The party subject to the force majeure event shall use its best efforts to continue to perform its obligations under this Master Agreement or any Contract, as the case may be, and to correct or cure the event or condition excusing performance and when the said party is able to resume performance of its obligations thereunder, it shall give the other party written notice to that effect and shall promptly resume performance thereunder. The time for performing the obligation shall be extended for a period equal to the time during which the party was subject to the event of force majeure. The parties shall explore all reasonable avenues available to avoid or resolve events of force majeure in the shortest time possible.

Notwithstanding the two preceding paragraphs, the settlement of any strike, lockout, restrictive work practice or other labour disturbance constituting a force majeure event shall be within the sole discretion of the party involved in such strike, lockout, restrictive work practice or other labour disturbance and nothing in the two preceding paragraphs shall require the said party to mitigate or alleviate the effects of such strike, lockout, restrictive work practice or other labour disturbance.

14.0 ASSIGNMENT

Neither this Master Agreement nor any Contract nor the rights and obligations under each thereof shall be assigned by either party hereto without the prior written consent of the other, which consent shall not be unreasonably withheld. Subject to the foregoing, this Master Agreement and each Contract shall enure to the benefit of the parties hereto and their respective successors and permitted assigns.

15.0 AMENDMENTS

Any amendment, modification or supplement to this Master Agreement shall not be valid or binding unless set out in writing and executed by the parties with the same degree of formality as the execution of this Master Agreement. Notwithstanding the foregoing, the parties acknowledge and agree that the Services Recipient shall be entitled to unilaterally change the General Standards and Specifications attached hereto as Schedule "A" provided however that the parties shall negotiate in good faith the effect of any such changes to the scope of work in any relevant Contract, time for completion of the said scope of work and the price therefor, in accordance with the process outlined in Section 7.0 above.

16.0 ENTIRE AGREEMENT

This Master Agreement, together with Schedules "A", "B", "C", "D", "E" and "F" attached hereto, represents the entire agreement between the parties hereto respecting the subject matter hereto and supersedes all prior agreements, understandings, discussions, negotiations, representations and correspondence made by or between them respecting the subject matter hereto.

17.0 CONFLICTS

In the event of any conflict between this Master Agreement and Schedules "A", "B", "C", "D", "E" and "F", the provisions of the former shall prevail. In the event of any conflict between this Master Agreement and any executed Contract, the provisions of the latter shall prevail. In the event of any conflict amongst the Schedules, then the Schedules shall take precedence in the following order: (i) Schedule "C", (ii) Schedule "D"; (iii) Schedule "B"; (iv) Schedule "A"; (v) Schedule "E" and (vi) Schedule "F".

18.0 GOVERNING LAW

This Master Agreement and the Contracts shall be governed by and construed in accordance with the laws of the Province of Ontario and the laws of Canada applicable therein.

19.0 SCHEDULES

Schedules "A", "B", "C", "D", "E" and "F" attached hereto are to be read with and form part of this Agreement.

20.0 COUNTERPARTS

This Master Agreement and the Contracts may be executed in counterparts and the counterparts together shall constitute an original.

IN WITNESS THEREOF the parties hereto have caused this Master Agreement to be executed by their respective representatives duly authorized in that behalf.

HYDRO ONE REMOTE COMMUNITIES INC.	**HYDRO ONE NETWORKS INC.**
Name: Myles D'Arcey	Name: Maureen Wareham
Title: SVP, Customer Operations	Title: Corporate Secretary (Acting)
I have authority to bind the corporation.	I have authority to bind the corporation.

Schedule "A"

GENERAL STANDARDS AND SPECIFICATIONS

REVISION HISTORY

Date	Revision No.	Modification	Comments

TABLE OF CONTENTS

GSS #1 USED, REUSABLE AND WASTE MATERIALS

1.1 DEFINITIONS

1.1.1 Reusable Material

Where practical, the Services Provider shall reuse and re-deploy all material that is removed from service, provided such material is still in good operating condition and satisfies the criteria indicated in this GSS #1.

1.1.2 Waste Material

All other material that is removed from service will be considered to be waste material.

1.1.3 Recycling

Recycling means using waste material for purposes other than those for which the material was originally intended: it does not include destruction (such as incineration or burning as a supplementary fuel) or use as land fill.

1.2 EXPECTATIONS

Costs for the management of used material that is associated with capital projects, including the disposition of such material for re-deployment, re-use and/or disposal, shall be identified in each Contract, where applicable (e.g. the cost to pickup, transport and dispose of PCB fluids and contaminated waste).

The Services Provider shall handle all reusable material removed from service in a manner that is consistent with the Contract (where identified) and in accordance with applicable legislation, statutes, by-laws, codes, guidelines, regulations, and Hydro One procedures. Such material shall be stored in a safe and secure manner to minimize any risk of physical damage and/or of environmental or health and safety impacts associated with such damage, pending re-deployment or shipment to storage.

The Services Provider shall manage and dispose of waste material in a manner that is consistent with the Contract (where identified) and in accordance with applicable legislation, statutes, by-laws, codes, guidelines, regulations, and Hydro One procedures. Preference will be given, where practical, to disposal options that maximize the potential for recycling.

1.3 CRITERIA FOR USED MATERIALS

Material	Criteria and Action
Poles	• Distribution poles shall be less than 16 years old • Transmission poles shall be less than 12 year old • Penta-treated poles shall not be reused • All wood poles no longer required by the Services Recipient shall be returned to the appropriate service/operations centre. • All wood poles no longer required by the Services Recipient shall be disposed of appropriately.

Material	Criteria and Action
Pole-Mounted Transformers	• Must be no older than 1974 • If less than 200ppm PCB, a pole-mounted transformer shall be drained, refilled and re-tested after 2 years • If bushings are side-mounted they shall be recycled • Pole-Mounted Transformers shall be visually inspected (remove cover). If the inspection indicates no damage to the coil, they shall be returned for repair • If a transformer fails inspection and is over 50ppm PCB, it shall be scrapped as PCB-contaminated waste
Pad-mount Transformers	• All such transformers shall be returned for repair • If less than 200ppm PCB, a pad-mounted transformer shall be drained, refilled and re-tested after 2 years • Pad-mounted transformers shall be visually inspected. If the inspection indicates no damage to the coil, they shall be returned for repair • If a transformer fails inspection and is over 50ppm PCB, it shall be scrapped as PCB-contaminated waste
Line Voltage Regulators	• This includes any 50A line regulator retained for parts; all others shall be returned for repair • If less than 200ppm PCB, line voltage regulators shall be drained, refilled and re-tested after 2 years • Line voltage regulators shall be visually inspected (remove cover). If the inspection indicates no damage to the coil, they shall be returned for repair • If a regulators fails inspection and is over 50ppm PCB, it shall be scrapped as PCB-contaminated waste
Oil Circuit Reclosers	• If less than 200ppm PCB, the reclosers shall be drained, refilled, and re-tested after 2 years • Reclosers shall be visually inspected (remove cover). If the inspection indicates that there is no damage, they shall be returned for repair • If a recloser fails inspection and is over 50ppm PCB, it shall be scrapped as PCB-contaminated waste
Metering Transformers / Units	• If less than 200ppm PCB, the units shall be drained, refilled and re-tested after 2 years • The units shall be visually inspected (remove cover). If the inspection indicates no damage to the coil, it shall be returned for repair • If a unit fails inspection and is over 50ppm PCB, it shall be scrapped as PCB-contaminated waste
Capacitors	• No PCB or Dielektrol I- or II-filled capacitors shall be reused • Capacitors shall not have an unknown PCB content unless permission is obtained from the Services Recipient. Some capacitors manufactured before January 1981 may contain PCB over 50 ppm.
Primary Conductors	• If less than 3/0, primary conductors shall be reused for extensions where the main line is of the same size • Before reusing, #2 shall be inspected for deterioration in the core • All other conductors shall be reused
Secondary Conductors/ Underground Cable	• Secondary Conductors/Underground Cables shall be reused if they pass an asset condition test • The units must contain no splices (in the underground cable) that test greater than 50 mg/kg PCB. In addition, end sections must not have come from terminations that test greater than 50 mg/kg PDB. • All secondary conductors shall be reused • No underground cables shall be reused if they are more than 10 years old
Submarine Cable	• No submarine cable shall be used if it is more than 5 years old

Material	Criteria and Action
Insulators	• All single piece porcelain pin insulators shall be reused (not other porcelain insulators): the intent is to replace insulators with silicone (polymer) types on 115 kv and 230 kv, where practical • Epac insulators shall not be reused • Cob porcelain post insulators shall not be reused
Cross-arms	***Distribution:*** • Cross-arms shall be reused if no apparent cracking or excessive aging is evident
	Transmission: • All wooden cross-arms shall be removed and disposed • All steel cross-arms shall be reused
Spool Bolts	• All spool bolts shall be reused
Switches	***Distribution:*** • No Kearney switches nor rigid polymeric insulator-type switches shall be reused
	Transmission: • All shall be 115 kV & 230 kV in-line polymeric switches • Only those switches that have tested satisfactorily shall be reused
Insulating Oil	• All insulating oil is required to meet specification for Voltesso 35 Category "B" oil OR have the potential to be upgraded to meet this specification • Insulating oil must contain less than 50 mg/kg PCB by laboratory test

1.4 FINANCIAL TREATMENT OF USED MATERIAL

The Services Provider shall report all units removed from service. When used materials are reused for capital or maintenance work, the materials shall be charged to the work as if the material was new.

1.5 INFORMATION REQUIREMENTS

The Services Provider shall record and report the following information to the Services Recipient according to a schedule specified in the applicable Contract(1).

- Transformer Units by MVA/kVA and voltage, whether installed, salvaged or disposed as waste (new or used material)
- Regulator/Rabbit Units by kVA and voltage, whether installed, salvaged or disposed as waste (new or used material)
- Recloser Units by voltage and interrupting rating
- Switches by manufacturer type and voltage rating
- Capacitor Units by total MVA/kVAR, including voltage, number of phases and control type, whether installed, salvaged or disposed as waste (new or used material)
- Transmission line structures and distribution pole units by type (steel or wood pole), height, age, ownership (Hydro/Bell Canada/MEU), Bell Canada I.D. (exchange, route and pole number), structure number
- Conductor Units by size, type and length, whether installed, salvaged or disposed as waste (new or used material)
- Cable size, type, length and voltage, whether installed, salvaged or disposed as waste (new or used material)
- Record or retained material, including volumes scrapped, reused or repaired and reused.

(1) Note: The information listed above is required for accounting purposes at the plant.

1.6 WASTE MATERIAL

For waste material that is classified as either hazardous or as liquid industrial, the Services Provider shall follow specific requirements. These requirements are detailed in the appropriate legislation (e.g., *Environmental Protection Act, Occupational Health & Safety Act*) and internal policies/standards/procedures (e.g., Waste Management Manual). Records of hazardous waste volumes shipped to disposal shall be reported to the Services Recipient and such records shall be maintained according to established records management. All hazardous waste material shall be handled and managed with due regard for worker and public health and safety.

GSS #2 ENVIRONMENT, HEALTH & SAFETY REQUIREMENTS

2.1 GENERAL STATEMENT OF COMPLIANCE AND REQUIREMENTS

The Services Recipient expects to receive the same level of compliance, where applicable, for services provided under all Contracts. As a minimum, the Services Provider shall comply with the following:

- Federal and Provincial legislation;
- Municipal by-laws;
- The Services Recipient's Safety Rules and Policies;
- All legacy Ontario Hydro policies, procedures and standards still applicable to the Services Recipient;
- Policies approved by the Services Recipient's Board of Directors;
- The Services Recipient's Environment, Health & Safety Management policies, procedures and associated standards; and
- The Services Recipient's Policy for Health & Safety Incident Management.

2.2 ENVIRONMENTAL REQUIREMENTS

2.2.1 General Requirements for Management of the Environment

For managing the environment, the Services Provider shall abide by the following:

a) The Services Provider shall design, construct, operate, maintain and decommission the Services Recipient's facilities in accordance with standards to be developed by the Services Recipient and made available to the Services Provider.

b) The Services Provider shall perform all work on behalf of the Services Recipient in a manner that is consistent with the principles of an environmental management system including, as a minimum:
   - Assigning and communicating individual accountability and responsibility for the environment;
   - Engaging qualified employees and agents (i.e. with respect to knowledge, training and experience to perform the work assigned) to perform the work;
   - Having emergency preparedness and response capability suitable to the range of issues that could be encountered during the course of the work detailed in the Contract;
   - Inspecting, maintaining and monitoring equipment, facilities and employees during the course of providing the Contracted services;
   - Reporting environmental incidents, performing incident investigations and implementing corrective actions in response to an incident; and
   - Periodically reviewing environmental management processes and making improvements, as necessary.

c) The Services Provider shall consider the environmental implications of all work and integrate environmental considerations into its plans for all work that could have an adverse effect on the environment.

d) In performing the services, the Services Provider shall:
   - Use materials, products and equipment that are government-approved, industry-accepted and sustainable (i.e., from environmental, economical, social perspectives). The Services provider shall give preference, where practical, to materials and products that have low toxicity and do not contain substances that are included on Schedule 1 (List of Toxic Substances) of the *Canadian Environmental Protection Act* or on the Priority Substances Lists 1 and 2.
   - Maximize the efficient use of resources;
   - Be energy efficient; and
   - Conserve heritage resources.

e) The Services Provider shall, when included in the project scope, prepare and implement project-specific environmental specifications when the prevention or mitigation of predicted environmental impacts can only be assured by the application of a specific damage prevention or mitigation approach. Such environmental management specifications will be consistent with applicable standards.

f) The Services Provider shall prepare and provide to the Services Recipient, project-specific, As-Constructed Reports for all projects that require any one or more of the following, where the Services Recipient and the Services Provider shall mutually determine which environmental authorities or industry or legislative standards shall be used in developing such reports:

- Environmental permits;
- Environmental considerations or special commitments;
- Access agreements, construction property agreements and special conditions that contain a record of the final environmental state of the project;
- Documentation of significant environmental situations or activities; and
- Property rights summaries.

g) The Services Provider shall provide to the Services Recipient, the records identified in (b), (e) and (f).

2.2.2 Environmental Incident Management

The Services Provider shall consistently respond and report environmental incidents and ensure that all such incidents involving Distribution or Transmission assets and lands are managed effectively. Included as “environmental incidents” are:

- Vandalism, natural events (such as lightning, ice, and wind) and animal activity;
- Accidental or inadvertent public contact with electrical system assets or equipment (such as motor vehicle accidents, ladders into lines);
- Mechanical/electrical failure for no apparent reason or unknown cause;
- Asset management standards that are subsequently shown to have contributed to the incident; and
- Operation or maintenance activities in accordance with accepted standards that would not normally be expected to cause leaking, equipment failure or malfunction.

The Services Provider shall document all environmental incidents (such as spills and fires) involving the Services Recipient’s assets and/or lands (owned or easement) (e.g., complete a Hydro One Environmental Incident Report). The Services provider shall enter this information into the Web Environmental Incident Collector (WebEIC) database and/or any other similar database, as directed by the Services Recipient.

The Services Provider shall consistently respond to, and report, environmental incidents. The Services Provider shall also ensure that all environmental incidents involving the Service Recipient’s assets and land are managed effectively.

2.3 HEALTH & SAFETY

2.3.1 Potential Hazards

There are two significant hazards associated with work on the Services Recipient’s assets:

- Hazards inherent to working in proximity to electrical equipment; and
- Hazards inherent to working at heights.

The Services Provider may also work in buildings or at sites where hazardous substances are present. Inventories and assessments of potentially hazardous or hazardous substances have been completed for the majority of the Services Recipient’s sites; they are available to the Services Provider on request. All requests should be made locally.

The Services Provider shall manage all hazards associated with all Contracts with the Services Recipient.

2.3.2 General Requirements for the Management of Health & Safety

The Services Provider shall perform all work on behalf of the Services Recipient in a manner that is consistent with the principles of a health and safety management system including, as a minimum:

(a) Assigning and communicating individual accountability and responsibility for health and safety;

(b) Engaging qualified employees and agents (i.e. with respect to knowledge, training and experience to perform the work assigned) to perform the work;

(c) Having emergency preparedness and response capability suitable to the range of issues that could be encountered during the course of the work detailed in the Contract;

(d) Inspecting, maintaining and monitoring equipment, facilities and employees during the course of providing the Contracted services;

(e) Reporting safety events, performing event investigations and implementing corrective actions in response to an event;
(f) Periodically reviewing health and safety management processes periodically and making improvements, as necessary; and
(g) Submitting the records identified in (e) and (f) to the Services Recipient.

The Services Provider shall ensure the protection of the public in the performance of all work for the Services Recipient.

2.3.3 Health & Safety Event Management

The Services Provider shall consistently respond and report all health and safety events involving the Services Recipient staff and/or members to the Services Recipient. Included as health and safety events are:

- Vandalism, natural events (such as lightning, ice, and wind) and animal activity;
- Accidental or inadvertent public contact with electrical system assets or equipment (such as motor vehicle accidents, ladders into lines);
- Mechanical/electrical failure for no apparent reason or unknown cause;
- Asset management standards that are subsequently shown to have contributed to the event; and
- Operation or maintenance activities in accordance with accepted standards that would not normally be expected to cause leaking, equipment failure or malfunction.

Schedule "B"

CONTRACT CHANGE NOTIFICATION FORM (No. xxx)

Date issued: xx-xxx-xx

Contract #		
Services Description		
Project ID	**Services Recipient**	**Services Provider**
Scope Change		
Reason for Change		
Schedule/Delivery Impact		
Impact on Price	**Old Contract Price:** **New Contract Price:**	
Approvals	**Hydro One Networks Inc.**	**Hydro One Remote Communities Inc.**
Effective Date of Change:		
Proposed By:		
Date:		
Reviewed By:	(Contract manager)	(Contract manager)
Date:		
Approved by:	(Authorized Signatory)	(Authorized Signatory)
Date:		

Schedule "C"

CONTRACT No. _______

THIS CONTRACT made this ____ day of _________, 2007 between **HYDRO ONE NETWORKS INC.** (the "Services Provider") and **HYDRO ONE REMOTE COMMUNITIES INC.** (the "Services Recipient").

WHEREAS the Services Provider and the Services Recipient have entered into a Master Agreement dated ______________ (the "Master Agreement"), which specifies the terms and conditions that govern this Contract;

AND WHEREAS the parties have agreed to enter into this Contract whereby the Services Provider has agreed to provide to the Services Recipient and the Services Recipient has agreed to acquire from the Services Provider, the services more specifically described in section A. below (the "Services"), pursuant to the terms and conditions herein and in the Master Agreement.

NOW THEREFORE in consideration of the terms, conditions and covenants contained herein and in the Master Agreement and other good and valuable consideration, the receipt and sufficiency of which is hereby irrevocably acknowledged, the parties hereto agree to the following:

A. Description of Services (Describe Scope of Work):

B. Term:

C. Price and Terms of Payment:
Base Price:
Provincial Sales Tax:

D. Exceptions/Additions to terms and conditions in Master Agreement:

E. Service Levels

F. Performance Targets:

G. The managers for this Contract shall be as follows:

Services Provider: Hydro One Networks Inc.
483 Bay Street TCT 8 G3
Toronto, Ontario M5G 2P5

Contract Manager: Name: **Greg Van Dusen**
Title: Director, Work Program Optimization
Tel. No. 416-345-5722
Fax. No. 416-345-6833

Services Recipient: Hydro One Remote Communities Inc.
483 Bay Street, TCT 14 A8
Toronto, Ontario M5G 2P5

Contract Manager: Name: **Una O'Reilly**
Title: Manager, Business Integration
Tel. No. 416-345-6698
Fax. No. 416-345-6356

The parties acknowledge and agree that the above terms and conditions and the terms and conditions contained in the Master Agreement shall govern this Contract except as otherwise agreed above under Section D. and the parties shall hereby be bound by and comply with all of the said terms and conditions.

IN WITNESS WHEREOF, the parties have caused this Contract to be executed by their respective representatives duly authorized in that behalf.

HYDRO ONE REMOTE COMMUNITIES INC.

Name:
Title:
I have authority to bind the corporation.

HYDRO ONE NETWORKS INC.

Name:
Title:
I have authority to bind the corporation.

Schedule "D"

COMMERCIAL GENERAL LIABILITY INSURANCE CERTIFICATE
SUPPLY ONLY TRADES

Issued in favour:
Insured:
XXXXXXXXXXXXXXXXXXXXX
XXXXXXXXXXXXXXXXXXXXX
XXXXXXXXXXXXXXXXXXXXX
XXXXXXXXXXXXXXXXXXXXX
This is to certify that policies of insurance listed below have been issued to the insured named above for the period indicated and cover operations of the insured in connection with the **SERVICES BEING PERFORMED UNDER CONTRACT NUMBER xxxxxxxxxx**

		Effective	**Expiration**	
	Policy	**Date**	**Date**	
Type of insurance	**Number**	**MM/DD/YR**	**MM/DD/YR**	
Commercial General Liability				$5,000,000
(X) Blanket Contractual Liability				$5,000,000
(X) Broad Form Property Damage				$5,000,000
(X) 3rd Party Property damage including loss of use				
(X) Sudden and Accidental Pollution Liability coverage				
(X) Products and Completed operations				
(X) Employer's Liability				
(X) Non-Owned Automobile Liability				
Automobile Liability				
(X) Owners				$5,000,000

Special Condition

Commercial General Liability policy shall i) include Hydro One Remote Communities Inc. as a named insured subject to sole agent provisions and ii) be primary non-contributing with and not excess of any other insurance available to Hydro One Remote Communities Inc. iii) contain a cross liability and severability of interest clause

The Insurer agrees to notify the certificate holder by registered mail not less than 30 days prior to any material change, which reduces or restricts cover, cancellation, termination or non-renewal.

Date:	
Name of Insurer:	
By: Authorized Official of the Insurance Company	
Print Name and Title of Above Official	

Schedule "E"

ADDITIONAL INSURANCE COVERAGES

1.01 Commercial General Liability and Excess Liability Insurance on an occurrence basis in an amount not less than $5,000,000 inclusive for both bodily injury, including death, personal injury and damage to property, including loss of use thereof, for each occurrence. To achieve the desired limit, umbrella or excess liability insurance may be used.

Coverage shall specifically include, but not be limited to, the following

i) Blasting, pile driving, caisson work, underground work;
ii) Products & Completed Operations including a provision that such coverage to be maintained for a period not less than 24 months post Final Performance;
iii) Errors and omissions integral to the operation of the Insured;
iv) Tenant's Legal Liability;
iv) Pesticide Liability; and
v) Rail Liability.

1.02 Contractor's Equipment Insurance covering equipment and tools, owned, rented or leased for the full replacement cost of such equipment on an "All Risks" basis including marine based risk subject to normal exclusions.

1.03 Pollution Liability Insurance: When remediation or abatement is included in the work, the Services Provider shall purchase a policy with limits of not less than $5,000,000 per occurrence covering bodily injury and property damage claims, including cleanup costs as a result of pollution conditions arising from the Services Provider's and/or its subcontractors' operations and completed operations. Completed operations coverage will remain in effect for no less than 3 years after final completion. The policy will have a retroactive date before the start of the work. To achieve the desired limit, umbrella or excess liability insurance may be used.

1.04 Errors & Omissions Insurance: Engineering, Architectural, Design or other Professionals or Consultants and the EPCM (Engineering, Procurement, Construction and Maintenance). The Services Provider shall, at all times, maintain in full force and effect professional liability insurance in an amount not less than $10,000,000 aggregate limit covering the period from start of conceptual design through to completion of the project and for a further discovery period of 5 years from the issuance of the certificate of Final Completion.

1.05 Transit insurance (including loading, unloading and storage during the course of transit including storage at secondary processing facilities) against All Risks of physical damage to the property of the Services Recipient in the Services Provider's care, custody and control until such property is received on the Services Recipient's site.

1.06 Aircraft and watercraft liability insurance with respect to owned or non-owned aircraft and watercraft if used directly or indirectly in the performance of the Services, including use of additional premises, shall be subject to limits of not less than $5,000,000.00 inclusive per occurrence for bodily injury, death and damage to property including loss of use thereof and limits of not less than $5,000,000.00 for aircraft passenger hazard. Such insurance shall be in a form acceptable to the Services Recipient. The policies shall be endorsed to provide the Services Recipient with not less than 15 days' notice in writing in advance of cancellation, change, or amendment restricting coverage. To achieve the desired limit, umbrella or excess liability insurance may be used.

1.07 Such other insurance as is mutually agreed upon between the Services Recipient and the Services Provider.

Where any of the above coverages are required for any Contract, the Services Provider shall be bound by and comply with the following:

1. Prior to the commencement of the performance of the Services, the Services Provider shall provide the Services Recipient with a certificate of insurance completed by a duly authorized representative of its insurer certifying that at least the minimum coverages required here are in effect and that the coverages will not be cancelled, nonrenewed, or materially changed by endorsement or otherwise so as to restrict or reduce coverage, without 30 days' advance written notice by registered mail, or courier, receipt required, to:

    Manager, Risk & Insurance Department, Hydro One Remote Communities Inc. 483 Bay Street, TCT8, South Tower , Toronto, Ontario. M5G 2P5

   If any of the coverages are required to remain in force after final payment, an additional certificate evidencing continuation of such coverage will be submitted with the Services Provider's final invoice.

2. All deductibles shall be to the account of the Services Provider.

3. All insurance noted above shall specify that it is primary coverage and not contributory with or in excess of any other insurance that may be maintained by the Services Recipient.

4 A waiver of subrogation shall be provided by the insurers to the Services Recipient for coverages 1.02 (Contractor's Equipment).

6. The Services Recipient shall be included as a Named Insured under coverages noted in 1.03 (Pollution Liability) subject to Sole Agent provisions.

7. Coverages noted in 1.03 (Pollution Liability) shall contain a Cross Liability clause and a Severability of Interests clause.

8. Coverage provided for shall not be invalidated by actions or inactions of others.

Schedule "F"

Receiving Party Security Safeguards Regarding Confidential Information Received from the Disclosing Party

The Receiving Party shall protect the Confidential Information by security safeguards appropriate to the sensitivity of the information.

1) The Receiving Party shall protect the Confidential Information against such risks as loss or theft, unauthorized access, disclosure, copying, use, modification or destruction, through appropriate security measures, regardless of the format in which it is held.

2) All of the Receiving Party's Representatives with access to the Confidential Information shall be contractually required to respect the confidentiality of that information.

3) The Receiving Party acknowledges and agrees that the nature of the safeguards will vary depending on the sensitivity, amount, distribution and format of the information, and the method of storage. The Receiving Party shall ensure that more sensitive information will be safeguarded by a higher level of protection.

4) The Receiving Party shall ensure that methods of protection will include:

(a) physical measures, for example, locked filing cabinets and restricted access to offices;

(b) organizational measures, for example, controlling entry to data centers and limiting access to information on a "need-to-know" basis;

(c) technological measures, for example, the use of passwords and encryption; and

(d) investigative measures, in cases where the Receiving Party has reasonable grounds to believe that the Confidential Information is being inappropriately collected, used or disclosed by anyone whom in law the Receiving Party is responsible.

AFFILIATE SERVICE AGREEMENTS

Appendix D

Hydro One Networks Inc.

Service Provision to:

Hydro One Remote Communities Inc.

2007

(President and CEO services)

THIS AGREEMENT made in duplicate this 1st day of January, 2007 (the "Effective Date").

BETWEEN:

HYDRO ONE NETWORKS INC.
(the "Services Provider")

- and -

HYDRO ONE REMOTE COMMUNITIES INC.
(the "Services Recipient")

1.0 PREFACE

This Agreement is intended to identify the services that are to be provided to the Services Recipient by the Services Provider in accordance with the terms and conditions herein. The term of this Agreement shall be for a period of 1 year commencing on the Effective Date.

2.0 SERVICES

The Services Provider shall provide chief and executive office and president services to the Services Recipient, which collectively constitute the Services and which are more particularly described in Schedule "A" attached hereto, as may be required by the Services Recipient from time to time during the term of this Agreement.

3.0 FEES PAYABLE

(a) The annual price for the performance of the Services for the Services Recipient shall be $80,000.00, exclusive of any sales and use taxes, as may be applicable. The said annual price for the Services shall be paid by the Services Recipient to the Services Provider by means of monthly electronic journal transfers which shall be reflected in the applicable books and records of each party In addition, each Services Recipient shall pay for any material costs which the Services Provider, acting reasonably, incurs as a result of resources, services and products that the Services Provider must purchase and that are in addition to the Services Provider's existing resources, services and products, in order to provide the said Services Recipient with specific services it requires and requests.

(b) If at any time during the performance of the Services, the Services Recipient is of the opinion that there are deficiencies in the Services provided to it and/or that the price payable is in any way inaccurate, the Services Recipient shall pay the entire relevant price payable by it in full and its sole remedy shall be to follow the dispute resolution procedures outlined in Section 6.0 herein to determine what amount, if any, shall be refunded to the Services Recipient and/or what Services, if any, shall be rectified or redone by the Services Provider.

c) The parties acknowledge and agree that they qualify as specified members of a closely related group under subsection 156(1) of the Excise Tax Act (Canada), as amended (the "Act") and have jointly executed a Form GST25, to make an election under subsection 156(2) of the Act to deem the purchase and sale of the Services to be made for nil consideration for Goods and Services Tax purposes.

4.0 REPRESENTATIONS AND WARRANTIES

(a) The Services Provider represents and warrants that:

- (i) it has all the necessary authority and capacity to enter into this Agreement and to perform its obligations hereunder;
- (ii) the execution of this Agreement and compliance with and performance of the terms, conditions, and covenants contemplated herein have been duly authorized by all necessary corporate action on the part of the Services Provider; and
- (iii) all staff employed in the performance of the Services shall have the qualifications, expertise and experience which could reasonably be expected of staff of a services provider performing work similar to the Services.

(b) The Services Recipient represents and warrants that:

- (i) it has all the necessary authority and capacity to enter into this Agreement and to perform its obligations hereunder; and
- (ii) the execution of this Agreement and compliance with and performance of the terms, conditions, and covenants contemplated herein have been duly authorized by all necessary corporate action on the part of the Services Recipient.

5.0 PERFORMANCE OF THE SERVICES

(a) **Compliance with Standards and Applicable Law**: The Services Provider shall perform the Services in a diligent and professional manner and shall comply with the Services Recipient's computer data management and data access protocols contained in the Services Recipient's documents entitled "Corporate Security Standard 600-3 – Information Security Policy" and "Corporate Security Policy 600 – Information Security Policy", both of which are dated January 17, 2000 and any amendments thereto which may be made from time to time by the Services Recipient. The Services Provider shall comply at all times with the statutes, regulations, by-laws, standards and codes, as amended, as may be applicable to the Services Provider in respect of the Services and the performance of its obligations hereunder and it shall, at its own expense, obtain and maintain in good standing all permits and licences required by any authorities having jurisdiction to perform the Services.

(b) **Safety and Security Measures**: When any part of the Services is to be performed at any of the Services Recipient's premises, all of the Services Provider's staff engaged in the performance of the Services at the said premises shall comply with the safety and security requirements and measures in effect at the said premises.

(c) **Meetings**: The parties shall, after the Effective Date, meet at least twice a year during the term of this Agreement to review performance, quality and timeliness of the Services provided by the Services Provider pursuant to this Agreement."

6.0 DISPUTE RESOLUTION PROCEDURES

Any controversy, dispute, difference, question or claim arising between any of the parties in connection with the interpretation, performance, construction or implementation of this Agreement that cannot be resolved by a director or manager from each of the said parties (collectively "Dispute") shall be settled in accordance with this Section. The aggrieved party shall send the other affected party(ies) written notice identifying the Dispute, the amount involved, if any, and the remedy sought, and invoking the procedures of this Section. The Presidents of each affected party shall confer in an effort to resolve the Dispute. If the Presidents are unable to resolve the Dispute within 5 business days after receipt of the written notice of the Dispute, then the affected parties shall submit the Dispute to the President of Hydro One Inc. for resolution.

7.0 CONFIDENTIALITY AND INTELLECTUAL PROPERTY

(a) Confidentiality:

Each party (the "Receiving Party") shall maintain in strict confidence this Agreement and the existence and contents thereof and all information, analysis, conclusions, drawings, reports, specifications or other information, proprietary or otherwise, whether transmitted orally, electronically or in written form, and received in furtherance of this Agreement from any of the other parties (the "Disclosing Party") or any of the Disclosing Party's directors, officers, employees, consultants, agents or legal and other advisors (the "Disclosing Party Representatives") (collectively the "Confidential Information"). Except as permitted herein, the Receiving Party shall not publish, reproduce, or disclose, either directly or indirectly, the said Confidential Information to any third party and shall not use the said Confidential Information for any purpose other than for purposes of this Agreement without the prior written consent of the Disclosing Party. The Receiving Party may disclose the Confidential Information only to its shareholder, directors, officers, employees, consultants, agents or professional advisors (the "Receiving Party Representatives") having a need to know same and who have undertaken a like obligation to maintain its confidentiality.

For greater certainty, Confidential Information includes any and all personal information (as that term is defined in the Freedom of Information and Protection of Privacy Act (Ontario) and the Personal Information Protection and Electronic Documents Act (Canada), as they may be amended, and any and all information regarding a consumer, retailer, wholesale buyer, wholesale supplier, or a generator, provided by the Disclosing Party to the Receiving Party for purposes of this Agreement, whether or not such information was initially provided prior to the Effective Date.

The Receiving Party undertakes to protect and safeguard all Confidential Information in its possession or under its control and received by the Disclosing Party, in the manner described in Schedule "B" attached hereto. The Disclosing Party may, on reasonable notice, and during regular business hours, audit the information management practices of the Receiving Party to confirm compliance with the terms and conditions of this Section 7.0 and all applicable statutes, regulations, by-laws, standards and codes, as amended.

The Receiving Party undertakes to notify the Disclosing Party immediately upon discovery of any unauthorized use and/or disclosure of any of the Disclosing Party's Confidential Information, to co-operate with the Disclosing Party to help regain possession of such Confidential Information, and to prevent its further unauthorized use and/or disclosure.

The foregoing obligations with respect to confidentiality, use, reproduction, dissemination, publication and non-disclosure herein shall not apply to any information that:

(i) is previously known to or lawfully in the possession of the Receiving Party prior to the date of disclosure as evidenced by the Receiving Party's written record;
(ii) is independently known to or discovered by the Receiving Party, without any reference to the information or material;
(iii) is obtained by the Receiving Party from an arm's length third party having a bona fide right to disclose same and who was not otherwise under an obligation of confidence or fiduciary duty to the Disclosing Party or the Disclosing Party Representatives;
(iv) is or becomes public knowledge through no fault or omission of, or breach of this Agreement by the Receiving Party or the Receiving Party Representatives; or
(v) is required to be disclosed pursuant to a final judicial or governmental order or other legal process.

Confidential Information (other than this Agreement which shall be jointly owned by the parties) shall remain the sole and exclusive property of the Disclosing Party that has disclosed the Confidential Information, and the Disclosing Party shall retain all right, title and interest in and to the said Confidential Information.

The Receiving Party shall keep a record of written Confidential Information furnished to it by the Disclosing Party in a location separate from those locations where the Receiving Party has stored information in respect of other third parties for which it performs work and it shall advise the Disclosing Party of such location.

All Confidential Information furnished by the Disclosing Party (other than this Agreement), including that portion of the Confidential Information which is contained in analyses, compilations, studies or other documents prepared by the Receiving Party or by the Receiving Party Representatives, is the Disclosing Party's property and will be returned immediately to the Disclosing Party upon its request.

(b) Intellectual Property:

The Services Recipient shall obtain all rights, title and interests, including copyright ownership, to any reports and any other deliverable that is to be produced and delivered to it by the Services Provider and, subject to applicable legislation and notwithstanding clause 7.0(a) above, the said Services Recipient may use, disclose or modify such reports or deliverable in any manner it deems appropriate. The Services Provider shall not do any act which may compromise or diminish the Services Recipient's interest as aforesaid.

(c) Survival of Obligations:

The obligations in this Section 7.0 shall forever survive the termination or expiration of this Agreement.

8.0 LIABILITY

Unless otherwise agreed in writing, each party shall indemnify the other party and that other party's successors and assigns, directors, officers, employees, contractors and agents from and against all direct costs or damages attributable to the indemnifying party's performance and/or non-performance of its obligations under this Agreement and any amendments or additions thereto that are mutually agreed to in writing, whether arising from or based on breach of contract, tort, negligence, strict liability or otherwise. Notwithstanding any other provision of this Agreement, neither party shall be liable for any economic loss, loss of goodwill, loss of profit or for any special, indirect or consequential damages, where the said losses or damages are incurred by the other or by any third party claiming through or under the other.

This Section 8.0 shall forever survive the termination or expiration of this Agreement.

9.0 AUTHORIZED REPRESENTATIVES

The authorized representatives of the parties hereto for purposes of this Agreement are the following:

HYDRO ONE REMOTE COMMUNITIES INC.
483 Bay Street,
North Tower, 14th Floor
Toronto, Ontario M5G 2P5
Attention: **Una O'Reilly**
TCT 14
Telephone: 416-345-6698
Telecopier: 416-345-6356

HYDRO ONE NETWORKS INC.
483 Bay St.
South Tower, 8th Floor
Toronto, Ontario M5G 2P5
Attention: **Greg Van Dusen**
Telephone: (416) 345-5722
Telecopier: (416) 345-6833

All correspondence, reports, documents and/or other communication concerning this Agreement and the Schedule attached hereto shall be directed to the attention of the authorized representatives noted above and shall be deemed to be sufficiently given if delivered personally, mailed or transmitted by fax to the attention of the authorized representatives at the addresses above, and any notice so given shall be deemed to have been made and received on the date of delivery or on the 5th business day following the day of mailing of same or on the day of transmission if transmitted during normal business hours, otherwise on the next business day, as the case may be.

10.0 CHANGE OF CONTROL

In the event of a change of control of the Services Provider, this Agreement shall immediately terminate. A change of control shall mean, as applicable, a purchase of more than fifty (50) percent of the outstanding capital by a non-affiliate third party.

11.0 ASSIGNMENT

Neither this Agreement nor any rights and obligations shall be assigned by either party without the prior written consent of the other party, which consent shall not be unreasonably withheld. Subject to the foregoing, this Agreement shall enure to the benefit of the parties hereto and their respective successors and permitted assigns.

12.0 RELATIONSHIP OF PARTIES:

Nothing in this Agreement creates the relationship of principal and agent, employer and employee, partnership or joint venture between the parties. The parties agree that they are and will at all times remain independent and are not and shall not present themselves to be the agent, employee, partner or joint venturer of the other. No representations will be made or acts taken by either party which could establish any apparent relationship of agency, employment, joint venture or partnership and neither party shall be bound in any manner whatsoever by any agreements, warranties or representations made by the other party to any other person nor with respect to any other action of the other party.

13.0 SCHEDULES

Schedules "A" and "B" attached hereto are to be read with and form part of this Agreement.

14.0 COUNTERPARTS

This Agreement may be executed in counterparts and the counterparts together shall constitute an original.

IN WITNESS THEREOF the parties hereto have caused this Agreement to be executed by their respective representatives duly authorized in that behalf.

HYDRO ONE NETWORKS INC.

Maureen Wareham

Name: Maureen Wareham
Title: Acting Secretary
I have authority to bind the corporation

HYDRO ONE REMOTE COMMUNITIES INC.

Name: Myles D'Arcey
Title: President & CEO
have authority to bind the corporation.

Schedule "A"

DESCRIPTION OF SERVICES:

The Services Provider shall provide the Services Recipient with the following services:

- Provide administrative services related to Corporate record-keeping, and signing of contracts and corporate documents that require strategic approval;
- Communicate Hydro One Inc.'s strategic goals, direction and policies to the Services Recipient and ensure that the Services Recipient adheres to these policies, goals and directions; and
- Advocate for the Services Recipient at the Hydro One Inc. level for budgetary items, operational issues and performance goals, and ensure that the Services Recipient's business is understood and communicated at the parent company level.

Schedule "B"

Receiving Party Security Safeguards Regarding Confidential Information Received from the Disclosing Party

The Receiving Party shall protect the Confidential Information by security safeguards appropriate to the sensitivity of the information.

1) The Receiving Party shall protect the Confidential Information against such risks as loss or theft, unauthorized access, disclosure, copying, use, modification or destruction, through appropriate security measures, regardless of the format in which it is held.

2) All of the Receiving Party Representatives with access to the Confidential Information shall be contractually required to respect the confidentiality of that information.

3) The Receiving Party acknowledges and agrees that the nature of the safeguards will vary depending on the sensitivity, amount, distribution and format of the information, and the method of storage. The Receiving Party shall ensure that more sensitive information will be safeguarded by a higher level of protection.

4) The Receiving Party shall ensure that methods of protection will include:

(a) physical measures, for example, locked filing cabinets and restricted access to offices;

(b) organizational measures, for example, controlling entry to data centers and limiting access to information on a "need-to-know" basis;

(c) technological measures, for example, the use of passwords and encryption; and

(d) investigative measures, in cases where the Receiving Party has reasonable grounds to believe that the Confidential Information is being inappropriately collected, used or disclosed by anyone whom in law the Receiving Party is responsible.

AFFILIATE SERVICE AGREEMENTS

Appendix E

Hydro One Telecom Inc.

Service Provision to:

Hydro One Networks Inc.

2007

(Telecommunications services)

TELECOMMUNICATIONS SERVICES AGREEMENT

THIS AGREEMENT made this 4th day of December, 2006 (the "Effective Date").

BETWEEN:

HYDRO ONE TELECOM INC.
("HOTelecom")

- and -

HYDRO ONE NETWORKS INC.
("HONI")

1.0 PREFACE

This Agreement is intended to identify certain telecommunications services that are to be provided to HONI by HOTelecom with respect to HONI's electricity distribution and transmission system (the "Power System") and HONI's business system (the "Business System") in accordance with the terms and conditions herein.

This Agreement, together with Schedules "A", "B" and "C" attached hereto, represents the entire agreement between the parties respecting the subject matter hereto and supersedes all prior agreements, understandings, discussions, negotiations, representations and correspondence made by or between them respecting the subject matter hereto.

2.0 TERM AND SERVICES

(a) Term:

Subject to the termination rights provided elsewhere in this Agreement and except as otherwise specified, this Agreement shall be effective as of the Effective Date and shall continue in full force and effect until December 31, 2008 . Clause 2.0(b), Section 3.0 and Sections 5.0 to 8.0 inclusive shall be effective as of January 1, 2007 and shall continue to be of full force and effect until such time that this Agreement is terminated in accordance with the terms and conditions herein (the "Term").

(b) Services:

Subject to the terms and conditions of this Agreement, HOTelecom shall provide to HONI and HONI shall acquire from HOTelecom, if and when required by HONI during the Term, the following services, which collectively constitute the Services and which are more particularly described in the following Schedules attached hereto:

- Schedule "A" – Power System – Operation of Telecommunications Services
- Schedule "B" – Business System – Operation of Telecommunications Services

3.0 FEES PAYABLE

(a) The price for the performance of each of the Services shall be as identified in each of the applicable Schedules attached hereto, exclusive of any sales and use taxes, as may be applicable. Except as may be specified otherwise in the applicable Schedules attached hereto, the relevant price for the Services shall be paid by HONI to HOTelecom by means of monthly electronic journal transfers which shall be reflected in the applicable books and records of each party. In addition, HONI shall pay for any material costs which HOTelecom, acting reasonably, incurs as a result of resources, services and products that HOTelecom must purchase and that are in addition to HOTelecom's existing resources, services and products, in order to provide HONI with specific services it requires and requests beyond those specified in applicable Schedules.

(b) The parties shall meet and review the volume and scope of each of the Services identified in the Schedules attached hereto in the second quarter of the second year of the Term in an attempt to arrive at estimated prices for any possible extension or renewal of this Agreement.

(c) If at any time during the performance of the Services, HONI is of the opinion that there are deficiencies in the Services provided to it and/or that the price payable is in any way inaccurate, HONI shall pay the entire relevant price payable by it in full and its sole remedy shall be to follow the dispute resolution procedures outlined in Section 6.0 herein to determine what amount, if any, shall be refunded to HONI and/or what Services, if any, shall be rectified or redone by HOTelecom.

(d) The parties acknowledge and agree that they qualify as specified members of a closely related group under subsection 156(1) of the *Excise Tax Act* (Canada), as amended (the "Act") and have jointly executed a Form GST25, to make an election under subsection 156(2) of the Act to deem the purchase and sale of the Services to be made for nil consideration for Goods and Services Tax purposes.

4.0 REPRESENTATIONS AND WARRANTIES

(a) HOTelecom represents and warrants that:
   - (i) it has all the necessary authority and capacity to enter into this Agreement and to perform its obligations hereunder;
   - (ii) the execution of this Agreement and compliance with and performance of the terms, conditions, and covenants contemplated herein have been duly authorized by all necessary corporate action on the part of HOTelecom; and
   - (iii) all staff employed in the performance of the Services shall have the qualifications, expertise and experience which could reasonably be expected of staff of a services provider performing work similar to the Services.
   - (iv) that the prices for the Services to be performed as specified in Schedules "A" and "B" attached hereto are no more than the fair market value of the Services and where a fair market value is not available for any of the Services, the prices are cost-based prices.

(b) HONI represents and warrants that:
   - (i) it has all the necessary authority and capacity to enter into this Agreement and to perform its obligations hereunder; and

(ii) the execution of this Agreement and compliance with and performance of the terms, conditions, and covenants contemplated herein have been duly authorized by all necessary corporate action on the part of HONI.

5.0 PERFORMANCE OF THE SERVICES

(a) **Compliance with Standards and Applicable Law:** HOTelecom shall perform the Services in a diligent and professional manner and shall comply with HONI's computer data management and data access protocols contained in HONI's documents entitled "Corporate Security Standard 600-3 – Information Security Policy" and "Corporate Security Policy 600 – Information Security Policy", both of which are dated January 17, 2000 and any amendments thereto which may be made from time to time by HONI. HOTelecom shall comply at all times with the statutes, regulations, by-laws, standards and codes, as amended, as may be applicable to HOTelecom in respect of the Services and the performance of its obligations hereunder and it shall, at its own expense, obtain and maintain in good standing all permits and licences required by any authorities having jurisdiction to perform the Services.

(b) **Safety and Security Measures**: When any part of the Services is to be performed at HONI's premises, all of HOTelecom's staff engaged in the performance of the Services at the said premises shall comply with the safety and security requirements and measures in effect at the said premises.

(c) **Meetings**: HONI and HOTelecom shall meet at least once a month to review performance, quality and timeliness of the Services and to discuss operational issues of the Services provided by HOTelecom pursuant to this Agreement.

6.0 DISPUTE RESOLUTION PROCEDURES

Any controversy, dispute, difference, question or claim arising between any of the parties in connection with the interpretation, performance, construction or implementation of this Agreement that cannot be resolved by a director or manager from each of the said parties (collectively "Dispute") shall be settled in accordance with this Section. The aggrieved party shall send the other party written notice identifying the Dispute, the amount involved, if any, and the remedy sought, and invoking the procedures of this Section. One Senior Manager of each party shall confer in an effort to resolve the Dispute. If the Senior Managers are unable to resolve the Dispute within 5 business days after receipt of the written notice of the Dispute, then the parties shall submit the Dispute to the President of Hydro One Inc. for resolution.

7.0 CONFIDENTIALITY AND INTELLECTUAL PROPERTY

(a) Confidentiality:

Each party (the "Receiving Party") shall maintain in strict confidence this Agreement and the existence and contents thereof and all information, analysis, conclusions, drawings, reports, specifications or other information, proprietary or otherwise, whether transmitted orally, electronically or in written form, and received in furtherance of this Agreement from the other party (the "Disclosing Party") or any of the Disclosing Party's directors, officers, employees, consultants, agents or legal and other advisors (the "Disclosing Party Representatives") (collectively the "Confidential Information"). Except as permitted herein, the Receiving Party shall publish, reproduce or disclose, either directly or indirectly, the said Confidential Information to any third party and shall not use the said Confidential Information for any purpose other than for purposes of this Agreement without the prior written consent of the Disclosing Party. The Receiving Party may disclose the Confidential Information only to its shareholder, directors, officers, employees, consultants, agents or professional advisors (the "Receiving Party Representatives") having a need to know same and who have undertaken a like obligation to maintain its confidentiality.

For greater certainty, Confidential Information includes any and all personal information (as that term is defined in the *Freedom of Information and Protection of Privacy Act* (Ontario) and the *Personal Information Protection and Electronic Documents Act* (Canada), as they may be amended, and any and all information regarding a consumer, retailer, wholesale buyer, wholesale supplier, or a generator provided by the Disclosing Party to the Receiving Party for purposes of this Agreement, whether or not such information was initially provided prior to the Effective Date.

The Receiving Party undertakes to protect and safeguard all Confidential Information in its possession or under its control and received by the Disclosing Party, in the manner described in Schedule "C" attached hereto. The Disclosing Party may, on reasonable notice, and during regular business hours, audit the information management practices of the Receiving Party to confirm compliance with the terms and conditions of this Section 7.0 and all applicable statutes, regulations, by-laws, standards and codes, as amended.

The Receiving Party undertakes to notify the Disclosing Party immediately upon discovery of any unauthorized use and/or disclosure of any of the Disclosing Party's Confidential Information, to co-operate with the Disclosing Party to help regain possession of such Confidential Information, and to prevent its further unauthorized use and/or disclosure.

The foregoing obligations with respect to confidentiality, use, reproduction, dissemination, publication and non-disclosure herein shall not apply to any information that:

(i) is previously known to or lawfully in the possession of the Receiving Party prior to the date of disclosure as evidenced by the Receiving Party's written record;
(ii) is independently known to or discovered by the Receiving Party, without any reference to the information or material;
(iii) is obtained by the Receiving Party from an arm's length third party having a bona fide right to disclose same and who was not otherwise under an obligation of confidence or fiduciary duty to the Disclosing Party or the Disclosing Party Representatives;
(iv) is or becomes public knowledge through no fault or omission of, or breach of this Agreement by the Receiving Party or the Receiving Party Representatives; or
(v) is required to be disclosed pursuant to a final judicial or governmental order or other legal process.

Confidential Information (other than this Agreement which shall be jointly owned by the parties) shall remain the sole and exclusive property of the Disclosing Party that has disclosed the Confidential Information, and the Disclosing Party shall retain all right, title and interest in and to the said Confidential Information.

The Receiving Party shall keep a record of written Confidential Information furnished to it by the Disclosing Party in a location separate from those locations where the Receiving Party has stored information in respect of other third parties for which it performs work and it shall advise the Disclosing Party of such location.

All Confidential Information furnished by the Disclosing Party (other than this Agreement), including that portion of the Confidential Information which is contained in analyses, compilations, studies or other documents prepared by the Receiving Party or by the Receiving Party Representatives, is the Disclosing Party's property and will be returned immediately to the Disclosing Party upon its request.

(b) Intellectual Property:

HONI shall obtain all rights, title and interests, including copyright ownership, to any reports and any other deliverable that is to be produced and delivered to it by HOTelecom and, subject to applicable legislation and notwithstanding clause 7.0(a) above, HONI may use, disclose or modify such reports or deliverable in any manner it deems appropriate. HOTelecom shall not do any act which may compromise or diminish HONI's interest as aforesaid.

(c) Survival of Obligations:

The obligations in this Section 7.0 shall forever survive the termination or expiration of this Agreement.

8.0 LIABILITY

Each party (the "Indemnifying Party") shall indemnify the other party (the "Indemnified Party") and the Indemnified Party's successors and assigns, directors, officers, employees, contractors and agents from and against all costs or damages attributable to the Indemnifying Party's performance and/or non-performance of its obligations under this Agreement and any amendments thereto, whether arising from or based on breach of contract, tort, negligence, strict liability or otherwise. Notwithstanding any other provision of this Agreement, neither party hereto shall be liable for any economic loss, loss of goodwill, loss of profit or for any special, indirect or consequential damages, where the said losses or damages are incurred by the other party or by any third party claiming through or under the other party.

This Section 8.0 shall forever survive the termination or expiration of this Agreement.

9.0 AUTHORIZED REPRESENTATIVES

The authorized representatives of the parties hereto for purposes of this Agreement are the following:

HYDRO ONE TELECOM INC.
175 Sandalwood Parkway West
Brampton, Ontario
L7A 1E81
Attention: Paul Marchant
Telephone: (905) 840- 0585 ext. 3340
Telecopier: (905) 840-1339

HYDRO ONE NETWORKS INC.

(a) 483 Bay Street
North Tower, 14h Floor
Toronto, Ontario
M5G 2P5
Attention: Ian Bradley
Telephone: (416) 345-6707
Telecopier: (416) 345-5424

-and-

(b) 483 Bay Street
South Tower, 8th Floor
Toronto, Ontario
M5G 2P5
Attention: Sandy Struthers
Telephone: (416) 345-6140
Telecopier: (416) 345-5695

All correspondence, reports, documents and/or other communication concerning this Agreement and the Schedules attached hereto shall be directed to the attention of the authorized representatives noted above and shall be deemed to be sufficiently given if delivered personally, mailed or transmitted by fax to the attention of the authorized representatives at the addresses above, and any notice so given shall be deemed to have been made and received on the date of delivery or on the 5th business day following the day of mailing of same or on the day of transmission if transmitted during normal business hours, otherwise on the next business day, as the case may be.

10.0 ASSIGNMENT AND CHANGE OF CONTROL

Assignment:

(a) Except as otherwise specified in this Agreement, neither this Agreement nor any rights, remedies, liabilities or obligations arising under it or by reason of it shall be assigned by either party without the prior written consent of the other party, which consent may be unreasonably withheld. Subject to the foregoing, this Agreement shall enure to the benefit of the parties hereto ad their respective successor and permitted assigns.

Change of Control:

(b) In the event of a change of control of either party, the parties shall negotiate in good faith for a period of 30 days after the effective date of the change of control with a view to executing a new agreement for the Services that were being performed by HOTelecom hereunder immediately prior to the effective date of said change of control. In the event that the parties cannot agree to a new agreement, this Agreement shall immediately terminate. A change of control shall mean, as applicable, a purchase of more than fifty (50) percent of the outstanding capital by a non-affiliate third party.

11.0 SCHEDULES

Schedules "A", "B" and "C" attached hereto are to be read with and form part of this Agreement.

12.0 COUNTERPARTS

This Agreement may be executed in counterparts and the counterparts together shall constitute an original.

IN WITNESS THEREOF the parties hereto have caused this Agreement to be executed by their respective representatives duly authorized in that behalf.

HYDRO ONE TELECOM INC.

Name: Paul Marchant
Title: President and CEO
I have authority to bind the corporation.

HYDRO ONE NETWORKS INC.

Name: Laura Formusa
Title: Secretary
I have authority to bind the corporation.

POWER SYSTEM - OPERATION OF TELECOMMUNICATION SERVICES

1. BACKGROUND

HOTelecom acknowledges the importance of teleprotection in order for HONI to maintain the reliability and integrity of HONI's electricity transmission and distribution systems (collectively, the "Electrical Network") in Ontario and its interactions with bordering networks. Teleprotection for an electric grid encompasses detailed utility policies and operating procedures which HOTelecom will effectively support. HOTelecom, through the Integrated Technology Management Center (ITMC), shall monitor teleprotection of HONI's Electrical Network and provides various Services, as defined in this Schedule, which Services are also collectively referred to as the "Power System Telecom Services" or "PSTS".

HONI has a vast number of systems that form the overall teleprotection of its Electrical Network. HOTelecom shall perform the Services described herein for the following components of HONI's teleprotection network:

- Analogue Microwave System
- Digital Microwave System
- Power Line Carrier (PLC) System
- Fibre Optic Transmission System
- HONI's Metallic Cable Systems
- Cable Protection Systems (neutralizing transformers, optical isolators)
- Provincial Mobile Radio System (Excludes mobile radios and control units)
- DOMC Mobile Radio System
- Teleprotection (CPE) Systems
- Telecom Management System (the ITMC operations and the backup ITMC facilities)
- Telemetering and control services
- Leased Power System Telecommunications Facilities

The vast number of systems results in hundreds of network elements that must be monitored. When the integrity and/or reliability of the above systems are impacted, the Services provided by HOTelecom as described in this Schedule form an integral part of the restoration effort that is ultimately controlled by HONI's Ontario Grid Control Centre (OGCC).

In performing the Services described in this Schedule, HOTelecom shall comply with HONI's policies and standards as may be applicable to HOTelecom in respect of the said Services and which policies and standards have been provided by HONI to HOTelecom on the Effective Date of the Agreement. In addition, HOTelecom will support HONI in its efforts to maintain compliance with North American Electric Reliability Council (NERC) requirements, specifically in the areas of security and auditability of the Power System Telecom Services. The parties acknowledge and agree that HONI shall be entitled to unilaterally amend the provisions of the said policies and standards or create new policies and standards throughout the Term of the Agreement that may be applicable to the Services described herein and HONI shall provide HOTelecom with 30 days' written notice of any such amendments and/or new policies and standards prior to the implementation of said amendments and/or new policies and standards and such amendments and HOTelecom shall comply with said amendments and/or new policies and standards commencing on the 31st day after the date of the notice referred herein.

2. DESCRIPTION OF SERVICES

HOTelecom shall perform the following Services related to the monitoring, management and operation of PSTS, as may be required by HONI:

1. Alarm Based Services
2. Coordinated Network Management Services
3. Systems Analysis Services
4. Carrier/Vendor Management Services

2.1 ALARM BASED SERVICES

2.1.1 Network Monitoring

- Monitor alarms from PSTS equipment and systems on a 24 hours / 7 day basis utilizing the ITMC or as required through the HOTelecom back-up control centre.
- Create trouble reports for alarms that require corrective action based on the following categorization of alarms:

SEVERITY LEVEL	DEFINITION	TIME DURING WHICH EVENT RESPONSE MUST BE MADE
1	**An incident or problem causing total loss of critical services such as Teleprotection or SCADA service**	7 X 24
2	**An incident or problem causing partial degradation or loss of redundancy for critical services**	7 X 24
3	**An incident or problem causing minor impact on network services**	Business Hours
4	**An incident or problem causing no impact on network services.**	Business Hours

- Restore failed or degraded telecommunications services remotely if possible.
- Assess, troubleshoot or co-ordinate troubleshooting, including engagement of second/third level engineering support, to restore PSTS services, as well as provide status updates to HONI designated personnel with respect to the restoration efforts.

2.1.2 Support for Trouble Calls & Corrective Maintenance

- Provide operational support, on a 24 hour / 7 day basis, for trouble calls and corrective maintenance activities on all failed or degraded telecom services and equipment - this Includes operational acceptance of replacement equipment or systems associated with trouble calls and corrective maintenance activities.
- Provide technical expertise to identify root causes, formulate corrective action plans and take charge of implementing the plan.
- Provide technical support and coordination, to the dispatched (internal or external) technical resources, in restoring failed or degraded services and effectively manage, in concert with HONI, the technical resources to achieve the following HONI designated restoration targets:

Severity Level	Service Restoration Target
1	Less than 4 hours
2	Less than 8 hours
3	More than 8 hours
4	More than 8 hours

- Perform analysis of, and prepare reports for, all PSTS "Severity Level 1 Incidents".

2.1.3 Notification and Reports

- Provide notification to the appropriate regulatory authorities with regard to lamps failures within HONI's microwave tower system.
- Monitor the actions of HONI's various third party telecommunications vendors as well as the broader Canadian and US telecommunications industry and advise HONI of any issues that may impact the PSTS.

2.1.4 Emergency Response Planning & Execution

- Assist, as requested by HONI, in the planning for large scale emergency situations affecting a large portion of or, in a worst case situation, the entire HONI Electrical Network.
- Having regard to HONI's emergency response plans, provide operational support for large scale critical situations which result in HONI activating its Incident Command Centre (ICC) and/or its Emergency Operations Centre (EOC).
- Activate the telecommunications component of the ICC to provide updates to HONI with respect to the resolution of the large scale critical situations until achievement of the resolution.
- Provide HONI with an on-call single point of contact at a senior management level to interact with HONI's ICC and/or EOC.
- Work with HONI to test the various emergency response plans as scheduled by HONI.
- Review the test results of the emergency response plans with HONI, identify any deficiencies and update the said plans as required by HONI.

2.1.5 Additional Deliverables: Alarm Based Service

- Provide real-time email distribution of all Severity 1 incidents trouble tickets to a HONI-provided distribution list.
- Within 5 business days of a Severity 1 incident, draft an "Incident Investigation Report" which will include a description of the incident, sequence of events, root cause analysis and corrective actions taken. In consultation with HONI, the format of this report may be modified as required by HONI.
- Ensure that HOTelecom's Senior Management, including the President, will be available on-call to deal with escalation or emergency situations.
- HOTelecom will notify HONI of any meetings HOTelecom has scheduled with third party carriers to discuss substandard service and assist in developing recommendations to improve the overall reliability of the service delivery to enable HONI to attend if it deems desirable.
- As required by HONI, HOTelecom will participate in HONI meetings to report on ITMC activity levels.

2.2 COORDINATED NETWORK MANAGEMENT SERVICES

2.2.1 Change Management

- Provide HONI with technical expertise to assist HONI in formulating change plans and in implementing the changes.
- Develop and maintain change management processes and measures that facilitate timely and controlled change for PSTS infrastructure.
- Ensure that standard telecommunications industry methods and techniques are used for efficient handling of changes, so that change related problems are prevented. Change management activities include acceptance, classification, assessment and planning, coordination and evaluation.
- Review all changes that are introduced into HONI's environment to ensure they are engineered, tested, commissioned and supported according to jointly defined HONI and HOTelecom standards for quality and performance.
- Input change records into HONI systems (i.e. NOMS – Network Outage Management System).
- Establish and chair regular Change Advisory Board (CAB) meetings with affected stakeholders who want to attend such meeting.
- HOTelecom will document and review with HONI all changes to HONI's teleprotection system. The documentation will specify the reason for the change, impacts of the

change, risks associated with the change, testing done, back-out plans, technical assessment, and management/risk assessment.
- Develop and maintain release management processes and measures that facilitate timely and controlled change (through regular meetings).
- Determine release strategies, controls, and co-ordinate the release of network hardware and software into the live environment.
- Coordinate operational acceptance and commissioning of new or replacement equipment/systems associated with minor projects.

2.2.2 Configuration Management

- Maintain and update configuration parameters and elements of each element of the HONI teleprotection network.
- Maintain up-to-date configuration documentation for every change implemented.
- Ensure configuration changes including drawings are documented in order to maintain the capability to enable re- configuration of services to maintain adequate operational control of infrastructure systems and components.
- Provide regular back-ups for the element configuration parameters and elements of the teleprotection network.

2.2.3 ITMC Support for Preventative Maintenance Program

- Provide support for HONI's teleprotection network hardware and software preventative maintenance program, including assistance in supporting business cases to justify expenditures.
- Recommend vendor upgrades and patches, and perform such upgrades and patches as directed by HONI.
- Provide First Level (Incident Management), Second Level (Problem Management) and Third Level (Vendor Management) technical support that includes on- site deployment of staff or management of vendor personnel necessary to resolve problems.
- Manage hardware and software maintenance for PSTS-related applications; work with hardware and software vendors and co-ordinate the installation, upgrade and maintenance of hardware and software; monitor vendors' service and performance to confirm compliance with the vendors' respective SLA; perform hardware and software maintenance outside of vendor support contracts.
- Provide corrective maintenance and repair for warranty and non-warranty components of the PSTS network; take necessary actions to coordinate repair of the failed component of the PSTS network to working order.

2.2.4 Operating Support System (OSS)

- HONI contributed and therefore has access to the development of the HOTelecom Operating Support System (OSS) which has four elements:
  - An inventory management system (Granite) for the BSTS wide-area network (HWAN)
  - Outside Plant (OSP)/fibre inventory system (Telcordia Network Engineer)
  - Network management system for HWAN and voice switches (HP Openview)
  - Service Management system (HP Service Desk) as adopted by PSTS and HOTelecom's commercial network for the HWAN. This includes incident management through trouble tickets, problem management, and change management functions.
- The OSS is vital to support the day-to-day ITMC operational functions including updating of fibre inventory, management and updating of network alarms, management of incidents [trouble tickets], and outage and change requests.

2.2.5 Additional Deliverables: Coordinated Network Management

- Due to the dynamic nature of telecom, coordinate, as required by HONI, meetings with third party service providers and stakeholders in HONI (such as E&CS Telecom

Engineering, and Grid Operations) to review overall roles and accountabilities to maximize an integrated approach to power system telecom operations.

- Provide HOTelecom's Change Management process, deliverables and documentation to HONI upon HONI's request.
- Maintain the OSS system applicable to the PSTS with current software releases and provide appropriate access, to designated HONI personnel.

2.3 SYSTEMS ANALYSIS SERVICES

2.3.1 Fibre Restoration Plan Management

- Provide on-going support for HONI's fibre optic network restoration capability plan.
- Participate in annual reviews of this plan with HONI's Engineering Service and Maintenance Service Providers.

2.3.2 Software Release Management

- Recommend software releases on all SONET fibre electronics to HONI
- Manage the upgrade of the software on SONET fibre electronics as required

2.3.3 Asset Performance Assessment

- Provide on-going trend analysis on telecom equipment failures and long duration and chronic outages with analysis and recommendations for corrective action.

2.3.4 NERC System Analysis Service

- Provide ongoing analysis and support in the areas of system security to HONI in response to NERC queries.
- Participate in the implementation of system security features as required by HONI to demonstrate compliance with NERC requirements.

2.3.5 Additional Deliverables: System Analysis Services

- Provide ongoing software release recommendations to the designated HONI contact and upon HONI's acceptance of the recommendations, report on any resulting activity.
- Provide an annual asset performance assessment report in consultation with HONI for the PSTS Severity 1 incidents including historical trend analysis.

2.4 CARRIER/VENDOR MANAGEMENT SERVICES

With the numerous teleprotection systems and the extent of HONI's various networks spread across its vast operating territory, there are numerous third party carriers who provide various telecommunications and equipment services to HONI. HOTelecom will be the single-point of contact for management of the third party providers.

2.4.1 Carrier Contract Management

- HOTelecom will negotiate, on behalf of HONI, best commercial terms and conditions governing all carrier contracts for HONI circuits
- HOTelecom will manage the contracts during the term of the contracts
- HOTelecom will attempt to leverage all of HONI's telecommunications purchases to obtain the best possible price to achieve the desired HONI telecommunication solution. This may include recommendations such as the use of alternative carriers and/or product solutions.

2.4.2 Carrier Circuit Management

- HOTelecom will be HONI's single-point of management for all PSTS requirements for third party telecommunications circuit services. HONI will direct HOTelecom with regard to what circuits are to be procured and HOTelecom will interact with the various HONI approved carriers in an effort to execute the following:

- Circuit ordering
- Circuit out-ordering
- Coordination of the carrier invoice payment and reconciliation
- Cost allocation and distribution to HONI directed end-accounts/projects
- Investigating any billing discrepancy and taking corrective action against any errors in billing by third party providers
- Liaise with third party providers to claim any applicable service credits
- Maintenance of records of service billing and payment history
- Provide support for billing and cost inquiries on specific leased circuits when requested by HONI

2.4.3 Provincial Mobile Radio ("PMR") Management

- As directed by HONI, HOTelecom will coordinate the payment of all microwave radio licenses.
- As directed by HONI, HOTelecom will coordinate the payment of all provincial mobile base station frequency licenses.
- Coordinate renewal of tower space lease agreements for the PMR network.
- Negotiate and administer HONI's contracts with third party providers, including resolving billing issues, violations of service level agreements, application for and collection of credits, and monitoring of delivery performance.
- Coordinate "lessons learned" meetings with third party providers to assess performance and make recommendations for service improvement.
- Liaise with the appropriate HONI personnel as designated by HONI in the field to facilitate implementation of work packages.
- Assist HONI in developing policies and procedures to effectively facilitate third party providers' support of HONI's mobile radio network.

2.4.4 Third Party Maintenance Contract Management

- HONI has various third party contracts with vendors of equipment that form the third level of support when resolving incidence that affects HONI's various networks. Some of these contracts include: Significant Event Notifications System, Voice Recorders at the OGCC, and UPS Maintenance contracts.
- As directed by HONI, HOTelecom will negotiate these support contracts and coordinate the payment of the contracts.

2.4.5 Additional Deliverables: Carrier/Vendor Management Services

- HOTelecom will administer meetings with third party carriers when determined necessary by HOTelecom. HOTelecom will draft, and provide to HONI, minutes of the meetings describing invoicing errors under investigation and resolution steps with the third party carrier.
- HOTelecom will provide a monthly report to HONI of the current month and year to date costs of all HONI circuit purchases and identify if any specified HONI account is over a HONI defined variance threshold. HOTelecom shall ensure that such reports will show a breakdown of costs by services and vendors will and will be distributed to the HONI provided distribution list.
- HOTelecom will provide status reports regarding the third party Maintenance contracts.

3. Pricing

The prices for the performance of the Services to be performed under this Schedule are as follows:

	2007	2008
Alarm Based Services	$1,747,128	$1,817,014
Coordinated Network Management Services	$1,477,605	$1,536,709
Systems Analysis Services	$394,990	$410,789
Carrier/Vendor Management Services	$835,594	$869,018
Total PSTS Charge	**$4,455,317**	**$4,633,530**

BUSINESS SYSTEM - OPERATION OF TELECOMMUNICATION SERVICES

1. Background

HONI maintains various technical and administrative locations throughout the Province of Ontario. Within HONI, the Corporate Services group is responsible for the connectivity of the various locations. In particular, the CIO's IT department is focused on the information technology needs and information management of HONI. HONI's telecommunications infrastructure provides the linkage for HONI's information needs and HONI has engaged the services of HOTelecom to provide various services in regard to the procurement and monitoring of telecommunication services.

HOTelecom recognizes that HONI's IT department helps form an integral part of HONI's ability to provide a reliable electricity network in the Province of Ontario. The monitoring of HONI's Power System Telecom Services ("PSTS") is dependant on HONI's IT department's voice and data network which is commonly referred to as the "Business System Telecom Services" (or "BSTS"). In addition, the BSTS is essential to maintain a high availability of HONI's mission critical business applications. HOTelecom shall provide the Services described herein through the Integrated Technology Management Center ("ITMC").

In performing the Services described in this Schedule, HOTelecom shall comply with HONI's policies and standards as may be applicable to HOTelecom in respect of the said Services and which policies and standards have been provided by HONI to HOTelecom on the Effective Date of the Agreement. The parties acknowledge and agree that HONI shall be entitled to unilaterally amend the provisions of the said policies and standards or create new policies and standards throughout the Term of the Agreement that may be applicable to the Services described herein and HONI shall provide HOTelecom with 30 days' written notice of any such amendments and/or new policies and standards prior to the implementation of said amendments and/or new policies and standards and such amendments and HOTelecom shall comply with said amendments and/or new policies and standards commencing on the 31st day after the date of the notice referred herein.

2. DESCRIPTION OF SERVICES

HOTelecom shall perform the following Services related to the monitoring, management and operation of BSTS, as may be required by HONI:

1. Alarm Based Services
2. Coordinated Network Management
3. Systems Analysis Services
4. Carrier/Vendor Management Services

2.1 ALARM BASED SERVICES

2.1.1 Network Monitoring

- Monitor alarms from BSTS equipment and systems on a 24 hours / 7 day basis utilizing the ITMC or as required through the HOTelecom back-up control centre.
- Create trouble reports for alarms that require corrective action based on the following categorization of alarms:

SEVERITY LEVEL	DEFINITION	EVENT RESPONSE
1	**An incident or problem causing total loss or severe degradation of network services.**	7 X 24
2	**An incident or problem causing partial degradation to network services**	7 X 24
3	**An incident or problem causing minor impact to network services.**	Business Hours
4	**An incident or problem causing no impact to network services.**	Business Hours

- Restore failed or degraded telecommunications services remotely if possible.

- Assess, troubleshoot or co-ordinate troubleshooting, including engagement of second/third level engineering support, to restore BSTS services, as well as provide status updates to HONI designated personnel with respect to the restoration efforts.

2.1.2 Support for Trouble Calls & Corrective Maintenance

- Provide operational support, on a 24 hour / 7 day basis, for trouble calls and corrective maintenance activities on all failed or degraded telecom services and equipment. Includes operational acceptance of replacement equipment or systems associated with trouble calls and corrective maintenance activities.
- Provide technical expertise to identify root causes, formulate corrective action plans and take charge of implementing the plan.
- Provide technical support and coordination, to the dispatched (internal or external) technical resources, in restoring failed or degraded services and effectively manage the technical resources to achieve the following HONI designated service restoration targets:

Severity Level	Service Restoration Target
1	Less than 4 hours
2	Within 8 business hours
3	Within 5 business days
4	Within 10 business days

- The severity rating of a problem ticket may be increased at the request of an authorized HONI representative in order to support business requirements.
- Perform analysis of, and prepare reports for, all BSTS "Severity Level 1 Incidents".

2.1.3 Notification

- Monitor the actions of HONI's various third party telecommunications vendors as well as the broader Canadian and US telecommunications industry and advise HONI of any issues that may impact the BSTS.

2.1.4 Emergency Response Planning & Execution

- Assist, as requested by HONI, in the planning for large scale emergency situations affecting a large portion of or, in a worst case situation, the entire HONI Electrical Network.
- Having regard to HONI's emergency response plans, provide operational support for large scale critical situations which result in HONI activating its Incident Command Centre (ICC) and/or its Emergency Operations Centre (EOC).
- Activate the telecommunications component of the ICC to provide updates to HONI with respect to the resolution of the large scale critical situations until achievement of the resolution.
- Provide HONI with an on-call single point of contact at a senior management level to interact with HONI's ICC and/or EOC.
- Work with HONI to test the various emergency response plans as scheduled by HONI.
- Review the test results of the emergency response plans with HONI, identify any deficiencies and update the said plans as required by HONI.

2.1.5 Additional Deliverables: Alarm Based Service

- Provide real-time email distribution of all Severity 1 incidents trouble tickets to a HONI-provided distribution list.
- Within 5 business days of a Severity 1 incident, draft an "Incident Investigation Report" which will include a description of the incident, sequence of events, root cause analysis and corrective actions taken. In consultation with HONI, the format of this report may be modified as required by HONI.

- Ensure that HOTelecom's Senior Management, including the President, will be available on-call to deal with escalation or emergency situations.
- HOTelecom will notify HONI of any meetings HOTelecom has scheduled with third party carriers to discuss substandard service and assist in developing recommendations to improve the overall reliability of the service delivery to enable HONI to attend if it deems desirable.
- As required by HONI, HOTelecom will participate in HONI meetings to report on ITMC activity levels.

2.2 COORDINATED NETWORK MANAGEMENT

2.2.1 Change Management

- Provide HONI with technical expertise to assist HONI in formulating change plans and in implementing the changes.
- Develop and maintain change management processes and measures that facilitate timely and controlled change for BSTS infrastructure.
- Ensure that standard telecommunications industry methods and techniques are used for efficient handling of changes, so that change related problems are prevented. Change management activities include acceptance, classification, assessment and planning, coordination and evaluation.
- Review all changes that are introduced into HONI's environment to ensure they are engineered, tested, commissioned and supported according to jointly defined HONI and HOTelecom standards for quality and performance.
- Establish and chair regular Change Advisory Board (CAB) meetings with affected stakeholders who want to attend such meetings.
- HOTelecom will document and review with HONI all changes to HONI's teleprotection system. The documentation will specify the reason for the change, impacts of the change, risks associated with the change, testing done, back-out plans, technical assessment, and management/risk assessment.
- Develop and maintain release management processes and measures that facilitate timely and controlled change (through regular meetings).
- Determine release strategies, controls, and co-ordinate the release of network hardware and software into the live environment.
- Coordinate operational acceptance and commissioning of new or replacement equipment/systems associated with minor projects.
- Perform twenty-four (24) site/network move/add/changes per year in conjunction with Inergi/Bell staff.

2.2.2 Configuration Management

- Maintain and update configuration parameters and elements of each element of the BSTS network.
- Maintain up-to-date configuration documentation for every change implemented.
- Ensure configuration changes including drawings are documented in order to maintain the capability to enable re- configuration of services to maintain adequate operational control of infrastructure systems and components.
- Provide regular back-ups for the element configuration parameters and elements of the BSTS network.

2.2.3 ITMC Support for Preventative Maintenance Program

- Provide support for HONI's BSTS network hardware and software preventative maintenance program, including assistance in writing business cases to justify expenditures.
- Recommend vendor upgrades and patches, and perform such upgrades and patches as directed by HONI.

- Provide First Level (Incident Management), Second Level (Problem Management) and Third Level (Vendor Management) technical support that includes on- site deployment of staff or management of vendor personnel necessary to resolve problems.
- Manage hardware and software maintenance for BSTS-related applications; work with hardware and software vendors and co-ordinate the installation, upgrade and maintenance of hardware and software; monitor vendors' service and performance to confirm compliance with the vendors' respective SLA; perform hardware and software maintenance outside of vendor support contracts.
- Provide corrective maintenance and repair for warranty and non-warranty components of the BSTS network; take necessary actions to coordinate repair of the failed component of the BSTS network to working order.

2.2.4 Operating Support System (OSS)

- HONI contributed and therefore has access to the development of the HOTelecom Operating Support System (OSS) which has four elements:
  - An inventory management system (Granite) for the BSTS wide-area network (HWAN)
  - Outside Plant (OSP)/fibre inventory system (Telcordia Network Engineer)
  - Network management system for HWAN and voice switches (HP Openview)
  - Service Management system (HP Service Desk) as adopted by PSTS and HOTelecom's commercial network for the HWAN. This includes incident management through trouble tickets, problem management, and change management functions.
- The OSS is vital to support the day-to-day ITMC operational functions including management and updating of network alarms, management of incidents [trouble tickets], and outage and change requests.

2.2.5 Additional Deliverables: Coordinated Network Management

- Due to the dynamic nature of telecom, coordinate on an as-need basis meetings with third party service providers and stakeholders in HONI to review overall roles and accountabilities to maximize an integrated approach to BSTS operations.
- Provide Change Management process, deliverables and documentation to HON upon their request.
- Maintain the OSS system applicable to the BSTS (does not include the OSP) with current software releases and provide appropriate access, to designated HONI personnel.

2.3 SYSTEMS ANALYSIS SERVICES

2.3.1 Security Management

- HOTelecom will familiarize itself with the current HONI IT security policies, and any subsequent updates provided by HONI to HOTelecom, and adhere to and follow the said policies.
- Provide security management services that include monitoring, reporting, and support incident resolution and escalation.
- React to, and resolve, network security incidents caused by viruses, hardware and software failures, or hackers.
- Provide HONI Corporate Security with copies of HOTelecom's security reports as requested by HONI, including reports dealing with long distance call records.
- Rectify security incidents or audit reports that identify gaps in security as required by HONI.
- Takes corrective actions with regard to security incidents, as required and directed by HONI.
- Escalates problems as they are identified to HONI's Corporate Security.

- Provide HONI security personnel with access to the BSTS to investigate specific security incidents and or security breaches.
- Carry out virus scanning and anti-spam filtering of incoming internet mail.
- Deploy and/or upgrade security-related network components in accordance with HONI's Infrastructure requirements. This includes enhance port security for Bill 198 Compliance.
- Provide ongoing maintenance and support to HONI deployed VPN concentrators.
- Proactively check vendor WEB sites and download and apply network security patches as provided by vendors.
- Intrusion Detection Service – detect unauthorized network access (e.g. INET)

2.3.2 LAN/WAN Services

- Manage HONI's LAN/WAN infrastructure including: providing support for audits, providing corrective service updates, and interfacing with vendors to ensure service quality.
- Establish operating practices used to support the provision of LAN/WAN services.
- Manage network hardware maintenance; work with hardware vendors and co-ordinate the installation, upgrade and maintenance of (existing) hardware.

2.3.3 Software Release Management

- Make recommendations to HONI with regard to software releases on all routers, switches and firewalls
- Manage the upgrade of the software on all routers, switches and firewalls as directed by HONI.

2.3.4 Performance Management

- Provide operational monitoring of system parameters, such as link capacity, collect performance statistics and system logs to determine historical and trend analysis.
- Assist HONI in developing recommendations and plans with regard to the BSTS capacity and performance issues.
- Provide HONI with a reactive data collection, analysis and make recommendations with respect to the BSTS's capability to deal with unexpected system capacity or performance issues.

2.3.5 Internet Services (IP Address Management)

- Provide Public IP address management
- Provide commissioning, managing, monitoring, and maintenance of firewalls and log files
- Manage external WWW access (blocking and monitoring)
- Operate and administer HONI's network components that provide the Internet Services, LAN/WAN interface, mail relay and WWW proxy services
- Manage hardware maintenance; work with hardware vendors, and co-ordinate the installation, upgrade and maintenance of hardware
- Assist HONI in establishing operating practices and infrastructure used to provide the Internet Services.
- Perform Backup and Recovery services, user account Management, Security and Access Controls, as well as performance management.
- Perform virus scanning for Internet emails and spam blocking

2.3.6 Additional Deliverables: System Analysis Services

- Provide monthly activity reports with regard to the Intrusion Detection System ("IDS") and firewall.

- Provide software release recommendations to the designated HONI contact and upon HONI's acceptance of the recommendations provide HONI with a written report on any resulting activity.
- Provide, as required by HONI, Performance Management reports.

2.4 CARRIER/VENDOR MANAGEMENT SERVICES

With the numerous components in the BSTS system and the extent of HONI's various networks spread across its vast operating territory, there are numerous third party carriers who provide various telecommunications and equipment services to HONI. HOTelecom will be the single-point of contact for management of the third party providers.

2.4.1 Carrier Contract Management

- HOTelecom will negotiate, on behalf of HONI, best commercial terms and conditions governing all carrier contracts for HONI circuits
- HOTelecom will manage the contracts during the term of the contracts
- HOTelecom will attempt to leverage all of HONI's telecommunications purchases to obtain the best possible price to achieve the desired HONI telecommunication solution. This may include recommendations such as the use of alternative carriers and/or product solutions.

2.4.2 Carrier Circuit Management

- HOTelecom will be HONI's single-point of management for all BSTS requirements for third party telecommunications circuit services. HONI will direct HOTelecom with regard to what circuits are to be procured and HOTelecom will interact with the various HONI approved carriers in an effort to execute the following:
    - Circuit ordering
    - Circuit out-ordering
    - Coordination of the carrier invoice payment and reconciliation
    - Cost allocation and distribution to HONI directed end-accounts/projects
    - Investigating any billing discrepancy and taking corrective action against any errors in billing by third party providers
    - Liaise with third party providers to claim any applicable service credits
    - Maintenance of records of service billing and payment history
    - Provide support for billing and cost inquiries on specific leased circuits when requested by HONI

2.4.3 3rd party Maintenance Contract Management

- HONI has various third party contracts with vendors of equipment that form the third level of support when resolving incidence that affects HONI's various networks. Some of these contracts include: Significant Event Notifications System, Voice Recorders at the OGCC, and UPS Maintenance contracts.
- As directed by HONI, HOTelecom will negotiate these support contracts and coordinate the payment of the contracts.

2.4.4 Bell Field Services

- Participate on HONI's designated committee's (Operations and Executive) overseeing the implementation of the outsourcing initiative to Bell Canada.
- Negotiate and administer HONI's contracts with third party providers, including resolving billing issues, violations of service level agreements, application for and collection of credits, and monitoring of delivery performance.
- Coordinate "lessons learned" meetings with third party providers to assess performance and make recommendations for service improvement.
- Liaise with the appropriate HONI personnel as designated by HONI in the field to facilitate implementation of work packages.

- Assist HONI in developing policies and procedures to effectively facilitate third party providers' delivery of the contracted services.

2.4.5 Additional Deliverables: Carrier/Vendor Management Services

- HOTelecom will administer meetings with third party carriers when determined necessary by HOTelecom. HOTelecom will draft, and provide to HONI, minutes of the meetings describing invoicing errors under investigation and resolution steps with the third party carrier.
- HOTelecom will provide a monthly report to HONI of the current month and year to date costs of all HONI circuit purchases and identify if any specified HONI account is over a HONI defined variance threshold. HOTelecom shall ensure that such reports will show a breakdown of costs by services and vendors will and will be distributed to the HONI provided distribution list.
- HOTelecom will provide status reports regarding the third party Maintenance contracts.

3. Pricing

The services listed in this Schedule have been priced as follows:

	2007	2008
Alarm Based	$1,861,038	$1,935,480
Coordinated Network Management	$774,766	$805,757
Systems Analysis Services	$609,552	$633,934
Carrier/Vendor Management Services	$954,965	$993,163
Total BSTS Charge	**$4,200,321**	**$4,368,334**

Schedule "C"

Receiving Party Security Safeguards Regarding Confidential Information Received from the Disclosing Party

The Receiving Party shall protect the Confidential Information by security safeguards appropriate to the sensitivity of the information.

1) The Receiving Party shall protect the Confidential Information against such risks as loss or theft, unauthorized access, disclosure, copying, use, modification or destruction, through appropriate security measures, regardless of the format in which it is held.

2) All of the Receiving Party's Representatives with access to the Confidential Information shall be contractually required to respect the confidentiality of that information.

3) The Receiving Party acknowledges and agrees that the nature of the safeguards will vary depending on the sensitivity, amount, distribution and format of the information, and the method of storage. The Receiving Party shall ensure that more sensitive information will be safeguarded by a higher level of protection.

4) The Receiving Party shall ensure that methods of protection will include:

(a) physical measures, for example, locked filing cabinets and restricted access to offices;

(b) organizational measures, for example, controlling entry to data centers and limiting access to information on a "need-to-know" basis;

(c) technological measures, for example, the use of passwords and encryption; and

(d) investigative measures, in cases where the Receiving Party has reasonable grounds to believe that the Confidential Information is being inappropriately collected, used or disclosed by anyone whom in law the Receiving Party is responsible.

AFFILIATE SERVICE AGREEMENTS

Appendix F

Hydro One Remote Communities Inc.

Service Provision to:

Hydro One Networks Inc.

2007

(Metering and lines services)

THIS AGREEMENT made in duplicate this 1st day of January, 2007 (the "Effective Date").

BETWEEN:

HYDRO ONE REMOTE COMMUNITIES INC.
(the "Services Provider")

- and -

HYDRO ONE NETWORKS INC.
(the "Services Recipient")

1.0 PREFACE

This Agreement is intended to identify the services that are to be provided to the Services Recipient by the Services Provider in accordance with the terms and conditions herein. The term of this Agreement shall be for a period of 1 year commencing on the Effective Date.

2.0 SERVICES

Subject to the Services Provider's availability of personnel and resources, which availability shall be determined by the Services Provider in its sole discretion, the Services Provider shall provide metering work, lines work and training for lines work to the Services Recipient, which collectively constitute the Services and which are more particularly described in Schedule "A" attached hereto, as may be required by the Services Recipient from time to time during the term of this Agreement.

3.0 FEES PAYABLE

(a) The price for the performance of the Services shall be on a time and materials basis in accordance with the Services Provider's 2007-2008 hourly rates by job category, which rates may be amended from time to time by mutual agreement of the parties. The parties acknowledge and agree that the Services Recipient has received the Services Provider's 2007-2008 hourly rates from the Services Provider.

(b) The parties agree that the price for the Services shall be paid by the Services Recipient to the Services Provider by direct time reporting through Hydro One Inc.'s payroll system.

(c) In addition, the Services Recipient shall pay for any material costs which the Services Provider, acting reasonably, incurs as a result of resources, services and products that the Services Provider must purchase and that are in addition to the Services Provider's existing resources, services and products, in order to provide the said Services Recipient with specific services it requires and requests.

(d) If at any time during the performance of the Services, the Services Recipient is of the opinion that there are deficiencies in the Services provided to it and/or that the price payable is in any way inaccurate, the Services Recipient shall pay the entire relevant price payable by it in full and its sole remedy shall be to follow the dispute resolution procedures outlined in Section 6.0 herein to determine what amount, if any, shall be refunded to the Services Recipient and/or what Services, if any, shall be rectified or redone by the Services Provider.

(e) The parties acknowledge and agree that they qualify as specified members of a closely related group under subsection 156(1) of the Excise Tax Act (Canada), as amended (the "Act") and have jointly executed a Form GST25, to make an election under subsection 156(2) of the Act to deem the purchase and sale of the Services to be made for nil consideration for Goods and Services Tax purposes.

4.0 REPRESENTATIONS AND WARRANTIES

(a) The Services Provider represents and warrants that:
   (i) it has all the necessary authority and capacity to enter into this Agreement and to perform its obligations hereunder;
   (ii) the execution of this Agreement and compliance with and performance of the terms, conditions, and covenants contemplated herein have been duly authorized by all necessary corporate action on the part of the Services Provider; and
   (iii) all staff employed in the performance of the Services shall have the qualifications, expertise and experience which could reasonably be expected of staff of a services provider performing work similar to the Services.

(b) The Services Recipient represents and warrants that:
   (i) it has all the necessary authority and capacity to enter into this Agreement and to perform its obligations hereunder; and
   (ii) the execution of this Agreement and compliance with and performance of the terms, conditions, and covenants contemplated herein have been duly authorized by all necessary corporate action on the part of the Services Recipient.

5.0 PERFORMANCE OF THE SERVICES

(a) **Compliance with Standards and Applicable Law**: The Services Provider shall perform the Services in a diligent and professional manner and shall comply with the Services Recipient's computer data management and data access protocols contained in the Services Recipient's documents entitled "Corporate Security Standard 600-3 – Information Security Policy" and "Corporate Security Policy 600 – Information Security Policy", both of which are dated January 17, 2000 and any amendments thereto which may be made from time to time by the Services Recipient. The Services Provider shall comply at all times with the statutes, regulations, by-laws, standards and codes, as amended, as may be applicable to the Services Provider in respect of the Services and the performance of its obligations hereunder and it shall, at its own expense, obtain and maintain in good standing all permits and licences required by any authorities having jurisdiction to perform the Services.

(b) **Safety and Security Measures**: When any part of the Services is to be performed at any of the Services Recipient's premises, all of the Services Provider's staff engaged in the performance of the Services at the said premises shall comply with the safety and security requirements and measures in effect at the said premises.

(c) **Meetings**: The parties shall, after the Effective Date, meet at least once during the term of this Agreement to review performance, quality and timeliness of the Services provided by the Services Provider pursuant to this Agreement.

6.0 DISPUTE RESOLUTION PROCEDURES

Any controversy, dispute, difference, question or claim arising between any of the parties in connection with the interpretation, performance, construction or implementation of this Agreement that cannot be resolved by a director or manager from each of the said parties (collectively "Dispute") shall be settled in accordance with this Section. The aggrieved party shall send the other affected party(ies) written notice identifying the Dispute, the amount involved, if any, and the remedy sought, and invoking the procedures of this Section. The Presidents of each affected party shall confer in an effort to resolve the Dispute. If the Presidents are unable to resolve the Dispute within 5 business days after receipt of the written notice of the Dispute, then the affected parties shall submit the Dispute to the President of Hydro One Inc. for resolution.

7.0 CONFIDENTIALITY AND INTELLECTUAL PROPERTY

(a) Confidentiality:

Each party (the "Receiving Party") shall maintain in strict confidence this Agreement and the existence and contents thereof and all information, analysis, conclusions, drawings, reports, specifications or other information, proprietary or otherwise, whether transmitted orally, electronically or in written form, and received in furtherance of this Agreement from any of the other parties (the "Disclosing Party") or any of the Disclosing Party's directors, officers, employees, consultants, agents or legal and other advisors (the "Disclosing Party Representatives") (collectively the "Confidential Information"). Except as permitted herein, the Receiving Party shall not publish, reproduce, or disclose, either directly or indirectly, the said Confidential Information to any third party and shall not use the said Confidential Information for any purpose other than for purposes of this Agreement without the prior written consent of the Disclosing Party. The Receiving Party may disclose the Confidential Information only to its shareholder, directors, officers, employees, consultants, agents or professional advisors (the "Receiving Party Representatives") having a need to know same and who have undertaken a like obligation to maintain its confidentiality.

For greater certainty, Confidential Information includes any and all personal information (as that term is defined in the Freedom of Information and Protection of Privacy Act (Ontario) and the Personal Information Protection and Electronic Documents Act (Canada), as they may be amended, and any and all information regarding a consumer, retailer, wholesale buyer, wholesale supplier, or a generator, provided by the Disclosing Party to the Receiving Party for purposes of this Agreement, whether or not such information was initially provided prior to the Effective Date.

The Receiving Party undertakes to protect and safeguard all Confidential Information in its possession or under its control and received by the Disclosing Party, in the manner described in Schedule "B" attached hereto. The Disclosing Party may, on reasonable notice, and during regular business hours, audit the information management practices of the Receiving Party to confirm compliance with the terms and conditions of this Section 7.0 and all applicable statutes, regulations, by-laws, standards and codes, as amended.

The Receiving Party undertakes to notify the Disclosing Party immediately upon discovery of any unauthorized use and/or disclosure of any of the Disclosing Party's Confidential Information, to co-operate with the Disclosing Party to help regain possession of such Confidential Information, and to prevent its further unauthorized use and/or disclosure.

The foregoing obligations with respect to confidentiality, use, reproduction, dissemination, publication and non-disclosure herein shall not apply to any information that:

(i) is previously known to or lawfully in the possession of the Receiving Party prior to the date of disclosure as evidenced by the Receiving Party's written record;
(ii) is independently known to or discovered by the Receiving Party, without any reference to the information or material;
(iii) is obtained by the Receiving Party from an arm's length third party having a bona fide right to disclose same and who was not otherwise under an obligation of confidence or fiduciary duty to the Disclosing Party or the Disclosing Party Representatives;
(iv) is or becomes public knowledge through no fault or omission of, or breach of this Agreement by the Receiving Party or the Receiving Party Representatives; or
(v) is required to be disclosed pursuant to a final judicial or governmental order or other legal process.

Confidential Information (other than this Agreement which shall be jointly owned by the parties) shall remain the sole and exclusive property of the Disclosing Party that has disclosed the Confidential Information, and the Disclosing Party shall retain all right, title and interest in and to the said Confidential Information.

The Receiving Party shall keep a record of written Confidential Information furnished to it by the Disclosing Party in a location separate from those locations where the Receiving Party has stored information in respect of other third parties for which it performs work and it shall advise the Disclosing Party of such location.

All Confidential Information furnished by the Disclosing Party (other than this Agreement), including that portion of the Confidential Information which is contained in analyses, compilations, studies or other documents prepared by the Receiving Party or by the Receiving Party Representatives, is the Disclosing Party's property and will be returned immediately to the Disclosing Party upon its request.

(b) Intellectual Property:

The Services Recipient shall obtain all rights, title and interests, including copyright ownership, to any reports and any other deliverable that is to be produced and delivered to it by the Services Provider and, subject to applicable legislation and notwithstanding clause 7.0(a) above, the said Services Recipient may use, disclose or modify such reports or deliverable in any manner it deems appropriate. The Services Provider shall not do any act which may compromise or diminish the Services Recipient's interest as aforesaid.

(c) Survival of Obligations:

The obligations in this Section 7.0 shall forever survive the termination or expiration of this Agreement.

8.0 LIABILITY

Unless otherwise agreed in writing, each party shall indemnify the other party and that other party's successors and assigns, directors, officers, employees, contractors and agents from and against all direct costs or damages attributable to the indemnifying party's performance and/or non-performance of its obligations under this Agreement and any amendments or additions thereto that are mutually agreed to in writing, whether arising from or based on breach of contract, tort, negligence, strict liability or otherwise. Notwithstanding any other provision of this Agreement, neither party shall be liable for any economic loss, loss of goodwill, loss of profit or for any special, indirect or consequential damages, where the said losses or damages are incurred by the other or by any third party claiming through or under the other.

This Section 8.0 shall forever survive the termination or expiration of this Agreement.

9.0 AUTHORIZED REPRESENTATIVES

The authorized representatives of the parties hereto for purposes of this Agreement are the following:

HYDRO ONE REMOTE COMMUNITIES INC.
483 Bay Street,
North Tower, 14th Floor
Toronto, Ontario M5G 2P5
Attention: **Una O'Reilly**
TCT 14
Telephone: 416-345-6698
Telecopier: 416-345-6356

HYDRO ONE NETWORKS INC.
483 Bay St.
South Tower, 8th Floor
Toronto, Ontario M5G 2P5
Attention: **Greg Van Dusen**
Telephone: (416) 345-5722
Telecopier: (416) 345-6833

All correspondence, reports, documents and/or other communication concerning this Agreement and the Schedule attached hereto shall be directed to the attention of the authorized representatives noted above and shall be deemed to be sufficiently given if delivered personally, mailed or transmitted by fax to the attention of the authorized representatives at the addresses above, and any notice so given shall be deemed to have been made and received on the date of delivery or on the 5th business day following the day of mailing of same or on the day of transmission if transmitted during normal business hours, otherwise on the next business day, as the case may be.

10.0 CHANGE OF CONTROL

In the event of a change of control of the Services Provider, this Agreement shall immediately terminate. A change of control shall mean, as applicable, a purchase of more than fifty (50) percent of the outstanding capital by a non-affiliate third party.

11.0 ASSIGNMENT

Neither this Agreement nor any rights and obligations shall be assigned by either party without the prior written consent of the other party, which consent shall not be unreasonably withheld. Subject to the foregoing, this Agreement shall enure to the benefit of the parties hereto and their respective successors and permitted assigns.

12.0 RELATIONSHIP OF PARTIES:

Nothing in this Agreement creates the relationship of principal and agent, employer and employee, partnership or joint venture between the parties. The parties agree that they are and will at all times remain independent and are not and shall not present themselves to be the agent, employee, partner or joint venturer of the other. No representations will be made or acts taken by either party which could establish any apparent relationship of agency, employment, joint venture or partnership and neither party shall be bound in any manner whatsoever by any agreements, warranties or representations made by the other party to any other person nor with respect to any other action of the other party.

13.0 SCHEDULES

Schedules "A" and "B" attached hereto are to be read with and form part of this Agreement.

14.0 COUNTERPARTS

This Agreement may be executed in counterparts and the counterparts together shall constitute an original.

IN WITNESS THEREOF the parties hereto have caused this Agreement to be executed by their respective representatives duly authorized in that behalf.

HYDRO ONE NETWORKS INC.

Maureen Wareham

Name: Maureen Wareham
Title: Acting Secretary
I have authority to bind the corporation

HYDRO ONE REMOTE COMMUNITIES INC.

Name: Myles D'Arcey
Title: ~~President~~ and CEO
have authority to bind the corporation.

Schedule "A"

DESCRIPTION OF SERVICES:

Subject to the Services Provider's availability of personnel and resources, which availability shall be determined by the Services Provider in its sole discretion, the Services Provider shall provide the Services Recipient with the following services as may be required by the Services Recipient from time to time during the term of this Agreement:

a. Metering/Technician Work:

- update, install, reverify and sample meters
- Smart meter change-outs
- line layout, estimating and staking
- voltage/current surveys and responding to voltage/current complaints

b. Lines Work:

- maintain the Services Recipient's transmission and distribution system in Northwestern Ontario by providing the following activities, as may be requested by the Services Recipient:
- power line maintenance, construction and repair
- trouble Call Response, power restoration and storm damage repairs

c. Training:

- Provide lines apprenticeship program instruction services

Schedule "B"

Receiving Party Security Safeguards Regarding Confidential Information Received from the Disclosing Party

The Receiving Party shall protect the Confidential Information by security safeguards appropriate to the sensitivity of the information.

1) The Receiving Party shall protect the Confidential Information against such risks as loss or theft, unauthorized access, disclosure, copying, use, modification or destruction, through appropriate security measures, regardless of the format in which it is held.

2) All of the Receiving Party Representatives with access to the Confidential Information shall be contractually required to respect the confidentiality of that information.

3) The Receiving Party acknowledges and agrees that the nature of the safeguards will vary depending on the sensitivity, amount, distribution and format of the information, and the method of storage. The Receiving Party shall ensure that more sensitive information will be safeguarded by a higher level of protection.

4) The Receiving Party shall ensure that methods of protection will include:

(a) physical measures, for example, locked filing cabinets and restricted access to offices;

(b) organizational measures, for example, controlling entry to data centers and limiting access to information on a "need-to-know" basis;

(c) technological measures, for example, the use of passwords and encryption; and

(d) investigative measures, in cases where the Receiving Party has reasonable grounds to believe that the Confidential Information is being inappropriately collected, used or disclosed by anyone whom in law the Receiving Party is responsible.

DISTRIBUTION FINANCIAL STATEMENTS AND UTILITY INCOME – HISTORIC YEARS (2004, 2005, AND 2006) AND BRIDGE YEAR (2007)

Included in this exhibit are the Historic Distribution Financial Statements as follows:

Attachment 1: 2004 Distribution Financial Statements
Attachment 2: 2005 Distribution Financial Statements
Attachment 3: 2006 Distribution Financial Statements
Attachment 4: 2007 Distribution Financial Statements

HYDRO ONE NETWORKS INC.

DISTRIBUTION BUSINESS

FINANCIAL STATEMENTS

FOR THE YEAR ENDED

DECEMBER 31, 2004

HYDRO ONE NETWORKS INC.
DISTRIBUTION BUSINESS
AUDITORS' REPORT

To the Directors of
Hydro One Networks Inc.

We have audited the balance sheets of the Distribution Business (a business of Hydro One Networks Inc.), as at December 31, 2004 and the statements of operations and cash flows of the Distribution Business for the year then ended. These financial statements are the responsibility of the management of the Distribution Business. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these financial statements present fairly, in all material respects, the financial position of the Distribution Business of Hydro One Networks Inc. as at December 31, 2004 and the results of its operations and its cash flows for the year then ended, in accordance with Canadian generally accepted accounting principles.

The Distribution Business has no separate legal status or existence (See Note 1).

Ernst & Young LLP

ERNST & YOUNG LLP
Chartered Accountants
Toronto, Canada

April 19, 2005

HYDRO ONE NETWORKS INC.
DISTRIBUTION BUSINESS
STATEMENTS OF OPERATIONS

Year ended December 31 (Canadian dollars in millions)	**2004**	**2003**
Revenues		
Energy sales	2,370	2,258
Rural rate protection *(Note 13)*	125	125
Other	55	32
	2,550	2,415
Costs		
Purchased power *(Note 13)*	1,752	1,646
Operation, maintenance and administration *(Note 13)*	356	349
Depreciation and amortization *(Note 4)*	216	206
	2,324	2,201
Regulatory recovery *(Note 3)*	102	-
Income before financing charges and provision for payments in lieu of corporate income taxes	328	214
Financing charges *(Notes 5 and 13)*	125	128
Income before provision for payments in lieu of corporate income taxes	203	86
Provision for payments in lieu of corporate income taxes *(Note 6)*	39	40
Net income	164	46

See accompanying notes to financial statements.

HYDRO ONE NETWORKS INC.
DISTRIBUTION BUSINESS
BALANCE SHEETS

December 31 (Canadian dollars in millions)	**2004**	**2003**
Assets		
Current assets		
Accounts receivable (net of allowance for doubtful accounts - $8 million; 2003 - $9 million) *(Note 13)*	499	449
Materials and supplies	16	15
	515	464
Fixed assets *(Note 7)*		
Fixed assets in service	5,210	4,927
Less: accumulated depreciation	2,037	1,903
	3,173	3,024
Construction in progress	53	64
	3,226	3,088
Other long-term assets		
Regulatory assets *(Note 8)*	330	277
Goodwill	73	73
Deferred debt costs	8	8
Long-term accounts receivable and other assets	8	2
	419	360
Total assets	4,160	3,912

See accompanying notes to financial statements.

HYDRO ONE NETWORKS INC.
DISTRIBUTION BUSINESS
BALANCE SHEETS (continued)

December 31 (Canadian dollars in millions)	**2004**	**2003**
Liabilities		
Current liabilities		
Inter-company demand facility *(Note 13)*	100	124
Accounts payable and accrued charges *(Note 13)*	388	384
Accrued interest	22	20
Long-term debt payable within one year *(Notes 9, 10 and 13)*	192	186
	702	714
Long-term debt *(Notes 9, 10 and 13)*	1,701	1,639
Other long-term liabilities		
Employee future benefits other than pension *(Note 11)*	360	327
Environmental liabilities *(Note 12)*	41	47
Regulatory liability *(Note 8)*	25	-
Long-term accounts payable and accrued charges	4	17
	430	391
Total liabilities	2,833	2,744
Contingencies and commitments *(Notes 15 and 16)*		
Excess of assets over liabilities	1,327	1,168
Total liabilities and excess of assets over liabilities	4,160	3,912

See accompanying notes to financial statements.

On behalf of the Board:

Tom Parkinson
Chair of the Board of Directors

Beth Summers
Director

HYDRO ONE NETWORKS INC.
DISTRIBUTION BUSINESS
STATEMENTS OF CASH FLOWS

Year ended December 31 (Canadian dollars in millions)	**2004**	**2003**
Operating activities		
Net income	164	46
Adjustments for non-cash items:		
Depreciation and amortization (net of removal costs)	194	182
Regulatory recovery	(102)	-
Retail settlements variance accounts	29	21
	285	249
Changes in non-cash balances related to operations *(Note 14)*	(52)	63
Net cash from operating activities	233	312
Investing activities		
Fixed assets	(272)	(280)
Net cash used in investing activities	(272)	(280)
Financing activities		
Change in allocated long-term debt	68	230
Payments to parent to finance dividends	(5)	(5)
Net cash from financing activities	63	225
Net change in intercompany demand facility	24	257
Inter-company demand facility, January 1	(124)	(381)
Inter-company demand facility, December 31	(100)	(124)

See accompanying notes to financial statements.

1. STATUS OF DISTRIBUTION BUSINESS AND DESCRIPTION OF BUSINESS

Hydro One Inc. (Hydro One) was incorporated on December 1, 1998, under the *Business Corporations Act* (Ontario) and is wholly owned by the Province of Ontario (the Province). The principal businesses of Hydro One are the transmission and distribution of electricity to customers within Ontario. These businesses are regulated by the Ontario Energy Board (OEB).

Hydro One Networks Inc. (Hydro One Networks or the Company) was incorporated on March 4, 1999 under the *Business Corporations Act* (Ontario) and is a wholly owned subsidiary of Hydro One. Hydro One Networks acquired and assumed the assets, liabilities rights and obligations of the electricity distribution business of Ontario Hydro on April 1, 1999.

Hydro One Networks' regulated distribution business (Distribution Business) operates a low-voltage electrical distribution network that distributes electricity from the transmission system, or directly from generators, to customers within Ontario. Distribution customers include small local distribution companies and large industrial customers with loads of less than 5 MW. The Distribution Business is comprised of the distribution business of Hydro One Networks.

2. SIGNIFICANT ACCOUNTING POLICIES

Basis of Accounting

The financial statements have been prepared in accordance with accounting principles generally accepted in Canada (Canadian GAAP). The financial statements have been prepared for the specific use of the OEB. Consolidated financial statements of Hydro One for the year ended December 31, 2004 have been prepared and are publicly available.

The financial statements have been prepared primarily through specific identification of assets, liabilities (other than debt), revenues and expenses that relate to the Distribution Business. Debt was allocated to the Distribution Business effective April 1, 1999, based on a formula of 60% of assigned assets minus liabilities (other than debt). Shared functions and services costs have been allocated to the Distribution Business on a fully allocated cost basis.

Rate-Setting

The rates of the Distribution Business are subject to regulation by the OEB. The OEB has the general power to include or exclude costs, revenues, losses or gains in the rates of a specific period, resulting in a change in the timing of accounting recognition from that which would have applied in an unregulated company. Such change in timing gives rise to the recognition of regulatory assets and liabilities. The Distribution Business's regulatory assets represent certain amounts receivable from future customers and costs that have been deferred for accounting purposes because it is probable that they will be recovered in future rates. In addition, the Company has recorded a regulatory liability that represents an amount incurred in a different period than would be the case had the Company been unregulated. Specific regulatory assets and liability recognized at December 31, 2004 are disclosed in Note 8.

On December 9, 2004, the OEB issued its decision on the prudence of various regulatory deferral accounts incurred prior to December 31, 2003, plus related interest. As a result of the OEB's decision, the proportion of the Company's regulatory assets subject to potential future OEB disallowance has been significantly reduced. However, regulatory asset amounts included in approved accounts that were recognized after December 31, 2003 have not yet been reviewed by the OEB. Similarly, the Company's deferred distribution-related pension expenditures have not yet been reviewed by the OEB for prudence. The Company continually assesses the likelihood of recovery of each of its regulatory assets and continues to believe that it is probable that the OEB will factor its regulatory assets and liability into the setting of future rates. If, at some future date, the Company judges that it is no longer probable that the OEB will include a regulatory asset or liability in future rates, the appropriate carrying amount will be reflected in results of operations in the period that the assessment is made.

Revenue Recognition

Revenue attributable to the delivery of electricity is based on OEB-approved distribution tariff rates and is recognized as electricity is delivered to customers. The Company estimates the monthly revenue for the period based on wholesale power purchases because customer meters are not generally read at the end of each month. Unbilled revenue included within accounts receivable as at December 31, 2004 amounted to $318 million (2003 - $281 million).

Revenue also includes an amount relating to rate protection for rural residential customers, which is received from the Independent Electricity System Operator (IESO) based on a standardized customer rate that is approved by the OEB. The current legislation provides rate protection for prescribed classes of rural residential customers by reducing the electricity rates that would otherwise apply.

Revenue also includes revenue related to sales of services and equipment. Such revenue is recognized as services are rendered or as equipment is delivered.

Corporate Income and Capital Taxes

Under the *Electricity Act, 1998*, Hydro One Networks is required to make payments in lieu of corporate taxes to the Ontario Electricity Financial Corporation (OEFC). These payments are calculated in accordance with the rules for computing income and taxable capital and other relevant amounts contained in the *Income Tax Act* (Canada) and the *Corporations Tax Act* (Ontario) as modified by the *Electricity Act, 1998* and related regulations.

The Distribution Business provides for its share of the Company's payments in lieu of corporate income taxes using the taxes payable method as directed by the OEB. Under the taxes payable method, no provisions are made for future income taxes as a result of temporary differences between the tax basis of assets and liabilities and their carrying amounts for accounting purposes. When unrecorded future income taxes become payable, it is expected that they will be included in the rates approved by the OEB and recovered from distribution customers at that time.

Inter-Company Demand Facility

Hydro One maintains pooled bank accounts for its use and for the use of its subsidiaries and, implicitly, by the regulated businesses of these subsidiaries. The inter-company demand facility represents the cumulative net effect of all deposits and withdrawals made by the Distribution Business to and from the pooled cash accounts. Interest is earned on positive inter-company balances based on the average of the bankers' acceptance rate at the beginning and end of the month, less 0.02%. Interest is charged on overdraft inter-company balances based on the same bankers' acceptance rate, plus 0.15%.

Materials and Supplies

Materials and supplies represent spare parts and construction material held for internal construction and maintenance of fixed assets. These assets are carried at lower of average cost or net realizable value.

Fixed Assets

Fixed assets are capitalized at cost, which comprises materials, labour, engineering costs, overheads, depreciation on service equipment and the approved allowance for funds used during construction applicable to capital construction activities. Fixed assets in service consist of distribution assets, communication, administration and service assets and easements.

During 2003, Hydro One adopted the Canadian Institute of Chartered Accountants' (CICA) Handbook Section 3110, *Asset Retirement Obligations*. This new accounting standard requires the Company to determine the fair value of the future expenditures required to settle legal obligations to remove fixed assets. If reasonably estimable, a liability is recognized equal to the present value of the estimated future removal expenditures. An equivalent amount is capitalized as an inherent cost of the associated fixed asset.

Some distribution assets, particularly those located on unowned easements and rights-of-way, may have asset retirement obligations. The majority of these easements and rights-of-way are either of perpetual duration or are automatically renewed annually. Land rights with finite terms are generally subject to extension or renewal. As the Company expects to use the majority of its installed assets for an indefinite period, no removal date can be determined and consequently a reasonable estimate of the fair value of any related asset retirement obligations cannot be made at this time. If, at some future date, it becomes possible to estimate the fair value cost of removing assets that the Company is legally required to remove, an asset retirement obligation will be recognized at that time.

Distribution

Distribution assets comprise assets related to the distribution of low-voltage electricity, including lines, poles, switches, transformers, protective devices and metering systems.

Communication, Administration and Service

Communication, administration and service assets include telecommunications equipment, towers, associated buildings, administrative buildings, major computer systems, personal computers, transport and work equipment, and tools, vehicles and minor fixed assets.

Easements

Easements include amounts incurred for easements and other access rights.

Construction in Progress

Overhead costs, including corporate functions and services costs, are capitalized on a fully allocated basis. Financing costs are capitalized on fixed assets under construction based on the allowance for funds used during construction (2004 – 7.0%; 2003 – 7.4%).

Depreciation

The capital costs of fixed assets are depreciated on a straight-line basis, except for transport and work equipment and personal computers, which are depreciated on a declining balance basis.

Depreciation rates for the various classes of assets are based on their estimated service lives. The average estimated remaining service lives and service life ranges of fixed assets are:

	Estimated service lives (years)	
	Range	Average
Distribution	15 - 75	41
Communication, administration and service	5 - 50	30

Depreciation rates for easements are based on their contract life. The majority of easements are held in perpetuity and not depreciated.

In accordance with group depreciation practices, the original cost of normal fixed asset retirements is charged to accumulated depreciation, with no gain or loss reflected in results of operations. Gains and losses on sales of fixed assets and losses on premature retirements are charged to results of operations as adjustments to depreciation expense. Depreciation expense also includes the costs incurred to remove fixed assets where an asset retirement obligation, as defined in CICA Handbook Section 3110, has been recognized.

The estimated service lives of fixed assets are subject to periodic review. Any changes arising out of such a review are implemented on a remaining service life basis from the year the changes can first be reflected in distribution rates.

Goodwill

Goodwill represents the cost of acquired local distribution companies in excess of fair value of the net identifiable assets purchased and is evaluated for impairment on an annual basis, or more frequently if circumstances require. Under CICA Handbook Section 3062, *Goodwill and Other Intangible Assets*, goodwill impairment is assessed based on a comparison of the fair value of the reporting unit to the underlying carrying value of the reporting unit's net assets, including goodwill, with any write-down of the carrying value of goodwill being charged against the results of operations.

The Company has determined that the goodwill of its Distribution Business is not impaired.

Deferred debt costs

Deferred debt costs include the unamortized amounts of debt issuance costs. Deferred debt costs are amortized on an annuity basis over the period to maturity of the debt.

Discounts, Premiums and Hedging

Allocated discounts, premiums and hedging gains and losses are amortized over the period of the related debt and are presented net with allocated long-term debt.

Employee Future Benefits

Employee future benefits for all employees of Hydro One and its subsidiaries include pension, group life insurance, health care, and long-term disability.

In accordance with the OEB's rate orders, pension costs are recorded when employer contributions are paid to the pension fund in accordance with the *Pension Benefits Act* (Ontario). Actuarial valuations are conducted at least every three years. Pension costs are also calculated on an accrual basis. Pension costs are actuarially determined using the projected benefit method prorated on service and based on assumptions that reflect management's best estimate of the effect of future events, including future compensation increases, on the actuarial present value of accrued pension benefits. Pension plan assets, consisting primarily of listed equity securities as well as corporate and government debt securities, are valued using fair values. Past service costs from plan amendments and all actuarial gains or losses are amortized on a straight-line basis over the expected average remaining service life of the employees covered.

Employee future benefits other than pension are recorded on an accrual basis. Costs are determined by independent actuaries using the projected benefit method prorated on service and based on assumptions that reflect management's best estimates. Past service costs from plan amendments and actuarial gains or losses are amortized on a straight-line basis over the expected average remaining service life of the employees covered.

Employee future benefit costs are attributed to labour and charged to operations or capitalized as part of the cost of fixed assets.

Environmental Costs

The Distribution Business has recognized a liability for estimated future expenditures associated with the assessment and remediation of contaminated lands and for the phase-out and destruction of polychlorinated biphenyl (PCB) contaminated mineral oil from electrical equipment, based on the net present value of these estimated future expenditures. As the Company anticipates that the related expenditures will continue to be recoverable in future rates, a regulatory asset has been recognized to reflect the future recovery of these costs from customers. The Company reviews its estimates of future environmental expenditures on an ongoing basis.

Use of Estimates

The preparation of financial statements in conformity with Canadian GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities at the date of the financial statements, and the reported amounts of revenues and expenses for the year. Actual results could differ from estimates, including changes as a result of future decisions made by the OEB or the Province of Ontario (the Province).

3. REGULATORY RECOVERY

The *Electricity Pricing, Conservation and Supply Act, 2002,* suspended a previously approved rate increase related to annual low-voltage services costs for embedded local distribution companies and direct customers. The associated costs are charged annually to the Distribution Business' results of operations. Subject to future OEB approval, the *Electricity Pricing, Conservation and Supply Act, 2002* also allowed for establishment of a regulatory deferral account to record suspended low voltage services amounts to be recovered from future customers. Due to uncertainty of recovery, amounts recorded in this regulatory deferral account between May 1, 2002 and December 9, 2004 were not previously recognized as regulatory assets. Similarly, the Company did not reflect certain other costs, such as interest, as regulatory assets in prior years' financial statements.

On May 31, 2004, Hydro One applied for recovery of approximately $156 million in various regulatory deferral accounts prior to December 31, 2003. The requested recovery primarily included the low voltage amounts not previously recognized as regulatory assets, as well as interest on all of the requested balances. As a result of the oral and written evidence submitted by the Company, the OEB issued a decision on December 9, 2004 regarding the prudence of the distribution-related deferral account balances included in the application. The OEB approved all but approximately $12 million of the requested amount for recovery over the period ending April 30, 2008. As a result of this successful regulatory recovery, the Distribution Business has recorded an increase in its regulatory asset balance, which primarily reflects future recovery of costs that had been previously charged to results of operations without recognition of corresponding revenue.

The regulatory recovery consists of the following components:

Year ended December 31 (Canadian dollars in millions)	**2004**
Low voltage services – 2002	17
Low voltage services – 2003	25
Low voltage services – 2004	23
Interest accretion	18
Other	19
	102

4. DEPRECIATION AND AMORTIZATION

Year ended December 31 (Canadian dollars in millions)	**2004**	**2003**
Depreciation of fixed assets in service	143	129
Fixed asset removal costs	22	24
Amortization of regulatory and other assets	51	53
	216	206

5. FINANCING CHARGES

Year ended December 31 (Canadian dollars in millions)	**2004**	**2003**
Interest on long-term debt payable	127	128
Interest on inter-company demand facility	2	5
Less: Interest capitalized on construction in progress	(4)	(5)
	125	128

6. PROVISION FOR PAYMENTS IN LIEU OF CORPORATE INCOME TAXES

The provision for payments in lieu of corporate income taxes (PILs) differs from the amount that would have been recorded using the combined Canadian Federal and Ontario statutory income tax rate. A reconciliation between the statutory and effective tax rate is provided as follows:

Year ended December 31 (Canadian dollars in millions)	**2004**	**2003**
Income before provision for PILs	203	86
Federal and Ontario statutory income tax rate	36.12%	36.62%
Provision for PILs at statutory rate	73	32
(Decrease) increase resulting from:		
Net temporary differences:		
Regulatory recovery	(37)	-
Pension contribution in excess of pension expense	(19)	-
Depreciation and amortization in excess of capital cost allowance	14	11
Retail settlements variance accounts	11	(4)
Employee future benefits other than pension expense in excess of cash payments	5	5
Environmental expenditures	(3)	(6)
Interest capitalized for accounting purposes but deducted for tax purposes	(2)	(2)
Charge for staff reduction program lower than cash payments	(1)	(4)
Other	(9)	-
Net temporary differences	(41)	-
Net permanent differences:		
Large corporations tax	6	7
Other	1	1
Net permanent differences	7	8
Provision for PILs	39	40
Effective income tax rate	19.21%	46.51%

Future income taxes have not been recorded in the accounts as they are expected to be recovered through future revenues. As at December 31, 2004, future income tax liabilities of $59 million (2003 - $23 million), based on substantively enacted income tax rates, have not been recorded.

7. FIXED ASSETS

December 31 (Canadian dollars in millions)	Fixed Assets in Service	Accumulated Depreciation	Construction in Progress	Total
2004				
Distribution	4,696	1,732	53	3,017
Communication, administration and service	506	302	-	204
Easements	8	3	-	5
	5,210	2,037	53	3,226
2003				
Distribution	4,456	1,652	60	2,864
Communication, administration and service	463	248	4	219
Easements	8	3	-	5
	4,927	1,903	64	3,088

Financing costs are capitalized on fixed assets under construction using the allowance for funds used during construction and were $4 million in 2004 (2003 - $5 million).

8. REGULATORY ASSETS AND LIABILITY

Regulatory assets and liabilities arise as a result of the ratemaking process. The Distribution Business has recorded the following regulatory assets and liability (see Notes 2 and 3):

December 31 (Canadian dollars in millions)	**2004**	**2003**
Regulatory assets:		
Regulatory asset recovery account	121	102
Employee future benefits other than pension	94	118
Environmental	50	57
Pension	34	-
Low voltage services	26	-
Other	5	-
Total regulatory assets	330	277
Regulatory liability:		
Retail settlement variance accounts	25	-
Total regulatory liability	25	-

Regulatory assets

Regulatory asset recovery account (RARA)

On December 9, 2004 the OEB issued a decision on the prudence of the distribution-related deferral account balances sought by the Company in its May 31, 2004 application. Recoverable amounts represent balances incurred prior to December 31, 2003, plus associated interest. The OEB ordered that the approved balances be aggregated into a single regulatory account to be recovered on a straight-line basis over the period ending April 30, 2008. The RARA includes distribution business low voltage services amounts, deferred environmental expenditures incurred in 2001 and 2002, deferred market ready expenditures, retail settlement variance amounts, and other amounts primarily consisting of accrued interest.

Employee future benefits other than pension

Employee future benefits other than pension are recorded using the accrual method as required by Canadian GAAP. The OEB has allowed for the recovery of past service costs, which arose on the adoption of the accrual method, in the revenue requirement on a straight-line basis over a 10-year period. As a result, in 1999 the Company recorded a regulatory asset, with an original balance of $226 million, to reflect this regulatory treatment. This regulatory asset has a remaining recovery period of 4 years (2003 - 5 years) and does not earn a return.

Environmental

The Company provides for estimated future expenditures required to remediate past environmental contamination. Because such expenditures are expected to be recoverable in future rates, the Company has recognized the net present value of these estimated future environmental expenditures as a regulatory asset. This regulatory asset is expected to be amortized to results of operations on a basis consistent with the pattern of actual expenditures expected to be incurred up to the year 2030. During 2003, the Company reduced, by $64 million, its estimated long-term liability and offsetting regulatory asset for the management of polychlorinated biphenyls (PCBs). This reduction was due to expected revisions to draft regulations proposed by Environment Canada. The OEB has the discretion to examine and assess the prudence and the timing of recovery of Hydro One's future regulatory expenditures.

Pension

In a July 14, 2004 decision, the OEB approved the Company's establishment of a regulatory deferral account to record the Company's distribution-related pension contributions that would otherwise have been charged to 2004 results of operations. The regulatory asset will also include amounts payable to Inergi LP commencing 2005 in respect of a risk sharing agreement related to the imbalance between pension fund assets and liabilities in respect of transferred staff. The amount related to the distribution business, as determined at December 31, 2004, was approximately $16 million. In its decision, the OEB concluded that prudently incurred expenditures of this type are generally recoverable as part of a general rate application. The Company will include its request for recovery as part of its next general distribution rate application during 2005.

Low voltage services

The OEB's December 9, 2004 decision allows for delayed recovery of previously approved low voltage services amounts, within the RARA, for the period up to December 31, 2003. Given this decision, the Company has determined that it was highly probable that, at some future date, the OEB will also approve recovery of the low voltage amount attributable to 2004, plus interest. As a result, the Company has recognized a regulatory asset reflecting this probable future recovery.

Regulatory liability

Retail settlement variance accounts

The Company has deferred certain retail settlement variance amounts under the provisions of Article 490 of the OEB's *Accounting Procedures Handbook*. The OEB's December 9, 2004 decision allows for recovery of retail settlement variance amounts accumulated prior to December 31, 2003, inclusive of interest, within the RARA. The Company anticipates that the OEB will include the net balance of this regulatory account attributable to 2004 activity in future rates.

9. DEBT

December 31 (Canadian dollars in millions)	**2004**	**2003**
Long-term debt payable within one year	192	186
Long-term debt	1,694	1,636
Net unamortized premiums	10	7
Unamortized hedging losses	(3)	(4)
Long-term debt	1,893	1,825

Debt represents various notes payable by Hydro One Networks to Hydro One. All notes are denominated in Canadian dollars and were notionally allocated to the Distribution Business based on 60% of the allocated net assets. This notional debt is summarized by years to maturity in the following table:

Years to Maturity	Principal Outstanding *(Canadian dollars in millions)*	Weighted Average Interest Rate *(per cent)*
1 year	192	7.6
2 years	179	10.3
3 years	105	8.6
4 years	210	4.0
5 years	88	4.0
	774	7.0
6 – 10 years	522	6.2
Over 10 years	590	6.8
	1,886	6.7

10. FAIR VALUE OF FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

The carrying amounts of all financial instruments, except long-term debt, approximate fair value. The fair value of long-term debt, based on year-end quoted market prices for same or similar debt of the same remaining maturities, is provided in the following table:

December 31 (Canadian dollars in millions)	**2004**		**2003**	
	Carrying Value	Fair Value	Carrying Value	Fair Value
Long-term debt[1]	1,886	2,009	1,822	1,988

[1] The carrying value of long-term debt represents the par value of the notes.

Financial assets create a risk that a counter-party will fail to discharge an obligation, causing a financial loss. As at December 31, 2004, there were no significant concentrations of credit risk with respect to any class of financial assets. The revenue of the Distribution Business is earned from a broad base of customers. The Distribution Business did not earn a significant amount of its revenue from any single customer. As at December 31, 2004, there were no significant balances of accounts receivable due from any single customer.

11. EMPLOYEE FUTURE BENEFITS

Pension

Hydro One has a contributory defined benefit pension plan covering all regular employees of Hydro One and its subsidiaries, except Hydro One Brampton. Employees at Hydro One Brampton participate in the Ontario Municipal Employees Retirement System (OMERS), a multi-employer public sector fund.

The Hydro One Pension Plan does not segregate assets in a separate account for individual subsidiaries, nor is the cost of the benefit plans allocated to, or funded separately by, entities within the consolidated group. Accordingly, for purposes of these financial statements, the pension plan is accounted for as a defined contribution plan and no deferred pension asset or liability is recorded.

Hydro One's pension plan provides benefits based on highest three-year average pensionable earnings. For new management employees who commenced employment on or after January 1, 2004, benefits are based on highest five-year average pensionable earnings. After retirement, pensions are fully indexed to inflation. The measurement date used to determine plan assets and the accrued benefit obligation is December 31. Based on the actuarial valuation filed on September 22, 2004, effective for December 31, 2003, Hydro One contributed $80 million to its pension plan in respect of 2004, payable one month in arrears, and will contribute a further $80 million in respect of 2005 and 2006 to satisfy minimum funding requirements. A significant portion of these contributions will be attributed to the Distribution Business. All of the contributions are expected to be in the form of cash. Hydro One has previously not been required to contribute to the pension plan because the contribution level, which was established from the last actuarial valuation at December 31, 2000 indicated that the plan had a surplus. Contributions after 2006 will be based on actuarial valuations as at December 31, 2006 and will depend on future investment returns, and changes in actuarial assumptions.

For Hydro One, the actuarial present value at December 31, 2004 of the accrued pension benefits, based on a projection of the valuation at December 31, 2004, was estimated to be $4,862 million (2003 - $4,323 million). Pension plan assets available for these benefits were $4,243 million (2003 - $3,939 million).

Employee Future Benefits other than Pension

During the year ended December 31, 2004, $32 million of employee future benefits other than pension costs were charged to the results of operations of the Distribution Business (2003 - $29 million), and $22 million was capitalized as part of the cost of fixed assets (2003 - $21 million). Benefits paid were $19 million (2003 - $18 million). The liability associated with employee future benefits other than pension for the Distribution Business at December 31, 2004 was $378 million (2003 - $343 million), including the current portion.

A detailed description of employee future benefits is provided in Note 11 of the Consolidated Financial Statements of Hydro One for the year ended December 31, 2004.

12. ENVIRONMENTAL LIABILITIES

December 31 (Canadian dollars in millions)	**2004**	**2003**
Environmental liabilities, January 1	57	130
Interest accretion	1	7
Expenditures	(8)	(16)
Revaluation adjustment *(Note 8)*	-	(64)
Environmental liabilities, December 31	50	57
Less: current portion	(9)	(10)
	41	47

Estimated future environmental expenditures for each of the five years subsequent to December 31, 2004 and in total thereafter are as follows: 2005 - $9 million; 2006 - $8 million; 2007 - $7 million; 2008 - $7 million; 2009 - $6 million; and thereafter - $30 million.

There are uncertainties in estimating future environmental costs due to potential external events such as changing regulations and advances in remediation technologies. Hydro One continuously reviews factors affecting its cost estimates as well as the environmental condition of the various properties. The actual cost of investigation or remediation may differ from current estimates.

13. RELATED PARTY TRANSACTIONS

The Province and Successor Corporations of Ontario Hydro

The Province, OEFC, Ontario Power Generation Inc. (OPG) and the IESO are related parties of Hydro One Networks' Distribution Business. Transactions between these parties and the Distribution Business were as follows:

The Distribution Business receives amounts for rural rate protection from the IESO. Revenue for 2004 include $127 million (2003 - $127 million) related to this program, of which $2 million (2003 - $2 million) was paid to local distribution companies in respect of annexation agreements.

The Distribution Business purchased power from the IESO-administered spot market in the amount of $1,752 million in 2004 (2003 - $1,646 million).

Hydro One Networks has service level agreements with Ontario Hydro's successor corporations, primarily OPG. These services include field and engineering, logistics, corporate, telecommunications and information technology services. Revenues related to the provision of services to the other successor corporations were $nil in 2004 (2003 - $1 million) and operation, maintenance and administration costs related to the purchase of services from the other successor corporations were less than $1 million in 2004 and 2003.

The provision for payments in lieu of corporate income taxes was paid or payable to the OEFC.

Subsidiaries of Hydro One Inc.

Hydro One Networks provides services to, and receives services from, Hydro One and its other subsidiaries. Amounts due to and from Hydro One and its subsidiaries are settled through the inter-company demand facility.

Hydro One Networks has entered into various agreements with Hydro One and its subsidiaries related to the provision of corporate functions and services, supply management, computer support and operational services such as environmental, forestry and line services. Revenues include $1 million (2003 - $1 million) related to the provision of services to Hydro One and its subsidiaries and operation, maintenance and administration costs include $1 million (2003 - $1 million) related to the purchase of services from Hydro One and its subsidiaries.

The debt of the Distribution Business is due to Hydro One. Financing charges include interest expense on this debt in the amount of $127 million (2003 - $128 million). In addition, balances payable or receivable under the inter-company demand facility are due to or from Hydro One. Financing charges of the Distribution Business include interest expense on this facility in the amount of $2 million (2003 - $5 million).

The amounts due to and from related parties as a result of the transactions referred to above are as follows:

December 31 (Canadian dollars in millions)	**2004**	**2003**
Accounts receivable	3	11
Accounts payable and accrued charges	179	175

Included in accounts payable and accrued charges are amounts owing to the IESO in respect of power purchases of $179 million (2003 - $149 million).

14. STATEMENTS OF CASH FLOWS

The changes in non-cash balances related to operations consist of the following:

Year ended December 31 (Canadian dollars in millions)	**2004**	**2003**
Accounts receivable (increase) decrease	(50)	14
Materials and supplies (increase) decrease	(1)	7
Accounts payable and accrued charges increase	4	30
Accrued interest increase	2	-
Employee future benefits other than pension increase	33	33
Long-term accounts payable and accrued charges decrease	(13)	-
Other	(27)	(21)
	(52)	63

15. CONTINGENCIES

Hydro One Networks is a wholly owned subsidiary of Hydro One. As such, the Distribution Business and its assets are available for the satisfaction of the debts, contingent liabilities and commitments of Hydro One Networks and Hydro One.

16. COMMITMENTS

Hydro One Networks has numerous commitments. These commitments have not been specifically allocated to the Distribution Business. However, the net assets of the Distribution Business are available to satisfy these commitments.

17. COMPARATIVE FIGURES

The comparative financial statements have been reclassified from statements previously presented to conform to the presentation of the December 31, 2004 financial statements.

HYDRO ONE NETWORKS INC.

DISTRIBUTION BUSINESS

FINANCIAL STATEMENTS

FOR THE YEAR ENDED

DECEMBER 31, 2005

HYDRO ONE NETWORKS INC.
DISTRIBUTION BUSINESS
AUDITORS' REPORT

To the Directors of Hydro One Networks Inc.

We have audited the balance sheets of the Distribution Business (a business of Hydro One Networks Inc.), as at December 31, 2005 and December 31, 2004 and the statements of operations, and cash flow of the Distribution Business for the year then ended. These financial statements are the responsibility of the management of the Distribution Business. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these financial statements present fairly, in all material respects, the financial position of the Distribution Business of Hydro One Networks Inc. as at December 31, 2005 and 2004 and the results of its operations and its cash flows for the years then ended, in accordance with Canadian generally accepted accounting principles.

The Distribution Business has no separate legal status or existence (See Note 1).

Ernst & Young LLP

Ernst & Young LLP
Chartered Accountants
Toronto, Canada
April 5, 2006

HYDRO ONE NETWORKS INC.
DISTRIBUTION BUSINESS
STATEMENTS OF OPERATIONS

Year ended December 31 (Canadian dollars in millions)	**2005**	**2004**
		(restated- Notes 1 and 18)
Revenues		
Energy sales *(Note 3)*	2,536	2,375
Rural rate protection *(Note 14)*	125	125
Other	45	55
	2,706	2,555
Costs		
Purchased power *(Notes 3 and 14)*	1,845	1,752
Operation, maintenance and administration *(Note 14)*	373	358
Depreciation and amortization *(Note 5)*	219	217
	2,437	2,327
Regulatory recovery *(Note 4)*	-	102
Income before financing charges and provision for payments in lieu of corporate income taxes	269	330
Financing charges *(Notes 6 and 14)*	117	125
Income before provision for payments in lieu of corporate income taxes	152	205
Provision for payments in lieu of corporate income taxes *(Note 7)*	56	40
Net income	96	165

See accompanying notes to financial statements.

HYDRO ONE NETWORKS INC.
DISTRIBUTION BUSINESS
BALANCE SHEETS

December 31 (Canadian dollars in millions)	**2005**	**2004**
		(restated- Notes 1 and 18)
Assets		
Current assets		
Inter-company demand facility *(Note 14)*	58	-
Accounts receivable (net of allowance for doubtful accounts - $9 million; 2004 - $8 million) *(Note 14)*	439	499
Materials and supplies	22	16
	519	515
Fixed assets *(Note 8)*		
Fixed assets in service	5,493	5,224
Less: accumulated depreciation	2,176	2,047
	3,317	3,177
Construction in progress	80	53
	3,397	3,230
Other long-term assets		
Regulatory assets *(Note 9)*	344	330
Goodwill	73	73
Deferred debt costs	8	8
Long-term accounts receivable and other assets	8	8
	433	419
Total assets	4,349	4,164

See accompanying notes to financial statements.

HYDRO ONE NETWORKS INC.
DISTRIBUTION BUSINESS
BALANCE SHEETS (continued)

December 31 (Canadian dollars in millions)	**2005**	**2004**
		(restated-Notes 1 and 18)
Liabilities		
Current liabilities		
Inter-company demand facility *(Note 14)*	-	102
Accounts payable and accrued charges *(Note 14)*	438	388
Accrued interest	23	22
Long-term debt payable within one year *(Notes 10, 11 and 14)*	179	192
	640	704
Long-term debt *(Notes 10, 11 and 14)*	1,809	1,701
Other long-term liabilities		
Employee future benefits other than pension *(Note 12)*	396	360
Environmental liabilities *(Note 13)*	43	41
Regulatory liability *(Note 9)*	41	25
Long-term accounts payable and accrued charges	3	4
	483	430
Total liabilities	2,932	2,835
Contingencies and commitments *(Notes 16 and 17)*		
Excess of assets over liabilities	1,417	1,329
Total liabilities and excess of assets over liabilities	4,349	4,164

See accompanying notes to financial statements.

On behalf of the Board:

Tom Parkinson
Chair

Beth Summers
Director

HYDRO ONE NETWORKS INC.
DISTRIBUTION BUSINESS
STATEMENTS OF CASH FLOWS

Year ended December 31 (Canadian dollars in millions)	**2005**	**2004**
		(restated- Notes 1 and 18)
Operating activities		
Net income	96	165
Adjustments for non-cash items:		
Depreciation and amortization (net of removal costs)	195	195
Regulatory recovery	-	(102)
Low voltage services	(24)	-
Retail settlements variance accounts	13	29
	280	287
Changes in non-cash balances related to operations *(Note 15)*	114	(54)
Net cash from operating activities	394	233
Investing activities		
Capital expenditures	(317)	(270)
Other assets	(1)	-
Net cash used in investing activities	(318)	(270)
Financing activities		
Change in allocated long-term debt	95	68
Payments to Hydro One Inc. to finance dividends	(46)	(5)
Issuance of preferred shares by Hydro One Networks	38	-
Termination of interest rate swap	(3)	-
Net cash from financing activities	84	63
Net change in intercompany demand facility	160	26
Inter-company demand facility, January 1	(102)	(128)
Inter-company demand facility, December 31	58	(102)

See accompanying notes to financial statements.

1. DESCRIPTION OF THE DISTRIBUTION BUSINESS

Hydro One Inc. (Hydro One) was incorporated on December 1, 1998, under the *Business Corporations Act* (Ontario) and is wholly owned by the Province of Ontario (the Province). The principal businesses of Hydro One are the transmission and distribution of electricity to customers within Ontario. These businesses are regulated by the Ontario Energy Board (OEB).

Hydro One Networks Inc. (Hydro One Networks or the Company) was incorporated on March 4, 1999 under the *Business Corporations Act* (Ontario) and is a wholly owned subsidiary of Hydro One. The Company owns and operates Hydro One's regulated transmission and distribution businesses. The regulated distribution business (Distribution Business) operates a low-voltage electrical distribution network that distributes electricity from the transmission system, or directly from generators, to customers within Ontario. Distribution customers include small local distribution companies and large industrial customers with loads of less than 5 MW.

In prior years, the results of the Company's Sentinel Light operations had not been included in the Distribution Business financial statements as these assets were considered to be unregulated. In August 2005, the Company filed its distribution rate application on a basis that included sentinel lights within the definition of the regulated Distribution Business. While the OEB has not rendered a decision as at the date of the financial statements, OEB approval of the inclusion of sentinel lights as part of the regulated Distribution Business is considered probable. As a result, the Balance Sheets, Statements of Operations and Statements of Cash Flows of the Distribution Business now reflect Sentinel Lights. The prior year comparative figures have been restated to reflect this change in business definition. The impact of the restatement on the financial position and results of operations of the Distribution Business was not significant.

2. SIGNIFICANT ACCOUNTING POLICIES

Basis of Accounting

The financial statements have been prepared in accordance with accounting principles generally accepted in Canada (Canadian GAAP). The financial statements have been prepared for the specific use of the OEB. Consolidated financial statements of Hydro One for the year ended December 31, 2005 have been prepared and are publicly available.

The financial statements have been prepared primarily through specific identification of assets, liabilities (other than debt), revenues and expenses that relate to the Distribution Business. The Company's long-term debt is allocated based on the respective borrowing requirements of the Company's Transmission Business and Distribution Business. A portion of the Company's shared functions and services costs are allocated to the Distribution Business on a fully allocated cost basis.

Rate-setting

The rates of the Distribution Business are subject to regulation by the OEB. The OEB has the general power to include or exclude costs, revenues, losses or gains in the rates of a specific period, resulting in a change in the timing of accounting recognition from that which would have applied in an unregulated company. Such change in timing gives rise to the recognition of regulatory assets and liabilities. The Distribution Business's regulatory assets represent certain amounts receivable from future customers and costs that have been deferred for accounting purposes because it is probable that they will be recovered in future rates. In addition, the Company has recorded a regulatory liability for a variance account balance expected to be disposed of in the favour of Distribution Business customers. The specific regulatory assets and liabilities recognized at December 31, 2005 are disclosed in Note 9.

The Company's distribution rates are based on a revenue requirement that includes a rate of return. Current distribution rates are based on a cost of service rate regulation model, which also includes a targeted return of 9.88% on deemed common equity. In August 2005, the Company filed a distribution rate application seeking approval for a $160 million increase in the 2006 revenue requirement for its Distribution Business. This revenue requirement is based on achieving a 9.00% return on equity, consistent with the OEB's guidance for setting 2006 rates. An oral hearing occurred in January 2006 and the OEB decision is expected to render its decision in the second quarter of 2006.

On December 9, 2004, the OEB issued its decision on the prudence of various regulatory deferral accounts incurred prior to December 31, 2003, including related interest. As a result of the OEB's December 9, 2004 decision, the proportion of the Company's regulatory assets subject to potential future OEB disallowance has been significantly reduced. The Company continually assesses the likelihood of recovery of each of its regulatory assets and continues to believe that it is probable that the OEB will factor its regulatory assets and liability into the setting of future rates. If, at some future date, the Company judges that it is no longer probable that the OEB will include a regulatory asset or liability in future rates, the appropriate carrying amount will be reflected in results of operations in the period that the assessment is made.

Revenue Recognition

Revenues attributable to the delivery of electricity are based on OEB-approved distribution tariff rates and are recognized as electricity is delivered to customers. The Company estimates the monthly revenue for the period based on wholesale power purchases because customer meters are not generally read at the end of each month. Unbilled revenue included within accounts receivable as at December 31, 2005 amounted to $344 million (2004 - $318 million).

Revenue also includes an amount relating to rate protection for rural residential customers, which is received from the Independent Electricity System Operator (IESO) based on a standardized customer rate that is approved by the OEB. The current legislation provides rate protection for prescribed classes of rural residential customers by reducing the electricity rates that would otherwise apply.

Revenues also include revenue related to sales of other services and equipment. Such revenue is recognized as services are rendered or as equipment is delivered.

Corporate Income and Capital Taxes

Under the *Electricity Act, 1998*, the Company is required to make payments in lieu of corporate income taxes to the Ontario Electricity Financial Corporation (OEFC). These payments are calculated in accordance with the rules for computing income and taxable capital and other relevant amounts contained in the *Income Tax Act* (Canada) and the *Corporations Tax Act* (Ontario) as modified by the *Electricity Act, 1998,* and related regulations.

The Distribution Business provides for its share of the Company's payments in lieu of corporate income taxes using the taxes payable method, as directed by the OEB. Under the taxes payable method, no provisions are made for future income taxes as a result of temporary differences between the tax basis of assets and liabilities and their carrying amounts for accounting purposes. When unrecorded future income taxes become payable, it is expected that they will be included in the rates approved by the OEB and recovered from Distribution Business customers at that time.

Inter-Company Demand Facility

Hydro One maintains pooled bank accounts for its use and for the use of its subsidiaries and, implicitly, by the regulated businesses of these subsidiaries. The inter-company demand facility represents the cumulative net effect of all deposits and withdrawals made by the Distribution Business to and from the pooled cash accounts. Interest is earned on positive inter-company balances based on the average of the bankers' acceptance rate at the beginning and end of the month, less 0.02%. Interest is charged on overdraft inter-company balances based on the same bankers' acceptance rate, plus 0.15%.

Materials and Supplies

Materials and supplies represent spare parts and construction material held for internal construction and maintenance of fixed assets. These assets are carried at lower of average cost or net realizable value.

Fixed Assets

Fixed assets are capitalized at cost, which comprises materials, labour, engineering costs, overheads, depreciation on service equipment and the approved allowance for funds used during construction applicable to capital construction activities. Fixed assets in service consist of: distribution assets; communication, administration and service assets; and easements.

Some distribution assets, particularly those located on unowned easements and rights-of-way, may have asset retirement obligations. The majority of the Company's easements and rights-of-way are either of perpetual duration or are automatically renewed annually. Land rights with finite terms are generally subject to extension or renewal. As the Company expects to use the majority of its installed assets for an indefinite period, no removal date can be determined and consequently a reasonable estimate of the fair value of any related asset retirement obligations cannot be made at this time. If, at some future date, it becomes possible to estimate the fair value cost of removing assets that the Company is legally required to remove, an asset retirement obligation will be recognized at that time.

Distribution

Distribution assets comprise assets related to the distribution of low-voltage electricity, including lines, poles, switches, transformers, protective devices and metering systems.

Communication, Administration and Service

Communication, administration and service assets include telecommunications equipment, towers, associated buildings, administrative buildings, major computer systems, personal computers, transport and work equipment, and tools, vehicles and minor fixed assets.

Easements

Easements include amounts incurred for easements and other access rights.

Construction in Progress

Overhead costs, including corporate functions and services costs, are capitalized on a fully allocated basis. Financing costs are capitalized on fixed assets under construction based on the allowance for funds used during construction (2005 – 6.8%; 2004 – 7.0%).

Depreciation

The capital costs of fixed assets are depreciated on a straight-line basis, except for transport and work equipment and personal computers, which are depreciated on a declining balance basis.

Depreciation rates for the various classes of assets are based on their estimated service lives. The average estimated remaining service lives and service life ranges of fixed assets are:

	Estimated service lives (years)	
	Range	Average
Distribution	15 - 75	41
Communication, administration and service	5 - 50	30

Depreciation rates for easements are based on their contract life. The majority of easements are held in perpetuity and are not depreciated.

In accordance with group depreciation practices, the original cost of normal fixed asset retirements is charged to accumulated depreciation, with no gain or loss reflected in results of operations. Gains and losses on sales of fixed assets and losses on premature retirements are charged to results of operations as adjustments to depreciation expense. Depreciation expense also includes the costs incurred to remove fixed assets where an asset retirement obligation has been recognized.

The estimated service lives of fixed assets are subject to periodic review. Any changes arising out of such a review are implemented on a remaining service life basis from the year the changes can first be reflected in distribution rates.

Goodwill

Goodwill represents the cost of acquired local distribution companies (LDCs) in excess of fair value of the net identifiable assets purchased and is evaluated for impairment on an annual basis, or more frequently if circumstances require. Under Canadian Institute of Chartered Accountants Handbook Section 3062, *Goodwill and Other Intangible Assets*, goodwill impairment is assessed based on a comparison of the fair value of the reporting unit to the underlying carrying value of the reporting unit's net assets, including goodwill, with any write-down of the carrying value of goodwill being charged against the results of operations.

The Company has determined that the Distribution Business' goodwill is not impaired.

Deferred Debt Costs

Deferred debt costs include the unamortized amounts of debt issuance costs incurred by Hydro One and allocated to its subsidiaries and their regulated businesses based on the Company's share of Hydro One's debt issue amount. Deferred debt costs are amortized on an annuity basis over the period to maturity of the debt.

Derivative Financial Instruments

Hydro One periodically uses interest rate swap contracts to manage interest rate risks. Payments and receipts under interest rate swap contracts are recognized as adjustments to interest expense on an accrual basis and are allocated to Hydro One subsidiaries and their regulated businesses. Hydro One formally designates its hedges, documents all hedging relationships and formally assesses hedge effectiveness. In the event a hedging relationship is extinguished or the relationship is found to be ineffective, realized or unrealized gains or losses are recognized in results of operations. Hydro One does not engage in derivative trading or speculative activities.

Discounts, Premiums and Hedging

The Distribution Business share of the Company's allocated discounts, premiums and hedging gains and losses are amortized over the period of the related debt and are presented net with long-term debt.

Employee Future Benefits

Employee future benefits provided by Hydro One and its subsidiaries include pension, group life insurance, health care and long-term disability.

In accordance with the OEB's rate orders, pension costs are recorded when employer contributions are paid to the pension fund in accordance with the *Pension Benefits Act* (Ontario). Actuarial valuations are conducted at least every three years. Pension costs are also calculated on an accrual basis. Pension costs are actuarially determined using the projected benefit method prorated on service and based on assumptions that reflect management's best estimate of the effect of future events, including future compensation increases, on the actuarial present value of accrued pension benefits. Pension plan assets, consisting primarily of listed equity securities as well as corporate and government debt securities, are valued using fair values. Past service costs from plan amendments and all actuarial gains or losses are amortized on a straight-line basis over the expected average remaining service life of the employees covered.

Employee future benefits other than pension are recorded on an accrual basis. Costs are determined by independent actuaries using the projected benefit method prorated on service and based on assumptions that reflect management's best estimates. Past service costs from plan amendments and actuarial gains or losses are amortized on a straight-line basis over the expected average remaining service life of the employees covered.

Employee future benefit costs are attributed to labour and charged to operations or capitalized as part of the cost of fixed assets.

Environmental Costs

The Distribution Business recognizes a liability for estimated future expenditures associated with the assessment and remediation of contaminated lands and for the phase-out and destruction of polychlorinated biphenyl (PCB) contaminated mineral oil from electrical equipment, based on the net present value of these estimated future expenditures. As the Company anticipates that the related expenditures will continue to be recoverable in future rates, a regulatory asset has been recognized to reflect the future recovery of these costs from customers. The Distribution Business reviews its estimates of future environmental expenditures on an ongoing basis.

Use of Estimates

The preparation of financial statements in conformity with Canadian GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities at the date of the financial statements, and the reported amounts of revenues and expenses for the year. Actual results could differ from estimates, including changes as a result of future decisions made by the OEB or the Province.

3. ELECTRICITY CREDITS

Under a new regulation issued in October 2005, Regulated Price Plan customers received a one-time credit reflecting a lower cost of power than the fixed commodity price between April 1, 2004 and March 31, 2005. In the fourth quarter of 2005, revenue and purchased power costs were each reduced by $129 million. The application of the one-time credit did not result in any adjustment to net income in the current or previously reported periods.

4. REGULATORY RECOVERY

The *Electricity Pricing, Conservation and Supply Act, 2002,* suspended a previously approved rate increase related to annual low-voltage services costs for embedded LDCs and direct customers. The associated costs are charged annually to the Distribution Business' results of operations. Subject to future OEB approval, the *Electricity Pricing, Conservation and Supply Act, 2002* also allowed for establishment of a regulatory deferral account to record suspended low voltage services amounts to be recovered from future customers. Due to uncertainty of recovery, amounts recorded in this regulatory deferral account between May 1, 2002 and December 9, 2004 were not previously recognized as regulatory assets. Similarly, the Company did not reflect certain other costs, such as interest, as regulatory assets in prior years' financial statements.

On May 31, 2004, Hydro One applied for recovery of approximately $156 million included within various regulatory deferral accounts prior to December 31, 2003. The requested recovery primarily included the low voltage amounts not previously recognized as regulatory assets, as well as interest on all of the requested balances. As a result of the oral and written evidence submitted by the Company, the OEB issued a decision on December 9, 2004 regarding the prudence of the distribution-related deferral account balances included in the application. The OEB approved all but approximately $12 million of the requested amount for recovery over the period ending April 30, 2008. As a result of this successful regulatory recovery, the Distribution Business recorded an increase in its regulatory asset balance, which primarily reflects future recovery of costs that had been previously charged to results of operations without recognition of corresponding revenue.

The 2004 regulatory recovery attributable to the Distribution Business consisted of the following components:

Year ended December 31 (Canadian dollars in millions)	**2004**
Low voltage services – 2002	17
Low voltage services – 2003	25
Low voltage services – 2004	23
Interest accretion	18
Other	19
	102

5. DEPRECIATION AND AMORTIZATION

Year ended December 31 (Canadian dollars in millions)	**2005**	**2004**
Depreciation of fixed assets in service	144	144
Fixed asset removal costs	24	22
Amortization of regulatory and other assets	51	51
	219	217

6. FINANCING CHARGES

Year ended December 31 (Canadian dollars in millions)	**2005**	**2004**
Interest on long-term debt payable	130	127
Interest on inter-company demand facility	2	2
Less: Interest capitalized on regulatory assets	(11)	-
Interest capitalized on construction in progress	(4)	(4)
	117	125

7. PROVISION FOR PAYMENTS IN LIEU OF CORPORATE INCOME TAXES

The provision for payments in lieu of corporate income taxes (PILs) differs from the amount that would have been recorded using the combined Canadian Federal and Ontario statutory income tax rate. A reconciliation between the statutory and effective tax rate is provided as follows:

Year ended December 31 (Canadian dollars in millions)	**2005**	**2004**
Income before provision for PILs	152	205
Federal and Ontario statutory income tax rate	36.12%	36.12%
Provision for PILs at statutory rate	55	74
(Decrease) increase resulting from:		
Net temporary differences:		
Regulatory recovery	-	(37)
Pension contribution in excess of pension expense	(21)	(19)
Depreciation and amortization in excess of capital cost allowance	20	14
Retail settlements variance accounts	6	11
Interest capitalized for accounting purposes but deducted for tax purposes	(6)	(2)
Employee future benefits other than pension expense in excess of cash payments	5	5
Environmental expenditures	(3)	(3)
Other	(6)	(10)
Net temporary differences	(5)	(41)
Net permanent differences:		
Large corporations tax	5	6
Other	1	1
Net permanent differences	6	7
Provision for PILs	56	40
Effective income tax rate	36.84%	19.51%

Future income taxes have not been recorded in the accounts as they are expected to be recovered through future revenues. As at December 31, 2005, future income tax liabilities of $64 million (2004 - $59 million), based on substantively enacted income tax rates, have not been recorded. In the absence of rate regulated accounting, the Company's provision for PILs would have been recognized on an accrual basis rather than under the taxes payable method. As a result, the provision for PILs would have been higher by approximately $5 million.

8. FIXED ASSETS

December 31 (Canadian dollars in millions)	Fixed Assets in Service	Accumulated Depreciation	Construction in Progress	Total
2005				
Distribution	4,934	1,828	80	3,186
Communication, administration and service	551	345	-	206
Easements	8	3	-	5
	5,493	2,176	80	3,397
2004				
Distribution	4,710	1,742	53	3,021
Communication, administration and service	506	302	-	204
Easements	8	3	-	5
	5,224	2,047	53	3,230

Financing costs capitalized on fixed assets under construction using the allowance for funds used during construction were $4 million in 2005 (2004 - $4 million).

9. REGULATORY ASSETS AND LIABILITIES

Regulatory assets and liabilities arise as a result of the ratemaking process. The Distribution Business has recorded the following regulatory assets and liabilities (see Notes 2 and 4):

December 31 (Canadian dollars in millions)	**2005**	**2004**
Regulatory assets:		
Regulatory asset recovery account	88	121
Pension	76	34
Employee future benefits other than pension	71	94
Low voltage services	53	26
Environmental	52	50
Other	4	5
	344	330
Regulatory liability:		
Retail settlement variance accounts	41	25
	41	25

Regulatory assets

Regulatory asset recovery account (RARA)

On December 9, 2004, the OEB issued a decision on the prudence of the distribution-related deferral account balances sought by the Company in its May 31, 2004 application (see Note 4). Recoverable amounts represent balances incurred prior to December 31, 2003, plus associated interest. The OEB ordered that the approved balances be aggregated into a single regulatory account to be recovered on a straight-line basis over the period ending April 30, 2008. The RARA includes distribution business low-voltage services amounts, deferred environmental expenditures incurred in 2001 and 2002, deferred market ready expenditures, retail settlement variance amounts, and other amounts primarily consisting of accrued interest. In the absence of rate regulated accounting, amortization expense in 2005 would have been lower by approximately $20 million. In addition, related financing charges would have been higher by $7 million.

Pension

In a July 14, 2004 decision, the OEB approved the Company's establishment of a regulatory deferral account to record distribution-related pension contributions that would otherwise have been charged to 2004 results of operations. The regulatory asset also includes amounts payable to Inergi LP commencing 2005 in respect of a risk sharing agreement related to the imbalance between pension fund assets and liabilities in respect of transferred staff. In its decision, the OEB concluded that prudently incurred expenditures of this type are generally recoverable as part of a general rate application. The Company has included its request for recovery as part of its distribution rate application currently under review by the OEB. In the absence of rate regulated accounting, the Company's pension expense would have been recognized on an accrual basis rather than on a cash basis. As a result, operation, maintenance and administration expense would have been higher by approximately $38 million, assuming no regulatory deferral of distribution and Inergi pension-related amounts. In addition, related financing charges would have been higher by $4 million.

Employee future benefits other than pension

Employee future benefits other than pension are recorded using the accrual method as required by Canadian GAAP. The OEB has allowed for the recovery of past service costs, which arose on the adoption of the accrual method, in the revenue requirement on a straight-line basis over a 10-year period. As a result, in 1999 the Distribution Business recorded a regulatory asset, with an original balance of $226 million, to reflect this regulatory treatment. This regulatory asset has a remaining recovery period of 3 years (2003 - 4 years) and does not earn a return. In the absence of rate regulated accounting, amortization expense in 2005 would have been lower by approximately $23 million.

Low voltage services

The OEB's December 9, 2004 decision allows for delayed recovery of previously approved low voltage services amounts, within the RARA, for the period up to December 31, 2003. Given this decision, the Company has determined that it was highly probable that, at some future date, the OEB will also approve recovery of the low voltage amount attributable to 2004 and 2005, plus interest. As a result, the Company has recognized a regulatory asset reflecting this probable future recovery.

Environmental

The Company provides for estimated future expenditures required to remediate past environmental contamination. Because such expenditures are expected to be recoverable in future rates, the Company has recognized the net present value of these estimated future environmental expenditures as a regulatory asset. This regulatory asset is expected to be amortized to results of operations on a basis consistent with the pattern of actual expenditures expected to be incurred up to the year 2030. During 2005, the Company increased its estimated long-term liability and offsetting regulatory asset in respect of future estimated land assessment and remediation costs by $6 million. In the absence of rate regulated accounting, amortization expense in 2005 would have been lower and operation, maintenance and administration expense would have been higher by $7 million. The OEB has the discretion to examine the prudence and the timing of the Company's future environmental expenditures.

Regulatory liability

Retail settlement variance accounts

The Company has deferred certain retail settlement variance amounts under the provisions of Article 490 of the OEB's *Accounting Procedures Handbook*. The OEB's December 9, 2004 decision allows for recovery of retail settlement variance amounts accumulated prior to December 31, 2003, inclusive of interest, within the RARA. The Company anticipates that the OEB will include the net balance of this regulatory account in future rates.

10. DEBT

December 31 (Canadian dollars in millions)	**2005**	**2004**
Long-term debt payable within one year	179	192
Long-term debt	1,804	1,694
	1,983	1,886
Net unamortized premiums	10	10
Unamortized hedging losses	(5)	(3)
	1,988	1,893

Debt represents the Distribution Business share of various notes payable by Hydro One Networks to Hydro One. This allocated debt is summarized by the number of years to maturity in the following table:

Years to Maturity	Principal Outstanding *(Canadian dollars in millions)*	Weighted Average Interest Rate *(percent)*
1 year	179	10.3
2 years	105	8.6
3 years	210	4.0
4 years	133	4.0
5 years	122	7.2
	749	6.7
6 – 10 years	546	5.6
Over 10 years	688	6.7
	1,983	6.4

11. FAIR VALUE OF FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

The carrying amounts of all financial instruments, except long-term debt, approximate fair value. The fair value of derivative financial instruments reflects the estimated amount that the Company, if required to settle an outstanding contract, would have been required to pay or would be entitled to receive at year end. The fair value of long-term debt, based on year end quoted market prices for the same or similar debt of the same remaining maturities, is provided in the following table:

December 31 (Canadian dollars in millions)	**2005**		**2004**	
	Carrying Value	Fair Value	Carrying Value	Fair Value
Long-term debt[1]	1,983	2,222	1,886	2,009

[1] The carrying value of long-term debt represents the par value of the notes.

Financial assets create a risk that a counter-party will fail to discharge an obligation, causing a financial loss. As at December 31, 2005, there were no significant concentrations of credit risk with respect to any class of financial assets. The revenue of the Distribution Business is earned from a broad base of customers. The Distribution Business did not earn a significant amount of its revenue from any single customer. As at December 31, 2005, there were no significant balances of accounts receivable due from any single customer.

12. EMPLOYEE FUTURE BENEFITS

Pension

Hydro One has a contributory defined benefit pension plan covering all regular employees of Hydro One and its subsidiaries, except Hydro One Brampton. The Hydro One Pension Plan does not segregate assets in a separate account for individual subsidiaries, nor is the cost of the benefit plans allocated to, or funded separately by, entities within the consolidated group. Accordingly, for purposes of these financial statements, the pension plan is accounted for as a defined contribution plan and no deferred pension asset or liability is recorded.

Hydro One's pension plan provides benefits based on highest three-year average pensionable earnings. For new management employees who commenced employment on or after January 1, 2004, and for Society of Energy Professionals' represented staff hired after November 17, 2005, benefits are based on highest five-year average pensionable earnings. After retirement, pensions are indexed to inflation. The measurement date used to determine plan assets and the accrued benefit obligation is December 31. Based on the actuarial valuation filed on September 22, 2004, effective for December 31, 2003, Hydro One contributed $83 million to its pension plan in respect of 2005 (2004 - $74 million), all of which will satisfy minimum funding requirements. Contributions are payable one month in arrears. A significant portion of these contributions are attributed to the Distribution Business. All of the contributions are expected to be in the form of cash. Prior to 2004, Hydro One was not required to contribute to the pension plan because the last actuarial valuation at December 31, 2000 indicated that the plan had a surplus. Contributions after 2006 will be based on an actuarial valuation no later than December 31, 2006 and will depend on future investment returns, and changes in benefits or actuarial assumptions.

For Hydro One, the actuarial present value at December 31, 2005 of the accrued pension benefits was estimated to be $5,355 million (2004 - $4,862 million). Pension plan assets available for these benefits were $4,713 million (2004 - $4,243 million).

Employee Future Benefits other than Pension

During the year ended December 31, 2005, $33 million of employee future benefits other than pension costs was charged to the results of operations of the Distribution Business (2004 - $32 million), and $23 million was capitalized as part of the cost of fixed assets (2004 - $22 million). Benefits paid were $20 million (2004 - $19 million). The liability associated with employee future benefits other than pension for the Distribution Business at December 31, 2005 was $414 million (2004 - $378 million), including the current portion.

A detailed description of employee future benefits is provided in Note 12 of the Consolidated Financial Statements of Hydro One for the year ended December 31, 2005.

13. ENVIRONMENTAL LIABILITIES

December 31 (Canadian dollars in millions)	**2005**	**2004**
Environmental liabilities, January 1	50	57
Interest accretion	3	3
Expenditures	(7)	(10)
Revaluation adjustment *(Note 9)*	6	-
Environmental liabilities, December 31	52	50
Less: current portion	(9)	(9)
	43	41

Estimated future environmental expenditures for each of the five years subsequent to December 31, 2005 and in total thereafter are as follows: 2006 - $9 million; 2007 - $8 million; 2008 - $7 million; 2009 - $7 million; 2010 - $6 million and thereafter - $31 million.

There are uncertainties in estimating future environmental costs due to potential external events such as changing regulations and advances in remediation technologies. The Company continuously reviews factors affecting its cost estimates as well as the environmental condition of the various properties. The actual cost of investigation or remediation may differ from current estimates.

14. RELATED PARTY TRANSACTIONS

The Province and Successor Corporations of Ontario Hydro

The Province, OEFC, Ontario Power Generation Inc. (OPG) and the IESO are related parties of Hydro One Networks' Distribution Business. In addition, the OEB is related to the Company by virtue of its status as a Provincial Crown Corporation. Transactions between these parties and the Distribution Business were as follows:

The Distribution Business received amounts for rural rate protection from the IESO. Revenues for 2005 include $125 million (2004 - $125 million) related to this program.

In 2005, the Distribution Business purchased power in the amount of $1,809 million (2004 - $1,716 million) from the IESO-administered electricity market and $36 million (2004 - $36 million) from OPG.

The Company has service level agreements with Ontario Hydro's successor corporations, primarily OPG. These services include field and engineering, logistics, corporate, telecommunications and information technology services. Operation, maintenance and administration costs related to the purchase of services from these successor corporations were less than $1 million in 2005 and 2004.

Under the Ontario Energy Board Act, 1998, the OEB is required to recover all of its annual operating costs from gas and electricity distributors and electricity transmitters. In 2005, the Distribution Business incurred $5 million (2004 - $3 million) in OEB fees.

The provision for payments in lieu of corporate income taxes was paid or payable to the OEFC.

Subsidiaries of Hydro One Inc.

The Company provides services to, and receives services from, Hydro One and its other subsidiaries. Amounts due to and from Hydro One and its subsidiaries are settled through the inter-company demand facility.

The Company has entered into various agreements with Hydro One and its subsidiaries related to the provision of corporate functions and services, supply management, computer support and operational services such as environmental, forestry and line services. Revenues include $1 million (2004 - $1 million) related to the provision of services to Hydro One and its subsidiaries and operation, maintenance and administration costs include $2 million (2004 - $1 million) related to the purchase of services from Hydro One and its subsidiaries.

The Company's debt, including the portion allocated to the Distribution Business, is due to Hydro One. Financing charges include interest expense on this debt in the amount of $130 million (2004 - $127 million). In addition, balances payable or receivable under the inter-company demand facility are due to or from Hydro One. Financing charges of the Distribution Business include interest expense on this facility in the amount of $2 million (2004 - $2 million).

The amounts due to and from related parties as a result of the transactions referred to above are as follows:

December 31 (Canadian dollars in millions)	**2005**	**2004**
Accounts receivable	1	3
Accounts payable and accrued charges	211	179

Included in accounts payable and accrued charges are amounts owing to the IESO in respect of power purchases of $183 million (2004 - $179 million).

15. STATEMENTS OF CASH FLOWS

The changes in non-cash balances related to operations consist of the following:

Year ended December 31 (Canadian dollars in millions)	**2005**	**2004**
Accounts receivable decrease (increase)	60	(50)
Materials and supplies increase	(6)	(1)
Accounts payable and accrued charges increase	50	4
Accrued interest increase	1	2
Employee future benefits other than pension increase	36	33
Long-term accounts payable and accrued charges decrease	(1)	(13)
Other	(26)	(29)
	114	(54)

16. CONTINGENCIES

The Company is a wholly owned subsidiary of Hydro One. As such, the assets of the Company's Distribution Business are available for the satisfaction of the debts, contingent liabilities and commitments of the Company and Hydro One.

17. COMMITMENTS

The Company and Hydro One have numerous commitments. These commitments have not been specifically allocated to the Distribution Business. However, the net assets of the Distribution Business are available to satisfy these commitments.

18. COMPARATIVE FIGURES

The comparative financial statements have been reclassified from statements previously presented to conform to the presentation of the December 31, 2005 financial statements. More specifically, the 2004 statements have been restated to reflect the inclusion of the Sentinel Lights operation of the Distribution Business (see Note 1).

HYDRO ONE NETWORKS INC.

DISTRIBUTION BUSINESS

FINANCIAL STATEMENTS

FOR THE YEAR ENDED

DECEMBER 31, 2006

HYDRO ONE NETWORKS INC.
DISTRIBUTION BUSINESS
AUDITORS' REPORT

To the Directors of Hydro One Networks Inc.

We have audited the balance sheets of the Distribution Business (a business of Hydro One Networks Inc.), as at December 31, 2006 and December 31, 2005 and the statements of operations, and cash flows of the Distribution Business for the years then ended. These financial statements are the responsibility of the management of the Distribution Business. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these financial statements present fairly, in all material respects, the financial position of the Distribution Business of Hydro One Networks Inc. as at December 31, 2006 and 2005 and the results of its operations and its cash flows for the years then ended in accordance with Canadian generally accepted accounting principles. These financial statements are solely for the information and use of the Directors of Hydro One Networks Inc. for filing with the Ontario Energy Board. These financial statements are not intended to be and should not be used by anyone other than the specified users or for any other purpose.

The Distribution Business has no separate legal status or existence (See Note 1).

Ernst & Young LLP

Toronto, Canada
April 18, 2007

Chartered Accountants
Licensed Public Accountants

HYDRO ONE NETWORKS INC.
DISTRIBUTION BUSINESS
STATEMENTS OF OPERATIONS

Year ended December 31 (Canadian dollars in millions)	**2006**	**2005**
Revenues		
Energy sales *(Note 3)*	2,740	2,536
Rural rate protection *(Note 14)*	125	125
Other	41	45
	2,906	2,706
Costs		
Purchased power *(Notes 3 and 14)*	1,954	1,845
Operation, maintenance and administration *(Note 14)*	416	373
Depreciation and amortization *(Note 4)*	249	219
	2,619	2,437
Income before financing charges and provision for payments in lieu of corporate income taxes	287	269
Financing charges *(Notes 5 and 14)*	115	117
Income before provision for payments in lieu of corporate income taxes	172	152
Provision for payments in lieu of corporate income taxes *(Notes 6 and 14)*	46	56
Net income	126	96

See accompanying notes to financial statements.

HYDRO ONE NETWORKS INC.
DISTRIBUTION BUSINESS
BALANCE SHEETS

December 31 (Canadian dollars in millions)	**2006**	**2005**
Assets		
Current assets		
Inter-company demand facility *(Note 14)*	-	58
Accounts receivable (net of allowance for doubtful accounts - $13 million; 2005 - $8 million) *(Note 14)*	585	445
Materials and supplies	23	22
Other	4	7
	612	532
Fixed assets *(Note 7)*		
Fixed assets in service	5,867	5,493
Less: accumulated depreciation	2,329	2,176
	3,538	3,317
Construction in progress	87	80
	3,625	3,397
Other long-term assets		
Regulatory assets *(Note 8)*	245	303
Goodwill	73	73
Deferred debt costs	9	8
Long-term accounts receivable and other assets	1	1
	328	385
Total assets	4,565	4,314

See accompanying notes to financial statements.

HYDRO ONE NETWORKS INC.
DISTRIBUTION BUSINESS
BALANCE SHEETS (continued)

December 31 (Canadian dollars in millions)	**2006**	**2005**
Liabilities		
Current liabilities		
Inter-company demand facility *(Note 14)*	68	-
Accounts payable and accrued charges *(Note 14)*	394	444
Accrued interest	21	23
Long-term debt payable within one year *(Notes 9, 10 and 14)*	105	179
	588	646
Long-term debt *(Notes 9, 10 and 14)*	1,990	1,809
Other long-term liabilities		
Employee future benefits other than pension *(Note 11)*	444	396
Environmental liabilities *(Note 12)*	37	43
Regulatory liabilities *(Note 8)*	5	-
Long-term accounts payable and accrued charges	5	3
	491	442
Total liabilities	3,069	2,897
Contingencies and commitments *(Notes10, 16 and 17)*		
Excess of assets over liabilities	1,496	1,417
Total liabilities and excess of assets over liabilities	4,565	4,314

See accompanying notes to financial statements.

On behalf of the Board:

Laura Formusa
Chair

Beth Summers
Director

HYDRO ONE NETWORKS INC.
DISTRIBUTION BUSINESS
STATEMENTS OF CASH FLOWS

Year ended December 31 (Canadian dollars in millions)	**2006**	**2005**
Operating activities		
Net income	126	96
Adjustments for non-cash items:		
Depreciation and amortization (net of removal costs)	219	195
Low voltage services	(8)	(24)
Retail settlements variance accounts	6	13
Amortization of premiums and hedges	2	-
	345	280
Changes in non-cash balances related to operations *(Note 15)*	(140)	114
Net cash from operating activities	205	394
Investing activities		
Capital expenditures	(393)	(317)
Other assets	1	(1)
Net cash used in investing activities	(392)	(318)
Financing activities		
Change in allocated long-term debt	108	95
Payments to Hydro One Inc. to finance dividends	(47)	(46)
Issuance of preferred shares by Hydro One Networks *(Note 13)*	-	38
Termination of interest rate swap	-	(3)
Net cash from financing activities	61	84
Net change in inter-company demand facility	(126)	160
Inter-company demand facility, January 1	58	(102)
Inter-company demand facility, December 31	(68)	58

See accompanying notes to financial statements.

HYDRO ONE NETWORKS INC.
DISTRIBUTION BUSINESS
NOTES TO FINANCIAL STATEMENTS

1. DESCRIPTION OF THE DISTRIBUTION BUSINESS

Hydro One Inc. (Hydro One) was incorporated on December 1, 1998, under the *Business Corporations Act* (Ontario) and is wholly owned by the Province of Ontario (the Province). The principal businesses of Hydro One are the transmission and distribution of electricity to customers within Ontario. These businesses are regulated by the Ontario Energy Board (OEB).

Hydro One Networks Inc. (Hydro One Networks or the Company) was incorporated on March 4, 1999 under the *Business Corporations Act* (Ontario) and is a wholly owned subsidiary of Hydro One. The Company owns and operates Hydro One's regulated transmission and distribution businesses. The regulated distribution business (the Distribution Business) operates a low-voltage electrical distribution network that distributes electricity from the transmission system, or directly from generators, to customers within Ontario. Distribution customers include small local distribution companies and large industrial customers with loads of less than 5 MW.

2. SIGNIFICANT ACCOUNTING POLICIES

Basis of Accounting

The financial statements have been prepared in accordance with accounting principles generally accepted in Canada (Canadian GAAP). The financial statements have been prepared for the specific use of the OEB. Consolidated financial statements of Hydro One for the year ended December 31, 2006 have been prepared and are publicly available.

These financial statements have been prepared on a carve-out basis to provide the financial position, results of operations, changes in the excess of assets over liabilities and cash flows of the Company's regulated Distribution Business on a basis approved by the OEB. The financial statements are considered by management to be a reasonable representation, prepared on a rational, systematic and consistent basis, of the financial results of that business. As a result of this basis of accounting, these financial statements may not necessarily be identical to the financial position and results of operations that would have resulted had the Distribution Business historically operated on a stand-alone basis.

The financial statements have been constructed primarily through specific identification of assets, liabilities (other than debt), revenues and expenses that relate to the Distribution Business. The Company's long-term debt is allocated based on the respective borrowing requirements of the Company's transmission and distribution businesses. A portion of the Company's shared functions and services costs are allocated to the Distribution Business on a fully allocated cost basis, consistent with OEB-approved independent studies. Payments in lieu of corporate income taxes have been recorded at effective rates based on income taxes as reported in the Statements of Operations as though the Distribution Business was a separate tax paying entity. Certain other amounts presented in these financial statements represent allocations subject to review and approval by the OEB.

Rate-setting

The rates of the Distribution Business are subject to regulation by the OEB. The Company's distribution rates are based on a revenue requirement that includes a rate of return. Current distribution rates are based on a cost of service rate regulation model, which also includes a targeted return on deemed common equity. The targeted return was originally set in 1999 at 9.88%. In August 2005, the Company filed a distribution rate application seeking approval for a $160 million increase in the 2006 revenue requirement for its Distribution Business.

This revenue requirement is based on achieving a 9.00% return on equity, consistent with the OEB's guidance for setting 2006 rates. An oral hearing occurred in January 2006 and on April 12, 2006, the OEB announced its decision regarding the Company's rate application in respect of the Company's Distribution Business. On the basis of the written and oral evidence submitted, the OEB approved the requested increase in the revenue requirement based on a reduction in the approved rate of return, from a targeted 9.88% to 9.00%, effective May 1, 2006.

The OEB has the general power to include or exclude costs, revenues, losses or gains in the rates of a specific period, resulting in a change in the timing of accounting recognition from that which would have applied in an unregulated company. Such change in timing gives rise to the recognition of regulatory assets and liabilities. The Distribution Business's regulatory assets represent certain amounts receivable from future customers and costs that have been deferred for accounting purposes because it is probable that they will be recovered in future rates. In addition, the Company has recorded regulatory liabilities, which represents amounts incurred in different periods than would be the case had the Company been unregulated. The specific regulatory assets and liabilities recognized at December 31, 2006 are disclosed in Note 8.

The Company continually assesses the likelihood of recovery of each of its regulatory assets and continues to believe that it is probable that the OEB will factor its regulatory assets and liabilities into the setting of future rates. If, at some future date, the Company judges that it is no longer probable that the OEB will include a regulatory asset or liability in future rates, the appropriate carrying amount will be reflected in results of operations in the period that the assessment is made.

Revenue Recognition

Revenues attributable to the delivery of electricity are based on OEB-approved distribution tariff rates and are recognized as electricity is delivered to customers. The Company estimates the monthly revenue for the period based on wholesale power purchases because customer meters are not generally read at the end of each month. Unbilled revenue included within accounts receivable as at December 31, 2006 amounted to $359 million (2005 - $344 million).

Revenue also includes an amount relating to rate protection for rural residential customers, which is received from the Independent Electricity System Operator (IESO) based on a standardized customer rate that is approved by the OEB. The current legislation provides rate protection for prescribed classes of rural residential customers by reducing the electricity rates that would otherwise apply.

Revenues also include amounts related to sales of other services and equipment. Such revenue is recognized as services are rendered or as equipment is delivered.

Corporate Income and Capital Taxes

Under the *Electricity Act, 1998*, the Company is required to make payments in lieu of corporate income taxes to the Ontario Electricity Financial Corporation (OEFC). These payments are calculated in accordance with the rules for computing income and taxable capital and other relevant amounts contained in the *Income Tax Act* (Canada) and the *Corporations Tax Act* (Ontario) as modified by the *Electricity Act, 1998,* and related regulations.

The Distribution Business provides for its share of the Company's payments in lieu of corporate income taxes using the taxes payable method as directed by the OEB. Under the taxes payable method, no provisions are made for future income taxes as a result of temporary differences between the tax basis of assets and liabilities and their carrying amounts for accounting purposes. When unrecorded future income taxes become payable, it is expected that they will be included in the rates approved by the OEB and recovered from Distribution Business customers at that time.

Inter-Company Demand Facility

Hydro One maintains pooled bank accounts for its use and for the use of its subsidiaries and, implicitly, by the regulated businesses of these subsidiaries. The inter-company demand facility represents the cumulative net effect of all deposits and withdrawals made by the Distribution Business to and from the pooled cash accounts. Interest is earned on positive inter-company balances based on the average of the bankers' acceptance rate at the beginning and end of the month, less 0.02%. Interest is charged on overdraft inter-company balances based on the same bankers' acceptance rate, plus 0.15%.

Materials and Supplies

Materials and supplies represent spare parts and construction material held for internal construction and maintenance of fixed assets. These assets are carried at lower of average cost or net realizable value.

Fixed Assets

Fixed assets are capitalized at cost, which comprises materials, labour, engineering costs, overheads, depreciation on service equipment and the approved allowance for funds used during construction applicable to capital construction activities. Fixed assets in service consist of: distribution assets; communication, administration and service assets; and easements.

Some distribution assets, particularly those located on unowned easements and rights-of-way, may have asset retirement obligations. The majority of the Company's easements and rights-of-way are either of perpetual duration or are automatically renewed annually. Land rights with finite terms are generally subject to extension or renewal. As the Company expects to use the majority of its installed assets for an indefinite period, no removal date can be determined and consequently a reasonable estimate of the fair value of any related asset retirement obligations cannot be made at this time. If, at some future date, it becomes possible to estimate the fair value cost of removing assets that the Company is legally required to remove, an asset retirement obligation will be recognized at that time.

Distribution

Distribution assets comprise assets related to the distribution of low-voltage electricity, including lines, poles, switches, transformers, protective devices and metering systems.

Communication, Administration and Service

Communication, administration and service assets include telecommunications equipment, towers, associated buildings, administrative buildings, major computer systems, personal computers, transport and work equipment, and tools, vehicles and minor fixed assets.

Easements

Easements include amounts incurred for easements and other access rights.

Construction in Progress

Overhead costs, including corporate functions and services costs, are capitalized on a fully allocated basis. Financing costs are capitalized on fixed assets under construction based on the allowance for funds used during construction (2006 – 6.32%; 2005 – 6.79%).

Depreciation

The capital costs of fixed assets are depreciated on a straight-line basis, except for transport and work equipment and personal computers, which are depreciated on a declining balance basis.

Depreciation rates for the various classes of assets are based on their estimated service lives. The average estimated remaining service lives and service life ranges of fixed assets are:

	Estimated service lives (years)	
	Range	Average
Distribution	15 - 75	41
Communication, administration and service	5 - 50	30

Depreciation rates for easements are based on their contract life. The majority of easements are held in perpetuity and are not depreciated.

In accordance with group depreciation practices, the original cost of normal fixed asset retirements is charged to accumulated depreciation, with no gain or loss reflected in results of operations. Gains and losses on sales of fixed assets and losses on premature retirements are charged to results of operations as adjustments to depreciation expense. Depreciation expense also includes the costs incurred to remove fixed assets where an asset retirement obligation has been recognized.

The estimated service lives of fixed assets are subject to periodic review. Any changes arising out of such a review are implemented on a remaining service life basis from the year the changes can first be reflected in distribution rates.

Goodwill

Goodwill represents the cost of acquired local distribution companies in excess of fair value of the net identifiable assets purchased and is evaluated for impairment on an annual basis, or more frequently if circumstances require. Goodwill impairment is assessed based on a comparison of the fair value of the reporting unit to the underlying carrying value of the reporting unit’s net assets, including goodwill, with any write-down of the carrying value of goodwill being charged against the results of operations.

The Company has determined that the Distribution Business’ goodwill is not impaired.

Deferred Debt Costs

Deferred debt costs include the unamortized amounts of debt issuance costs incurred by Hydro One and allocated to its subsidiaries and their regulated businesses based on the Company's share of Hydro One’s debt issue amount. Deferred debt costs are amortized on an annuity basis over the period to maturity of the debt.

Financial Instruments

Hydro One periodically uses interest rate swap contracts to manage interest rate risks. Payments and receipts under interest rate swap contracts are recognized as adjustments to interest expense on an accrual basis and are allocated to Hydro One subsidiaries and their regulated businesses. Hydro One formally designates its hedges, documents all hedging relationships and formally assesses hedge effectiveness. In the event a hedging relationship is extinguished or the relationship is found to be ineffective, realized or unrealized gains or losses are recognized in results of operations. Hedging gains and losses are amortized over the period of the related debt. Hydro One does not engage in derivative trading or speculative activities.

Discounts, Premiums and Hedging

The Distribution Business share of the Company's allocated discounts, premiums and hedging gains and losses are amortized over the period of the related debt and are presented net with long-term debt.

Employee Future Benefits

Employee future benefits provided by Hydro One and its subsidiaries include pension, group life insurance, health care and long-term disability.

In accordance with the OEB's rate orders, pension costs are recorded when employer contributions are paid to the pension fund in accordance with the *Pension Benefits Act* (Ontario). Actuarial valuations are conducted at least every three years. Pension costs are also calculated on an accrual basis. Pension costs are actuarially determined using the projected benefit method prorated on service and based on assumptions that reflect management's best estimate of the effect of future events, including future compensation increases, on the actuarial present value of accrued pension benefits. Pension plan assets, consisting primarily of listed equity securities as well as corporate and government debt securities, are valued using fair values. Past service costs from plan amendments and all actuarial gains or losses are amortized on a straight-line basis over the expected average remaining service life of the employees covered.

Employee future benefits other than pension are recorded on an accrual basis. Costs are determined by independent actuaries using the projected benefit method prorated on service and based on assumptions that reflect management's best estimates. Past service costs from plan amendments and actuarial gains or losses are amortized on a straight-line basis over the expected average remaining service life of the employees covered.

Employee future benefit costs are attributed to labour and charged to operations or capitalized as part of the cost of fixed assets.

Environmental Costs

The Distribution Business recognizes a liability for estimated future expenditures associated with the assessment and remediation of contaminated lands and for the phase-out and destruction of polychlorinated biphenyl (PCB) contaminated mineral oil from electrical equipment, based on the net present value of these estimated future expenditures. As the Company anticipates that the related expenditures will continue to be recoverable in future rates, a regulatory asset has been recognized to reflect the future recovery of these costs from customers. The Distribution Business reviews its estimates of future environmental expenditures on an ongoing basis.

Use of Estimates

The preparation of financial statements in conformity with Canadian GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities at the date of the financial statements, and the reported amounts of revenues and expenses for the year. Actual results could differ from estimates, including changes as a result of future decisions made by the OEB or the Province.

3. ELECTRICITY CREDITS

Under a regulation issued in October 2005, Regulated Price Plan customers received a credit reflecting a lower cost of power than the fixed commodity price between April 1, 2004 and March 31, 2005. In the fourth quarter of 2005, revenue and purchased power costs were each reduced by $129 million. The application of the credit did not result in any adjustment to net income.

4. DEPRECIATION AND AMORTIZATION

Year ended December 31 (Canadian dollars in millions)	**2006**	**2005**
Depreciation of fixed assets in service	148	144
Fixed asset removal costs	30	24
Amortization of regulatory and other assets	71	51
	249	219

5. FINANCING CHARGES

Year ended December 31 (Canadian dollars in millions)	**2006**	**2005**
Interest on long-term debt payable	127	130
Amortization of premiums and hedges	2	-
Interest on inter-company demand facility	2	2
Less: Interest capitalized on regulatory assets	(11)	(11)
Interest capitalized on construction in progress	(5)	(4)
	115	117

6. PROVISION FOR PAYMENTS IN LIEU OF CORPORATE INCOME TAXES

The provision for payments in lieu of corporate income taxes (PILs) differs from the amount that would have been recorded using the combined Canadian Federal and Ontario statutory income tax rate. A reconciliation between the statutory and effective tax rate is provided as follows:

Year ended December 31 (Canadian dollars in millions)	**2006**	**2005**
Income before provision for PILs	172	152
Federal and Ontario statutory income tax rate	36.12%	36.12%
Provision for PILs at statutory rate	62	55
Increase (decrease) resulting from:		
Net temporary differences:		
Depreciation and amortization in excess of capital cost allowance	19	20
Recovery of PILs related to prior years	(14)	-
Pension contribution in excess of pension expense	(12)	(21)
Employee future benefits other than pension expense in excess of cash payments	8	5
Retail settlements variance accounts	7	6
Interest capitalized for accounting purposes but deducted for tax purposes	(6)	(6)
Overhead capitalized for accounting but deducted for tax purposes	(5)	(5)
Environmental expenditures	(4)	(3)
Other	(8)	(1)
Net temporary differences	(15)	(5)
Net permanent differences:		
Large corporations tax	-	5
Other	(1)	1
Net permanent differences	(1)	6
Provision for PILs	46	56
Effective income tax rate	26.74%	36.84%

In 2006, the Distribution Business recognized a tax benefit of approximately $14 million in respect of Hydro One's recovery of PILs from prior years following a successful appeal allowing a deduction for certain overhead costs that had been previously capitalized.

Future income taxes have not been recorded in the accounts as they are expected to be recovered through future revenues. As at December 31, 2006, future income tax liabilities of $72 million (2005 - $64 million), based on substantively enacted income tax rates, have not been recorded. In the absence of rate regulated accounting, the Company's provision for PILs would have been recognized using the liability method rather than the taxes payable method. As a result, the provision for PILs would have been higher by approximately $8 million (2005 - $5 million) including the impact of a rate change in substantively enacted tax rates.

7. FIXED ASSETS

December 31 (Canadian dollars in millions)	Fixed Assets in Service	Accumulated Depreciation	Construction in Progress	Total
2006				
Distribution	5,247	1,948	87	3,386
Communication, administration and service	612	378	-	234
Easements	8	3	-	5
	5,867	2,329	87	3,625
2005				
Distribution	4,934	1,828	80	3,186
Communication, administration and service	551	345	-	206
Easements	8	3	-	5
	5,493	2,176	80	3,397

Financing costs capitalized on fixed assets under construction using the allowance for funds used during construction were $5 million in 2006 (2005 - $4 million).

8. REGULATORY ASSETS AND LIABILITIES

Regulatory assets and liabilities arise as a result of the ratemaking process. The Distribution Business has recorded the following regulatory assets and liabilities (see Notes 2 and 4):

December 31 (Canadian dollars in millions)	**2006**	**2005**
Regulatory assets:		
Regulatory asset recovery account I	55	88
Regulatory asset recovery account II	87	92
Employee future benefits other than pension	47	71
Environmental	45	52
Smart meters	10	-
Other	1	-
Total regulatory assets	245	303
Regulatory liabilities:		
Retail settlement variance accounts	2	-
Other	3	-
Total regulatory liabilities	5	-

Regulatory assets

Regulatory asset recovery account I (RARA I)

On December 9, 2004, the OEB issued a decision on the prudence of the distribution-related deferral account balances sought by the Company in its May 31, 2004 application. Amounts for which recovery was approved represented balances incurred prior to December 31, 2003, plus associated interest. The OEB ordered that the approved balances be aggregated into a single regulatory account to be recovered on a straight-line basis over the period ending April 30, 2008. The RARA I includes distribution business low-voltage services amounts, deferred environmental expenditures incurred in 2001 and 2002, deferred market ready expenditures, retail settlement variance amounts, and other amounts primarily consisting of accrued interest. In the absence of rate regulated accounting, amortization expense in 2006 would have been lower by approximately $20 million (2005 - $20 million). In addition, related financing charges would have been higher by $3 million (2005 - $7 million).

Regulatory asset recovery account II (RARA II)

On April 12, 2006, the OEB announced its decision regarding the Company's rate application in respect of the distribution business of Hydro One Networks. As part of this decision, the OEB also approved the distribution-related deferral account balances sought by Hydro One. The OEB ordered that the approved balances be recovered on a straight-line basis over a four year period from May 1, 2006 to April 30, 2010. The RARA II includes retail settlement and cost variance amounts and distribution low-voltage service amounts, plus accrued interest. In the absence of rate regulated accounting, amortization expense in 2006 would have been lower by approximately $16 million. In addition, related financing charges would have been higher by $5 million.

Employee future benefits other than pension

Employee future benefits other than pension are recorded using the accrual method as required by Canadian GAAP. The OEB has allowed for the recovery of past service costs, which arose on the adoption of the accrual method, in the revenue requirement on a straight-line basis over a 10-year period. As a result, in 1999 the Distribution Business recorded a regulatory asset, with an original balance of $236 million, to reflect this regulatory treatment. This regulatory asset has a remaining recovery period of 2 years (2005 - 3 years) and does not earn a return. In the absence of rate regulated accounting, amortization expense in 2006 would have been lower by approximately $24 million (2005 - $23 million).

Environmental

The Company records a liability for the estimated future expenditures required to remediate past environmental contamination. Because such expenditures are expected to be recoverable in future rates, the Company has recognized an equivalent amount as a regulatory asset. This regulatory asset is expected to be amortized to results of operations on a basis consistent with the pattern of actual expenditures expected to be incurred up to the year 2030. The OEB has the discretion to examine and assess the prudence and the timing of recovery of all of the Company's future regulatory expenditures. In the absence of rate regulated accounting, amortization expense in 2006 would have been lower and operation, maintenance and administration expense would have been higher by $12 million (2005 - $7 million).

Smart meters

On March 21, 2006, the OEB approved the establishment of deferral accounts for smart meter related expenditures and a monthly customer charge of thirty cents per residential customer was reflected in Hydro One's revenue requirement. Consistent with the OEB's direction and pending further guidance, the Company has recognized a regulatory asset consisting of the net balance of capital and operating expenditures for smart meters less recoveries received from customers. In the absence of rate regulated accounting, the Company's operation, maintenance and administration expense would have been higher by $4 million and revenues would have been higher by $2 million.

Regulatory liabilities

Retail settlement variance accounts

The Company has deferred certain retail settlement variance amounts under the provisions of Article 490 of the OEB's *Accounting Procedures Handbook*. The OEB's December 9, 2004 decision allowed for recovery of retail settlement variance amounts accumulated prior to December 31, 2003, inclusive of interest, within the RARA I. The OEB's April 12, 2006 decision allowed for recovery of retail settlement variance amounts accumulated since January 1, 2004 and forecasted through to April 30, 2006, inclusive of interest, within the RARA II. The Company has accumulated a net liability in its retail settlement variance accounts since May 1, 2006 and anticipates that the OEB will include the net balance of this regulatory account in future rates.

9. DEBT

December 31 (Canadian dollars in millions)	**2006**	**2005**
Long-term debt payable within one year	105	179
Long-term debt	1,986	1,804
	2,091	1,983
Net unamortized premiums	8	10
Unamortized hedging losses	(4)	(5)
	2,095	1,988

Debt represents the Distribution Business share of various notes payable by Hydro One Networks to Hydro One. This allocated debt is summarized by the number of years to maturity in the following table:

Years to Maturity	Principal Outstanding *(Canadian dollars in millions)*	Weighted Average Interest Rate *(percent)*
1 year	105	8.6
2 years	210	4.0
3 years	133	4.0
4 years	122	7.2
5 years	76	6.4
	646	5.6
6 – 10 years	650	5.2
Over 10 years	795	6.4
	2,091	5.8

10. FAIR VALUE OF FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

The carrying amounts of all financial instruments, except long-term debt, approximate fair value. The fair value of derivative financial instruments reflects the estimated amount that the Company, if required to settle an outstanding contract, would have been required to pay or would be entitled to receive at year end. The fair value of long-term debt, based on year end quoted market prices for the same or similar debt of the same remaining maturities, is provided in the following table:

December 31 (Canadian dollars in millions)	2006		2005	
	Carrying Value	Fair Value	Carrying Value	Fair Value
Long-term debt[1]	2,091	2,301	1,983	2,222

[1] The carrying value of long-term debt represents the par value of the notes.

Financial assets create a risk that a counter-party will fail to discharge an obligation, causing a financial loss. As at December 31, 2006, there were no significant concentrations of credit risk with respect to any class of financial assets. The revenue of the Distribution Business is earned from a broad base of customers. The Distribution Business did not earn a significant amount of its revenue from any single customer. As at December 31, 2006, there were no significant balances of accounts receivable due from any single customer.

11. EMPLOYEE FUTURE BENEFITS

Pension

Hydro One has a contributory defined benefit pension plan covering all regular employees of Hydro One and its subsidiaries, except Hydro One Brampton. The Hydro One Pension Plan does not segregate assets in a separate account for individual subsidiaries, nor is the cost of the benefit plans allocated to, or funded separately by, entities within the consolidated group. Accordingly, for purposes of these financial statements, the pension plan is accounted for as a defined contribution plan and no deferred pension asset or liability is recorded.

Hydro One's pension plan provides benefits based on highest three-year average pensionable earnings. For new management employees who commenced employment on or after January 1, 2004, and for Society of Energy Professionals' represented staff hired after November 17, 2005, benefits are based on highest five-year average pensionable earnings. After retirement, pensions are indexed to inflation. The measurement date used to determine plan assets and the accrued benefit obligation is December 31. Based on the actuarial valuation filed on September 22, 2004, effective for December 31, 2003, Hydro One contributed $86 million to its pension plan in respect of 2006 (2005 - $83 million), all of which will satisfy minimum funding requirements. Contributions are payable one month in arrears. A portion of these contributions are attributed to the Remote Communities business. All of the contributions are expected to be in the form of cash. Prior to 2004, Hydro One was not required to contribute to the pension plan because the last actuarial valuation at December 31, 2000 indicated that the plan had a surplus. Contributions after 2006 will be based on an actuarial valuation no later than December 31, 2006 and will depend on future investment returns, and changes in benefits or actuarial assumptions.

For Hydro One, the actuarial present value at December 31, 2006 of the accrued pension benefits, based on a projection of the valuation at December 31, 2006, was estimated to be $5,411 million (2005 - $5,355 million). Pension plan assets available for these benefits were $5,123 million (2005 - $4,713 million).

Employee Future Benefits other than Pension

During the year ended December 31, 2006, $39 million of employee future benefits other than pension costs was charged to the results of operations of the Distribution Business (2005 - $33 million), and $27 million was capitalized as part of the cost of fixed assets (2005 - $23 million). Benefits paid were $18 million (2005 - $19 million). The liability associated with employee future benefits other than pension for the Distribution Business at December 31, 2006 was $462 million (2005 - $414 million), including the current portion.

A detailed description of employee future benefits is provided in Note 11 of the Consolidated Financial Statements of Hydro One for the year ended December 31, 2006.

12. ENVIRONMENTAL LIABILITIES

December 31 (Canadian dollars in millions)	**2006**	**2005**
Environmental liabilities, January 1	52	50
Interest accretion	3	3
Expenditures	(12)	(7)
Revaluation adjustment	2	6
Environmental liabilities, December 31	45	52
Less: current portion	(8)	(9)
	37	43

Estimated future environmental expenditures for each of the five years subsequent to December 31, 2006 and in total thereafter are as follows: 2007 - $8 million; 2008 - $7 million; 2009 - $6 million; 2010 - $5 million; 2011 - $4 million and thereafter - $15 million.

There are uncertainties in estimating future environmental costs due to potential external events such as changing regulations and advances in remediation technologies. The Company continuously reviews factors affecting its cost estimates as well as the environmental condition of the various properties. The actual cost of investigation or remediation may differ from current estimates.

13. ISSUANCE OF PREFERRED SHARES

Hydro One Networks is authorized to issue an unlimited number of preferred shares and common shares. On November 21, 2005, the Company issued an additional 1,955,720 preferred series A shares to Hydro One. The Distribution Business' share of the issuance was approximately $38 million. The 5.5% series A cumulative preferred shares have a redemption value of $25.00 per share.

14. RELATED PARTY TRANSACTIONS

The Province and Successor Corporations of Ontario Hydro

The Province, OEFC, IESO, and Ontario Power Generation Inc. (OPG) are related parties of Hydro One Networks' Distribution Business. In addition, the OEB is related to the Company by virtue of its status as a Provincial Crown Corporation, although as a self-financing and self-sufficient regulatory organization, it carries out independent regulation for Ontario's energy sector, including Hydro One's regulated Distribution Business. Transactions between these parties and the Distribution Business were as follows:

The Distribution Business received amounts for rural rate protection from the IESO. Revenues for 2006 include $125 million (2005 - $125 million) related to this program.

In 2006, the Distribution Business purchased power in the amount of $1,916 million (2005 - $1,809 million) from the IESO-administered electricity market and $38 million (2005 - $36 million) from OPG.

Under the Ontario Energy Board Act, 1998, the OEB is required to recover all of its annual operating costs from gas and electricity distributors and electricity transmitters. In 2006, the Distribution Business incurred $4 million (2005 - $5 million) in OEB fees.

The Company has service level agreements with Ontario Hydro's successor corporations, primarily OPG. These services include field and engineering, logistics, corporate, telecommunications and information technology services. Operation, maintenance and administration costs related to the purchase of services from these successor corporations were less than $1 million in 2006 and 2005.

The provision for payments in lieu of corporate income taxes was paid or payable by the Company to the OEFC.

Subsidiaries of Hydro One Inc.

The Company provides services to, and receives services from, Hydro One and its other subsidiaries. Amounts due to and from Hydro One and its subsidiaries are settled through the inter-company demand facility.

The Company has entered into various agreements with Hydro One and its subsidiaries related to the provision of corporate functions and services, supply management, computer support and operational services such as environmental, forestry and line services. Revenues include $1 million (2005 - $1 million) related to the provision of services to Hydro One and its subsidiaries and operation, maintenance and administration costs include $3 million (2005 - $2 million) related to the purchase of services from Hydro One and its subsidiaries.

The Company's debt, including the portion allocated to the Distribution Business, is due to Hydro One. Financing charges include interest expense on this debt in the amount of $127 million (2005 - $130 million). In addition, balances payable or receivable under the inter-company demand facility are due to or from Hydro One. Financing charges of the Distribution Business include interest expense on this facility in the amount of $2 million (2005 - $2 million).

The amounts due to and from related parties as a result of the transactions referred to above are as follows:

December 31 (Canadian dollars in millions)	**2006**	**2005**
Accounts receivable	2	1
Accounts payable and accrued charges	(181)	(211)

Included in accounts payable and accrued charges are amounts owing to the IESO in respect of power purchases of $175 million (2005 - $183 million).

15. STATEMENTS OF CASH FLOWS

The changes in non-cash balances related to operations consist of the following:

Year ended December 31 (Canadian dollars in millions)	**2006**	**2005**
Accounts receivable (increase) decrease	(140)	62
Materials and supplies increase	(1)	(6)
Other current assets decrease	3	1
Accounts payable and accrued charges (decrease) increase	(50)	48
Accrued interest (decrease) increase	(2)	1
Employee future benefits other than pension increase	48	36
Long-term accounts payable and accrued charges increase (decrease)	2	(1)
Other	-	(27)
	(140)	114

16. CONTINGENCIES

The Company is a wholly owned subsidiary of Hydro One. As such, the assets of the Company's Distribution Business are available for the satisfaction of the debts, contingent liabilities and commitments of the Company and Hydro One.

17. COMMITMENTS

The Company and Hydro One have numerous commitments. These commitments have not been specifically allocated to the Distribution Business. However, the net assets of the Distribution Business are available to satisfy these commitments.

18. SUBSEQUENT EVENT

On March 13, 2007, Hydro One issued additional notes under the Company's medium term note program. The issue was comprised of medium term notes with a principal amount of $400 million having a 30-year term with a coupon rate of 4.91%. The notes are due March 13, 2037. The Distribution business's proportion of the issue was $160 million.

19. COMPARATIVE FIGURES

The comparative financial statements have been reclassified from statements previously presented to conform to the presentation of the December 31, 2006 financial statements.

HYDRO ONE NETWORKS INC.

DISTRIBUTION BUSINESS

FINANCIAL STATEMENTS

FOR THE YEAR ENDED

DECEMBER 31, 2007

HYDRO ONE NETWORKS INC.
DISTRIBUTION BUSINESS
AUDITORS' REPORT

To the Directors of Hydro One Networks Inc.

We have audited the Balance Sheets of the Distribution Business (a business of Hydro One Networks Inc.), as at December 31, 2007 and December 31, 2006 and the Statements of Operations, and Cash Flows of the Distribution Business for the years then ended. These financial statements are the responsibility of the management of the Distribution Business. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these financial statements present fairly, in all material respects, the financial position of the Distribution Business of Hydro One Networks Inc. as at December 31, 2007 and 2006 and the results of its operations and its cash flows for the years then ended, in accordance with Canadian generally accepted accounting principles. These financial statements are solely for the information and use of the Directors of Hydro One Networks Inc. for filing with the Ontario Energy Board. These financial statements are not intended to be and should not be used by anyone other than the specified users or for any other purpose.

The Distribution Business has no separate legal status or existence (See Note 1).

Ernst & Young LLP

Chartered Accountants
Licensed Public Accountants
Toronto, Canada
April 23, 2008

HYDRO ONE NETWORKS INC.
DISTRIBUTION BUSINESS
STATEMENTS OF OPERATIONS

Year ended December 31 (Canadian dollars in millions)	**2007**	**2006**
Revenues		
Energy sales	2,836	2,740
Rural rate protection *(Note 13)*	125	125
Other	44	41
	3,005	2,906
Costs		
Purchased power *(Note 13)*	1,964	1,954
Operation, maintenance and administration *(Note 13)*	503	416
Depreciation and amortization *(Note 3)*	254	249
	2,721	2,619
Income before financing charges and provision for payments in lieu of corporate income taxes	284	287
Financing charges *(Notes 4 and 13)*	120	115
Income before provision for payments in lieu of corporate income taxes	164	172
Provision for payments in lieu of corporate income taxes *(Notes 5 and 13)*	77	46
Net income	87	126
Other comprehensive income	1	-
Comprehensive Income	88	126

See accompanying notes to financial statements.

HYDRO ONE NETWORKS INC.
DISTRIBUTION BUSINESS
BALANCE SHEETS

December 31 (Canadian dollars in millions)	**2007**	**2006**
Assets		
Current assets		
Accounts receivable (net of allowance for doubtful accounts – $18 million; 2006 - $16 million) *(Note 13)*	571	585
Regulatory assets *(Note 7)*	73	94
Materials and supplies	28	23
Other	8	4
	680	706
Fixed assets *(Note 6)*		
Fixed assets in service	6,098	5,867
Less: accumulated depreciation	2,305	2,329
	3,793	3,538
Construction in progress	150	87
	3,943	3,625
Other long-term assets		
Regulatory assets *(Note 7)*	85	151
Goodwill	73	73
Long-term accounts receivable and other assets	1	1
	159	225
Total assets	4,782	4,556

See accompanying notes to financial statements.

HYDRO ONE NETWORKS INC.
DISTRIBUTION BUSINESS
BALANCE SHEETS (continued)

December 31 (Canadian dollars in millions)	**2007**	**2006**
Liabilities		
Current liabilities		
Inter-company demand facility *(Note 13)*	158	68
Accounts payable and accrued charges *(Note 13)*	431	394
Accrued interest	21	21
Long-term debt payable within one year *(Notes 8, 9 and 13)*	224	105
	834	588
Long-term debt *(Notes 8, 9 and 13)*	1,864	1,981
Other long-term liabilities		
Employee future benefits other than pension *(Note 10)*	475	444
Environmental liabilities *(Note 11)*	34	37
Regulatory liabilities *(Note 7)*	48	5
Long-term accounts payable and accrued charges	4	5
	561	491
Total liabilities	3,259	3,060
Contingencies and commitments *(Notes 9, 15 and 16)*		
Excess of assets over liabilities	1,523	1,496
Total liabilities and excess of assets over liabilities	4,782	4,556

See accompanying notes to financial statements.

On behalf of the Board:

Laura Formusa
Chair

Beth Summers
Director

HYDRO ONE NETWORKS INC.
DISTRIBUTION BUSINESS
STATEMENTS OF CASH FLOWS

Year ended December 31 (Canadian dollars in millions)	**2007**	**2006**
Operating activities		
Net income	87	126
Adjustments for non-cash items:		
Depreciation and amortization (net of removal costs)	226	219
Retail settlements variance accounts	40	6
Other regulatory assets and liabilities accounts	24	(8)
	377	343
Changes in non-cash balances related to operations *(Note 14)*	63	(137)
Net cash from operating activities	440	206
Investing activities		
Capital expenditures	(477)	(393)
Other assets	2	1
Net cash used in investing activities	(475)	(392)
Financing activities		
Change in allocated long-term debt	2	107
Payments to Hydro One Inc. to finance dividends	(57)	(47)
Net cash from (used in) financing activities	(55)	60
Net change in inter-company demand facility	(90)	(126)
Inter-company demand facility, January 1	(68)	58
Inter-company demand facility, December 31	(158)	(68)

See accompanying notes to financial statements.

1. DESCRIPTION OF THE DISTRIBUTION BUSINESS

Hydro One Inc. (Hydro One) was incorporated on December 1, 1998, under the *Business Corporations Act* (Ontario) and is wholly owned by the Province of Ontario (the Province). The principal businesses of Hydro One are the transmission and distribution of electricity to customers within Ontario. These businesses are regulated by the Ontario Energy Board (OEB).

Hydro One Networks Inc. (Hydro One Networks or the Company) was incorporated on March 4, 1999 under the *Business Corporations Act* (Ontario) and is a wholly owned subsidiary of Hydro One. The Company owns and operates Hydro One's regulated transmission and distribution businesses. The regulated distribution business (the Distribution Business) operates a low-voltage electrical distribution network that distributes electricity from the transmission system, or directly from generators, to customers within Ontario. Distribution customers include small local distribution companies and large industrial customers with loads of less than 5 MW.

2. SIGNIFICANT ACCOUNTING POLICIES

Basis of Accounting

The financial statements have been prepared in accordance with accounting principles generally accepted in Canada (Canadian GAAP). The financial statements have been prepared for the specific use of the OEB. Consolidated financial statements of Hydro One for the year ended December 31, 2007 have been prepared and are publicly available.

These financial statements have been prepared on a carve-out basis to provide the financial position, results of operations, changes in the excess of assets over liabilities and cash flows of the Company's regulated Distribution Business on a basis approved by the OEB. The financial statements are considered by management to be a reasonable representation, prepared on a rational, systematic and consistent basis, of the financial results of that business. As a result of this basis of accounting, these financial statements may not necessarily be identical to the financial position and results of operations that would have resulted had the Distribution Business historically operated on a stand-alone basis.

The financial statements have been constructed primarily through specific identification of assets, liabilities (other than debt), revenues and expenses that relate to the Distribution Business. The Company's long-term debt is allocated based on the respective borrowing requirements of the Company's transmission and distribution businesses. A portion of the Company's shared functions and services costs are allocated to the Distribution Business on a fully allocated cost basis, consistent with OEB-approved independent studies. Payments in lieu of corporate income taxes have been recorded at effective rates based on income taxes as reported in the Statements of Operations as though the Distribution Business was a separate tax paying entity. Certain other amounts presented in these financial statements represent allocations subject to review and approval by the OEB.

Rate-setting

The rates of the Distribution Business are subject to regulation by the OEB. Current distribution rates are based on a cost of service rate regulation model, which also includes a targeted return on deemed common equity. On April 12, 2006, the OEB announced its decision regarding the Company's most recent rate application. On the basis of the written evidence submitted, the OEB approved the requested increase in the revenue requirement based on a reduction in the approved rate of return, from a targeted 9.88% to 9.00%, effective May 1, 2006.

In 2006, the OEB commenced a process of establishing an Incentive Regulation Mechanism (IRM) for the years 2007 to 2010. The process includes a formulaic approach to establishing 2007 rates with a rate rebasing approach to be staggered across all Ontario distributors between 2008 and 2010. The Company applied for marginal distribution rate adjustments in February 2007, based on an OEB-approved formula that considers inflation, efficiency targets and significant events outside the control of management. In April 2007, the OEB approved the Company's submissions on the basis of its cost of capital and second generation IRM policies, and the revised rates were implemented effective May 1, 2007.

The Company submitted the revenue requirement portion of its 2008 cost of service application in accordance with the OEB's multi-year distribution rate-setting plan on August 15, 2007. This application seeks the approval of a revenue requirement of $1,067 million based on a return of 8.64% for 2008. On December 18, 2007, the Company filed the details of its cost allocation and rate design proposals, which include a plan to reduce the number of rate classes for its customers and consolidate or harmonize the rates for its existing rate classes to the new proposed rate classes. Based on the OEB's processing guidelines, a decision is anticipated in the Fall of 2008.

The OEB has the general authority to include or exclude costs, revenues, losses or gains in the rates of a specific period, resulting in a change in the timing of accounting recognition from that which would have applied in an unregulated company. Such change in timing gives rise to the recognition of regulatory assets and liabilities. The Distribution Business' regulatory assets represent certain amounts receivable from future customers and costs that have been deferred for accounting purposes because it is probable that they will be recovered in future rates. In addition, the Company has recorded regulatory liabilities, which represents amounts incurred in different periods than would be the case had the Company been unregulated. The specific regulatory assets and liabilities recognized at December 31, 2007 are disclosed in Note 7.

The Company continually assesses the likelihood of recovery of each of its regulatory assets and continues to believe that it is probable that the OEB will factor its regulatory assets and liabilities into the setting of future rates. If, at some future date, the Company judges that it is no longer probable that the OEB will include a regulatory asset or liability in future rates, the appropriate carrying amount will be reflected in results of operations in the period that the assessment is made.

Revenue Recognition

Revenues attributable to the delivery of electricity are based on OEB-approved distribution tariff rates and are recognized as electricity is delivered to customers. The Company estimates the monthly revenue for the period based on wholesale power purchases because customer meters are not generally read at the end of each month. Unbilled revenue included within accounts receivable as at December 31, 2007 amounted to $382 million (2006 - $359 million).

Revenue also includes an amount relating to rate protection for rural residential customers, which is received from the Independent Electricity System Operator (IESO) based on a standardized customer rate that is approved by the OEB. The current legislation provides rate protection for prescribed classes of rural residential customers by reducing the electricity rates that would otherwise apply.

Revenues also include amounts related to sales of other services and equipment. Such revenue is recognized as services are rendered or as equipment is delivered.

Corporate Income and Capital Taxes

Under the *Electricity Act, 1998*, the Company is required to make payments in lieu of corporate income taxes to the Ontario Electricity Financial Corporation (OEFC). These payments are calculated in accordance with the rules for computing income and taxable capital and other relevant amounts contained in the *Income Tax Act* (Canada) and the *Corporations Tax Act* (Ontario) as modified by the *Electricity Act, 1998,* and related regulations.

The Distribution Business provides for its share of the Company's payments in lieu of corporate income taxes using the taxes payable method as directed by the OEB. Under the taxes payable method, no provisions are made for future income taxes as a result of temporary differences between the tax basis of assets and liabilities and their carrying amounts for accounting purposes. When unrecorded future income taxes become payable, it is expected that they will be included in the rates approved by the OEB and recovered from Distribution Business customers at that time.

Inter-Company Demand Facility

Hydro One maintains pooled bank accounts for its use and for the use of its subsidiaries and, implicitly, by the regulated businesses of these subsidiaries. The inter-company demand facility represents the cumulative net effect of all deposits and withdrawals made by the Distribution Business to and from the pooled cash accounts. Interest is earned on positive inter-company balances based on the average of the bankers' acceptance rate at the beginning and end of the month, less 0.02%. Interest is charged on overdraft inter-company balances based on the same bankers' acceptance rate, plus 0.15%.

Materials and Supplies

Materials and supplies represent spare parts and construction material held for internal construction and maintenance of fixed assets. These assets are carried at lower of average cost or net realizable value.

Fixed Assets

Fixed assets are capitalized at cost, which comprises materials, labour, engineering costs, overheads, depreciation on service equipment and the approved allowance for funds used during construction applicable to capital construction activities. Fixed assets in service consist of: distribution assets; communication, administration and service assets; and easements.

Some distribution assets, particularly those located on unowned easements and rights-of-way, may have asset retirement obligations. The majority of the Company's easements and rights-of-way are either of perpetual duration or are automatically renewed annually. Land rights with finite terms are generally subject to extension or renewal. As the Company expects to use the majority of its installed assets for an indefinite period, no removal date can be determined and consequently a reasonable estimate of the fair value of any related asset retirement obligations cannot be made at this time. If, at some future date, it becomes possible to estimate the fair value cost of removing assets that the Company is legally required to remove, an asset retirement obligation will be recognized at that time.

Distribution

Distribution assets comprise assets related to the distribution of low-voltage electricity, including lines, poles, switches, transformers, protective devices and metering systems.

Communication, Administration and Service

Communication, administration and service assets include telecommunications equipment, towers, associated buildings, administrative buildings, major computer systems, personal computers, transport and work equipment, and tools, vehicles and minor fixed assets.

Easements

Easements include amounts incurred for easements and other access rights.

Construction in Progress

Overhead costs, including corporate functions and services costs, are capitalized on a fully allocated basis, consistent with an OEB-approved methodology. Financing costs are capitalized on fixed assets under construction based on the OEB's approved allowance for funds used during construction (2007 – 4.95%; 2006 – 6.32%).

Depreciation

The capital costs of fixed assets are depreciated on a straight-line basis, except for transport and work equipment, which is depreciated on a declining balance basis.

Effective January 1, 2007, the Company prospectively revised its fixed asset depreciation rates resulting from a periodic external review required by the OEB. The estimated impact of the change in rates is a reduction in depreciation expense of approximately $4 million per annum. A summary of the new rates for the various classes of assets is included below:

	Depreciation rates (%)	
	Range	Average
Distribution	1% - 5%	2%
Communication, Administration and Service	1% - 15%	8%
Easements	1% - 1%	1%

Depreciation rates for easements are based on their contract life. The majority of easements are held in perpetuity and are not depreciated.

In accordance with group depreciation practices, the original cost of normal fixed asset retirements is charged to accumulated depreciation, with no gain or loss reflected in results of operations. Gains and losses on sales of fixed assets and losses on premature retirements are charged to results of operations as adjustments to depreciation expense. Depreciation expense also includes the costs incurred to remove fixed assets.

The estimated service lives of fixed assets are subject to periodic review. Any changes arising out of such a review are implemented on a remaining service life basis consistent with their inclusion in rates.

Goodwill

Goodwill represents the cost of acquired local distribution companies in excess of fair value of the net identifiable assets purchased and is evaluated for impairment on an annual basis, or more frequently if circumstances require. Goodwill impairment is assessed based on a comparison of the fair value of the reporting unit to the underlying carrying value of the reporting unit's net assets, including goodwill, with any write-down of the carrying value of goodwill being charged against results of operations.

The Company has determined that goodwill is not impaired.

Discounts and Premiums on Debt

Discounts and premiums are amortized over the period of the related debt using the effective interest rate method.

Financial Instruments

Hydro One periodically uses interest rate swap contracts to manage interest rate risks. Payments and receipts under interest rate swap contracts are recognized as adjustments to interest expense on an accrual basis and are allocated to Hydro One subsidiaries and their regulated businesses. Hydro One does not engage in derivative trading or speculative activities.

Effective January 1, 2007, the Company adopted four new accounting standards comprising the Canadian Institute of Chartered Accountants' (CICA) Handbook Sections 1530, *Comprehensive Income*; 3855, *Financial Instruments – Recognition and Measurement*; 3861, *Financial Instruments – Disclosure and Presentation;* and 3865, *Hedges*. The adoption of these new standards required changes in the accounting for financial instruments and hedges, and the recognition of certain transition adjustments that are recorded in opening accumulated other comprehensive income (AOCI) as described below, consistent with the CICA Handbook sections. The principal changes in the accounting for financial instruments and hedges due to the adoption of these accounting standards are described below.

Comprehensive Income

Comprehensive income is composed of the Company's net income and other comprehensive income (OCI). OCI includes the amortization of unamortized hedging losses on cash flow hedges that had been discontinued prior to the transition date. The impact of this amortization is immaterial to the Statement of Operations.

Financial Assets and Liabilities

Under the new standards, all financial instruments are classified into one of the following five categories: held-to-maturity investments, loans and receivables, held-for-trading, other liabilities or available-for-sale. All financial instruments, including derivatives, are carried at fair value on the consolidated balance sheet except for loans and receivables, held-to-maturity investments and other financial liabilities, which are measured at amortized cost. Held-for-trading financial instruments are measured at fair value and all gains and losses are included in financing charges in the period which they arise. Available-for-sale financial instruments are measured at fair value with revaluation gains and losses included in OCI until the instrument is derecognized or impaired. The Company has classified its financial instruments as follows:

Long-term accounts receivable	Loans and receivables
Inter-company demand facility	Other liabilities
Long-term debt	Other liabilities
$40 million note due May 15, 2008	Designated as held-for-trading

The $40 million note is a step-up coupon note with extendable maturity dates up to 2011.

Where there is an economic hedge, as in the case of the $40 million note and associated interest rate swap, the Company has applied the fair value option without hedge accounting. The impact was not material.

All financial instrument transactions are recorded at trade date.

Derivatives and Hedge Accounting

All derivative instruments, including embedded derivatives, are carried at fair value on the Balance Sheet unless exempted from derivative treatment as a normal purchase and sale. All changes in fair value are recorded in financing charges unless cash flow hedge accounting is used, in which case changes in fair value are recorded in OCI to the extent that the hedge is effective. The impact of the change in the accounting policy related to embedded derivatives was not material.

Hydro One periodically develops hedging strategies for execution taking into account risk management objectives. At the inception of a hedging relationship, Hydro One documents the relationship between the hedging instrument and the hedged item. This would include linking all derivatives to specific assets and liabilities on the consolidated balance sheet or to specific firm commitments or forecasted transactions. Hydro One would also assess, both at the inception of the hedge and on an ongoing basis, whether the derivatives that are used are effective in offsetting changes in fair values or cash flows of hedged items.

Upon adoption of the new standards, the Company reclassified allocated unamortized hedging losses on cash flow hedges that had been discontinued prior to the transition date to accumulated other comprehensive income, which is included as a component of excess of assets over liabilities. The hedging losses are amortized through OCI using the effective interest method over the term of the hedged debt.

Transaction Costs

Transaction costs for financial assets and liabilities that are other than held-for-trading, are added to the carrying value of the asset or liability and then amortized over the expected life of the instrument using the effective interest method. The impact of the change in amortization method from an annuity basis to the effective interest method was not material.

Employee Future Benefits

Employee future benefits provided by Hydro One and its subsidiaries include pension, group life insurance, health care and long-term disability.

In accordance with the OEB’s rate orders, pension costs are recorded when employer contributions are paid to the pension fund in accordance with the *Pension Benefits Act* (Ontario). Actuarial valuations are conducted at least every three years. Pension costs are also calculated on an accrual basis. Pension costs are actuarially determined using the projected benefit method prorated on service and based on assumptions that reflect management’s best estimate of the effect of future events, including future compensation increases, on the actuarial present value of accrued pension benefits. Pension plan assets, consisting primarily of listed equity securities as well as corporate and government debt securities, are valued using fair values. Past service costs from plan amendments and all actuarial gains or losses are amortized on a straight-line basis over the expected average remaining service life of the employees covered.

Employee future benefits other than pension are recorded on an accrual basis. Costs are determined by independent actuaries using the projected benefit method prorated on service and based on assumptions that reflect management’s best estimates. Past service costs from plan amendments and actuarial gains or losses are amortized on a straight-line basis over the expected average remaining service life of the employees covered.

Employee future benefit costs are attributed to labour and charged to operations or capitalized as part of the cost of fixed assets.

Environmental Costs

The Distribution Business recognizes a liability for estimated future expenditures associated with the assessment and remediation of contaminated lands and for the phase-out and destruction of polychlorinated biphenyl (PCB) contaminated mineral oil from electrical equipment, based on the net present value of these estimated future expenditures. As the Company anticipates that the related expenditures will continue to be recoverable in future rates, a regulatory asset has been recognized to reflect the future recovery of these costs from customers. The Distribution Business reviews its estimates of future environmental expenditures on an ongoing basis.

Use of Estimates

The preparation of financial statements in conformity with Canadian GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities at the date of the financial statements, and the reported amounts of revenues and expenses for the year. Actual results could differ from estimates, including changes as a result of future decisions made by the OEB or the Province.

3. DEPRECIATION AND AMORTIZATION

Year ended December 31 (Canadian dollars in millions)	**2007**	**2006**
Depreciation of fixed assets in service	153	148
Fixed asset removal costs	28	30
Amortization of regulatory and other assets	73	71
	254	249

4. FINANCING CHARGES

Year ended December 31 (Canadian dollars in millions)	**2007**	**2006**
Interest on long-term debt payable	122	127
Amortization of premiums and hedges	2	2
Interest on inter-company demand facility	4	2
Less: Interest accreted on regulatory accounts	(3)	(11)
Interest capitalized on construction in progress	(5)	(5)
	120	115

5. PROVISION FOR PAYMENTS IN LIEU OF CORPORATE INCOME TAXES

The provision for payments in lieu of corporate income taxes (PILs) differs from the amount that would have been recorded using the combined Canadian Federal and Ontario statutory income tax rate. A reconciliation between the statutory and effective tax rate is provided as follows:

Year ended December 31 (Canadian dollars in millions)	**2007**	**2006**
Income before provision for PILs	164	172
Federal and Ontario statutory income tax rate	36.12%	36.12%
Provision for PILs at statutory rate	59	62
Increase (decrease) resulting from:		
Net temporary differences:		
Depreciation and amortization in excess of capital cost allowance	14	19
Retail settlement variance accounts	13	7
Pension contribution in excess of pension expense	(8)	(12)
Overheads capitalized for accounting but deducted for tax purposes	(5)	(5)
Employee future benefits other than pension expense in excess of cash payments	4	8
Interest capitalized for accounting purposes but deducted for tax purposes	(3)	(6)
Environmental expenditures	(3)	(4)
Recovery of PILs related to prior years	-	(14)
Other	5	(8)
Net temporary differences	17	(15)
Net permanent differences	1	(1)
Provision for PILs	77	46
Effective income tax rate	46.95%	26.74%

In 2006, the Distribution Business recognized a tax benefit of approximately $14 million in respect of Hydro One's recovery of PILs from prior years following a successful appeal allowing a deduction for certain overhead costs that had been previously capitalized.

Future income taxes have not been recorded in the accounts as they are expected to be recovered through future revenues. As at December 31, 2007, future income tax liabilities of $50 million (2006 - $72 million), based on substantively enacted income tax rates, have not been recorded. In the absence of rate regulated accounting, the Company's provision for PILs would have been recognized using the liability method rather than the taxes payable method. As a result, the provision for PILs would have been lower by approximately $22 million (2006 – higher by $8 million) including the impact of a rate change in substantively enacted tax rates.

6. FIXED ASSETS

December 31 (Canadian dollars in millions)	Fixed Assets in Service	Accumulated Depreciation	Construction in Progress	Total
2007				
Distribution	5,476	1,926	110	3,660
Communication, administration and service	614	376	40	278
Easements	8	3	-	5
	6,098	2,305	150	3,943
2006				
Distribution	5,247	1,948	83	3,382
Communication, administration and service	612	378	4	238
Easements	8	3	-	5
	5,867	2,329	87	3,625

Financing costs capitalized on fixed assets under construction using the allowance for funds used during construction were $5 million in 2007 (2006 - $5 million).

7. REGULATORY ASSETS AND LIABILITIES

Regulatory assets and liabilities arise as a result of the ratemaking process. The Distribution Business has recorded the following regulatory assets and liabilities:

December 31 (Canadian dollars in millions)	**2007**	**2006**
Regulatory assets:		
Regulatory asset recovery account II	66	87
Environmental	41	45
Employee future benefits other than pension	24	47
Regulatory asset recovery account I	18	55
Smart meters	5	10
Other	4	1
Total regulatory assets	158	245
Less: current portion	73	94
	85	151
Regulatory liabilities:		
Retail settlement variance accounts	42	2
Other	6	3
Total regulatory liabilities	48	5

Regulatory assets

Regulatory asset recovery account II (RARA II)

On April 12, 2006, the OEB announced its decision regarding the Company's rate application in respect of the Distribution Business. As part of this decision, the OEB also approved the distribution-related deferral account balances sought by Hydro One Networks. The OEB ordered that the approved balances be recovered on a straight-line basis over a four year period from May 1, 2006 to April 30, 2010. The RARA II includes retail settlement and cost variance amounts and distribution low-voltage service amounts, plus accrued interest. In the absence of rate regulated accounting, amortization expense in 2007 would have been lower by approximately $23 million (2006 - $16 million). In addition, related financing charges would have been higher by $3 million (2006 - $5 million).

Environmental

The Company records a liability for the estimated future expenditures required to remediate past environmental contamination. Because such expenditures are expected to be recoverable in future rates, the Company has recognized an equivalent amount as a regulatory asset. This regulatory asset is expected to be amortized to results of operations on a basis consistent with the pattern of actual expenditures expected to be incurred up to the year 2030. The OEB has the discretion to examine and assess the prudence and the timing of recovery of all of the Company's future regulatory expenditures. In the absence of rate regulated accounting, amortization expense in 2007 would have been lower by $6 million (2006 - $12 million).

Employee future benefits other than pension

Employee future benefits other than pension are recorded using the accrual method as required by Canadian GAAP. The OEB has allowed for the recovery of past service costs, which arose on the adoption of the accrual method, in the revenue requirement on a straight-line basis over a 10-year period. As a result, in 1999 the Distribution Business recorded a regulatory asset, with an original balance of $236 million, to reflect this regulatory treatment. This regulatory asset has a remaining recovery period of 1 year (2006 - 2 years) and does not earn a return. In the absence of rate regulated accounting, amortization expense in 2007 would have been lower by $24 million (2006 - $24 million).

Regulatory asset recovery account I (RARA I)

On December 9, 2004, the OEB issued a decision on the prudence of the distribution-related deferral account balances sought by the Company in its May 31, 2004 application. Amounts for which recovery was approved represented balances incurred prior to December 31, 2003, plus associated interest. The OEB ordered that the approved balances be aggregated into a single regulatory account to be recovered on a straight-line basis over the period ending April 30, 2008. The Company has requested an extension of the period for the RARA I recovery, until such time as new rates are implemented. The RARA I includes distribution business low-voltage services amounts, deferred environmental expenditures incurred in 2001 and 2002, deferred market ready expenditures, retail settlement variance amounts, and other amounts primarily consisting of accrued interest. Any over or under recovery of the RARA I due to the continuance of the rate rider will be tracked for disposition at a future date. In the absence of rate regulated accounting, amortization expense in 2007 would have been lower by approximately $20 million (2006 - $20 million). In addition, related financing charges would have been higher by $1 million (2006 - $3 million).

Smart meters

On March 21, 2006, the OEB approved the establishment of regulatory deferral accounts for smart meter-related expenditures and a monthly customer charge of 27 cents per metered customer was reflected in the Company's revenue requirement. Consistent with the OEB's direction and pending further guidance, the Company recognized a regulatory asset consisting of the net balance of capital and operating expenditures for smart meters less recoveries received from customers. In April 2007, as part of its decision regarding the Company's 2007 distribution rate applications, the OEB increased the monthly customer charge effective May 1, 2007 to 93 cents per metered customer.

On August 8, 2007, the OEB issued a decision on its combined proceeding to determine recoverability of expenditures incurred by distributors. Expenditures associated with the minimum functionality for advanced metering infrastructure incurred by the Company were approved for recovery. As a result of this decision, smart meter expenditures are no longer deferred as regulatory assets. Such expenditures are now classified as capital or are charged to results of operations consistent with the Company's standard accounting practices. Expenditures determined to be above the minimum functionality have been brought forward for review in the Company's cost of service rate application filed in 2007.

The OEB decision also required that related revenues be based upon a calculated revenue requirement specific to smart meters. As a result, the carrying value of the smart meter regulatory asset account represents the difference between revenue recorded on this basis and actual recoveries received under existing rate adders. In the absence of rate regulated accounting, year-to-date operation, maintenance and administration expense would have been lower by $3 million (2006 – higher by $4 million) and revenues would have been lower by $2 million (2006 – higher by $2 million).

Regulatory liabilities

Retail settlement variance accounts

The Company has deferred certain retail settlement variance amounts under the provisions of Article 490 of the OEB's Accounting Procedures Handbook. The OEB's December 9, 2004 decision allowed for recovery of retail settlement variance amounts accumulated prior to December 31, 2003, inclusive of interest, within the RARA I. The OEB's April 12, 2006 decision allowed for recovery of retail settlement variance amounts accumulated since January 1, 2004 and forecasted through to April 30, 2006, inclusive of interest, within the RARA II. The Company has accumulated a net liability in its RSVA since May 1, 2006 which was taken into consideration in the revenue requirement of the Company as part of the 2008 distribution rate application filed with the OEB in December 2007.

8. DEBT

December 31 (Canadian dollars in millions)	**2007**	**2006**
Long-term debt payable within one year	224	105
Long-term debt	1,865	1,986
	2,089	2,091
Net unamortized premiums	8	8
Unamortized hedging losses[1]	-	(4)
Unamortized transaction costs	(9)	(9)
	2,088	2,086

[1] Unamortized net losses relating to settled swap agreements were reclassified to AOCI on January 1, 2007 without prior year reclassification.

Debt represents the Distribution Business share of various notes payable by Hydro One Networks to Hydro One. This allocated debt is summarized by the number of years to maturity in the following table:

Years to Maturity	Principal Outstanding *(Canadian dollars in millions)*	Weighted Average Interest Rate *(percent)*
1 year	224	4.1
2 years	132	4.0
3 years	122	7.2
4 years	76	6.4
5 years	324	5.8
	878	5.3
6 – 10 years	255	4.8
Over 10 years	956	6.2
	2,089	5.6

9. FAIR VALUE OF FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

The carrying amounts of all financial instruments, except long-term debt, approximate fair value. The fair value of derivative financial instruments reflects the estimated amount that the Company, if required to settle an outstanding contract, would have been required to pay or would be entitled to receive at year end. The fair value of long-term debt, based on year end quoted market prices for the same or similar debt of the same remaining maturities, is provided in the following table:

December 31 (Canadian dollars in millions)	**2007**		**2006**	
	Carrying Value	Fair Value	Carrying Value	Fair Value
Long-term debt[1]	2,089	2,230	2,091	2,301

[1] The carrying value of long-term debt represents the par value of the notes.

Financial assets create a risk that a counter-party will fail to discharge an obligation, causing a financial loss. As at December 31, 2007, there were no significant concentrations of credit risk with respect to any class of financial assets. The revenue of the Distribution Business is earned from a broad base of customers. The Distribution Business did not earn a significant amount of its revenue from any single customer. As at December 31, 2007, there were no significant balances of accounts receivable due from any single customer.

Hydro One may enter into derivative agreements to hedge against the effect of future interest rate movements on long-term fixed rate borrowing requirements. These transactions are accounted for as cash flow hedges of anticipated transactions. Upon issuance of the related debt, Hydro One records the net gain or loss as other comprehensive income and amortizes it over the life of the related debt. At the same time, Hydro One Networks issues notes payable to Hydro One for equal amounts and allocates the related other comprehensive income to the businesses of Hydro One Networks.

In the third quarter of 2007, Hydro One entered into two forward starting pay fixed interest rate swap agreements to hedge against the effect of future interest rate movements on long-term fixed rate borrowing requirements. The transactions, with notional amounts of $150 million and $50 million respectively, were used to fix the interest rate of a forecasted debt issuance planned for later in the year and were accounted for as cash flow hedges of a forecasted transaction. In October 2007, upon issuance of debt under its medium term note program, Hydro One terminated the two forward interest rate swap agreements. The resulting net gain from these transactions was $0.4

million, of which $0.1 million pertained to the Distribution Business and has been recorded in other comprehensive income. In late 2007, Hydro One entered into two new forward starting pay fixed interest rate swap agreements with a notional amount of $140 million.

10. EMPLOYEE FUTURE BENEFITS

Pension

Hydro One has a contributory defined benefit pension plan covering all regular employees of Hydro One and its subsidiaries, except Hydro One Brampton. The Hydro One Pension Plan does not segregate assets in a separate account for individual subsidiaries, nor is the cost of the benefit plans allocated to, or funded separately by, entities within the consolidated group. Accordingly, for purposes of these financial statements, the pension plan is accounted for as a defined contribution plan and no deferred pension asset or liability is recorded.

The Company's pension plan provides benefits based on highest three-year average pensionable earnings. For new management employees who commenced employment on or after January 1, 2004, and for new Society of Energy Professionals hired after November 17, 2005, benefits are based on highest five-year average pensionable earnings. After retirement, pensions are indexed to inflation. The measurement date used to determine plan assets and the accrued benefit obligation is December 31. Based on the actuarial valuation filed on September 20, 2007, effective for December 31, 2006, the Company contributed $95 million to its pension plan in respect of 2007 (2006 - $86 million), all of which is required to satisfy minimum funding requirements. Contributions are payable one month in arrears. All of the contributions are expected to be in the form of cash. Contributions after 2009 will be based on actuarial valuation effective December 31, 2009 and will depend on future investment returns, and changes in benefits or actuarial assumptions.

For Hydro One, the actuarial present value at December 31, 2007 of the accrued pension benefits, based on a projection of the valuation at December 31, 2007, was estimated to be $5,077 million (2006 - $5,411 million). Pension plan assets available for these benefits were $5,100 million (2006 - $5,123 million).

Employee Future Benefits other than Pension

During the year ended December 31, 2007, $33 million of employee future benefits other than pension costs was charged to the results of operations of the Distribution Business (2006 - $39 million), and $22 million was capitalized as part of the cost of fixed assets (2006 - $27 million). Benefits paid were $22 million (2006 - $18 million). The liability associated with employee future benefits other than pension for the Distribution Business at December 31, 2007 was $495 million (2006 - $462 million), including the current portion.

A detailed description of employee future benefits is provided in Note 10 of the Consolidated Financial Statements of Hydro One for the year ended December 31, 2007.

11. ENVIRONMENTAL LIABILITIES

December 31 (Canadian dollars in millions)	**2007**	**2006**
Environmental liabilities, January 1	45	52
Interest accretion	3	3
Expenditures	(6)	(12)
Revaluation adjustment	(1)	2
Environmental liabilities, December 31	41	45
Less: current portion	(7)	(8)
	34	37

Estimated future environmental expenditures for each of the five years subsequent to December 31, 2007 and in total thereafter are as follows: 2008 - $7 million; 2009 - $7 million; 2010 - $6 million; 2011 - $4 million; 2012 - $4 million and thereafter - $28 million.

There are uncertainties in estimating future environmental costs due to potential external events such as changing regulations and advances in remediation technologies. The Company continuously reviews factors affecting its cost estimates as well as the environmental condition of the various properties. The actual cost of investigation or remediation may differ from current estimates.

12. HYDRO ONE NETWORKS' SHARE CAPITAL

Hydro One Networks is authorized to issue an unlimited number of preferred shares and common shares.

13. RELATED PARTY TRANSACTIONS

The Province and Successor Corporations of Ontario Hydro

The Province, OEFC, IESO, Ontario Power Authority (OPA) and Ontario Power Generation Inc. (OPG) are related parties of Hydro One Networks' Distribution Business. In addition, the OEB is related to the Company by virtue of its status as a Provincial Crown Corporation, although as a self-financing and self-sufficient regulatory organization, it carries out independent regulation for Ontario's energy sector, including Hydro One's regulated Distribution Business. Transactions between these parties and the Distribution Business were as follows:

The Distribution Business received amounts for rural rate protection from the IESO. Revenues for 2007 include $125 million (2006 - $125 million) related to this program.

In 2007, the Distribution Business purchased power in the amount of $1,937 million (2006 - $1,916 million) from the IESO-administered electricity market and $27 million (2006 - $38 million) from OPG.

Under the Ontario Energy Board Act, 1998, the OEB is required to recover all of its annual operating costs from gas and electricity distributors and electricity transmitters. In 2007, the Distribution Business incurred $5 million (2006 - $4 million) in OEB fees.

The Company has service level agreements with Ontario Hydro's successor corporations, primarily OPG. These services include field and engineering, logistics, corporate, telecommunications and information technology services. Operation, maintenance and administration costs related to the purchase of services from these successor corporations were less than $1 million in each of 2007 and 2006.

Consistent with the OPA mandate, the OPA is responsible for some of the Company's Conservation Demand Management (CDM) programs. The funding includes program costs, incentives and management fees and bonuses. In 2007, the Company received $3 million (2006 – $nil) from the OPA in respect of the CDM programs and had a net accounts receivable of $3 million (2006 – $nil).

The provision for payments in lieu of corporate income taxes was paid or payable by the Company to the OEFC.

Subsidiaries of Hydro One Inc.

The Company provides services to, and receives services from, Hydro One and its other subsidiaries. Amounts due to and from Hydro One and its subsidiaries are settled through the inter-company demand facility.

The Company has entered into various agreements with Hydro One and its subsidiaries related to the provision of corporate functions and services, supply management, computer support and operational services such as environmental, forestry and line services. Revenues include $1 million (2006 - $1 million) related to the provision of services to Hydro One and its subsidiaries and operation, maintenance and administration costs include $3 million (2006 - $3 million) related to the purchase of services from Hydro One and its subsidiaries.

The Company's debt, including the portion allocated to the Distribution Business, is due to Hydro One. Financing charges include interest expense on this debt in the amount of $122 million (2006 - $127 million). In addition, balances payable or receivable under the inter-company demand facility are due to or from Hydro One. Financing charges of the Distribution Business include interest expense on this facility in the amount of $4 million (2006 - $2 million).

The amounts due to and from related parties as a result of the transactions referred to above are as follows:

December 31 (Canadian dollars in millions)	**2007**	**2006**
Accounts receivable	3	2
Accounts payable and accrued charges	(181)	(181)

Included in accounts payable and accrued charges are amounts owing to the IESO in respect of power purchases of $179 million (2006 - $175 million).

14. STATEMENTS OF CASH FLOWS

The changes in non-cash balances related to operations consist of the following:

Year ended December 31 (Canadian dollars in millions)	**2007**	**2006**
Accounts receivable decrease (increase)	14	(140)
Materials and supplies increase	(5)	(1)
Other current assets (increase) decrease	(4)	3
Accounts payable and accrued charges increase (decrease)	37	(50)
Accrued interest decrease	-	(2)
Employee future benefits other than pension increase	31	48
Long-term accounts payable and accrued charges (decrease) increase	(1)	2
Other	(9)	3
	63	(137)

15. CONTINGENCIES

The Company is a wholly owned subsidiary of Hydro One. As such, the assets of the Company's Distribution Business are available for the satisfaction of the debts, contingent liabilities and commitments of the Company and Hydro One.

16. COMMITMENTS

The Company and Hydro One have numerous commitments. These commitments have not been specifically allocated to the Distribution Business. However, the net assets of the Distribution Business are available to satisfy these commitments.

17. SUBSEQUENT EVENTS

Effective March 1, 2002, Hydro One began receiving a range of services from Inergi LP, including information technology, customer care, supply chain and certain human resources and financial services. In connection with this agreement, the Company transferred approximately 770 regular employees to Inergi LP. On March 10, 2008, the Company was granted consent from the Financial Services Commission of Ontario to transfer pension assets for affected employees from the Hydro One Pension Plan to the Inergi LP Pension Plan. The pension asset transfer will occur in the second quarter.

On March 3, 2008, Hydro One issued additional notes under the Company's medium term note program. On the same date Hydro One Networks issued notes payable to Hydro One Inc. in the amounts of $300 million and $250 million with maturity dates of October 18, 2017 and March 3, 2011, respectively. The Distribution Business' share of the notes payable by Hydro One Networks to Hydro One are $180 million and $150 million, respectively. Upon issuance of these notes, Hydro One terminated three forward interest rate swaps, having a total notional principal amount of $200 million, entered into in the fourth quarter of 2007($140 million) and first quarter of 2008 ($60 million).

On April 11, 2008, the OEB ordered that existing 2007 Distribution rates be declared interim as of May 1, 2008. The Board also noted that it will allow Hydro One to track in a variance account the difference between revenue based on current rates and the distribution 2008 revenue requirement to be approved later this year for the period from May 1, 2008 until such time as final rates are implemented. The disposition of any such balance will be decided when the Board issues its 2008 rate decision.

On April 11, 2008, Hydro One gave notice that it will not extend the maturity date of its $40 million extendible step-up note beyond its current maturity date of May 15, 2008. The notes will be redeemed at that time at a redemption price equal to the principal amount plus any accrued and unpaid interest. The principal attributable to the Distribution Business is $14 million.

18. COMPARATIVE FIGURES

The comparative financial statements have been reclassified from statements previously presented to conform to the presentation of the December 31, 2007 financial statements.

HYDRO ONE NETWORKS INC.
DISTRIBUTION
Pro Forma Statement of Income
Bridge Year (2007) and Forecast Year (2008)
Year Ending December 31
($ Millions)

Line No.	Particulars	2007 (a)	2008 (b)
	Revenues		
1	Retail power & energy	945	1,000
2	Commodity flow-through	1,969	1,959
3	LV	26	26
4	Other	41	42
5		2,982	3,027
	Costs		
6	OM&A	490	489
7	Cost of power	1,969	1,959
8	Depreciation	255	266
9	Capital tax	11	12
10		2,725	2,726
11	Earnings before interest and income tax	256	301
12	Interest expense	112	122
13	Earnings before income tax	145	179
14	Income tax	51	42
15	Net income	94	138

HYDRO ONE INC. – HISTORICAL YEAR (2006) AND BRIDGE YEAR (2007) ANNUAL REPORT

Included as Attachment 1 in this exhibit is the 2006 Hydro One Inc. Annual Report and Attachment 2 in this exhibits is the 2007 Hydro One Inc. Annual Report.

Hydro One Annual Report 2006

Putting power to work

Hydro One Annual Report 2006

hydro One

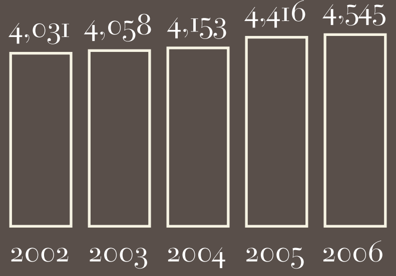
Consolidated financial

highlights and statistics

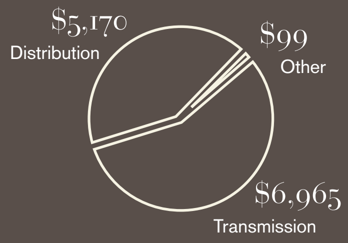
Year ended December 31 (Canadian dollars in millions)	2006	2005	Change	% Change
Revenues	**4,545**	4,416	129	3
Purchased power	**2,221**	2,131	90	4
Operating costs	**1,395**	1,279	116	9
Net income	**455**	483	(28)	(6)
Net cash from operations	**896**	1,169	(273)	(23)
Average annual Ontario 60-minute peak demand *(MW)*[1]	**22,650**	23,074	(424)	(2)
Distribution – units distributed to our customers *(TWh)*[1]	**29.0**	29.7	(0.7)	(2)

1 System-related statistics include preliminary figures for December.

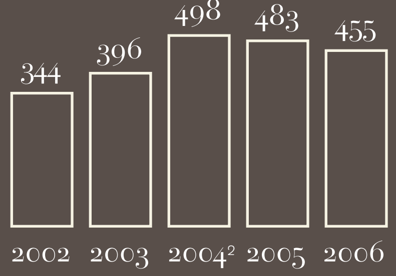
Revenues
(Cdn $ millions)



Total Assets
December 31, 2006
(Cdn $ millions)



Net Income
(Cdn $ millions)



2 Net income for 2004 includes a one-time regulatory recovery of $91 million.

The Hydro One Family of Companies

Hydro One Inc.
Is a holding company with subsidiaries that operate in the business areas of electricity transmission and distribution and telecom. The subsidiaries are necessary to meet legislative and regulatory requirements.

Hydro One Networks Inc.
Represents the significant majority of our business, which is regulated by the Ontario Energy Board. It is involved in the planning, construction, operation and maintenance of our transmission and distribution networks.

Hydro One Brampton Networks Inc.
Distributes electricity to one of the fastest growing urban centres in Canada, just 30 kilometres outside of Toronto.

Hydro One Remote Communities Inc.
Operates and maintains the generation and distribution assets used to supply electricity to 20 remote communities across northern Ontario that are not connected to the province's electricity transmission grid.

Hydro One Telecom Inc.
Markets our fibre-optic capacity to business customers and represents less than 1% of our total assets.

Hydro One's 2006 accomplishments

Our power at work

Customer satisfaction continued to climb in 2006, with

86%

of our Large Transmission Customers saying they were satisfied with our level of service. This is a 4% increase from last year and is moving steadily towards our goal of 90% customer satisfaction. Our Large Industrial Customer satisfaction improved 11% this year, hitting the 90% mark.

The North American Electric Reliability Council (NERC) awarded our transmission operations facilities, work processes and staff a grading of excellence for our ability to reliably operate and maintain Ontario's electricity transmission system. NERC's audit singled out our industry-leading physical security procedures, infrastructure and communication systems.

During a two-month period, three intense storms tested Ontario and knocked out power to more than 400,000 of our customers. The excellence of our restoration efforts earned us a prestigious *Emergency Recovery Award* from the Edison Electric Institute. This is the first time this award has gone to a utility based outside of the United States.

The Ontario Energy Board approved an increase of approximately

$160M

in our annual distribution revenue requirement. This decision demonstrates the OEB's confidence in our ability to maintain and operate Ontario's electricity system. The increased funds will enable us to make important investments we need in our distribution system.

Message from our Chair, Rita Burak

Ensuring that Ontario continues to have the electricity delivery system that it needs and deserves.

This year, Hydro One successfully operated and maintained Ontario's transmission and largest distribution system, expertly meeting the operational challenges posed by multiple severe storms that affected many of our customers. The company embarked on several large projects to ensure the delivery of safe, reliable electricity to the people of Ontario.

The company's net income in 2006 decreased by $28 million, or 6%, to $455 million compared to 2005. This decrease primarily reflects increased expenditures required to operate and maintain our transmission and distribution systems, particularly as a result of the damaging storms we experienced this year, and lower transmission tariff revenues resulting from lower demand and changes to transmission regulations.

As Chair of Hydro One, I understand that the good governance of Hydro One is essential to our shareholder, the Province of Ontario, our bond holders and the people of Ontario who depend upon Hydro One's electricity delivery system. Hydro One was focused on new securities regulations this year and is now fully compliant with the strict new financial control and disclosure requirements.

We take our financial obligations seriously and our financial controls and disclosure practices are solid and undergo regular external scrutiny. We operate in a highly transparent manner. Hydro One has embraced all 13 recommendations of Ontario's Auditor General to improve compliance with our internal policies and procedures.

Hydro One made critical investments both in transmission and in distribution infrastructure as well as in maintenance programs designed to ensure the reliability of the system. Hydro One spent $1.7 billion in 2006 in total capital and operation, maintenance and administrative expenditures.

Our ability to arrange sufficient and cost-effective financing supports our improving long-term credit rating. This is vital to our ability to refinance maturing debt, fund capital expenditures and address other requirements. In particular, Hydro One has access to long-term funding that better matches our debt to our long-lived assets. The upgrades to our credit ratings reflect the confidence of the rating agencies and investors in the performance and management of the company.

The Board expects continued strong, stable financial performance and is confident in the management team's ability to meet the challenges in the coming year. In the past two years Hydro One has begun a major new construction phase and this will continue in the years ahead. Major projects vital to the economic well-being of Ontario are underway, including a new interconnection with Quebec, transmission upgrades in Toronto and the connection of new sources of generation as they become available across Ontario.

Hydro One paid its shareholder, the Province of Ontario, dividends of $350 million. Hydro One recorded $179 million of payments in lieu of income taxes, which helps reduce the legacy-stranded debt held by the Province.

On behalf of the Board of Directors, I would like to thank Hydro One's management and employees for their valued contribution and their dedication to their vital role. The Board looks forward to continuing the work of Hydro One in providing a safe, reliable electricity delivery system for the people of Ontario.

Rita Burak
Chair

Message from our President and CEO (Acting), Laura Formusa

Our work is complex, but the reason we do it is simple: Ontario depends upon Hydro One to deliver the electricity needed to put power to work.

Hydro One exists to ensure that the people, businesses, industries and communities of Ontario have the electricity they need to put power to work for them. Our transmission system represents more than 96% of Ontario's capacity.

We understand that our customers and other stakeholders expect Hydro One to be managed in a responsible manner, respecting the public trust placed in us to ensure the safe and reliable delivery of electricity at reasonable cost.

We take this trust seriously and believe that our performance and achievements of this past year bear this out.

Serving our customers drives everything we do. And our customers are diverse. From industrial giants like mining company Inco, Ontario's largest electricity consumer, to greenhouse operations in Leamington, to summer camps in Deep River and family homes in every corner of the province, we deliver electricity to a wide range of consumers.

In 2006, our customers told us that our service was better than ever. We made an honest appraisal of how we could do a better job of meeting our customers' needs, which enabled us to make major advances in improving our relationships. We have seen double-digit increases in customer satisfaction levels and we aim to reach customer satisfaction levels of 90%, on average, across all customer segments.

NERC gave our transmission operations facilities, work processes and staff a grading of excellence for our ability to reliably operate and maintain Ontario's electricity transmission system. The report singled out our industry-leading physical security procedures, infrastructure and program management as well as our innovative and fully integrated, multi-functional communications system.

We became the first utility based outside of the United States to receive the prestigious Edison Electric Institute *Emergency Recovery Award* recognizing the company's outstanding efforts in restoring power to more than 400,000 customers following three severe storms.

Our financial performance in 2006 was strong, with a net income of $455 million, and we paid our shareholder a healthy dividend.

As stewards of this province's massive and complex electricity transmission and delivery systems, we made significant progress on a number of critical system investment initiatives. We signed an agreement with Hydro-Québec TransÉnergie Inc. for construction of state-of-the-art power transmission equipment including new circuits across the Ottawa River connecting the two provincial high-voltage power systems. This $124 million investment will add an important new connection between the two grids and increase Ontario's ability to access electricity generated through renewable resources.

In November 2006, construction crews restored the Ontario to Michigan interconnection in the Sarnia area with the transmission operator in Michigan. This interconnection improves overall supply reliability in Ontario by increasing electricity import/export capacity and maximizes the effectiveness of the existing high-voltage transmission system. This circuit will increase our import and export capacity by about 400MW and 200MW respectively.

We completed the excavation of a 2.2-kilometre tunnel beneath the streets of Toronto. This innovative $45 million investment will carry an array of electricity transmission lines to tie the east and west sides of the city together with minimal disruption. This work will let power flow more freely across the city, giving Toronto increased flexibility, reliability and supply.

In 2006, we launched several new conservation and demand management programs in line with the Province's goal to create a culture of conservation in Ontario. Our programs mirror our customer base; some help Ontario families save electricity and money, while others use innovative technology to allow our larger customers to ease strain on the provincial electricity grid during peak demand periods.

While we're proud of our accomplishments, our main focus is on the challenges facing Ontario's electricity transmission system. Meeting these challenges by constructing the necessary transmission infrastructure will require cooperation with all of our stakeholders.

As guardians of the province's electricity transmission system, we have a number of key investment initiatives that require our utmost attention in the year ahead. Most significant of those initiatives is the proposed construction of a new 500-kV transmission line to deliver additional electricity to southern Ontario. We are undertaking consultations with the public and other interested groups about the routing of the line as well as its benefits and impacts.

We will continue to seek approvals for a number of other major projects which are geared to improving the reliability of supply to local areas within Ontario.

My management team and I will continue to ensure that Hydro One works efficiently, effectively and in the best interests of the people of Ontario. I am enthusiastic about the challenges that lie ahead of us and proud of our record of past achievements.

I'd like to thank Hydro One's employees for working safely and with the utmost commitment to our customers. We rely on the work our employees do every day to make sure that the people of Ontario can put power to work.

L Formusa

Laura Formusa
President and Chief Executive Officer (Acting)

Stephanie Oatway, Energy Analyst, CVRD Inco, Sudbury

Power on demand

"Power is useless unless it is there when you need it. That is why reliable transmission is so critical to our business," says Stephanie Oatway, Energy Analyst, CVRD Inco.

When Ontario's largest single-point electricity user speaks, Hydro One listens. Every year Inco's Ontario operations represent about ¾ of 1% of Ontario's total electricity consumption. How much is that? 1,400 Gigawatt hours, enough to power a city the size of Barrie.

While Inco generates about 20% of the electricity that it needs, it depends on the reliability of Hydro One's transmission system to keep it operating safely and profitably. With as many as 2,000 people working as far as two kilometres underground, having a secure, stable source of electricity is a serious matter.

And with today's on-demand supply management systems and the booming nickel market, losing time to electricity failures is unacceptable.

Stephanie Oatway is responsible for making sure Inco has the electricity it needs to produce the 275 million pounds of nickel per year plus copper and other precious metals. As a representative of our largest customer, she is in constant contact with Hydro One to make sure we deliver on our promises.

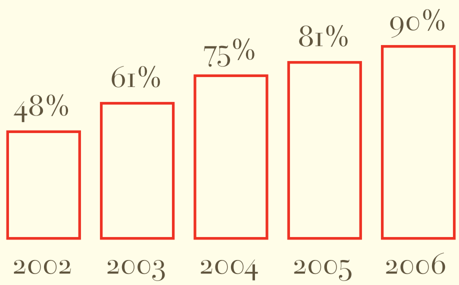
Last year our customers, big and small, told us we were doing better than ever on communicating and meeting our commitments to them.

275

MILLION POUNDS,

the amount of nickel Inco's Sudbury operations produce per year.

Large Industrial Customer Satisfaction



Customer satisfaction continued to climb in 2006, with 86% of our Large Transmission Customers saying they were satisfied with our level of service. This is a 4% increase from last year and is moving steadily towards our goal of 90% customer satisfaction. Our Large Industrial Customer satisfaction improved 11% this year, hitting the 90% mark.

Transmission reliability is a big reason our customers are more satisfied than ever before. The North American Electric Reliability Council awarded our transmission operations facilities, work processes and staff a grading of excellence for our ability to reliably operate and maintain Ontario's electricity transmission system. NERC's extensive audit singled out our industry-leading physical security procedures, infrastructure and communication systems.

Hydro One's senior management team devotes time and energy to getting to know our Large Customers' businesses. Each member of the senior management team has direct relationships with our customers. They meet on a regular basis and are available any time if a customer has a question or an issue.

"Hydro One's people have taken the time to understand our business and they know what's at stake for us. They get it," Oatway says.

Inco uses 1,400 Gigawatt hours of electricity per year to power its operations – making it Ontario's largest single-point user.

Camp Lau-Ren, Deep River

The buzz of camp

Shortly after dinner on July 17, dark clouds filled the sky over Camp Lau-Ren on the edge of the Ottawa River.

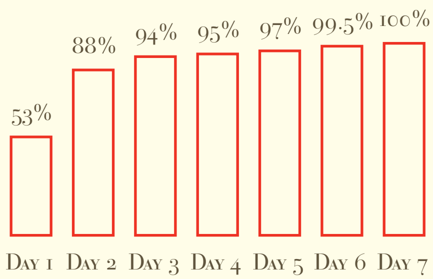
"The winds came right through the camp toppling trees and knocking down power lines. It was a matter of seconds and the power was out," says Nicky Nel, a volunteer counsellor for the last 15 years with Camp Lau-Ren. "We rushed around and made sure everyone was safe and after it was all done our first question was, 'Can camp happen without electricity?'"

The campers at Camp Lau-Ren weren't the only people asking that question.

Across Ontario, 170,000 Hydro One customers lost electricity. With tens of thousands of trees down, more than a thousand power poles broken and hundreds of kilometres of electricity line buried beneath trees snapped like matchsticks, it was the worst damage we'd seen since the 1998 Ice Storm. It would be more than a week until everyone had their power back on.

Storm Recovery

(Percentage of 170,000 affected customers restored)



120 KM/h

winds during three major storms and eight tornadoes pounded Ontario in the summer of 2006.

Hydro One responded to this storm by mobilizing our highly trained workforce, bringing in partners from other utilities and working long days to safely return electricity service to our customers. Our fleet of helicopters filled the sky and crews worked tirelessly to rebuild Ontario's electricity delivery system. In the first 24 hours, we restored electricity to 90,000 of the customers that had been affected.

For our work on this storm and two others in a two-month period, the Edison Electric Institute awarded Hydro One the *Emergency Recovery Award*, the first time this honour has been bestowed on a utility based outside of the United States.

While recognition from our peers as one of the best in the business at storm recovery means a lot, it pales in comparison to the way our customers responded. After four days of sharing two outhouses between 60 people, with no electricity, no flush toilets, no electric lights and no running water, Hydro One trucks were treated to a hero's welcome when they finally pulled into Lau-Ren.

"When we saw the trucks, we knew Hydro One had reached us," Nicky says. "The campers were yelling and greeting them with signs. It was a great moment. I think for a lot of the campers, they had a whole new appreciation for electricity."

Hydro One deployed more than 1,000 workers, who worked 16-hour days to restore electricity and repair the worst damage since the 1998 Ice Storm.

Cole Cacciavillani of CF Group Greenhouses, Leamington

Green power blooms

Keeping a greenhouse's climate at the perfect temperature and humidity depends upon electricity. The summer heat inside the greenhouse is so great that without the electric fans, the plants would never survive to bloom. During Ontario's coldest months, without electricity there'd be no flowers for Valentine's Day.

Backup electricity generation for Ontario's greenhouse industry is truly a matter of life and death.

"If we lose power, we're out of business," says Cole Cacciavillani, whose father Floyd started the family business with a single greenhouse in the 1950s.

In the last decade, CF Group Greenhouses (CF Group) has grown enough potted plants to cover Ontario. It's also developed generator technology to help greenhouses and other critical electricity users meet their own urgent power needs.

"All greenhouses invest in backup generation, but we only need it in emergencies. With help from Hydro One, we've connected that generation to the grid to put it to work for the rest of Ontario," says Cacciavillani.

Working with Hydro One, Cacciavillani has connected close to 4 MW of power that Ontario can call on when it needs more supply. The connection contributes to Ontario's supply reliability, takes stress off of Hydro One's transmission system and helps Ontario greenhouses turn a backup system into an asset.

4,000

Number of old, energy-sapping refrigerators, freezers and room air conditioners collected from our customers.

880,000

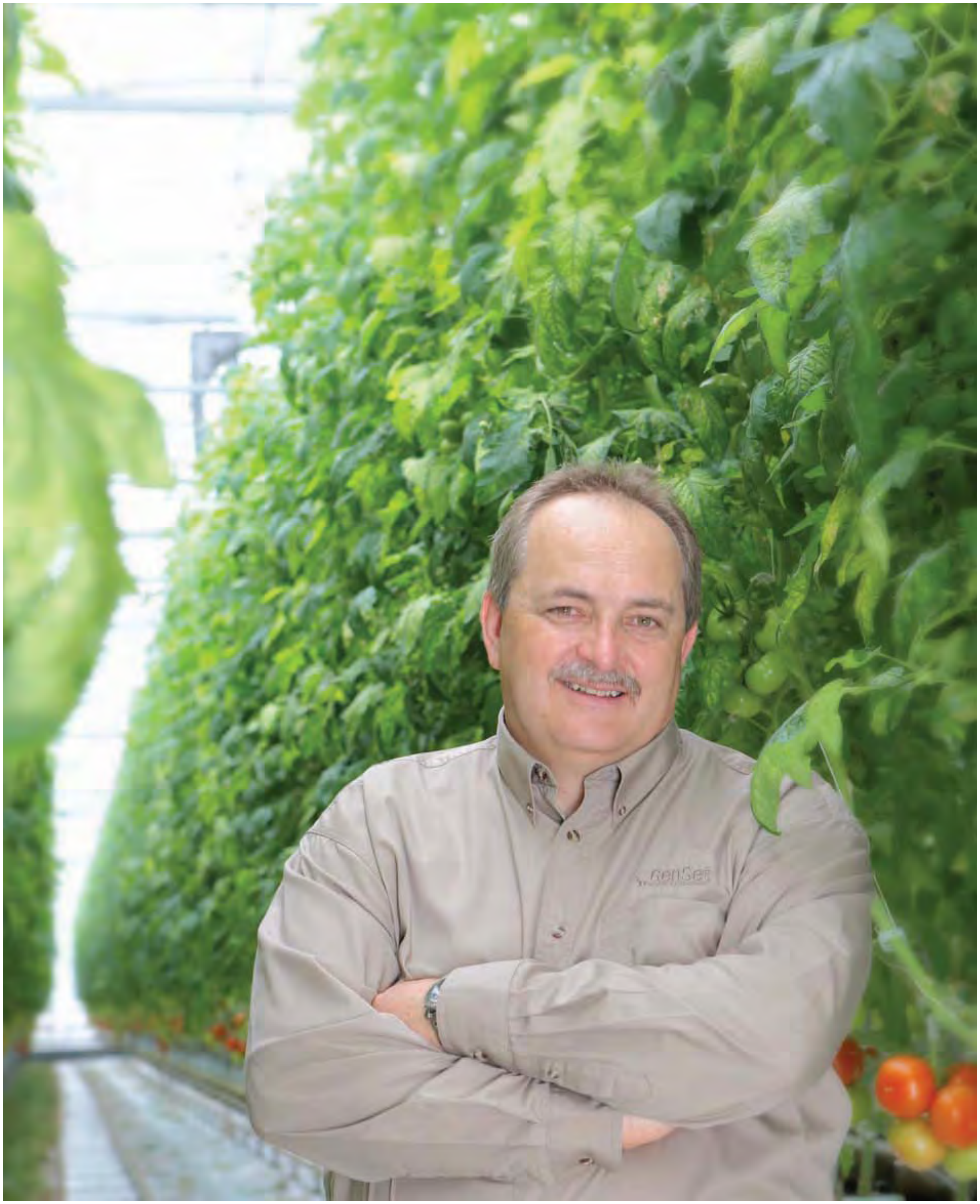
Number of our customers who participated in one of our conservation and demand management programs.

Ontario's greenhouses not only contribute about $2 billion a year to the province's economy, the network of generators managed by the CF Group and connected to Hydro One's grid now contributes about 4 MW of electricity, enough to power 1,300 homes.

Finding new ways for customers to use electricity wisely is the goal of Hydro One's Conservation and Demand Management group. In 2006, Hydro One not only helped enterprises like greenhouses and wind farms connect to the grid, we worked with our approximately 1.3 million residential customers to reduce peak demand.

Programs like SmartStat, the PowerCost Monitor and Appliance Retirement made a concrete difference to the amount of electricity Hydro One customers used. Our team removed more than 4,000 energy-hogging refrigerators from the grid. Our Power$aver tour, in conjunction with Home Depot, travelled the province and provided customers with vital information on ways to reduce electricity usage and offered advice on energy efficient products.

By working together and encouraging innovation, Hydro One and Ontario energy users and generators can meet future challenges.



Hydro One helped CF Group Greenhouses connect about 4 MW of electricity to the grid, enough to power about 1,300 homes in times of short supply.

Hydro One's 2006

accomplishments

Hydro One has signed an agreement with Hydro-Québec TransÉnergie Inc. for construction of state-of-the-art power transmission equipment including new circuits across the Ottawa River connecting the two provincial high-voltage power systems.

The $124 million investment for Hydro One will add an important new connection between the two grids. The first phase of the project – the new connection with Ontario – will come into service in early 2009, and will have a capacity of 900 MW. The second phase – the addition of a reinforcement line – will be brought into service in the spring of 2010, and will increase the connection's capacity to 1,250 MW.

In 2006, Hydro One completed digging a 2.2-kilometre tunnel beneath the streets of Toronto. This innovative project will carry an array of electricity transmission lines to tie the east and west halves of the city together, with minimal disruption to traffic or residents. Expanding the links between east and west by running new transmission lines through the $45 million investment will let power flow more freely across the city, giving Toronto increased flexibility, reliability and supply.

The project is scheduled for completion late next year with the new 230-kV circuit expected to be operational by early 2008.

Highly Rated

Dominion Bond Rating Service raised our long-term debt rating to A (high), with a stable trend, from A with a positive trend. In addition, our short-term debt rating was upgraded to R-1 (middle) from R-1 (low).

Construction crews rebuilt the interconnection in the Sarnia area with the transmission operator in Michigan. This connection improves overall supply reliability in Ontario by increasing electricity import/export capacity and maximizes the effectiveness of our existing high-voltage transmission system.

Hydro One is reinforcing the high-voltage transmission system in the Niagara region which will help significantly in meeting electricity needs in Southern Ontario during high-demand periods.

These upgrades will increase power import capacity from New York State up to 800 megawatts – enough power to meet the needs of about 260,000 homes – and accommodate additional power supplied by Ontario Power Generation's Sir Adam Beck stations after completion of a third tunnel at Niagara Falls.

Close to

100

MILLION kWh,

enough electricity to power 8,200 homes for one year, were saved by Hydro One's customers through our conservation and demand management programs.

In August, the Kleinburg Training Centre opened its doors to teach Ontario's future electricity workers.

The need for the facility was clear with the number of apprentices needing training doubling from 176 in 2003 to close to 400 in 2006.

This facility allows us to give the next generation of line maintainers, meter readers, distribution technicians, protection and control trainees hands-on experience in a safe environment.

The centre not only provides vital training to Hydro One apprentices, it's a Ministry of Training, Colleges and Universities certified facility. Apprentices from utilities across the province come here to put spurs on for the first time and take those tentative first steps up a wooden pole.

Customers told us the old system for checking outages on our website was cumbersome, so we improved it. Our redesigned online Power Outage Notification system improves communications between Hydro One and the public and provides real-time information to the media during major storms or other outage situations. The new system paints a very accurate picture of the status of our electricity transmission and distribution system.

$807,728

was raised by Hydro One employees for charities of their choice in 2006.

Hydro One Senior Management

Laura Formusa
President and Chief Executive Officer
(Acting)
Hydro One Inc.

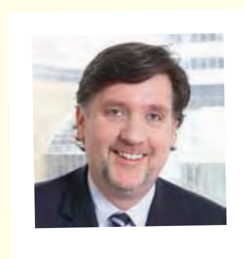
Joe Agostino
General Counsel
(Acting)

Myles D'Arcey
Senior Vice-president,
Customer Operations

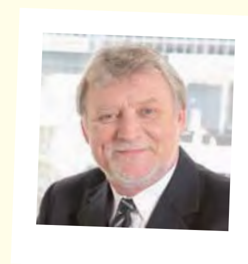
Steve Dorey
Vice-president,
External Relations

John Fraser
Vice-president, Internal Audit
and Chief Risk Officer

Tom Goldie
Senior Vice-president,
Corporate Services



Peter Gregg
Vice-president,
Corporate and Regulatory Affairs
and Executive Office



Rick Kellestine
Vice-president,
Culture

Nairn McQueen
Vice-president,
Engineering and
Construction Services

Geoff Ogram
Vice-president,
Asset Management

Wayne Smith
Vice-president,
Grid Operations

Beth Summers
Chief Financial Officer

Management's Discussion and Analysis

We prepare our financial statements in Canadian dollars and in accordance with accounting principles generally accepted in Canada. The following discussion is based upon our Consolidated Financial Statements for the years ended December 31, 2006 and 2005.

Overview

We are wholly owned by the Province of Ontario (the Province) and our transmission and distribution businesses are regulated by the Ontario Energy Board (OEB). We are the leading electricity transmitter and distributor in Ontario, delivering power safely and reliably to homes and businesses. As stewards of this province's massive and complex transmission and delivery system, our mission is to be an efficient and dynamic transmission and distribution company that is best in North America in the areas of safety, customer service and reliability, while focusing on the development and retention of our employees and creating shareholder value. In 2006, we continued our focus on our core businesses, substantially maintained and improved our performance in various key areas of the business, and made important contributions to the rebuilding of Ontario's core infrastructure.

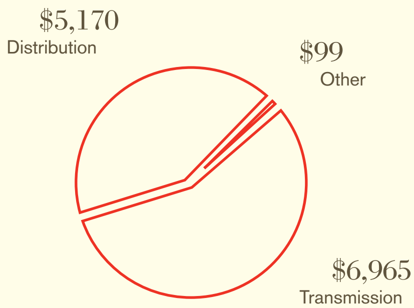
Transmission

Substantially all of Ontario's electricity transmission system is owned and operated by our company. In 2006, we earned total transmission revenues of $1,245 million primarily by transmitting approximately 151 TWh of electricity, directly or indirectly, to more than 4 million customers. Our transmission system is one of the largest in North America, and is linked to five adjoining jurisdictions through 26 interconnections. Through these interconnections, we can accommodate imports of about 4,000 MW and exports of approximately 5,800 MW of electricity. In terms of assets, our transmission business is our largest segment, representing approximately 60% of our total assets.

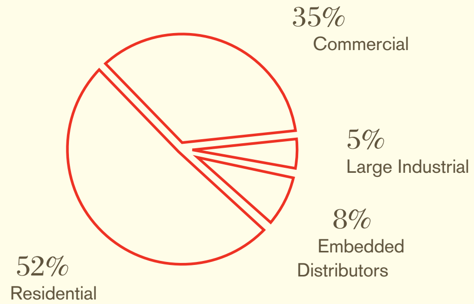
Distribution

Our distribution system is the largest in Ontario and spans roughly 75% of the province, serving approximately 1.3 million rural and urban customers, and 48 large industrial customers. We also operate small, regulated generation and distribution systems in a number of remote communities across Northern Ontario that are not connected to Ontario's electricity grid. As illustrated in the accompanying chart, over half of our distribution revenues are earned from our residential customers.

Total Assets
December 31, 2006
(Cdn $ millions)



2006 Distribution Revenues



Other

Our other business segment contributed revenues of $27 million in 2006 and has assets of about $99 million, which constitute less than 1% of our total assets. This segment primarily represents the operations of our wholly owned subsidiary, Hydro One Telecom Inc., which markets fibre-optic capacity to telecommunications carriers and commercial customers with broadband network requirements.

Our Strategy

In 2006, we maintained our strategic focus on our core operations and built upon our accomplishments. Our goals are to be recognized by our customers as their best service provider, by our peers as their benchmark for excellence, and by our shareholder as delivering superior value, while striving to attract, develop and retain productive employees.

We seek to achieve these goals by continuing to implement the following strategies:

— *Safety:* Create and maintain an injury-free workplace with a concentrated focus on elimination of serious injury and "near misses" in high potential harm categories of work.

— *Customers:* Become a leading customer-focused company. We intend to maintain our focus and commitment to improving our customers' level of satisfaction. We strive to strengthen relationships with our large and mid-sized customers acknowledging their commercial requirements. For residential customers, our key focus is on improving the quality of customer services such as billing, call handling, outage management, and meter reading. We also aim to make positive contributions in communities across Ontario through our corporate citizenship programs.

— *Reliability:* Enhance the reliability of our transmission and distribution systems. In transmission, we have assumed a proactive leadership role in developing the system to meet Ontario's power needs. Within distribution, we are focused on reliability while recognizing the challenges in operating a system with low customer density and vast geography.

— *Financial:* Ensure our actions contribute towards maximizing the value of our company, while maintaining effective access to funds on a long-term basis at reasonable rates and delivering appropriate financial returns to our shareholder.

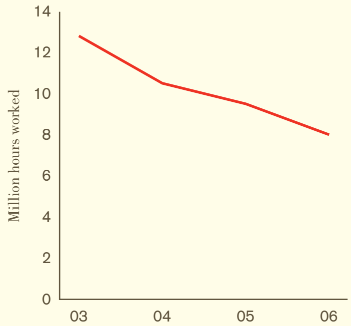
— *Employees:* Manage the challenges of labour demographics by attracting, developing and retaining productive employees.

Performance Measures and Targets

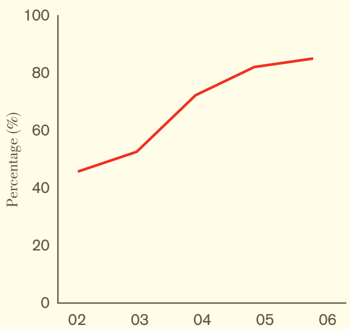
We measure and target our performance in all of the above strategic areas, ensuring that we are recognizing the needs of all of our key stakeholders. We substantially met or exceeded our challenging 2006 objectives, improving in a number of areas over 2005, and are moving towards achieving our strategic goals.

The potentially hazardous nature of our business requires a strong focus on safety. Consequently, one of our goals is to achieve a record of no serious injuries and no serious near misses. Accordingly, we measure our high Maximum Reasonable Potential for Harm (MRPH) incidents rate to identify possible problems or situations that may increase the risk of injury. As shown in the accompanying chart, we had eight high MRPH incidents per million hours worked in 2006, which is 16% lower than 2005, 24% lower than 2004, and 38% lower than 2003.

High MRPHs



Large Transmission Customer Satisfaction



We also maintain our focus on serious incidents in high risk areas including electrical contacts, preventable motor vehicle accidents and work equipment operations, among others. The number of serious incidents declined from about nine incidents per million hours worked in 2003, to approximately five in 2006. Going forward, we will continue to stress the importance of safety through a sustained cultural change, with emphasis on human factors and the role of human traits in determining safe work performance. Planned initiatives include increased facility and site assessments, development of a learning management system and further use of decision analysis tools to reduce human error and its consequences.

Customer satisfaction is also vital to our success. As shown in the accompanying chart, our Large Transmission Customer Satisfaction Survey results improved from 83% to 86% satisfied as compared to 2005. Moreover, we have seen continuous improvement over the last five years. We also continue to be conscious of the needs of our Residential and Small Business Customers and survey results show an increase in the level of satisfaction to 83% satisfied from 81% last year. While our 2006 Generator satisfaction level of 74% was acceptable, it was slightly below our annual target, and addressing the concerns identified will be an area of focus in 2007. We will continue to focus on improving the level of customer satisfaction across all customer segments by targeting our responses to the unique requirements of each segment.

Weather patterns and generation constraints require exemplary performance from both our transmission and our distribution systems. We are conscious that businesses of all sizes require reliable service and consequently, we focus on achieving top-quartile reliability in relation to other comparable systems. In 2006, we met our annual reliability targets and achieved some improvements over 2005. We did so while managing the impacts of a number of devastating storms throughout the year, including the back-to-back storms experienced over the summer. We enhanced our storm response and communication, including improving processes, improving our website and providing "real time" information through emails and faxes. Subsequent to year end, the Edison Electric Institute (EEI) honoured us with an emergency recovery award for our outstanding efforts to restore electricity service during these storms. This is the first time this prestigious award has been won by a utility outside of the U.S.

Meeting our shareholder requirements is an integral part of our business focus. Strong financial performance was again characterized by our 2006 results and we maintained or improved credit ratings on both our short-term and long-term debt. On June 23, 2006, Dominion Bond Rating Service Inc. raised our short-term debt rating to R-1 (middle) and our long-term debt rating to A (high), as a result of key factors including their expectation that our financial profile will remain strong over the medium to long term.

Regulation

Our electricity transmission and distribution businesses are licensed and regulated by the OEB. The OEB sets rates following oral or written public hearings. Our transmission revenues primarily include our transmission tariff, which is based on the uniform province-wide transmission rates approved by the OEB for all transmitters across Ontario. Our distribution revenues primarily include our distribution tariff, which is also based on OEB-approved rates, and the recovery of the cost of purchased power used by our customers. Consequently, our distribution business does not have commodity price risk. Transmission and distribution tariff rates are set based on an approved revenue requirement that provides cost recovery and includes a return on deemed common equity. In addition, the OEB approves rate riders to allow for the recovery or disposition of specific regulatory assets and liabilities over a specified timeframe.

Under the current market structure, low-volume and designated consumers pay electricity rates established through the Regulated Price Plan (RPP) and wholesale electricity consumers pay a blend of regulated, contract and wholesale spot market prices. The OEB sets prices for RPP customers based on a two-tiered electricity pricing structure with seasonal consumption thresholds. Unexpected shortfalls or overpayments associated with the RPP are financed by the Ontario Power Authority (OPA). The OEB sets prices at least every 12 months, or more frequently, and may upon review, reset prices over the next 12 months to better reflect the cost of supply. The OEB currently plans to review the need to reset prices every six months. Customers who are not eligible for the RPP, or wholesale customers, pay the market price for electricity adjusted for the difference between market prices and prices paid to generators under the *Electricity Restructuring Act, 2004*. The Independent Electricity System Operator (IESO) is responsible for overseeing and operating the wholesale market, as well as ensuring the reliability of the integrated power system.

In addition to the oversight role of the OEB and the market monitoring and coordination role of the IESO, the OPA was created through the *Electricity Restructuring Act, 2004* to ensure the long-term supply of electricity, facilitate load management and conservation, and to assist with the stability of rates for RPP customers, among others. As part of its mandate to ensure the adequate long-term supply of electricity, and consistent with the Province's direction regarding supply mix, the OPA is in the process of developing the Integrated Power System Plan (IPSP), which must be submitted for review and approval to the OEB which will conduct public hearings and consultation. The OPA currently expects to submit the IPSP to the OEB in March 2007. As part of the IPSP process, the OPA has issued a number of discussion papers for comment by stakeholders. Of the papers issued to date, two are most important to the transmission business and influence our capital expenditures; "Discussion Paper 5 – Transmission" and "Discussion Paper 7: Integrating the Elements – A Preliminary Plan" (See "Future Capital Expenditures" on page 29).

The OPA is also responsible for coordinating the delivery and funding of conservation and demand management (CDM) programs. This coordination will further initiatives undertaken by individual local distribution companies (LDCs), including our distribution business, as a result of distribution rate increases approved in 2005. Some of the funds associated with this increase were required to be used on CDM programs. Our programs amounted to approximately $43 million over the period 2005 to 2007, consistent with this direction. The overall goal of the CDM programs is to reduce provincial demand by 6,300 MW by 2025. The OPA issued "Discussion Paper 3 – Conservation & Demand Management" and is expected to submit a CDM plan as part of the IPSP.

The *Energy Conservation Responsibility Act, 2006* furthers the broad objectives of CDM by providing the framework for the installation of 800,000 smart meters in Ontario homes and businesses by the end of 2007, with installation in all homes and businesses to be completed by the end of 2010. These meters will be capable of measuring and reporting usage over predetermined periods, being read remotely and providing customers with access to information about their consumption. A new entity will oversee the communications systems and technologies, collect and manage data, and facilitate meter procurement. LDCs, including our distribution businesses, will own, install, operate and maintain their own meters. We are currently deploying smart meters under our program (See "Future Capital Expenditures" on page 29).

Transmission Rates

The IESO remits payments to us based on the uniform transmission rates approved by the OEB for all transmitters across Ontario. In 2000, the OEB approved a transmission revenue requirement that provides for cost recovery and includes a return on deemed common equity targeted to be 9.88%.

In October 2005, the OEB initiated a proceeding to review our transmission rates and revenue requirements for 2006, 2007, and 2008. On February 21, 2006, the OEB announced a decision to apply an earnings sharing mechanism to equally share, between our shareholder and customers, any transmission earnings in excess of the approved rate of return of 9.88% for the period January 1, 2006 until new transmission rates are set.

In September 2006, we filed a transmission rate application through our subsidiary, Hydro One Networks Inc. (Hydro One Networks), seeking approval of a revenue requirement of $1,263 million for 2007 and $1,298 million for 2008, subject to minor updates in the normal course. This application is based on achieving a 10.5% return on equity and an increase in the common equity component of the capital structure from 36% to 40%. The proposed rate increases are 4.3% in 2007 and 2.7% in 2008, with the impact on an average customer's total bill estimated to be less than 0.5% in both years. Consistent with the OPA discussion papers, the application includes funding to enable new generation and ensure the adequacy of area supply, as well as the continued reliability of aging transmission assets. We believe the proposed regulated return, in conjunction with capital structure, supports the financial metrics underlying an A credit rating category, facilitating access to capital markets at reasonable rates.

On December 8, 2005, the OEB adjusted the revenue allocation factors for the Province's electricity transmitters. As a result, our share of overall provincial transmission revenue decreased by approximately $13 million per year, beginning in 2006.

Distribution Rates

As a distributor, we are responsible for delivering electricity and billing our customers for approved distribution rates, purchased power costs, and other approved regulatory charges. Our distribution rates were initially approved by the OEB in 2000 to provide for cost recovery and a return on deemed common equity targeted to be 9.88%. Related distribution rate increases were phased in over a number of years, with the final installment approved by the OEB in March 2005. In August 2005, we filed a distribution rate application seeking approval for a $160 million increase in the 2006 revenue requirement for our distribution business operated through Hydro One Networks. On April 12, 2006, the OEB announced its decisions regarding this application and that of our distribution business conducted by Hydro One Brampton Networks Inc. (Hydro One Brampton). On the basis of the written and oral evidence submitted, the OEB approved the requested increases in the revenue requirements based on an approved rate of return of 9.00%, effective May 1, 2006.

While current distribution rates are based on a cost of service rate regulation model, the OEB is in the process of establishing an Incentive Regulation Mechanism (IRM) for the years 2007–2010. Consistent with OEB guidelines, we plan to apply for distribution rate adjustments in February 2007, with minimal impact anticipated on the total customer bill. This application is based on an OEB-approved formula that considers inflation, efficiency targets and significant events outside the control of management.

On March 21, 2006, the OEB approved a monthly rate of 30 cents per residential customer, effective May 1, 2006, as initial funding for the required investment in smart meters. The distribution rate application, to be filed with the OEB in February 2007, will include a request to increase this level of smart meter funding. Expenditures in excess of recoveries are currently being recorded as a regulatory asset, with disposition to be established at a later date.

Results of Operations

Revenues

Year ended December 31

(Canadian dollars in millions)	2006	2005	$ Change	% Change
Transmission	1,245	1,310	(65)	(5)
Distribution	3,273	3,085	188	6
Other	27	21	6	29
	4,545	4,416	129	3
Average annual Ontario 60-minute peak demand *(MW)* [1]	22,650	23,074	(424)	(2)
Distribution – units distributed to customers *(TWh)* [1]	29.0	29.7	(0.7)	(2)

[1] System-related statistics include preliminary figures for December.

Transmission

Transmission revenues consist predominantly of our transmission tariff, which is based on the monthly peak demand for electricity across our high-voltage network. The tariff is designed to recover revenues necessary to support a transmission system with sufficient capacity to accommodate maximum expected demand, which is primarily influenced by weather as well as economic conditions. Transmission revenues also include minor amounts of ancillary revenues which are primarily attributable to maintenance services provided to generators and secondary use of our land rights-of-way.

Transmission revenues decreased by $65 million, or 5% in 2006, compared to last year, reflecting two recent OEB decisions. On February 21, 2006, the OEB applied an earnings sharing mechanism to any transmission earnings in excess of our approved rate of return of 9.88% for the period January 1, 2006 until new rates are set. Consequently, 50% of excess earnings recovered from customers are deferred as a regulatory liability. This decision had the effect of reducing transmission revenues by $33 million for the year. On December 8, 2005, the OEB adjusted revenue allocation factors for all of the Province's electricity transmitters, reducing 2006 transmission revenues by $13 million.

In addition, 2006 monthly peak demands were generally lower than last year. While there were a few exceptions, notably the all-time record peak demand of 27,005 MW set on August 1 and the May record peak demand of 24,857 MW, our average annual Ontario 60-minute peak demand was 424 MW lower and the overall related load was 5,083 MW lower than last year, resulting in lower revenues of $26 million. The impact of these reductions was partially offset by a marginal increase in ancillary revenues related to revenues earned from the secondary use of our land rights-of-way.

Distribution

Distribution revenues include our distribution tariff, which is based on OEB-approved rates, as well as amounts to recover the cost of purchased power used by our customers. Accordingly, distribution revenues are influenced by our distribution rates, the amount of electricity we distribute and the cost of purchased power. Distribution revenues also include minor ancillary services revenues, such as rental fees charged to telecommunications and cable television companies for the use of our poles, and miscellaneous charges such as those made for late payments.

Distribution revenues increased by $188 million, or 6%, in 2006 compared to last year, primarily as a result of two OEB-approved distribution tariff rate increases that became effective April 1, 2005 and May 1, 2006. The April 1, 2005 increase was originally scheduled to be effective March 1, 2003, and was subsequently suspended for all LDCs by the *Electricity Pricing Conservation and Supply Act, 2002*. On April 12, 2006, after reviewing our evidence, the OEB approved increases in distribution tariff rates for our distribution businesses conducted by Hydro One Networks and Hydro One Brampton, effective on May 1, 2006. We also received OEB approval for low-voltage rates for services provided to LDCs that are embedded within our service territory. These tariff rate increases support the maintenance and investment requirements of our distribution system, enabling the safe and reliable delivery of electricity to our customers throughout Ontario, and resulted in higher distribution revenues of $105 million compared to last year.

Distribution revenues also include the recovery of increased purchased power costs of $90 million, as described below under "Purchased Power." The impact of the increases in tariff rates and purchased power costs was partially offset by lower distribution tariff revenues of $5 million associated with lower demand, as well as marginally lower ancillary revenues.

Purchased Power

Purchased power costs incurred by our distribution business represent the cost of electricity delivered to customers within our distribution service territory. These costs consist of the wholesale commodity cost of electricity, the IESO's wholesale market service charges, and transmission charges levied by the IESO. From April 1, 2004 to March 31, 2005, for certain low-volume and designated customers, the commodity price of electricity was based on an interim two-tiered pricing structure. This structure was subsequently replaced by the OEB's RPP, which consists of a two-tiered pricing structure with threshold amounts adjusted twice annually. Customers who are not eligible for the RPP continue to pay the market price for electricity, adjusted for the difference between market prices and the prices paid to generators under the *Electricity Restructuring Act, 2004*. A summary of the interim pricing plan and RPP affecting the two-year period 2005 and 2006 is provided below.

Summary of Interim Pricing Plan & RPP

		Tier Threshold (kWh/month)		Tier Rates (cents/kWh)	
Price Plan	Effective Date	Residential	Non-Residential	First Tier	Second Tier
Interim	April 1, 2004	750	750	4.7	5.5
RPP	April 1, 2005	750	750	5.0	5.8
RPP	November 1, 2005	1,000	750	5.0	5.8
RPP	May 1, 2006	600	750	5.8	6.7
RPP	November 1, 2006	1,000	750	5.5	6.4

Purchased power costs increased in 2006 by $90 million, or 4%, to $2,221 million compared to last year. Our increased purchased power costs were primarily due to higher costs of $189 million associated with the OEB's RPP for residential and other eligible customers, combined with the 2005 impact of providing the *Ontario Price Credit* to RPP customers in accordance with a regulation issued in October 2005. This $140 million credit was provided to RPP customers in 2005 to recognize a lower cost of power than the fixed commodity price for the period April 1, 2004 to March 31, 2005. These increases were partially offset by lower wholesale commodity prices of $137 million for customers who are not eligible for the RPP, and lower wholesale market service charges levied by the IESO of $55 million. The remaining $47 million reduction was due to a lower demand for electricity.

Operation, Maintenance and Administration

Our operation, maintenance and administration costs are comprised primarily of labour, material, equipment and purchased services in support of the operation and maintenance of the transmission and distribution systems. These costs also include property taxes and payments in lieu thereof on our transmission and distribution lines, stations and buildings.

Operation, maintenance and administration costs for each of our three business segments were as follows:

Year ended December 31 (Canadian dollars in millions)	2006	2005	$ Change	% Change
Transmission	390	353	37	10
Distribution	460	413	47	11
Other	30	26	4	15
	880	792	88	11

Transmission

Operation, maintenance and administration expenditures incurred to sustain our high-voltage transmission stations, lines and rights-of-way increased by $37 million, or 10%, in 2006 compared to last year. Within our work programs, we continued to make the investments necessary to ensure the safe and reliable operation of our installed transmission system, with particular focus on the assets that are critical to generation and to the unrestricted supply of electricity to our customers. We experienced increased work program requirements of approximately $32 million this year, primarily related to increased station maintenance expenditures, including our focus on our 750 MVA autotransformers, higher employee benefit costs attributable to a lower discount rate for actuarially determined benefit costs, economic increases in materials and fuel costs and the impact of a labour disruption in 2005. Other support costs increased marginally by $5 million in 2006 compared to the previous year. Higher information technology requirements this year, combined with the impact of last year's recoveries associated with insurance settlements and bad debt recoveries, were substantially offset by this year's cost reduction associated with a negotiated property tax settlement.

Distribution

Operation, maintenance and administration expenditures necessary to maintain our low-voltage distribution system increased by $47 million, or 11%, compared to last year. We experienced increased work program requirements of approximately $50 million, primarily within our lines and customer care work programs. These increases reflect our recovery efforts following a series of destructive storms, particularly in the third quarter. In 2006, we experienced 10 significant storm events, compared to 4 in 2005. Consequently, our storm-related repair and maintenance expenditures for our distribution business increased by approximately $13 million to $21 million. In addition, our annual work program expenditures were impacted by higher fuel costs, the same economic increases that we experienced within our transmission business, and the effects of last year's labour disruption. Other costs incurred to support our distribution work programs declined by about $3 million, primarily as a result of our reassignment of resources to support our larger capital program this year, partially offset by the impact of higher information technology requirements.

Depreciation and Amortization

Depreciation and amortization expense increased by $28 million, or 6%, to $515 million this year. Depreciation expense was higher by $10 million relative to 2005, primarily as a result of the placement of new assets in service, consistent with our ongoing capital work program. Year-over-year, amortization of regulatory and other assets increased by $18 million. This increase was attributable to increased amortization of our regulatory assets as a result of the OEB's April 12, 2006 decision to approve recovery of certain regulatory assets.

Financing Charges

Financing charges declined by $30 million, or 9%, to $295 million compared to last year. Approximately $25 million of this decrease was due to a lower average effective interest rate on our outstanding long-term debt. In addition, we capitalized approximately $5 million more interest this year, primarily as a result of a higher level of capital expenditures.

Provision for Payments in Lieu of Corporate Income Taxes

We make payments in lieu of corporate income taxes to the Ontario Electricity Financial Corporation (OEFC) in accordance with the *Electricity Act, 1998* and on the same basis as if we were subject to federal and provincial corporate taxes. In providing for payments in lieu of corporate income taxes relating to our regulated businesses, the taxes payable method is used, whereas the liability method is used in computing the tax provision for our unregulated businesses.

The provision for payments in lieu of corporate income taxes declined by $19 million, or 10%, to $179 million in 2006 compared to 2005. Approximately $17 million of this reduction was due to this year's lower taxable income. The tax benefit of approximately $30 million that was recognized in the first quarter of 2006 pertaining to the recovery of prior years' corporate income taxes, was partially offset by the impact of last year's second quarter tax benefit in the amount of $21 million, which pertained to prior period tax losses of one of our subsidiaries. Payments in lieu of corporate income taxes were also reduced by tax changes enacted in the second quarter of 2006 relating to the elimination of the federal large corporations tax and higher capital cost allowance rates. These impacts were partially offset by taxes payable on transmission amounts received but not recognized for accounting purposes, primarily due to the OEB's earnings sharing mechanism.

Net Income

Net income of $455 million was lower by $28 million, or 6%, compared to 2005 results. Our net income for the year reflects higher expenditures required to operate and maintain our transmission and distribution systems, particularly as a result of the damaging storms we experienced this year, combined with lower transmission tariff revenues resulting from lower demand and the effects of the OEB's earnings sharing mechanism. The impact of these factors was partially offset by higher distribution tariff revenues associated with OEB-approved tariff rate increases and a marginal reduction in our effective tax rate. This tax rate reduction primarily resulted from the relative sizes of the tax benefits recognized in the first quarter of 2006 and in the second quarter of 2005.

Quarterly Results of Operations

The following table sets forth unaudited quarterly information for each of the eight quarters from March 31, 2005 through December 31, 2006. This information has been derived from our unaudited interim Consolidated Financial Statements which, in the opinion of our management, have been prepared on a basis consistent with the audited annual Consolidated Financial Statements and which include all adjustments, consisting only of normal recurring adjustments, necessary for fair presentation of our financial position and results of operations for those periods. These operating results are not necessarily indicative of results for any future period and should not be relied upon to predict our future performance.

(Canadian dollars in millions)				2006				2005
Quarter ended	**Dec. 31**	**Sep. 30**	**Jun. 30**	**Mar. 31**	Dec. 31	Sep. 30	Jun. 30	Mar. 31
Total revenues [1,2]	**1,142**	**1,165**	**1,078**	**1,160**	1,025	1,179	1,018	1,194
Net income [1,2]	**101**	**103**	**99**	**152**	104	133	115	131
Net income to common shareholder [1,2]	**96**	**99**	**94**	**148**	99	129	110	127

[1] The demand for electricity generally follows normal weather-related variations, and therefore our electricity-related revenues and net income, all other things being equal, would tend to be higher in the first and third quarters than in the second and fourth quarters.

[2] Under a new regulation issued in October 2005, RPP customers received a one-time credit reflecting a lower cost of power than the fixed commodity price between April 1, 2004 and March 31, 2005. In the fourth quarter of 2005, revenue and cost of power were both reduced by approximately $140 million. The application of the one-time credit did not result in any adjustment to net income.

Liquidity and Capital Resources

Our primary sources of liquidity and capital resources are funds generated from operations, debt capital market borrowings and bank financing. These sources will be used to satisfy our capital resource requirements, which continue to include capital expenditures, servicing and repayment of our debt, and payments related to our outsourcing arrangements, investing activities, and dividends.

Summary of Sources and Uses of Cash

Year ended December 31

(Canadian dollars in millions)	2006	2005
Operating activities	896	1,169
Financing activities		
Long-term debt issued	775	500
Long-term debt retired	(589)	(648)
Short-term notes payable	60	(40)
Dividends paid	(350)	(291)
Investing activities		
Capital expenditures	(823)	(691)
Other financing and investing activities	11	1
Net change in cash and cash equivalents	(20)	–

Operating Activities

Net cash from operating activities decreased by $273 million to $896 million, compared to 2005 results. This reduction primarily reflects the impact on our working capital requirements of providing RPP customers with the $140 million *Ontario Price Credit* early in 2006, funding for which was received by us from the IESO in late 2005. Our working capital requirements were also impacted by higher electricity prices charged to RPP customers in 2006, changes in the timing of tax payments and changes in trade accounts payable balances related to our work programs.

Financing Activities

Short-term liquidity is provided through funds from operations and our commercial paper program, under which we are authorized to issue up to $1 billion in short-term notes with a term to maturity of less than 365 days. The commercial paper program is supported by a $750 million committed revolving credit facility with a syndicate of banks which matures in August 2007 and which has a two-year extension option. As at December 31, 2006, we had $60 million in short-term notes outstanding. The short-term liquidity under this program and anticipated levels of funds from operations should be sufficient to fund our normal operating requirements. At December 31, 2006, we had $5,270 million in long-term debt outstanding, including the current portion. Long-term financing is provided by our access to the debt markets, including our medium-term note program. Our notes and debentures mature between 2007 and 2046. We currently plan to refinance maturing debt principally through our medium-term note program. The maximum authorized principal amount of medium-term notes issuable under this program is $2,500 million, of which $1,725 million is remaining and is currently available until July 2007.

During 2006, Dominion Bond Rating Service Inc. raised our long-term debt rating to A (high), with a stable trend, from A with a positive trend. Our short-term debt rating was upgraded to R-1 (middle) from R-1 (low). Our credit ratings are:

	Rating	
Rating Agency	Short-term Debt	Long-term Debt
Standard & Poor's Ratings Services Inc.	A-1	A
Dominion Bond Rating Service Inc.	R-1 (middle)	A (high)
Moody's Investors Service Inc.	Prime-1	Aa3

We have customary covenants normally associated with long-term debt. Among other things, our long-term debt covenants limit our permissible debt as a percentage of our total capitalization, limit our ability to sell assets and impose a negative pledge provision, subject to customary exceptions. The credit agreement that supports our $750 million credit facility has no material adverse change clauses that could trigger default. However, the credit agreement requires that we provide notice to the lenders of any material adverse change within three business days of the occurrence. The agreement also provides limitations that debt cannot exceed 75% of total capitalization and that debt issued by our subsidiaries cannot exceed 10% of the total book value of our assets. We are in compliance with all of these covenants and limitations.

During 2006, we issued $775 million in long-term debt under our medium-term note program and we repaid $589 million in maturing long-term debt. In comparison, during 2005 we issued $500 million in debt under our medium-term note program and we repaid $648 million in maturing long-term debt. In 2006, we increased our short-term notes by $60 million compared to a reduction of $40 million in 2005.

In 2006, we paid dividends to the Province in the amount of $350 million, consisting of $332 million in common dividends and $18 million in preferred dividends. In the comparative period, we paid common dividends of $273 million and preferred dividends of $18 million. In 2006, cash dividends per common share were $3,320 compared to $2,730 per common share in 2005. Cash dividends per preferred share were $1.375 in both 2006 and 2005.

Common dividends are declared at the sole discretion of our Board of Directors, and are recommended by management based on results of operations, financial condition, cash requirements and other relevant factors such as industry practice, shareholder expectations, the level of net income and timing. Common dividends pertaining to the quarterly financial results are generally declared and paid in the immediately following quarter.

Investing Activities

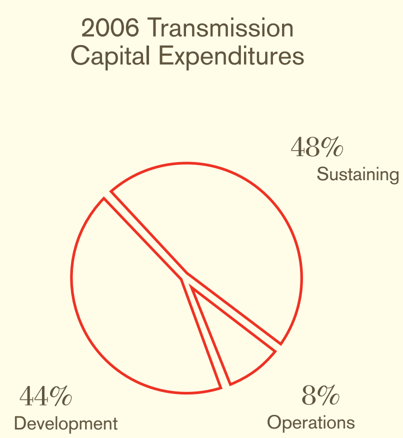
Cash used for investing activities, primarily representing capital expenditures to enhance and reinforce our transmission and distribution infrastructure in the public interest, was as follows:

Year ended December 31 (Canadian dollars in millions)	**2006**	2005	$ Change	% Change
Transmission	**402**	349	53	15
Distribution	**417**	338	79	23
Other	**4**	4	–	–
	823	691	132	19

Transmission

Transmission capital expenditures increased by $53 million in 2006 to $402 million, compared to 2005. Expenditures to expand and reinforce the transmission system were $179 million, $54 million higher than last year. These increased development investments primarily reflect higher required generation and load customer connection expenditures in this year. Our generation-related expenditures included a major reconfiguration of our Lambton Transformer Station, to enable the connection of new gas-fired generation. Increased load customer connection work included construction of a new transformer station to accommodate growth in Simcoe Region and work on transformer station improvements in Durham Region. Our development expenditures also included two critical projects to improve the flow of electricity in recognition of growing needs: the Niagara Reinforcement Project, which will reinforce the transmission system in the Niagara region and provide access to new sources of generation; and our Downtown Toronto Cable Project, which involves the construction of two underground cable circuits to reinforce our electricity transmission facilities. Our Niagara Reinforcement Project is essentially complete. Final completion continues to be delayed by the aboriginal land dispute in the Caledonia area and discussions continue between the affected aboriginal peoples and the various government entities involved. Once we regain access and perform a site condition assessment, we expect project completion within six weeks. In 2005, we substantially completed construction of the Parkway Transformer Station and refurbishment of the Cooksville Transformer Station. Both projects were carried out to accommodate the closure of the Lakeview Generating Station.

Our expenditures to sustain the existing transmission system were $192 million, representing a marginal decrease of $1 million compared to last year. Additional sustainment expenditures were made to replace storm-damaged equipment and to purchase new transformers. The impact of these requirements, together with the impact of last year's labour disruption, were substantially offset by reduced engineering and construction expenditures related to the refurbishment and replacement of end-of-life lines, stations and telecommunications assets. Other transmission capital expenditures were $31 million, unchanged from last year.

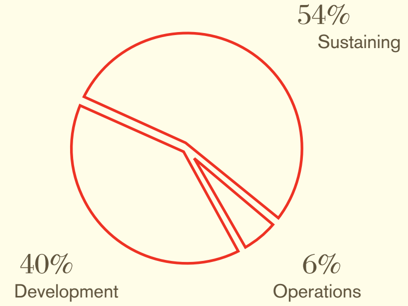


Distribution

Distribution capital expenditures increased by $79 million to $417 million in 2006, compared to the prior year. Expenditures to sustain our low-voltage distribution system were $225 million, an increase of $63 million over 2005. This increase was primarily a result of higher storm-related expenditures to replace damaged assets. Year-over-year capital expenditures for storm restoration were $62 million, an increase of $36 million. As a result of the significant storm activity this year, we replaced more than 1,600 distribution poles and more than 200 kilometres of line. Increased sustainment expenditures also reflect higher planned replacements of end-of-life assets, unplanned asset replacements and line relocations, as well as the impact of last year's labour disruption.

Capital expenditures to expand and reinforce our distribution network were $167 million, an increase of $20 million compared to last year. This increase primarily reflects our deployment of smart meters during the year. Our other distribution capital expenditures decreased by $4 million to $25 million.

2006 Distribution Capital Expenditures



Future Capital Expenditures
(Cdn $ millions)

Future Capital Expenditures

Our capital expenditures in 2007 are budgeted at about $1.25 billion, an increase of over $400 million from 2006 levels. The 2007 capital budgets for our transmission and distribution businesses are about $700 million and $500 million, respectively. Capital expenditures, as shown in the accompanying chart, are expected to be approximately $1.35 billion in 2008 and $1.5 billion in 2009, primarily reflecting increasing investments in necessary transmission infrastructure. The overall investment levels reflect transmission infrastructure requirements consistent with the OPA's discussion papers and the needs of our aging transmission system under continued challenging conditions of tight generation supply. These investments will facilitate an adequate and reliable supply of electricity in the public interest. The investment levels also reflect the mass deployment of smart meters within our distribution businesses beginning in 2007. The replacement of critical information technology systems is also contemplated. Capital expenditures of our other business segment are budgeted at about $20 million in 2007, largely due to the implementation of a dedicated optical network to provide secure, high capacity connectivity across numerous health care locations in Ontario.

Transmission

Transmission system capital expenditures are anticipated to be significant over the period 2007 to 2009, amounting to almost $2.4 billion. Our investment plan will address new development and supply enhancement initiatives, including system expansion, generation requirements and load connections. The transmission program also continues the focus on "mission critical" assets, which are those assets critical to generation facilities and the unrestricted transmission of energy to our customers.

The development component of our investment plan for transmission includes enhancements to the transmission system in the Bruce Peninsula to accommodate new wind generation and redeveloped nuclear generation; transmission reinforcements in the Greater Toronto Area (GTA), Southern Georgian Bay, Woodstock and Midtown Toronto; and a new interconnection between Ontario and Quebec. Initiatives taken by the Province and the OPA have led to many new generation developments and we are undertaking investments to connect many of these to the transmission system. Major connections include large new gas generators in Sarnia, the west GTA and downtown Toronto, and several large new wind farms. Several projects have need dates that cannot be met if approvals are delayed beyond the release of the IPSP. As such, we have initiated the processes required to file Leave-to-Construct applications with the OEB and to receive other approvals as required.

The investment plan also includes increased program expenditures to manage the replacement and refurbishment of our aging transmission infrastructure. Investments in mission critical assets ensure a reliable supply of energy throughout the province. Through targeted replacement programs for components such as gas insulated switchgear, air blast circuit breakers, and 750 MVA autotransformers, improved performance is anticipated, which should reduce system integrity risks.

At the local level, we continue to proactively address supply needs with our customers in order to meet load growth. For projects required to provide reliable delivery of electricity to communities, the participation and support of the affected LDCs as partners in joint planning studies and throughout the consultation and approval processes, continues to be essential. Examples of projects initiated to meet the growing needs of our customers include new transformer stations to serve Essex County and Simcoe County, and expansions of transformer stations serving Brampton, Kingston and Red Lake. Targeted investments in customer delivery point performance, power quality and our 115kV and 230kV systems will lead to improved reliability.

The timing of many development projects is uncertain as they are dependent upon the final IPSP and, in some instances, require approvals from various regulatory bodies, as well as negotiations and consultations with customers, neighbouring utilities and other stakeholders. We will not undertake large capital expenditures without a reasonable expectation of recovering them in our rates.

Distribution

Consistent with our approved 2006 distribution rate applications, capital expenditures for the period 2007 to 2009 are budgeted at approximately $1.7 billion. This amount includes core development and sustainment work as well as our smart meter program. Our core work will focus on new load connections, trouble calls and storm damage, wood pole replacement, and system capability reinforcement. Given initiatives to encourage renewable energy technologies, we also anticipate increased connection of new generators which could trigger the need for larger system modifications.

Our distribution investment plan includes the mass rollout of the smart meter program. Over the period 2007 to 2010, we anticipate installing over 1 million meters throughout our service territory. Consistent with the government policy, all homes and small businesses are to receive a smart meter by 2010. Total project costs are anticipated to be significant. In 2007, we plan to invest approximately $75 million under our smart meter program and install 240,000 meters. At the Province's request, we will review our implementation plan and associated costs for the period 2008 to 2010.

Summary of Contractual Obligations and Other Commercial Commitments

The following table presents a summary of our debt and other major contractual obligations, as well as other major commercial commitments:

December 31, 2006

(Canadian dollars in millions)	Total	2007	2008/2009	2010/2011	After 2011
Contractual obligations (due by year):					
Short-term note payable	60	60	–	–	–
Long-term debt – principal repayments	5,270	395	900	650	3,325
Long-term debt – interest payments	4,769	291	524	448	3,506
Inergi LP (Inergi) outsourcing agreement [1]	496	110	192	178	16
Operating lease commitments	16	5	9	1	1
Total contractual obligations	10,611	861	1,625	1,277	6,848
Other commercial commitments (by year of expiry):					
Bank line [2]	750	750	–	–	–
Letters of credit [3]	118	118	–	–	–
Guarantees [3]	275	275	–	–	–
Pension [4]	8	8	–	–	–
Total other commercial commitments	1,151	1,151	–	–	–

[1] On March 1, 2002, Inergi began providing a range of services to us for a 10-year period, including information technology, customer care, supply chain and certain human resources and finance services.

[2] As a backstop to our commercial paper program, we have a $750 million, 364-day revolving standby credit facility with a syndicate of banks that matures in August 2007, with a two-year extension option.

[3] We currently have bank letters of credit of $93 million outstanding relating to retirement compensation arrangements. We have also provided prudential support to the IESO as required by the Market Rules, using a combination of bank letters of credit of $22 million and parental guarantees of $275 million. Currently, the amount of prudential support that we provide in the form of bank letters of credit to the IESO is based on our highest long-term credit rating which is in the "Aa" category. The amount of bank letters of credit provided would need to increase if our highest credit rating deteriorated. For example, if our credit rating declined to the "A" category, the amount of bank letters of credit required to meet our prudential support obligation would be 1.7 times our current amount, and if our credit ratings declined to "BBB" category, the amount of bank letters of credit required to meet our prudential support obligation would be 3.3 times the current amount. The remaining amounts included in letters of credit pertain to operating letters of credit and to surety bonds.

[4] Contributions to the pension fund are made one month in arrears. Contributions after 2006 will be based on an actuarial valuation effective December 31, 2006 and will depend on future investment returns, changes in benefits or actuarial assumptions. Based on current factors, we currently estimate our annual pension contributions for 2007 and beyond to be up to $100 million.

The long-term debt amounts in the above table are not charged to our results of operations, but are reflected on our Balance Sheet and Statement of Cash Flows. Interest associated with this debt is recorded under financing charges on our Statement of Operations or within our capital expenditures. Payments in respect of operating leases and our outsourcing agreement with Inergi are recorded under operation, maintenance and administration costs on our Statement of Operations or within our capital expenditures.

Related Party Transactions

Related party transactions primarily consist of our transmission revenues received from, and our power purchases payments made to, the IESO, which is a related party by virtue of its status as an agency of our shareholder, the Province. The year-over-year changes in these amounts are described more fully in our discussion of our transmission revenues and purchased power costs. Other significant related party transactions include our dividends, which are paid to the Province, and our payments in lieu of corporate income taxes, which are paid or payable to the OEFC.

Risk Management and Risk Factors

We have an enterprise risk management program that aims at balancing business risks and returns. An enterprise-wide approach enables regulatory, strategic, operational and financial risks to be managed and aligned with our strategic business objectives.

While our philosophy is that risk management is the responsibility of all employees, the Audit and Finance Committee of our Board of Directors annually reviews our company's risk tolerances, our risk profile and the status of our internal control framework. Our President and Chief Executive Officer has ultimate accountability for risk management. Our Leadership Team, comprising direct reports to the President and Chief Executive Officer, provides senior management oversight of risk in our company. Our Chief Risk Officer is responsible for the ongoing monitoring and review of our risk profile and practices and our Chief Financial Officer for ensuring that the risk management program is an integral part of our business strategy, planning and objective setting. Each of our subsidiaries, as well as key specialist functions and field services, is required to complete a formal risk assessment and to develop a risk mitigation strategy.

The Audit and Finance Committee, the President and Chief Executive Officer, and the Chief Financial Officer are supported by our Chief Risk Officer. This support includes coordinating risk policies and programs, establishing risk tolerances, preparing risk assessments and profiles and assisting line and functional managers in fulfilling their responsibilities. Our internal audit staff is responsible for performing independent reviews of the effectiveness of risk management policies, processes and systems.

Ownership by the Province of Ontario

The Province owns all of our outstanding shares. Accordingly, the Province has the power to determine the composition of our Board of Directors and appoint the Chair, and thus influence major business and corporate decisions. Conflicts of interest may arise as a result of the Province's obligation to act in the best interests of the residents of Ontario in a broad range of matters, including the regulation of Ontario's electricity industry and environmental matters, any future sale or other transaction by the Province with respect to its ownership interest in our company and the determination of the amount of dividend or proxy tax payments. We may not be able to resolve potential conflicts with the Province on terms satisfactory to us.

Regulatory Risk

We are subject to regulatory risks, including the approval by the OEB of rates for our transmission and distribution businesses that permit a reasonable opportunity to recover the estimated costs of providing service on a timely basis and to earn the approved rates of return.

On September 12, 2006, Hydro One Networks filed, with the OEB, its application and evidence in support of its 2007 and 2008 transmission revenue requirements based on a capital structure with a higher equity component and a higher return on equity. Our operation, maintenance and administration expense levels have increased over time and our transmission business rate base has increased, reflecting prudent expenditures, since transmission rates were initially established. However, there is the risk that these increases may be disallowed by the OEB. Any disallowed capital expenditures would be charged to the results of operations in the period that the OEB renders its decision. Insufficient funding for our transmission business could adversely impact our financial results and the operating performance of the transmission system.

The OEB approves our transmission and distribution rates based on projected electricity load and consumption levels. If actual load or consumption falls below projected levels, our rate of return for either, or both, of these businesses could be adversely affected. Also, our current revenue requirements for these businesses are based on cost assumptions that may not materialize. There is no assurance that the OEB would allow rate increases sufficient to offset unfavourable financial impacts from unanticipated changes in electricity demand or in our costs.

Our load could also be negatively impacted by successful CDM programs. Current requirements for CDM call for a 5% reduction in Ontario's projected peak electricity demand by 2007, which could significantly reduce our revenues, particularly transmission. The OEB has recognized the need to compensate utilities for such lost revenue, but the approach, level and timing of such compensation is yet to be determined. We are also subject to risk of revenue loss from other factors. For example, recent revisions to the OEB's *Transmission System Code* have resulted in customers gaining the right to bypass some of our transmission facilities by constructing their own assets under certain conditions.

There is also a risk we could be required to invest in large-scale transmission infrastructure projects, to incur unexpected capital expenditures to maintain or improve our assets, and to connect new third-party generation assets. The Province has passed regulations authorizing us to procure smart meters but we are only currently authorized to recover 30 cents of the associated costs in rates. While we expect all of our expenditures to be fully recoverable after OEB review, any future regulatory decision to disallow or limit the recovery of such costs would lead to potential charges to our results of operations.

Asset Condition

We continually maintain our assets to provide reliable service and to accommodate customer needs. However, our installed asset base is aging to the point where the assets require increased maintenance, major refurbishment or replacement. Executing these activities is also becoming more challenging as the opportunities to remove equipment from service to accommodate work are becoming increasingly limited. Consequently, we may not be able to complete the necessary repairs and replacements on a cost-effective or timely basis, which could affect transmission reliability and our ability to deliver sufficient electricity.

Risk Associated with Transmission Projects

Significant investments are needed to increase transmission capacity and enable the delivery of reliable electricity from existing and new generation sources to Ontario consumers. These investments are, in most cases, subject to OEB approvals, which can include expropriation, and where required, environmental approvals and consultation and possibly accommodation with First Nations. The ability to make such investments may also be impacted by public opposition. If we are unable to make these necessary investments, the reliability of our transmission system and our ability to deliver sufficient electricity could be materially adversely affected.

Work Force Demographic Risk

Approximately 25% of our employees will be eligible for retirement by 2008. We expect the skilled labour market for our industry to remain highly competitive in the future. Consequently, we must continue to advance our training and apprenticeship programs and succession plans to ensure that our future operational staffing needs will be met. If we are unable to attract and retain qualified personnel, our operations could be adversely affected.

Labour Relations Risk

The substantial majority of our employees are represented by either the Power Workers' Union or the Society of Energy Professionals. Existing collective agreements with the Power Workers' Union and the Society of Energy Professionals expire on March 31, 2008. We face financial risks related to our ability to negotiate collective agreements consistent with our rate orders. In the event of a labour dispute, we could face some degree of operational risk related to continued compliance with our licence requirements of providing service to customers.

Environmental Risk

We are subject to extensive environmental regulation and failure to comply could subject us to fines and other penalties. In addition, the presence or release of hazardous or other substances could lead to claims by third parties and/or governmental orders requiring us to take specific actions such as investigating, controlling and remediating the effects of these substances. We are currently undertaking a voluntary land assessment and remediation program covering most of our stations and service centres. There is also risk associated with obtaining governmental approvals, permits, or renewals of existing approvals and permits related to constructing or operating facilities. This may require environmental assessment or result in the imposition of conditions, or both, which could mean delays and cost increases.

Future changes in environmental regulations may result in material changes to our estimates of future expenditures to complete this work. On November 4, 2006, Environment Canada published new draft regulations governing the management of polychlorinated biphenyls (PCBs). It is expected that these draft regulations will be finalized later in 2007. We have estimated the non-capital expenditures for complying with these draft regulations to be between $250 million and $375 million in excess of amounts we have already recorded as environmental liabilities on our balance sheet. If required, most of these additional expenditures would be incurred in the 2013 to 2025 period. No obligation has been recorded in the financial statements for these increased expenditures due to continued uncertainty regarding the timing and content of the final regulations. In any case, actual future environmental expenditures may vary materially from the estimates used in the calculation of the environmental liabilities on our balance sheet. We do not have insurance coverage for these environmental expenditures.

Scientists and public health experts have been studying the possibility that exposure to electric and magnetic fields emanating from power lines and other electric sources may cause health problems. If it were to be concluded that electric and magnetic fields present a health risk, we could face litigation, be required to take costly mitigation measures such as relocating some of our facilities or experience difficulties in locating and building new facilities.

Risk of Natural and Other Unexpected Occurrences

Our facilities are exposed to the effects of severe weather conditions, natural disasters and catastrophic events. Although constructed, operated and maintained to withstand such occurrences, our facilities may not do so in all circumstances. We do not have insurance for damage to our assets located outside our transmission and distribution stations. Lost revenues, repair costs, damage and claims from third parties could be substantial. In the event of a large uninsured loss, we would apply to the OEB for the recovery. However, there is no assurance that the OEB would approve such an application.

Risk Associated with Arranging Debt Financing

We expect to borrow to repay our existing indebtedness and to fund capital expenditures. A substantial portion of our existing debt matures between 2007 and 2010. We also plan to incur total capital expenditures of approximately $1.25 billion in 2007 and $1.35 billion in 2008. Cash generated from operations, after the payment of expected dividends, will not be sufficient to fund the repayment of our existing indebtedness and our future capital expenditures. Our ability to arrange sufficient and cost-effective debt financing could be adversely affected by numerous factors, including the regulatory environment in Ontario, our results of operations and financial position, market conditions, the ratings assigned to our debt securities by credit rating agencies and general economic conditions. Any failure or inability on our part to borrow substantial amounts of debt on satisfactory terms could impair our ability to repay maturing debt, fund capital expenditures and meet other obligations and requirements and, as a result, could have a material adverse effect on our business.

Pension Plan Risk

We have a defined benefit registered pension plan for the majority of our employees. Contributions to the pension plan are established by actuarial valuations which are filed with the Financial Services Commission of Ontario on a tri-annual basis. The next valuation will be prepared as at December 31, 2006 and must be filed on or before September 30, 2007. The required level of contributions effective January 1, 2007 will depend on future investment returns, changes in benefits, and changes in actuarial assumptions. Based on current factors, we estimate annual pension contributions for 2007 and beyond to be up to $100 million per annum. Pension costs are subject to approval by the OEB. Failure to attain OEB approval could have an adverse effect on our results of operations.

Risk from Transfer of Assets Located on Indian Lands

The transfer orders by which we acquired certain of Ontario Hydro's businesses as of April 1, 1999 did not transfer title to some assets located on lands held for bands or bodies of Indians under the *Indian Act* (Canada). Currently, the OEFC holds these assets. Under the terms of the transfer orders, we are required to manage these assets until we have obtained all consents necessary to complete the transfer of title of these assets to us. We cannot predict the aggregate amount that we may have to pay, either on an annual or one-time basis, to obtain the required consents. However, we anticipate having to pay more than the approximately $850,000 per year that we are currently paying to these Indian bands and bodies. If we cannot obtain consents from the Indian bands and bodies, the OEFC will continue to hold these assets for an indefinite period of time. If we cannot reach a satisfactory settlement, we may have to relocate these assets from the Indian lands to other locations or replace them at a cost that could be substantial. These potential costs could have an adverse effect on our results of operations if we are unable to recover them in future rate orders.

Risk from Provincial Ownership of Transmission Corridors

Although we have the statutory right to use the transmission corridors, we may be limited in our ability to expand our systems. Also, other uses of the transmission corridors in conjunction with the operation our systems may increase safety or environmental risks.

Risk Associated with Information Technology Infrastructure

Our ability to operate effectively in the Ontario electricity market is in part dependent upon us developing, maintaining and managing complex information technology systems that are employed to operate our transmission and distribution facilities, financial and billing systems, capture data and produce timely and accurate information used in our business. System failures could have a material adverse effect on our company.

Risk Associated with Outsourcing Arrangement

Consistent with our strategy of reducing our operating costs, in 2002 we entered into an outsourcing services agreement with Inergi. If this agreement is terminated for any reason, we could be required to incur significant expenses to re-establish all or some of the outsourced functions, which could have an adverse effect on our results of operations.

Market and Credit Risk

Market risk refers primarily to risk of loss related to changes in commodity prices, foreign exchange and interest rates. We do not have commodity risk and our foreign exchange risk is currently insignificant, although we could in future decide to issue foreign currency denominated debt. We are exposed to fluctuations in interest rates as our maturing long-term debt is refinanced. We estimate that a 1% change in interest rates on the refinancing of long-term debt maturing in 2007 and 2008 would have an impact on net income of approximately $2 million and $4 million, respectively. We periodically utilize interest rate swap agreements to mitigate elements of interest rate risk.

Financial assets create a risk that a counter-party will fail to discharge an obligation, causing a financial loss. Derivative financial instruments result in exposure to credit risk, since there is a risk of counter-party default. We monitor and minimize credit risk through various techniques, including dealing with highly rated counter-parties, limiting total exposure levels with individual counter-parties, and by entering into master agreements which enable net settlement. We do not trade in any energy derivatives. We currently have one interest rate swap contract outstanding with a notional principal amount of $40 million and an insignificant fair value.

Currently, there are no significant concentrations of credit risk with respect to any class of financial assets. We are required to procure electricity on behalf of competitive retailers and embedded LDCs for resale to their customers. The resulting concentrations of credit risk are mitigated through the use of various security arrangements, including letters of credit, which are incorporated into our service agreements with these retailers in accordance with the OEB's *Retail Settlements Code*.

Critical Accounting Estimates

The preparation of our financial statements requires us to make estimates and judgements that affect the reported amounts of assets, liabilities, revenues and costs, and related disclosures of contingencies. We base our estimates and judgements on historical experience, current conditions and various other assumptions that are believed to be reasonable under the circumstances, the results of which form the basis for making judgements about the carrying values of assets and liabilities as well as identifying and assessing our accounting treatment with respect to commitments and contingencies. Actual results may differ from these estimates and judgements under different assumptions or conditions.

We believe the following critical accounting estimates involve the more significant estimates and judgements used in the preparation of our financial statements:

Regulatory Assets and Liabilities

Regulatory assets as at December 31, 2006 amounted to $311 million and principally relate to the regulatory asset recovery accounts (RARAs), employee future benefits other than pension, environmental costs, and expenditures associated with the smart meter program. We have also recorded regulatory liabilities amounting to $473 million as at December 31, 2006. These amounts pertain primarily to pension, export and wheeling fees, and the transmission earnings sharing mechanism. These assets and liabilities can be recognized for rate-setting and financial reporting purposes only if the OEB directs the relevant regulatory treatment, as it has for employee future benefits other than pension regulatory asset, the environmental regulatory asset and the RARAs, or if future OEB direction is judged to be probable. Most of our regulatory assets have been reviewed by the OEB and confirmed as recoverable.

To date, our smart meter expenditures and recoveries have been recorded in regulatory asset accounts consistent with OEB guidance. The timing and amount of inclusion of these amounts in our Statement of Operations is currently uncertain and will depend on future OEB decisions as well as other factors.

If management judges that it is no longer probable that the OEB will include a regulatory asset or liability in the setting of future rates, the relevant regulatory asset or liability would be charged or credited to results of operations in the period in which that judgement is made.

Environmental Liabilities

We record liabilities and related assets for the present value of the estimated future expenditures to be made to settle obligations related to legacy environmental contamination inherited upon our demerger from Ontario Hydro in 1999. These liabilities fall into two main categories: the management of PCB-contaminated assets and mineral oils and the assessment and remediation of contaminated lands. In determining the amounts to be recorded as environmental liabilities, we estimate the current cost of completing the work and make assumptions for when the future expenditures will actually be incurred to generate future cash flow information. A long-term inflation assumption of 2% has been used to express current cost estimates as future expenditures. These expenditure amounts have been discounted using a factor of 6.25%. Recording a liability for such long-term future expenditures requires that many other assumptions be made, such as the number of contaminated properties and the extent of contamination, and the number and contamination levels of assets with PCBs. All factors used in deriving our environmental liabilities represent management's best estimates. However, it is reasonably possible that numbers or volumes of contaminated assets, current cost estimates, inflation assumptions and assumed pattern of annual cash flows may differ significantly from our assumptions. Estimated environmental liabilities are reviewed annually or whenever significant changes in regulation occur. Estimate changes are accounted for prospectively.

Employee Future Benefits

We provide employee future benefits to our current and retired employees, including pension, group life insurance, health care and long-term disability.

In accordance with our rate orders, we record pension costs when employer contributions are paid to the pension fund in accordance with the *Pension Benefits Act* (Ontario). Our annual pension contributions are approximately $80 million per year over the period 2004 through to 2006. Contributions after 2006 will be based on an actuarial valuation effective December 31, 2006 and will depend on future investment returns, changes in benefits or actuarial assumptions. Pension costs are also disclosed in the notes to the financial statements on an accrual basis. We record employee future benefit costs other than pension on an accrual basis. The accrual costs are determined by independent actuaries using the projected benefit method prorated on service and based on assumptions that reflect management's best estimates. The assumptions were determined by management recognizing the recommendations of our actuaries.

The assumed return on pension plan assets of 6.75% per annum is based on expectations of long-term rates of return at the beginning of the fiscal year and reflects a pension asset mix consistent with the Fund's investment policy. During the year the Fund's target asset mix was changed to 62% exposure to equities, 33% to fixed income and 5% in alternative assets consisting of hedge funds and private equity. Returns on the respective portfolios are determined with reference to published Canadian and U.S. stock indices and long-term bond and treasury bill indices. The assumed rate of return on pension plan assets reflects our long-term expectations. We believe that this assumption is reasonable because, with the fund's balanced investment approach, the higher volatility of equity investment returns is offset by the greater stability of fixed income and short-term investment returns. The net result, on a long-term basis, is a somewhat lower return than might be expected by investing in equities alone. The return on pension plan assets exceeded this long-term assumption in 2006.

The weighted-average discount rate used to calculate the accrued benefit obligations is determined each year end by referring to the most recently available market interest rates based on AA corporate bond yields reflecting the duration of the applicable employee future benefit plan. The discount rates at December 31, 2006 increased by 0.25% from those at December 31, 2005 in conjunction with increase in bond yields over this period. The increase in discount rates has resulted in a corresponding reduction in liabilities.

The costs of employee future benefits other than pension are determined at the beginning of the year. The costs are based on assumptions for expected claims experience and future health care cost inflation. A 1% increase in the health care cost trends would result in an increase in service cost and interest cost of about $13 million per year.

Employee future benefits are included in labour costs that are either charged to results of operations or capitalized as part of the cost of fixed assets. Changes in assumptions will affect the accrued benefit obligation of the employee future benefits and the future years' amounts that will be charged to our results of operations or capitalized as a cost of fixed assets.

Goodwill

In assessing the recoverability of goodwill, we must make assumptions regarding estimated future cash flows and other factors to determine the fair value of the distribution reporting unit. If these estimates or their related assumptions change in the future, we may be required to record impairment charges related to goodwill. An impairment review of goodwill was carried out during 2006 and we determined that the carrying value of our goodwill has not been impaired.

Emerging Accounting Pronouncements

Transition to International Financial Reporting Standards (IFRS)

On January 10, 2006, the Canadian Accounting Standards Board (AcSB) ratified a new strategic plan that will significantly affect the way financial reporting will be carried out in Canada. For companies such as ours, the plan entails converging Canadian generally accepted accounting principles (GAAP) with IFRS over a five-year transitional period. The AcSB published an updated detailed implementation plan for achieving convergence in June 2006. The plan calls for the first year of reporting under IFRS to be 2011. At that point, Canadian GAAP will cease to exist as a separate, distinct basis of financial reporting for public companies. Due to the complexity of implementing this new accounting framework, we began our transition preparations in 2006.

Accounting for Rate-Regulated Operations

Following the approval of its new strategic plan to adopt IFRS, the AcSB revisited the scope of its project on rate-regulated accounting in recognition of the fact that that IFRS does not currently provide any special accounting treatment for rate-regulated enterprises. As a result, the AcSB is expected to issue an exposure draft in early 2007 to propose removal of all specific references to rate-regulated accounting from the Handbook of the Canadian Institute of Chartered Accountants (CICA). It is expected that the AcSB will allow qualifying enterprises to apply the relevant U.S. accounting standard, Statement of Financial Accounting Standard 71 *Accounting for the Effects of Certain Types of Rate Regulation* (SFAS 71). Enterprises subject to rate regulation will be qualified to use SFAS 71 as long as they meet the specific criteria found in that accounting standard and as long as they apply it in the manner the U.S. standard setter intended. We believe our company meets these criteria. The future application of SFAS 71 will have an impact on our financial statements. Accrual accounting practices will be followed for payments in lieu of corporate taxes, which are currently accounted for on a cash basis as a result of specific OEB direction. The difference between the accrual and cash basis will be reflected through the recognition of additional regulatory assets and, consequently, the impact on our results of operations is expected to be minimal.

Financial Instruments

In 2005, the CICA issued new accounting standards comprising Handbook Section 3855, *Financial Instruments Recognition and Measurement;* Section 3865, *Hedges and* Section 1530, *Comprehensive Income*, all of which become effective for us on January 1, 2007.

The standards require that all financial assets, including derivatives, be carried at fair value on the balance sheet, with the exception of loans, receivables and investments classified as held to maturity, which will be measured at amortized cost. Similarly, all derivative financial liabilities will be measured at fair value on the balance sheet. Other financial liabilities will be measured at amortized cost.

The standards also revise the existing accounting requirements for hedges and establish guidance for reporting comprehensive income, which includes net income and other comprehensive income. Any hedge ineffectiveness will be recognized immediately in the results of operations. Any changes in the fair value of cash flow hedging instruments, to the extent effective, will be recorded in other comprehensive income until the asset or liability being hedged affects the Statement of Operations, at which time the related change in fair value of the derivative will also be recorded in the Statement of Operations. Unrealized gains and losses on changes in the fair value of cash flow hedging instruments will be recorded as other comprehensive income until recognized in the Statement of Operations. This would include any remaining balance of deferred gain or loss on a cash flow hedge that was discontinued prior to the transition date.

Given the nature of our financial instruments and borrowing programs, we do not believe that the transitional impact of the new accounting standards will have a material financial impact on our company.

Accounting for Pension and Other Post-Retirement Costs

In October 2006, the AcSB commenced a project that is expected to result in a requirement to include the funded status (the difference between the plan assets and obligations) of an entity's post-retirement benefit plans on the balance sheet and to recognize changes in the funded status in comprehensive income in the year in which the changes occur. Current Canadian GAAP only requires disclosure of the funded status in the notes to the financial statements. The project will affect disclosures relating to our pension plan, supplementary pension plan, other post-employment and other post-retirement benefits. In addition, the proposals are expected to have a significant adverse impact on our financial ratios. The proposals, however, are not expected to impact our credit rating. The AcSB expects to publish the exposure draft for public comment in the first quarter of 2007 and it is expected to be effective for our company on December 31, 2007. This timing is expected to allow sufficient time to assess the effects on financial metrics referred to in existing contractual arrangements, including debt covenants.

Disclosure Controls and Internal Controls Over Financial Reporting

As a reporting issuer we are required to comply with the Ontario Securities Commission's Multilateral Instrument 52-109 (Multilateral Instrument) concerning internal control and related certifications, often referred to as Bill 198. In 2004, we initiated a formal project to evaluate our disclosure controls and internal controls over financial reporting. During 2005, we designed and evaluated the effectiveness of our disclosure control procedures. Commencing with our Consolidated Financial Statements for the year ended December 31, 2005, we certified that these disclosure controls and procedures provide reasonable assurance that all information considered necessary for appropriate disclosure has been accumulated and communicated to management on a timely basis.

During 2006 we completed our documentation, evaluation and remediation of internal controls over financial reporting. Our documentation includes flowcharts of key processes, risk matrices, and overviews of test results and remediation activities. The majority of findings related to the evidencing of controls and all remediation was completed during the period. Our focus for 2007 will be the ongoing sustainment of our control environment including communication, evaluation and enhancements, as required to support the certifications of our President and Chief Executive Officer, and Chief Financial Officer (Certifying Officers).

In compliance with the requirements of the Multilateral Instrument, our Certifying Officers have reviewed and certified the Consolidated Financial Statements for the year ended December 31, 2006, together with other financial information included in annual securities filings. Our Certifying Officers have also certified that disclosure controls and procedures have been designed to provide reasonable assurance that material information relating to our company is made known within our company and operated effectively during the period. Further, our Certifying Officers have also certified that internal controls over financial reporting are designed to provide reasonable assurance regarding the reliability of financial reporting and the presentation of financial statements for external purposes in accordance with GAAP. Our Certifying Officers have evaluated the effectiveness of our disclosure controls and procedures and have found them to be effective.

Outlook

To meet our challenge of being the best transmission and distribution company in North America, we will continue to concentrate on our top strategic priorities relating to safety, our customers, system reliability, financial stewardship and our employees. Significant improvements have been made toward achieving our long-term customer satisfaction and safety targets, while we maintain our strong financial profile and reliability performance. In addition, the North American Electric Reliability Council gave our transmission operating facilities, work processes and staff a grading of excellence for our ability to reliably operate and maintain Ontario's electricity transmission system. The EEI has also honoured us with an emergency recovery award, recognizing the outstanding efforts of our staff in restoring electricity service this summer after the significant damage caused by successive storms.

With the approval and implementation of the 2006 distribution rate increase, we are reasonably well positioned to address current distribution work program requirements and to earn the regulated rate of return. This will allow us to further the forestry program and continue initiatives to improve reliability and customer service. We continue to face challenges with regard to funding for our smart meter program. We expect to address some of the shortfall in our February 2007 application and anticipate full funding to be achieved over time.

We remain committed to a prudent and measured approach to distribution rationalization. The Province plans to lift the moratorium on the purchase and sale of electricity distribution assets by Hydro One, with the understanding that any future asset purchases or dispositions help further overall provincial policy interests in the sector. We plan to respond to opportunities, on a voluntary and commercial basis, where they are consistent with strategy. The investment plan does not include any funding for LDC acquisitions or divestitures. In addition, the distribution investment plan does not provide for the implementation of a Smart Network, which would leverage the smart meter technology to enable further internal productivity initiatives through wireless broadband.

Consistent with our continued commitment to the public interest and the Province's energy policies, we are planning significant investments in transmission infrastructure and the continued proactive maintenance of mission critical assets to ensure the system's continued reliability. Our transmission investment plan supports the achievement of supply mix goals, facilitates the development and use of renewable energy resources, promotes system efficiency and congestion reduction, and facilitates the integration of new supply. The OPA has presented the needs and options for reinforcing and expanding Ontario's transmission system, and discussed the specific transmission initiatives forming the basis of the preliminary IPSP. Significant investments in transmission will be required over the 20-year planning horizon of the IPSP, which is expected to be submitted by the OPA to the OEB in March 2007. In September, we filed a transmission cost of service rate application with the OEB that includes the funding required for this necessary transmission infrastructure, which is vital to the Ontario economy. Given the issued schedule, a decision on our rate application is anticipated late in 2007. Our outlook is premised on the successful outcome of this application.

Our investment plan does not include spending for large-scale investments, such as the expansion of the east-west transmission grid. Funding for required infrastructure to accommodate Bruce Peninsula supply continues beyond the planning period to 2011. Completion of the Toronto third supply option, which is expected to cost in the order of $400 million, also extends beyond the current planning horizon. This project is required to mitigate the risks associated with having only two major supply corridors to the City of Toronto and, as such, to maintain reliability.

Through the outlook period, we anticipate that our financial returns will be sufficient to maintain a healthy financial condition, stable credit quality and consistent credit ratings on our long-term debt.

Forward-Looking Statements and Information

Our oral and written public communications, including this Management's Discussion and Analysis (MD&A), often contain forward-looking statements that are based on current expectations, estimates, forecasts and projections about our business and the industry in which we operate and include beliefs and assumptions made by the management of our company. Such statements include, but are not limited to statements regarding future capital expenditures; statements about the installation and cost of smart meters; expectations surrounding future pension contributions; statements regarding potential incremental environmental expenditures; and expectations concerning the impact of new accounting standards. Words such as "expect," "anticipate," "intend," "attempt," "may," "plan," "will," "believe," "seek," "estimate," and variations of such words and similar expressions are intended to identify such forward-looking statements. These statements are not guarantees of future performance and involve assumptions and risks and uncertainties that are difficult to predict. Therefore, actual outcomes and results may differ materially from what is expressed, implied or forecasted in such forward-looking statements. We do not intend, and we disclaim any obligation to update any forward-looking statements, whether written or oral, or whether as a result of new information, future events or otherwise, except as required by law.

These forward-looking statements are based on a variety of factors and assumptions including, but not limited to the following: no unforeseen changes in the legislative and operating framework for Ontario's electricity market; favourable decisions from the OEB and other regulatory bodies concerning outstanding rate and other applications; and no significant events occurring outside the ordinary course of business. These assumptions are based on information currently available to us, including information obtained from third-party industry analysts. Actual results may differ materially from those predicted by such forward-looking statements. While we do not know what impact any of these differences may have, our business, results of operations, financial condition and our credit stability may be materially adversely affected. Factors that could cause actual results or outcomes to differ materially from the results expressed or implied by forward-looking statements include, among other things:

— the content of the final IPSP, as approved by the OEB;

— delays or denials of the requisite approvals for planned future capital expenditures;

— regulatory decisions regarding our revenue requirements and tariff rates;

— significant changes to Environment Canada's draft PCB regulations issued on November 4, 2006; and

— future interest rates, inflation, changes in benefits and changes in actuarial assumptions.

We caution the reader that the above list of factors is not exhaustive. Some of these and other factors are discussed in more detail under "Risk Management and Risk Factors" in this Management's Discussion and Analysis. You should review the section entitled "Risk Management and Risk Factors" in detail.

This Management's Discussion and Analysis is dated as at February 14, 2007. Additional information about our company, including our annual information form, is available on SEDAR at www.sedar.com.

Management's Report

The Consolidated Financial Statements, Management's Discussion and Analysis (MD&A) and related financial information presented in this Annual Report have been prepared by the management of Hydro One Inc. ("Hydro One" or the "Company"). Management is responsible for the integrity, consistency and reliability of all such information presented. The Consolidated Financial Statements have been prepared in accordance with accounting principles generally accepted in Canada and applicable securities legislation. The MD&A has been prepared in accordance with National Instrument 51-102, Part 5.

The preparation of the Consolidated Financial Statements and information in the MD&A involves the use of estimates and assumptions based on management's judgement, particularly when transactions affecting the current accounting period cannot be finalized with certainty until future periods. Estimates and assumptions are based on historical experience, current conditions and various other assumptions believed to be reasonable in the circumstances, with critical analysis of the significant accounting policies followed by the Company as described in Note 2 to the Consolidated Financial Statements. The preparation of the Consolidated Financial Statements and the MD&A includes information regarding the estimated impact of future events and transactions. The MD&A also includes information regarding sources of liquidity and capital resources, operating trends, risks and uncertainties. Actual results in the future may differ materially from the present assessment of this information because future events and circumstances may not occur as expected. The Consolidated Financial Statements and MD&A have been properly prepared within reasonable limits of materiality and in light of information up to February 14, 2007.

In meeting the responsibility for the reliability of financial information, management maintains and relies on a comprehensive system of internal control and internal audit. The system of internal control includes a written corporate conduct policy; implementation of a risk management framework; effective segregation of duties and delegation of authorities; and sound and conservative accounting policies that are regularly reviewed. This structure is designed to provide reasonable assurance that assets are safeguarded and that reliable information is available on a timely basis. An internal audit function independently evaluates the effectiveness of these internal controls on an ongoing basis and reports its findings to management and the Audit and Finance Committee of the Hydro One Board of Directors.

The Consolidated Financial Statements have been examined by Ernst & Young LLP, independent external auditors appointed by the Hydro One Board of Directors. The external auditors' responsibility is to express their opinion on whether the Consolidated Financial Statements are fairly presented in accordance with generally accepted accounting principles. The Auditors' Report, which appears on page 45, outlines the scope of their examination and their opinion.

The Hydro One Board of Directors, through its Audit and Finance Committee, is responsible for ensuring that management fulfills its responsibilities for financial reporting and internal controls. The Audit and Finance Committee of Hydro One met periodically with management, the internal auditors, and the external auditors to satisfy itself that each group had properly discharged its respective responsibility and to review the Consolidated Financial Statements before recommending approval by the Board of Directors. The external auditors had direct and full access to the Audit and Finance Committee, with and without the presence of management, to discuss their audit and their findings as to the integrity of the financial reporting and the effectiveness of the system of internal controls.

The Company's President and Chief Executive Officer, and Chief Financial Officer have certified Hydro One's annual Consolidated Financial Statements and annual MD&A filed under provincial securities legislation, and related disclosure controls and procedures, pursuant to Multilateral Instrument 52-109.

On behalf of Hydro One Inc.'s management:

Laura Formusa
President and Chief Executive Officer (Acting)

Beth Summers
Chief Financial Officer

Auditors' Report

To the Shareholder of Hydro One Inc.

We have audited the Consolidated Balance Sheets of Hydro One Inc. (the Company) as at December 31, 2006 and December 31, 2005, and the Consolidated Statements of Operations, Retained Earnings and Cash Flows of the Company for each of the years in the two-year period ended December 31, 2006. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these Consolidated Financial Statements present fairly, in all material respects, the financial position of the Company as at December 31, 2006 and December 31, 2005, the results of its operations and its cash flows for each of the years in the two-year period ended December 31, 2006 in accordance with Canadian generally accepted accounting principles.

Ernst & Young LLP

Ernst & Young LLP
Chartered Accountants

Toronto, Canada
February 14, 2007

Consolidated Statements of Operations

Year ended December 31 (Canadian dollars in millions)	2006	2005
Revenues		
Transmission *(Notes 8 and 14)*	1,245	1,310
Distribution *(Notes 3 and 14)*	3,273	3,085
Other	27	21
	4,545	4,416
Costs		
Purchased power *(Notes 3 and 14)*	2,221	2,131
Operation, maintenance and administration	880	792
Depreciation and amortization *(Note 4)*	515	487
	3,616	3,410
Income before financing charges and provision for payments in lieu of corporate income taxes	929	1,006
Financing charges *(Note 5)*	295	325
Income before provision for payments in lieu of corporate income taxes	634	681
Provision for payments in lieu of corporate income taxes *(Notes 6 and 14)*	179	198
Net income	455	483
Basic and fully diluted earnings per common share (Canadian dollars) *(Note 13)*	4,366	4,652

Consolidated Statements of Retained Earnings

Year ended December 31 (Canadian dollars in millions)	2006	2005
Retained earnings, January 1	1,079	887
Net income	455	483
Dividends *(Note 13)*	(350)	(291)
Retained earnings, December 31	1,184	1,079

See accompanying notes to Consolidated Financial Statements.

Consolidated Balance Sheets

December 31 (Canadian dollars in millions)	**2006**	2005
Assets		
Current assets:		
Accounts receivable		
(net of allowance for doubtful accounts – $19 million;		
2005 – $14 million) *(Note 14)*	**777**	628
Materials and supplies	**56**	56
Other	**13**	12
	846	696
Fixed assets *(Note 7)*:		
Fixed assets in service	**16,238**	15,553
Less: accumulated depreciation	**6,180**	5,818
	10,058	9,735
Construction in progress	**468**	375
	10,526	10,110
Other long-term assets:		
Deferred pension asset *(Note 11)*	**382**	449
Regulatory assets *(Note 8)*	**311**	400
Goodwill	**133**	133
Deferred debt costs	**24**	23
Other assets	**12**	10
	862	1,015
Total assets	**12,234**	11,821

See accompanying notes to Consolidated Financial Statements.

Consolidated Balance Sheets (continued)

December 31 (Canadian dollars in millions)	**2006**	2005
Liabilities		
Current liabilities:		
Bank indebtedness	**29**	9
Accounts payable and accrued charges *(Note 14)*	**661**	700
Accrued interest	**49**	43
Short-term notes payable *(Note 9)*	**60**	–
Long-term debt payable within one year *(Note 9)*	**395**	589
	1,194	1,341
Long-term debt *(Note 9)*	**4,872**	4,466
Other long-term liabilities:		
Regulatory liabilities *(Note 8)*	**473**	495
Employee future benefits other than pension *(Note 11)*	**803**	716
Environmental liabilities *(Note 12)*	**55**	64
Long-term accounts payable and accrued charges	**16**	23
	1,347	1,298
Total liabilities	**7,413**	7,105
Contingencies and commitments *(Notes 10, 16 and 17)*		
Shareholder's equity *(Note 13)*		
Preferred shares (authorized: unlimited; issued: 12,920,000)	**323**	323
Common shares (authorized: unlimited; issued: 100,000)	**3,314**	3,314
Retained earnings	**1,184**	1,079
Total shareholder's equity	**4,821**	4,716
Total liabilities and shareholder's equity	**12,234**	11,821

See accompanying notes to Consolidated Financial Statements.

On behalf of the Board of Directors:

Rita Burak
Chair

Eileen Mercier
Chair, Audit and Finance Committee

Consolidated Statements of Cash Flows

Year ended December 31 (Canadian dollars in millions)	**2006**	2005
Operating activities		
Net income	**455**	483
Adjustments for non-cash items:		
Depreciation and amortization (net of removal costs)	**474**	446
Transmission earnings sharing	**33**	–
Amortization of discount	**27**	58
Retail settlement variance accounts	**7**	12
Low-voltage services	**(8)**	(24)
	988	975
Changes in non-cash balances related to operations *(Note 15)*	**(92)**	194
Net cash from operating activities	**896**	1,169
Financing activities		
Long-term debt issued	**775**	500
Long-term debt retired	**(589)**	(648)
Short-term notes payable	**60**	(40)
Dividends paid	**(350)**	(291)
Termination of interest rate swap	**–**	(10)
Other	**(4)**	2
Net cash used in financing activities	**(108)**	(487)
Investing activities		
Capital expenditures	**(823)**	(691)
Other assets	**15**	9
Net cash used in investing activities	**(808)**	(682)
Net change in cash and cash equivalents	**(20)**	–
Cash and cash equivalents, January 1	**(9)**	(9)
Cash and cash equivalents, December 31 *(Note 15)*	**(29)**	(9)

See accompanying notes to Consolidated Financial Statements.

Note 1.
Description of the Business

Hydro One Inc. (Hydro One or the Company) was incorporated on December 1, 1998, under the *Business Corporations Act* (Ontario) and is wholly owned by the Province of Ontario (the Province). The principal businesses of Hydro One are the transmission and distribution of electricity to customers within Ontario. These businesses are regulated by the Ontario Energy Board (OEB).

Note 2.
Significant Accounting Policies

Basis of Consolidation

The Consolidated Financial Statements include the accounts of the Company and its wholly owned subsidiaries: Hydro One Networks Inc. (Hydro One Networks), Hydro One Remote Communities Inc. (Hydro One Remote Communities), Hydro One Brampton Inc., Hydro One Brampton Networks Inc. (Hydro One Brampton), Hydro One Telecom Inc., Hydro One Delivery Services Company Inc., Hydro One Network Services Inc. (Hydro One Network Services), 1316664 Ontario Inc., formerly Ontario Hydro Energy Inc. (Ontario Hydro Energy), and Hydro One Markets Inc. (Hydro One Markets).

Hydro One Brampton Inc. was dissolved on January 30, 2007. Hydro One Network Services will be dissolved pursuant to the *Business Corporations Act* (Ontario) in 2007. The former Ontario Hydro Energy and Hydro One Markets were dissolved during 2005.

Basis of Accounting

The Consolidated Financial Statements are prepared in accordance with accounting principles generally accepted in Canada (Canadian GAAP).

Rate Setting

The rates of the Company's electricity transmission and distribution businesses are subject to regulation by the OEB. Existing transmission rates were set in 1999 to provide a targeted return of 9.88% on deemed common equity and were based on cost of service rate regulation. In October 2005, the OEB initiated a proceeding to review Hydro One's transmission rates and to approve revenue requirements for 2006, 2007 and 2008. On February 21, 2006, the OEB announced a decision to apply an earnings sharing mechanism to equally share, between Hydro One's shareholder and its customers, any transmission earnings in excess of the approved rate of return of 9.88% for the period January 1, 2006 until new transmission rates are set. In September 2006, Hydro One Networks filed a transmission rate application. A decision on this application and the resulting revised transmission rates are anticipated in 2007.

The Company's distribution rates are also based on a revenue requirement that includes a rate of return. On April 12, 2006, the OEB announced its decision regarding the Company's rate application in respect of the distribution business of Hydro One Networks. On the basis of the written and oral evidence submitted, the OEB approved the requested increase in the revenue requirement based on a reduction in the approved rate of return, from a targeted 9.88% to 9.00%, effective May 1, 2006.

The OEB has the general power to include or exclude costs, revenues, losses or gains in the rates of a specific period, resulting in a change in the timing of accounting recognition from that which would have applied in an unregulated company. Such change in timing involves the application of rate-regulated accounting, giving rise to the recognition of regulatory assets and liabilities. The Company's regulatory assets represent certain amounts receivable from future customers and costs that have been deferred for accounting purposes because it is probable that they will be recovered in future rates. In addition, the Company has recorded regulatory liabilities which represent amounts for expenses incurred in different periods than would be the case had the Company been unregulated. The Company continually assesses the likelihood of recovery of each of its regulatory assets and continues to believe that it is probable that the OEB will factor its regulatory assets and liabilities into the setting of future rates. If, at some future date, the Company judges that it is no longer probable that the OEB will include a regulatory asset or liability in future rates, the appropriate carrying amount will be reflected in results of operations in the period that the assessment is made. Specific regulatory assets and liabilities are disclosed in Note 8.

Revenue Recognition and Allocation

Transmission revenues are collected through OEB-approved rates, which are based on an approved revenue requirement that includes a rate of return. Such revenue is recognized as power is transmitted and delivered to customers.

Distribution revenues attributable to the delivery of electricity are based on OEB-approved distribution rates and are recognized as electricity is delivered to customers. The Company estimates the monthly revenue for the period based on wholesale power purchases because customer meters are not generally read at the end of each month. Unbilled revenue included within accounts receivable as at December 31, 2006 amounted to $386 million (2005 – $377 million).

Distribution revenue also includes an amount relating to rate protection for rural residential and remote customers, which is received from the Independent Electricity System Operator (IESO) based on a standardized customer rate that is approved by the OEB. The current legislation provides rate protection for prescribed classes of rural residential and remote consumers by reducing the electricity rates that would otherwise apply.

Segment revenues for transmission, distribution and other also include revenue related to sales of other services and equipment. Such revenue is recognized as services are rendered or as equipment is delivered.

Corporate Income and Capital Taxes

Under the *Electricity Act, 1998*, Hydro One is required to make payments in lieu of corporate taxes to the Ontario Electricity Financial Corporation (OEFC). These payments are calculated in accordance with the rules for computing income and taxable capital and other relevant amounts contained in the *Income Tax Act* (Canada) and the *Corporations Tax Act* (Ontario) as modified by the *Electricity Act, 1998*, and related regulations.

The Company provides for payments in lieu of corporate income taxes relating to its regulated businesses using the taxes payable method as directed by the OEB. Under the taxes payable method, no provisions are made for future income taxes as a result of temporary differences between the tax basis of assets and liabilities and their carrying amounts for accounting purposes. When unrecorded future income taxes become payable, it is expected that they will be included in the rates approved by the OEB and recovered from the customers of Hydro One at that time. The Company provides for payments in lieu of corporate income taxes relating to its unregulated businesses using the liability method.

Materials and Supplies

Materials and supplies represent spare parts and construction material held for internal construction and maintenance of fixed assets. These assets are carried at lower of average cost or net realizable value.

Fixed Assets

Fixed assets are capitalized at cost, which comprises materials, labour, engineering costs, overheads, depreciation on service equipment and the approved allowance for funds used during construction applicable to capital construction activities within regulated businesses, or interest applicable to capital construction activities within unregulated businesses.

Fixed assets in service consist of transmission, distribution, communication, administration and service assets and easements. Fixed assets also include future use assets such as land and capitalized development costs associated with deferred capital projects.

Some of the Company's transmission and distribution assets, particularly those located on unowned easements and rights-of-way, may have asset retirement obligations, conditional or otherwise. The majority of the Company's easements and rights-of-way are either of perpetual duration or are automatically renewed annually. Land rights with finite terms are generally subject to extension or renewal. As the Company expects to use the majority of its installed assets for an indefinite period, no removal date can be determined and consequently a reasonable estimate of the fair value of most asset retirement obligations cannot be made at this time. If, at some future date, it becomes possible to estimate the fair value cost of disposing of assets that the Company is legally required to remove, a related asset retirement obligation will be recognized at that time.

Transmission

Transmission assets include assets used for the transmission of high-voltage electricity, such as transmission lines, support structures, foundations, insulators, connecting hardware and grounding systems, and assets used to step up the voltage of electricity from generating stations for transmission and to step down voltages for distribution, such as transformers, circuit breakers and switches.

Distribution

Distribution assets comprise assets related to the distribution of low-voltage electricity, including lines, poles, switches, transformers, protective devices and metering systems.

Communication

Communication assets include the fibre-optic and microwave radio system, optical ground wire, towers, telephone equipment and associated buildings.

Administration and Service

Administration and service assets include administrative buildings, major computer systems, personal computers, transport and work equipment, tools, vehicles and minor fixed assets.

Easements

Easements include statutory rights of use to transmission corridors and abutting lands granted under the *Reliable Energy and Consumer Protection Act, 2002*, as well as other amounts related to access rights.

Construction in Progress

Overhead costs, including corporate functions and services costs, are capitalized on a fully allocated basis. Financing costs are capitalized on fixed assets under construction based on the allowance for funds used during construction (2006 – 6.39%; 2005 – 6.80%).

Depreciation

The capital costs of fixed assets are depreciated on a straight-line basis, except for transport and work equipment and personal computers, which are depreciated on a declining balance basis.

Depreciation rates for the various classes of assets are based on their estimated service lives. The average estimated remaining service lives and service life ranges of fixed assets are:

	Estimated Service Lives (years)	
	Range	Average
Transmission	12–100	55
Distribution	15–75	41
Communication	7–40	19
Administration and service	5–50	39

Depreciation rates for easements are based on their contract life. The majority of easements are held in perpetuity and are not depreciated.

In accordance with group depreciation practices, the original cost of normal fixed asset retirements is charged to accumulated depreciation, with no gain or loss reflected in results of operations. Gains and losses on sales of fixed assets and losses on premature retirements are charged to results of operations as adjustments to depreciation expense. Depreciation expense also includes the costs incurred to remove fixed assets where an asset retirement obligation has been recognized.

The estimated service lives of fixed assets are subject to periodic review. Any changes arising from such a review are implemented on a remaining service life basis from the year the changes can first be reflected in rates.

Goodwill

Goodwill represents the cost of acquired local distribution companies in excess of fair value of the net identifiable assets purchased and is evaluated for impairment on an annual basis, or more frequently if circumstances require. Goodwill impairment is assessed based on a comparison of the fair value of the reporting unit to the underlying carrying value of the reporting unit's net assets, including goodwill, with any write-down of the carrying value of goodwill being charged against the results of operations.

The Company has determined that goodwill is not impaired. All of the goodwill is attributable to the distribution business segment.

Deferred Debt Costs

Deferred debt costs include the unamortized amounts of debt issuance costs. Deferred debt costs are amortized on an annuity basis over the period to maturity of the debt.

Discounts and Premiums on Debt

Discounts and premiums are amortized over the period of the related debt.

Financial Instruments

The Company periodically uses interest rate swap contracts to manage interest rate risks. Payments and receipts under interest rate swap contracts are recognized as adjustments to interest expense on an accrual basis. The Company formally designates its hedges, documents all hedging relationships and formally assesses hedge effectiveness. In the event a hedging relationship is extinguished or the relationship is found to be ineffective, realized or unrealized gains or losses are recognized in results of operations. Hedging gains and losses are amortized over the period of the related debt.

The Company does not engage in derivative trading or speculative activities.

Employee Future Benefits

Employee future benefits provided by Hydro One include pension, group life insurance, health care and long-term disability.

In accordance with the OEB's rate orders, pension costs are recorded when employer contributions are paid to the pension fund in accordance with the *Pension Benefits Act* (Ontario). Actuarial valuations are conducted at least every three years. Pension costs are also calculated on an accrual basis. Pension costs are actuarially determined using the projected benefit method prorated on service and based on assumptions that reflect management's best estimate of the effect of future events, including future compensation increases, on the actuarial present value of accrued pension benefits. Pension plan assets, consisting primarily of listed equity securities as well as corporate and government debt securities, are valued using fair values. Past service costs from plan amendments and all actuarial gains or losses are amortized on a straight-line basis over the expected average remaining service life of the employees covered.

Employee future benefits other than pension are recorded on an accrual basis. Costs are determined by independent actuaries using the projected benefit method prorated on service and based on assumptions that reflect management's best estimates. Past service costs from plan amendments and actuarial gains or losses are amortized on a straight-line basis over the expected average remaining service life of the employees covered.

Employee future benefit costs are attributed to labour and charged to operations or capitalized as part of the cost of fixed assets.

Environmental Costs

Hydro One recognizes a liability for estimated future expenditures associated with the assessment and remediation of contaminated lands and for the phase-out and destruction of polychlorinated biphenyl (PCB) contaminated mineral oil from electrical equipment, based on the net present value of these estimated future expenditures. As the Company anticipates that the related expenditures will continue to be recoverable in future rates, a regulatory asset has been recognized to reflect the future recovery of these costs from customers. Hydro One reviews its estimates of future environmental expenditures on an ongoing basis.

Use of Estimates

The preparation of financial statements in conformity with Canadian GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities at the date of the financial statements, and the reported amounts of revenues and expenses for the year. Actual results could differ from estimates, including changes as a result of future decisions made by the OEB or the Province.

Note 3.
Electricity Credits to Customers

Under a regulation issued in October 2005, Regulated Price Plan customers received a credit reflecting a lower cost of power than the fixed commodity price between April 1, 2004 and March 31, 2005. In the fourth quarter of 2005, revenue and purchased power costs were each reduced by $140 million. The application of the credit did not result in any adjustment to net income.

Note 4.
Depreciation and Amortization

Year ended December 31

(Canadian dollars in millions)	2006	2005
Depreciation of fixed assets in service	379	369
Fixed asset removal costs	41	41
Amortization of regulatory and other assets	95	77
	515	487

Note 5.
Financing Charges

Year ended December 31

(Canadian dollars in millions)	2006	2005
Interest on short-term notes payable	2	1
Interest on long-term debt payable	296	297
Amortization of discount	27	58
Other	9	5
Less: Interest capitalized on construction in progress	(28)	(21)
Interest capitalized on regulatory assets	(7)	(10)
Interest earned on investments	(4)	(5)
	295	325

Note 6.
Provision for Payments in Lieu of Corporate Income Taxes

The provision for payments in lieu of corporate income taxes (PILs) differs from the amount that would have been recorded using the combined Canadian Federal and Ontario statutory income tax rate. A reconciliation between the statutory and effective tax rates is provided as follows:

Year ended December 31 (Canadian dollars in millions)	2006	2005
Income before provision for PILs	634	681
Federal and Ontario statutory income tax rate	36.12%	36.12%
Provision for PILs at statutory rate	229	246
(Decrease) increase resulting from:		
Net temporary differences:		
Recovery of PILs related to prior years	(30)	(21)
Pension contribution in excess of pension expense	(16)	(25)
Employee future benefits other than pension expense in excess of cash payments	14	8
Transmission amounts received but not recognized for accounting purposes due to earnings sharing mechanism	12	–
Overhead capitalized for accounting but deducted for tax purposes	(11)	(10)
Interest capitalized for accounting purposes but deducted for tax purposes	(13)	(11)
Environmental expenditures	(6)	(5)
Capital cost allowance (in excess of) less than depreciation and amortization	(3)	1
Other	4	1
Net temporary differences	(49)	(62)
Permanent differences:		
Large corporations tax	–	13
Other	(1)	1
Net permanent differences	(1)	14
Provision for PILs	179	198
Effective income tax rate	28.23%	29.07%

In 2006, Hydro One recognized a tax benefit of approximately $30 million in respect of a recovery of PILs from prior years following a successful appeal allowing a deduction for certain overhead costs that had been previously capitalized. In 2005, Hydro One reached an agreement to settle an outstanding legal claim allowing for the dissolution of one of its subsidiaries. As a result, it was determined to be more likely than not that Hydro One would be able to utilize the subsidiary's accumulated tax losses and a future tax asset of approximately $21 million was recognized. As at December 31, 2006, approximately $2 million of the 2005 amount remains available for use in 2007.

Future income taxes relating to the regulated businesses have not been recorded in the accounts as they are expected to be recovered through future revenues. As at December 31, 2006, future income tax liabilities of $281 million (2005 – $265 million), based on substantively enacted income tax rates, have not been recorded. In the absence of rate-regulated accounting, the Company's provision for PILs would have been recognized using the liability method rather than the taxes payable method. As a result, the provision for PILs would have been higher by approximately $16 million, including the impact of a change in substantively enacted tax rates.

Note 7.
Fixed Assets

December 31 (Canadian dollars in millions)	Fixed Assets in Service	Accumulated Depreciation	Construction in Progress	Total
2006				
Transmission	8,293	3,024	359	5,628
Distribution	5,651	2,129	86	3,608
Communication	822	383	18	457
Administration and service	989	583	5	411
Easements	483	61	–	422
	16,238	6,180	468	10,526
2005				
Transmission	8,124	2,889	233	5,468
Distribution	5,319	1,995	65	3,389
Communication	752	344	46	454
Administration and service	877	530	31	378
Easements	481	60	–	421
	15,553	5,818	375	10,110

Financing costs are capitalized on fixed assets under construction, including allowance for funds used during construction on regulated assets and interest on unregulated assets, and were $28 million in 2006 (2005 – $21 million).

Note 8.
Regulatory Assets and Liabilities

Regulatory assets and liabilities arise as a result of the rate-making process. Hydro One has recorded the following regulatory assets and liabilities (see Note 2):

December 31 (Canadian dollars in millions)	2006	2005
Regulatory assets:		
Regulatory asset recovery account I	58	88
Regulatory asset recovery account II	87	92
Employee future benefits other than pension	84	126
Environmental	70	79
Smart meters	10	–
Retail settlement variance accounts	–	11
Other	2	4
Total regulatory assets	311	400
Regulatory liabilities:		
Deferred pension	382	449
Export and wheeling fees	49	32
Transmission earnings sharing	34	–
Retail settlement variance accounts	2	–
Other	6	14
Total regulatory liabilities	473	495

Regulatory Assets

Regulatory Asset Recovery Account I (RARA I)

On December 9, 2004, the OEB issued a decision on the prudence of the distribution-related deferral account balances for which recovery was sought by Hydro One in its May 31, 2004 application. Amounts for which recovery was approved represented balances incurred prior to December 31, 2003, plus associated interest. The OEB ordered that the approved amounts be aggregated into a single regulatory account to be recovered on a straight-line basis over the period ending April 30, 2008. The RARA I includes distribution business low-voltage services amounts, deferred environmental expenditures incurred in 2001 and 2002, deferred market ready expenditures, retail settlement variance amounts, and other amounts primarily consisting of accrued interest. In the absence of rate-regulated accounting, amortization expense in 2006 would have been lower by approximately $20 million (2005 – $20 million). In addition, related financing charges would have been higher by $3 million (2005 – $7 million).

Regulatory Asset Recovery Account II (RARA II)
On April 12, 2006, the OEB announced its decision regarding the Company's rate application in respect of the distribution business of Hydro One Networks. As part of this decision, the OEB also approved the distribution-related deferral account balances sought by Hydro One. The OEB ordered that the approved balances be recovered on a straight-line basis over a four-year period from May 1, 2006 to April 30, 2010. The RARA II includes retail settlement and cost variance amounts and distribution low-voltage service amounts, plus accrued interest. In the absence of rate-regulated accounting, amortization expense in 2006 would have been lower by approximately $16 million. In addition, related financing charges would have been higher by $5 million.

Employee Future Benefits Other than Pension
Employee future benefits other than pension are recorded using the accrual method as required by Canadian GAAP. The OEB has allowed for the recovery of past service costs, which arose on the adoption of the accrual method, in the revenue requirement on a straight-line basis over a 10-year period. As a result, in 1999 Hydro One recorded a regulatory asset, with an original balance of $419 million, to reflect this regulatory treatment. This regulatory asset has a remaining recovery period of two years (2005 – three years) and does not earn a return. In the absence of rate-regulated accounting, amortization expense in 2006 would have been lower by approximately $42 million (2005 – $42 million).

Environmental
Hydro One records a liability for the estimated future expenditures required to remediate past environmental contamination. Because such expenditures are expected to be recoverable in future rates, the Company has recognized an equivalent amount as a regulatory asset. This regulatory asset is expected to be amortized to results of operations on a basis consistent with the pattern of actual expenditures expected to be incurred up to the year 2030. The OEB has the discretion to examine and assess the prudence and the timing of recovery of all of Hydro One's future regulatory expenditures. In the absence of rate-regulated accounting, amortization expense in 2006 would have been lower and operation, maintenance and administration expense would have been higher by $17 million (2005 – $14 million).

Smart Meters
On March 21, 2006, the OEB approved the establishment of deferral accounts for smart meter related expenditures and a monthly customer charge of 30 cents per residential customer was reflected in Hydro One's revenue requirement. Consistent with the OEB's direction and pending further guidance, the Company has recognized a regulatory asset consisting of the net balance of capital and operating expenditures for smart meters less recoveries received from customers. In the absence of rate-regulated accounting, the Company's operation, maintenance and administration expense would have been higher by $4 million and revenues would have been higher by $2 million.

Regulatory Liabilities

Deferred Pension

In accordance with the OEB's 1999 transitional rate order, pension costs are recorded in results of operations when employer contributions are paid to the pension plan. The Company's deferred pension asset represents the cumulative difference between employer contributions and pension costs and the deferred pension regulatory liability results from the Company's recognition, as the result of OEB direction, of revenues and expenses in different periods than would be the case for an unregulated enterprise. In the absence of rate-regulated accounting, the Company's pension expense would have been recognized on an accrual basis rather than on a cash basis. As a result, operation, maintenance and administration expense would have been higher by approximately $12 million (2005 – $38 million), assuming no regulatory deferral of distribution and Inergi LP (Inergi) pension-related amounts. In addition, related financing charges would have been higher by $2 million (2005 – $4 million).

Export and Wheeling Fees

Consistent with the market rules, an export and wheeling fee is collected by the IESO and remitted to Hydro One at the rate of $1 per MWh on electricity exported outside of Ontario. The amounts collected in respect of this export and wheeling fee, plus interest, were taken into consideration in the revenue requirement of Hydro One's transmission business as part of the Company's transmission rate application filed with the OEB in September 2006.

Transmission Earnings Sharing

On February 21, 2006, the OEB issued a decision that established an earnings sharing mechanism in which 50% of any transmission earnings in excess of the approved rate of return of 9.88%, for the period January 1, 2006 until new transmission rates are set, will be equally split between the Company's shareholder and ratepayers. The excess earnings calculation will be based on the 2006 audited financial statements of Hydro One Networks' transmission business. The application of the earning sharing mechanism will be subject to future OEB review and approval. Any changes resulting from this review will be reflected in results of operations when the OEB renders its decision.

Retail Settlement Variance Accounts

Hydro One has deferred certain retail settlement variance amounts under the provisions of Article 490 of the OEB's Accounting Procedures Handbook. The OEB's December 9, 2004 decision allowed for recovery of retail settlement variance amounts accumulated prior to December 31, 2003, inclusive of interest, within the RARA I. The OEB's April 12, 2006 decision allowed for recovery of retail settlement variance amounts accumulated since January 1, 2004 and forecasted through to April 30, 2006, inclusive of interest, within the RARA II. The Company has accumulated a net liability in its retail settlement variance accounts since May 1, 2006 and anticipates that the OEB will include the net balance of this regulatory account in future rates.

Note 9.
Debt

December 31

(Canadian dollars in millions)	2006	2005
Short-term notes payable	60	–
Long-term debt:		
4.15% notes due 2006	–	280
4.20% notes due 2006	–	168
4.30% notes due 2006	–	141
4.45% notes due 2007	282	282
4.55% notes due 2007	73	73
4.10% notes due 2007[1]	40	40
4.00% notes due 2008	500	500
3.95% notes due 2009	400	400
7.15% debentures due 2010	400	400
6.40% notes due 2011	250	250
5.77% notes due 2012	600	600
4.64% notes due 2016	450	–
7.35% debentures due 2030	400	400
6.93% notes due 2032	500	500
6.35% notes due 2034	385	385
5.36% notes due 2036	600	350
6.59% notes due 2043	315	315
5.00% notes due 2046	75	–
	5,270	5,084
Less: Long-term debt payable within one year	(395)	(589)
Net unamortized premiums (discounts)	9	(14)
Unamortized hedging losses	(12)	(15)
Long-term debt	4,872	4,466

[1] Step-up coupon, after year three from 4.10% to 6.40%, extendable to 2011.

Short-term debt represents promissory notes issued pursuant to the Company's commercial paper program. The notes are denominated in Canadian dollars with varying maturities not exceeding 365 days. In 2006, the notes had a weighted-average interest rate of 4.2%.

Hydro One has a $750 million committed and unused revolving credit facility with a syndicate of banks maturing in August 2007, with a two-year extension option. If used, interest on the facility would apply based on Canadian benchmark rates. This credit facility supports the Company's commercial paper program.

The Company issues notes for long-term financing under the medium-term note program. The maximum authorized principal amount of medium-term notes issuable under this program is $2,500 million of which $1,725 million is remaining and is currently available until July 2007.

The long-term debt is subject to covenants that, among other things, limit permissible debt as a percentage of total capitalization, limit ability to sell assets and impose a negative pledge provision, subject to customary exceptions. At December 31, 2006, the Company was in compliance with these covenants.

The long-term debt is unsecured and denominated in Canadian dollars. Such debt is summarized by the number of years to maturity in the following table:

Years to Maturity	Principal Outstanding on Notes and Debentures (Canadian dollars in millions)	Weighted Average Interest Rate (%)
1 year	395	4.4
2 years	500	4.0
3 years	400	4.0
4 years	400	7.2
5 years	250	6.4
	1,945	5.0
6–10 years	1,050	5.3
Over 10 years	2,275	6.4
	5,270	5.7

Note 10.
Fair Value of Financial Instruments and Risk Management

The carrying amounts of all financial instruments, except long-term debt, approximate fair value. The fair value of derivative financial instruments reflects the estimated amount that the Company, if required to settle an outstanding contract, would have been required to pay or would be entitled to receive at year end. The fair value of long-term debt, based on year end quoted market prices for the same or similar debt of the same remaining maturities, is provided in the following table:

December 31 (Canadian dollars in millions)	2006		2005	
	Carrying Value	**Fair Value**	Carrying Value	Fair Value
Long-term debt[1]	**5,270**	**5,831**	5,084	5,697

[1] The carrying value of long-term debt represents the par value of the notes and debentures.

Hydro One may enter into derivative agreements, such as forward fixed interest rate swap agreements, to hedge against the effect of future interest rate movements on long-term fixed rate borrowing requirements. These transactions are accounted for as cash flow hedges of anticipated transactions. In 2006, Hydro One did not enter into any such derivative agreements. In 2005, Hydro One terminated forward interest rate swap agreements entered into in 2005 and 2004 and having a total notional principal amount of $150 million, resulting in a loss of $10 million. The loss is being amortized on an annuity basis over the 30-year term of the related debt.

As at December 31, 2006, the Company had a pay floating interest rate swap agreement related to a step-up coupon note issuance with an initial maturity date in 2007, and with extended maturity dates up to 2011. The interest rate swap is being accounted for as a fair value hedge. This agreement has a notional principal amount of $40 million and a fair value of $nil (2005 – $nil).

The Company has no significant counter-party credit risk exposure as the fair value of the interest rate swap contracts was not significant in 2006 or in 2005.

Financial assets create a risk that a counter-party will fail to discharge an obligation, causing a financial loss. As at December 31, 2006, there were no significant concentrations of credit risk with respect to any class of financial assets. The Company's revenue is earned from a broad base of customers. As a result, Hydro One did not earn a significant amount of revenue from any single customer. As at December 31, 2006, there were no significant balances of accounts receivable due from any single customer.

The Company will continue to use derivative instruments to manage interest rate risk. Derivative financial instruments result in exposure to credit risk, since there is a risk of counter-party default. Hydro One monitors and minimizes credit risk through various techniques including dealing with highly rated counter-parties, limiting total exposure levels with individual counter-parties and entering into master agreements which enable net settlement.

Note 11.
Employee Future Benefits

Hydro One has a contributory defined benefit pension plan covering all regular employees of Hydro One and its subsidiaries, except Hydro One Brampton. Employees of Hydro One Brampton participate in the Ontario Municipal Employees Retirement System (OMERS), a multi-employer public sector pension fund. Current contributions by Hydro One Brampton are approximately $1 million annually.

Plan Asset Mix

Hydro One's pension plan asset mix at December 31, 2006 and 2005 was as follows:

	% of Plan Assets	
December 31	**2006**	2005
Equity securities	**64.6**	60.6
Debt securities	**32.0**	36.2
Other	**3.4**	3.2
	100.0	100.0

Supplementary Information

The Hydro One pension plan does not hold any direct securities of the Company, but did hold debt securities of the Province of $92 million and $79 million at December 31, 2006 and 2005, respectively.

The Company's pension plan provides benefits based on highest three-year average pensionable earnings. For new management employees who commenced employment on or after January 1, 2004, and for new Society of Energy Professionals hired after November 17, 2005, benefits are based on highest five-year average pensionable earnings. After retirement, pensions are indexed to inflation. The measurement date used to determine plan assets and the accrued benefit obligation is December 31. Based on the actuarial valuation filed on September 22, 2004, effective for December 31, 2003, the Company contributed $86 million to its pension plan in respect of 2006 (2005 – $83 million), all of which is required to satisfy minimum funding requirements. Contributions are payable one month in arrears. All of the contributions are expected to be in the form of cash. Prior to 2004, the Company was not required to contribute to the pension plan because the last actuarial valuation at December 31, 2000 indicated that the plan had a surplus. Contributions after 2006 will be based on actuarial valuation effective December 31, 2006 and will depend on future investment returns, and changes in benefits or actuarial assumptions.

Total cash payments for employee future benefits made in 2006, consisting of cash contributed by the Company to its funded pension plan and cash payments directly to beneficiaries for its unfunded other benefit plans was $122 million in 2006 (2005 – $123 million).

Year ended December 31	Pension		Employee Future Benefits Other than Pension	
(Canadian dollars in millions)	**2006**	2005	**2006**	2005
Change in accrued benefit obligation				
Accrued benefit obligation, January 1	**5,355**	4,862	**1,143**	966
Current service cost	**106**	83	**33**	26
Interest cost	**267**	277	**58**	57
Benefits paid	**(253)**	(248)	**(36)**	(40)
Plan amendments	**6**	–	**22**	1
Net actuarial (gain) loss	**(70)**	381	**(120)**	133
Accrued benefit obligation, December 31	**5,411**	5,355	**1,100**	1,143
Change in plan assets				
Fair value of plan assets, January 1	**4,713**	4,243	**–**	–
Actual return on plan assets	**571**	630	**–**	–
Benefits paid	**(253)**	(248)	**–**	–
Employer's contributions[1]	**86**	83	**–**	–
Employees' contributions	**17**	16	**–**	–
Administrative expenses	**(11)**	(11)	**–**	–
Fair value of plan assets, December 31	**5,123**	4,713	**–**	–
Funded status				
(Unfunded benefit obligation)	**(288)**	(642)	**(1,100)**	(1,143)
Unamortized net actuarial losses	**645**	1,069	**236**	385
Unamortized past service costs	**25**	22	**25**	6
Deferred pension asset (accrued benefit liability)	**382**	449	**(839)**	(752)
Less: current portion	**–**	–	**36**	36
Deferred pension asset (long-term liability)	**382**	449	**(803)**	(716)

[1] In January 2007, the Company made a contribution of $8 million in respect of 2006 (2006 – $8 million in respect of 2005).

Year ended December 31 (Canadian dollars in millions)	Pension 2006	Pension 2005	Employee Future Benefits Other than Pension 2006	Employee Future Benefits Other than Pension 2005
Components of net periodic benefit cost				
Current service cost, net of employee contributions	**89**	67	**33**	26
Interest cost	**267**	277	**58**	57
Actual return on plan asset net of expenses	**(560)**	(619)	**–**	–
Actuarial (gain) loss	**(70)**	381	**(120)**	133
Plan amendments	**6**	–	**22**	–
Other	**(1)**	–	**(1)**	–
Costs arising in the period	**(269)**	106	**(8)**	216
Differences between costs arising in the period and costs recognized in the period in respect of:				
Return on plan assets	**248**	327	**–**	–
Actuarial loss (gain)	**177**	(268)	**149**	(113)
Plan amendments	**(3)**	3	**(19)**	–
Net periodic benefit cost [2]	**153**	168	**122**	103
Charged to results of operations [2]	**42**	23	**75**	64
Effect of 1% increase in health care cost trends on:				
Accrued benefit obligation, December 31	**–**	–	**156**	171
Service cost and interest cost	**–**	–	**13**	12
Effect of 1% decrease in health care cost trends on:				
Accrued benefit obligation, December 31	**–**	–	**(124)**	(133)
Service cost and interest cost	**–**	–	**(10)**	(10)
Significant assumptions				
For net periodic benefit cost:				
Expected rate of return on plan assets	**6.75%**	7.00%	**–**	–
Weighted-average discount rate	**5.00%**	5.75%	**4.98%**	5.93%
Rate of compensation scale escalation (without merit)	**3.25%**	3.25%	**3.25%**	3.25%
Rate of cost of living increase	**2.50%**	2.75%	**2.50%**	2.75%
Average remaining service life of employees *(years)*	**10**	10	**10**	10
Rate of increase in health care cost trend [3]	**–**	–	**4.40%**	4.40%
For accrued benefit obligation, December 31:				
Weighted-average discount rate	**5.25%**	5.00%	**5.24%**	4.98%
Rate of compensation scale escalation (without merit)	**3.25%**	3.25%	**3.25%**	3.25%
Rate of cost of living increase	**2.50%**	2.50%	**2.50%**	2.50%
Rate of increase in health care cost trend [4]	**–**	–	**4.40%**	4.40%

[2] The Company follows the cash basis of accounting. During 2006, pension costs of $86 million (2005 – $83 million) were attributed to labour, of which $42 million (2005 – $23 million) was charged to operations, $34 million (2005 – $32 million) was capitalized as part of the cost of fixed assets, and $10 million (2005– $28 million) was attributed to a regulatory asset.

[3] 7.87% in 2006 grading down to 4.40% per annum in and after 2014 (2005 – 8.47% in 2005 grading down to 4.40% per annum in and after 2014).

[4] 8.69% in 2007 grading down to 4.40% per annum in and after 2014 (2005 – 7.87% in 2005 grading down to 4.40% per annum in and after 2014).

Note 12.
Environmental Liabilities

December 31

(Canadian dollars in millions)	2006	2005
Environmental liabilities, January 1	79	89
Interest accretion	5	5
Expenditures	(17)	(14)
Revaluation adjustment	3	(1)
Environmental liabilities, December 31	70	79
Less: current portion	(15)	(15)
	55	64

Estimated future environmental expenditures for each of the five years subsequent to December 31, 2006 and in total thereafter are as follows: 2007 – $15 million; 2008 – $14 million; 2009 – $12 million; 2010 – $10 million; 2011 – $7 million; and thereafter – $31 million.

There are uncertainties in estimating future environmental costs due to potential external events such as changing regulations and advances in remediation technologies. Hydro One continuously reviews factors affecting its cost estimates as well as the environmental condition of the various properties. The actual cost of investigation or remediation may differ from current estimates.

Note 13.
Share Capital

Common and Preferred Shares

On March 31, 2000, the Company issued to the Province 12,920,000 5.5% cumulative preferred shares with a redemption value of $25.00 per share, and 99,990 common shares, bringing the total number of outstanding common shares to 100,000. The Company is authorized to issue an unlimited number of preferred and common shares.

The preferred shares are entitled to an annual cumulative dividend of $18 million, which is payable on a quarterly basis. The preferred shares are redeemable at the option of the Province at a price of $25 per share, representing the stated value, plus any accrued and unpaid dividends if the Province sells a number of the common shares which it owns to the public such that the Province's holdings are reduced to less than 50% of the common shares of the Company. Hydro One may elect, without condition, to pay all or part of this redemption price by issuing additional common shares to the Province. If the Province does not exercise its redemption right, the Company would have the ability to adjust the dividend on the preferred shares to produce a yield that is 0.50% less than the then-current dividend market yield for similarly rated preferred shares. The preferred shares do not carry voting rights, except in limited circumstances, and would rank in priority over the common shares upon liquidation.

Dividends

Common dividends are declared at the sole discretion of the Hydro One Board of Directors, and are recommended by management based on results of operations, financial condition, cash requirements and other relevant factors such as industry practice and shareholder expectations.

In 2006, preferred dividends in the amount of $18 million (2005 – $18 million) and common dividends in the amount of $332 million (2005 – $273 million) were declared.

Earnings per Share

Earnings per share is calculated as net income during the year, after cumulative preferred dividends, divided by the weighted-average number of common shares outstanding during the year.

Note 14.
Related Party Transactions

The Province, OEFC, IESO and Ontario Power Generation Inc. (OPG) are related parties of Hydro One. In addition the OEB is related to the Company by virtue of its status as a Provincial Crown Corporation. Transactions between these parties and Hydro One were as follows:

Hydro One received revenue for transmission services from IESO, based on uniform transmission rates approved by the OEB. Transmission revenue for 2006 includes $1,206 million (2005 – $1,276 million) related to these services.

Hydro One receives amounts for rural rate protection from the IESO. Distribution revenue for 2006 includes $127 million (2005 – $127 million) related to this program. Hydro One also received revenue related to the supply of electricity to remote northern communities from the IESO. Distribution revenue for 2006 includes $21 million (2005 – $21 million) related to these services.

In 2006, Hydro One purchased power in the amount of $2,183 million (2005 – $2,095 million) from the IESO administered electricity market and $38 million (2005 – $36 million) from OPG.

Under the *Ontario Energy Board Act, 1998*, the OEB is required to recover all of its annual operating costs from gas and electricity distributors and electricity transmitters. In 2006, Hydro One incurred $9 million (2005 – $7 million) in OEB fees.

Hydro One has service level agreements with the other successor corporations. These services include field, engineering, logistics and telecommunications services. Revenues related to the provision of construction and equipment maintenance services to the other successor corporations were $15 million (2005 – $11 million), primarily for the transmission business. Operation, maintenance and administration costs related to the purchase of services from the other successor corporations were less than $1 million in each of 2006 and 2005.

The provision for payments in lieu of corporate income taxes was paid or payable to the OEFC and dividends were paid or payable to the Province (see Note 2).

The amounts due to and from related parties as a result of the transactions referred to above are as follows:

December 31 (Canadian dollars in millions)	2006	2005
Accounts receivable	114	116
Accounts payable and accrued charges	(230)	(263)

Included in accounts payable and accrued charges are amounts owing to the IESO in respect of power purchases of $195 million (2005 – $213 million).

Note 15.
Consolidated Statements of Cash Flows

For the purposes of the consolidated statements of cash flows, "cash and cash equivalents" refers to the balance sheet item "bank indebtedness."

The changes in non-cash balances related to operations consist of the following:

Year ended December 31 (Canadian dollars in millions)	2006	2005
Accounts receivable (increase) decrease	(149)	87
Materials and supplies increase	–	(9)
Accounts payable and accrued charges (decrease) increase	(39)	68
Accrued interest increase (decrease)	6	(1)
Long-term accounts payable and accrued charges decrease	(7)	(3)
Employee future benefits other than pension increase	87	62
Other	10	(10)
	(92)	194
Supplementary information:		
Interest paid	302	300
Payments in lieu of corporate income taxes	252	210

Note 16.
Contingencies

Legal Proceedings

Hydro One is involved in various lawsuits, claims and regulatory proceedings in the normal course of business. In the opinion of management, the outcome of such matters, except as noted below, will not have a materially adverse effect on the Company's consolidated financial position, results of operations or cash flows.

On March 29, 1999, the Whitesand First Nation Band commenced an action in the Ontario Court (General Division), now the Superior Court Justice, naming as defendants the Province, the Attorney General of Canada, Ontario Hydro, OEFC, OPG and the Company. On May 24, 2001, the Whitesand First Nation Band issued an almost identical claim against the same parties. The reason for the second claim is the procedural defence of the Province that proper notice of the first claim was not given under the *Proceedings Against the Crown Act* (Ontario). These actions seek declaratory relief, injunctive relief and damages in an unspecified amount. The Whitesand Band alleges that since at least the first half of the twentieth century, Ontario Hydro has erected dams, generating stations and other facilities within or affecting the band's traditional lands and that those facilities have caused damage to band members and the lands, including substantial flooding and erosion. The Whitesand Band also claims treaty rights to a share of the profits arising from the activities of these Ontario Hydro facilities, an entitlement to increases in annuity payments established by treaty and for breach of an alleged contract to reimburse the band for negotiation costs with Ontario Hydro. The Whitesand Band asserts multiple causes of action, including trespass, breach of fiduciary duty, nuisance and negligence. The May 24, 2001 case was consolidated in 2004 with a similar claim by Red Rock First Nation Band which commenced on September 7, 2001 as all procedural issues in both matters were the same. There is now one action in which the claims of both Whitesand and Red Rock are set out. The claims relating to activities of Ontario Hydro (i.e., flooding) are the matters for which OPG would have responsibility pursuant to Transfer Orders under the *Electricity Act*, 1998. In the consolidated claim, Whitesand and Red Rock seek to tie Hydro One into the flooding allegations on the alleged basis of the integrated nature of the transmission system with the entire electricity system, which includes the method of generating power. To date, Hydro One has not filed a defence. Hydro One believes that it is unlikely that the outcome of this litigation will have a material adverse effect on its consolidated financial position, results of operations or cash flows.

Transfer of Assets

On April 1, 1999, in connection with the acquisition of its operations, Hydro One acquired and assumed the assets, liabilities, rights and obligations of Ontario Hydro's electricity transmission, distribution and energy services businesses, except for certain transmission, distribution and other assets located on lands held for bands or bodies of Indians under the *Indian Act* (Canada). Transfer of title to these assets did not occur because authorizations originally granted by the Minister of Indian Affairs and Northern Development (Canada) for the construction and operation of these assets could not be transferred without the consent of the Minister and the relevant Indian bands or bodies or, in several cases, because the authorizations had either expired or had never been properly issued. Hydro One manages these assets, which are currently owned by the OEFC.

Hydro One has commenced negotiations with the relevant Indian bands and bodies to obtain the authorizations and consents necessary to complete the transfer of these transmission, distribution and other assets. Hydro One cannot predict the aggregate amount that it may have to pay to obtain the required authorizations and consents. Hydro One expects to pay more than $850,000 per year, which was the amount previously paid to these Indian bands and bodies by Ontario Hydro and which was the total amount of allowed costs in the transitional rate orders. If, after taking all reasonable steps, Hydro One cannot otherwise obtain the authorizations and consents from the Indian bands and bodies, the OEFC will continue to hold these assets for an indefinite period of time. Alternatively, Hydro One may have to relocate these assets from the Indian lands to other locations at a cost that could be substantial, or, in a limited number of cases, to abandon a line and replace it with diesel generation facilities. In such cases, Hydro One would apply to recover these costs in future rate orders.

Note 17.
Commitments

Agreement with Inergi

Effective March 1, 2002, Cap Gemini Canada Inc. began providing services to Hydro One through Inergi. As a result of this initiative, Hydro One receives from Inergi a range of services including information technology, customer care, supply chain and certain human resources and finance services for a 10-year period. The initial service level price ranged between $90 million and $130 million per year, subject to external benchmarking every three years to ensure Hydro One is receiving a defined competitive and continuously improved price. In connection with this agreement, on March 1, 2002 the Company transferred approximately 900 employees to Inergi, including about 130 non-regular employees.

The annual commitments under the agreement in each of the five years subsequent to December 31, 2006, and in total thereafter are as follows: 2007 – $110 million; 2008 – $98 million, 2009 – $94 million; 2010 – $91 million; 2011 – $87 million; and thereafter – $16 million.

Prudential Support

Purchasers of electricity in Ontario, through the IESO, are required to provide security to mitigate the risk of their default based on their expected activity in the market. The IESO could draw on these guarantees if Hydro One Networks or Hydro One Brampton fails to make a payment required by a default notice issued by the IESO. The maximum potential payment is the face value of the bank letters of credit plus the nominal amount of the parental guarantee. As at December 31, 2006, the Company provided prudential support, using a combination of bank letters of credit of $22 million (2005 – $21 million) and parental guarantees of $275 million (2005 – $275 million).

Retirement Compensation Arrangements

Bank letters of credit have been issued to provide security for the Company's liability under the terms of a trust fund established pursuant to the supplementary pension plan for the employees of Hydro One and its subsidiaries. The trustee is required to draw upon the letters of credit if Hydro One is in default of its obligations under the terms of this plan. Such obligations include the requirement to provide the trustee with an annual actuarial report as well as letters of credit sufficient to secure the Company's liability under the plan, to pay benefits payable under the plan and to pay the letter of credit fee. The maximum potential payment is the face value of the bank letters of credit. As at December 31, 2006, Hydro One had bank letters of credit of $93 million (2005 – $82 million) outstanding relating to retirement compensation arrangements.

Operating Leases

The future minimum lease payments under operating leases for each of the five years subsequent to December 31, 2006 and in total thereafter are as follows: 2007 – $5 million; 2008 – $5 million; 2009 – $4 million; 2010 – $1 million; 2011 – $nil; and thereafter – $1 million.

Note 18.
Segment Reporting

Hydro One has three reportable segments:

— The transmission business, which comprises the core business of providing transportation and connection services, is responsible for transmitting electricity throughout the Ontario electricity grid;

— The distribution business, which comprises the core business of delivering and selling electricity to customers; and

— The "other" segment, which primarily consists of the telecommunications business.

The designation of segments is based on a combination of regulatory status and the nature of the products and services provided. The accounting policies followed by the segments are the same as those described in the summary of significant accounting policies (see Note 2). Segment information on the above basis is as follows:

Year ended December 31

(Canadian dollars in millions)	Transmission	Distribution	Other	Consolidated
2006				
Segment profit				
Revenues	1,245	3,273	27	4,545
Purchased power	–	2,221	–	2,221
Operation, maintenance and administration	390	460	30	880
Depreciation and amortization	241	269	5	515
Income (loss) before financing charges and provision for payments in lieu of corporate income taxes	614	323	(8)	929
Financing charges				295
Income before provision for payments in lieu of corporate income taxes				634
Capital expenditures	402	417	4	823
2005				
Segment profit				
Revenues	1,310	3,085	21	4,416
Purchased power	–	2,131	–	2,131
Operation, maintenance and administration	353	413	26	792
Depreciation and amortization	246	236	5	487
Income (loss) before financing charges and provision for payments in lieu of corporate income taxes	711	305	(10)	1,006
Financing charges				325
Income before provision for payments in lieu of corporate income taxes				681
Capital expenditures	349	338	4	691

December 31

(Canadian dollars in millions)	2006	2005
Total assets		
Transmission	6,965	6,827
Distribution	5,170	4,902
Other	99	92
	12,234	11,821

All revenues, costs and assets, as the case may be, are earned, incurred or held in Canada.

Note 19.
Comparative Figures

The comparative Consolidated Financial Statements have been reclassified from statements previously presented to conform to the presentation of the December 31, 2006 Consolidated Financial Statements.

Five-Year Summary of Financial and Operating Statistics

Year ended December 31 (Canadian dollars in millions)	**2006**	2005	2004	2003	2002
Statement of operations data					
Revenues					
Transmission	**1,245**	1,310	1,262	1,298	1,317
Distribution	**3,273**	3,085	2,874	2,734	2,682
Other	**27**	21	17	26	32
	4,545	4,416	4,153	4,058	4,031
Costs					
Purchased power	**2,221**	2,131	1,987	1,872	1,858
Operation, maintenance and administration[1]	**880**	792	771	795	832
Depreciation and amortization	**515**	487	480	454	411
	3,616	3,410	3,238	3,121	3,101
Regulatory recovery[2]	**–**	–	91	–	–
Income before financing charges and provision for payments in lieu of corporate income taxes	**929**	1,006	1,006	937	930
Financing charges	**295**	325	331	348	353
Income before provision for payments in lieu of corporate income taxes	**634**	681	675	589	577
Provision for payments in lieu of corporate income taxes	**179**	198	177	193	233
Net income	**455**	483	498	396	344
Basic and fully diluted earnings per common share *(Canadian dollars)*	**4,366**	4,652	4,798	3,779	3,258

December 31 (Canadian dollars in millions)					
Balance sheet data					
Assets					
Transmission	**6,965**	6,827	6,785	6,589	6,638
Distribution	**5,170**	4,902	4,845	4,623	4,694
Other	**99**	92	95	94	90
Total assets	**12,234**	11,821	11,725	11,306	11,422
Liabilities					
Current liabilities (including current portion of long-term debt)	**1,194**	1,341	1,262	1,192	1,894
Long-term debt	**4,872**	4,466	4,613	4,539	3,938
Other long-term liabilities	**1,347**	1,298	1,326	1,284	1,451
Shareholder's equity					
Share capital	**3,637**	3,637	3,637	3,637	3,637
Retained earnings	**1,184**	1,079	887	654	502
Total liabilities and shareholder's equity	**12,234**	11,821	11,725	11,306	11,422

Year ended December 31 (Canadian dollars in millions)	2006	2005	2004	2003	2002
Other financial data					
Capital expenditures					
Transmission	402	349	432	289	260
Distribution	417	338	288	292	286
Other	4	4	7	16	24
Total capital expenditures	823	691	727	597	570
Ratios					
Net asset coverage on long-term debt[3]	1.92	1.93	1.88	1.86	1.90
Earnings coverage ratio[4]	2.67	2.69	2.70	2.43	2.35
Operating statistics					
Transmission					
Units transmitted *(TWh)*[5]	151.1	157.0	153.4	151.7	153.2
Ontario 20-minute system peak demand *(MW)*[5]	27,056	26,219	25,204	24,849	25,629
Ontario 60-minute system peak demand *(MW)*[5]	27,005	26,160	24,979	24,753	25,414
Total transmission lines *(circuit-kilometres)*	28,600	28,547	28,643	28,621	28,492
Distribution					
Units distributed to Hydro One customers *(TWh)*[5]	29.0	29.7	28.5	27.9	27.1
Units distributed through Hydro One lines *(TWh)*[5,6]	44.7	45.6	44.8	44.7	45.1
Total distribution lines *(circuit-kilometres)*	122,460	122,118	121,736	121,285	120,767
Customers	1,293,396	1,273,768	1,258,925	1,238,748	1,219,614
Total regular employees	4,295	4,189	4,118	3,967	3,933

1 Operation, maintenance and administration costs for 2002 included a charge of $25 million for a staff reduction program.

2 As a result of the oral and written evidence submitted by Hydro One, on December 9, 2004 the OEB issued a ruling, citing prudence, and approving recovery of amounts previously delayed by the *Electricity Pricing, Conservation and Supply Act, 2002*, relating to regulatory deferral account balances sought by Hydro One in its May 31, 2004 submission. Consequently, a one-time regulatory recovery of $91 million was recorded.

3 The net asset coverage on long-term debt ratio is calculated as total assets minus total liabilities excluding long-term debt (including current portion) divided by long-term debt (including current portion).

4 The earnings coverage ratio has been calculated as the sum of net income, financing charges and provision for payments in lieu of corporate income taxes divided by the sum of financing charges, capitalized interest and cumulative preferred dividends.

5 System-related statistics include preliminary figures for December.

6 Units distributed through Hydro One lines represent total distribution system requirements and include electricity distributed to consumers who purchased power directly from the IESO.

Board of Directors (as at December 31, 2006)

Rita Burak[2]
Chair of the Board of Directors, Hydro One Inc.

Sami Bébawi[5,6]
Executive Vice President, Office of the President, President, Socodec Inc., SNC-Lavalin Group Inc.

Murray J. Elston[1,3,5]
President and CEO, Canadian Nuclear Association

Don MacKinnon[5,6]
President, Power Workers' Union

Eileen A. Mercier[1,2,4]*
Corporate Director
Resigned March 16, 2007

Walter Murray[1,3,4]
Corporate Director

Kathleen O'Neill[1,2,3,4]*
Corporate Director
Resigned January 24, 2007

Douglas E. Speers[1,4,6]
Chairman and Director, Emco Corporation

Kenneth D. Taylor[5,6]*
Chair, Taylor and Ryan Inc.
Resigned February 27, 2007

Blake Wallace, Q.C.[2,3,5]*
Vice President and Director, Murray & Company
Resigned February 26, 2007

Board Committees

[1] Audit and Finance Committee
The Audit and Finance Committee oversees the integrity of accounting policies and financial reporting, internal controls, internal audit, significant corporate risk exposures and financial compliance.
The committee met five times in 2006.

[2] Corporate Governance Committee
The Corporate Governance Committee is responsible for the Board's governance of the Company. It recommends issues to be discussed at meetings of the Board of Directors, reviews the mandates of each committee of the Board, conducts Board Assessments, monitors the quality of management's relationship with the Board and recommends suitable nominees for election to the Board of Directors.
The committee met four times in 2006.

[3] Human Resources and Public Policy Committee
The Human Resources and Public Policy Committee is responsible for reviewing the appropriateness of our current and future organizational structure, succession plans for corporate and divisional officers, the code of business conduct, the performance and remuneration of our senior executives, including recommending to the Board the remuneration of the President and CEO, and for identifying, assessing and providing advice to the Board of Directors on public affairs issues that have significant impact on us. The committee met eight times in 2006.

[4] Information Technology Committee
The Information Technology Committee is an advisory committee of the Board established to assist the Board in its oversight responsibility on matters related to the Company's enterprise application systems replacement strategy. The committee met three times in 2006.

[5] Regulatory and Environment Committee
The Regulatory and Environment Committee monitors the Company's compliance with applicable regulatory requirements and environmental legislation. The committee oversees compliance programs, policies, standards and procedures, reviews the Company's proposals for rate applications and reviews compliance actions and reports.
The committee met five times in 2006.

[6] Health and Safety Committee
The Health and Safety Committee is responsible for reviewing occupational health and safety policies, standards, and programs, compliance with occupational health and safety legislation, policies and standards, and public health and safety issues. The committee met four times in 2006.

* Effective March 30, 2007, the following directors were elected to the Board of Directors of Hydro One Inc. by our shareholder: Kathryn Bouey; Laura Formusa; Michael Mueller; Robert Pace; and Gale Rubenstein in place of Eileen Mercier, Kathleen O'Neill, Tom Parkinson, Honourable Bob Rae, Kenneth Taylor and Blake Wallace, who have resigned as members of the Board.
As well, the number of directors of the Corporation was reduced from 12 to 11.

Corporate Information

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(416) 345-5000
1-877-955-1155
www.HydroOne.com

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investor.relations@HydroOne.com

Media Inquiries
(416) 345-6868
1-877-506-7584

Customer Inquiries
Power outage and
emergency number:
1-800-434-1235

Residential, farm &
small business accounts:
1-888-664-9376

Business accounts:
1-877-447-4412

Auditors
Ernst & Young LLP

Concept and Design: THE WORKS www.worksdesign.com

Making life better for electrical burn patients

In 2006, Hydro One, Sunnybrook Health Sciences Centre and St. John's Rehab Hospital announced the Hydro One Chair in Electrical Injury, a permanently endowed fund to support clinical and academic leadership in the field of electrical injury. Over the next five years, Hydro One has committed $500,000 to push forward research and treatment of electrical burn patients.

"Electrical burns are not very well understood and often the damage they do goes unseen and undiagnosed," said Dr. Joel Fish, Medical Director at the Ross Tilley Burn Centre at Sunnybrook Health Sciences Centre. "The research enabled by this funding will do a great deal to improve treatment and rehabilitation for burn patients."

Since 2003, Hydro One and Sunnybrook Health Sciences Centre have worked together to make the expertise of the Ross Tilley Burn Centre available through the hospital's teleconference capability and the NORTH Network telemedicine network to electrical burn patients across Ontario and Canada. Every year, between 600 and 800 workplace electrical burns occur in Canada, the vast majority of them to workers outside of the electricity sector.

The proper care and treatment for electrical burn patients is important not only to those of us in the electrical industry, but also to workers in every sector.

Dr. Joel Fish
Medical Director, Ross Tilley Burn Centre

hydro One

Sunnybrook
ROSS TILLEY BURN CENTRE

hydroOne

Our mission is to be an efficient and dynamic transmission and distribution company that is best in North America in the areas of safety, customer service and reliability, while focusing on the development and retention of our employees and creating shareholder value.

Hydro One Inc.

483 Bay Street
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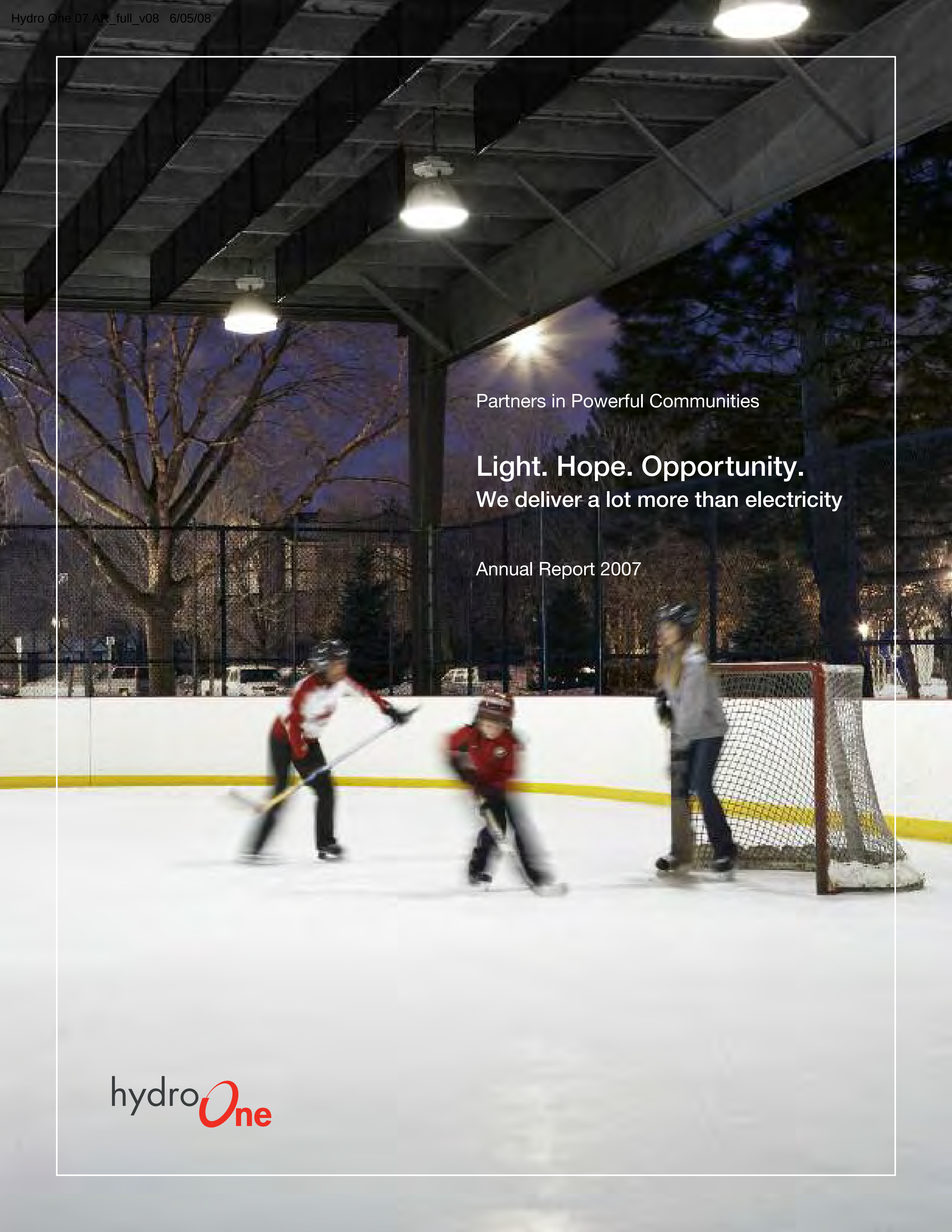


Partners in Powerful Communities

Light. Hope. Opportunity.

We deliver a lot more than electricity

Annual Report 2007

hydro One

Our mission is to be an efficient and dynamic electricity transmission and distribution company that is best in North America in the areas of safety, customer service and reliability, while focusing on our people and creating shareholder value.

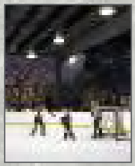
Hydro One Inc.
Is a holding company with subsidiaries that operate in the business areas of electricity transmission and distribution and telecom services.

Hydro One Networks Inc.
Represents the majority of our business, which is regulated by the Ontario Energy Board. It is involved in the planning, construction, operation and maintenance of our transmission and distribution networks.

Hydro One Brampton Networks Inc.
Distributes electricity to one of the fastest growing urban centres in Canada, just 30 kilometres outside of Toronto.

Hydro One Remote Communities Inc.
Operates and maintains the generation and distribution assets used to supply electricity to 20 remote communities across northern Ontario that are not connected to the province's electricity transmission grid.

Hydro One Telecom Inc.
Markets our excess fibre-optic capacity to business customers. This business represents less than 1% of our total assets.



Cover image:
Healthy, powerful communities require a reliable, safe and secure electricity system. Hydro One is working to connect Ontario communities to the electricity necessary for a vibrant and growing economy.

95% satisfaction

Overall customer satisfaction levels for Large Transmission Customers reached 95% this year, an increase of 10% from 2006.

$839,728 raised

Our staff raised $839,728 for charities of their choice, through the 9th Annual Hydro One Employees' and Pensioners' Charity Campaign.

75,044,621 kWh saved

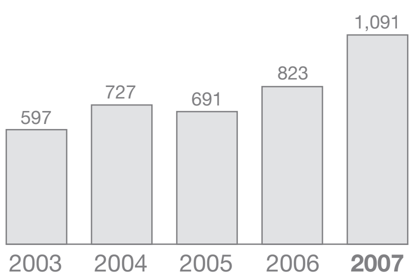
Hydro One customers are saving more than 75 million kWh from energy efficient products purchased during the spring Every Kilowatt Counts program.

Consolidated financial highlights and statistics

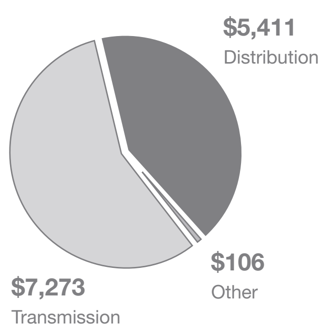
Year ended December 31 (Cdn $ millions)	**2007**	2006	Change	% Change
Revenues	**4,655**	4,545	110	2
Purchased power	**2,240**	2,221	19	1
Operating costs	**1,516**	1,395	121	9
Net income	**399**	455	(56)	(12)
Net cash from operations	**1,141**	909	232	26
Average annual Ontario 60-minute peak demand (MW)[1]	**22,988**	22,650	338	1
Distribution – units distributed to our customers (TWh)[1]	**30.2**	29.0	1.2	4

[1] System-related statistics include preliminary figures for December.

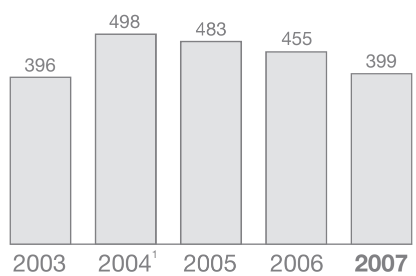
Capital Expenditures
(Cdn $ millions)



Total Assets
December 31, 2007
(Cdn $ millions)



Net Income
(Cdn $ millions)



[1] Net income includes a one-time regulatory recovery of $91 million.

Letter from the Chair

Rita Burak
Chair

When I was appointed to the position of Chair in 2003, Ontario's electricity sector was still grappling with the impact of significant restructuring. Five years later, the sector has evolved and matured with a clear mandate and we have a firm understanding of our role in Ontario. We are the stewards of a strategic and vital public asset. We work so that Ontario can.

2007 saw Hydro One deliver on its commitments: earn solid returns for our shareholder, provide exceptional service to our customers and make investments in the electrical infrastructure vital to the continued delivery of safe, reliable electricity to the people of Ontario.

The Company's net income in 2007 decreased by $56 million, or 12%, to $399 million compared to 2006. This decrease reflects lower transmission tariff revenues resulting from changes to transmission tariffs and increased expenditures required to operate and maintain our transmission and distribution systems.

Hydro One made critical investments both in transmission and distribution infrastructure as well as in maintenance programs designed to ensure the reliability of the system. Total capital and operation, maintenance and administrative expenditures for 2007 were $2,086 million.

In the past three years Hydro One has begun a major new construction phase and this will continue in the years and decades ahead. The projects planned with our industry partners at the Ontario Power Authority and the Independent Electricity System Operator are fundamental to delivering the safe, reliable electricity a growing Ontario needs.

We are the stewards of a strategic and vital public asset. We work so that Ontario can.

At this critical juncture, our ability to arrange sufficient and cost-effective financing is vital. This is facilitated by our strong and stable long-term credit rating that reflects the confidence of rating agencies and investors in the performance, management and future of the Company.

In the past few years, all Boards of Directors have spent tremendous energy on the governance and compliance functions; the Hydro One Board has also made these issues a top priority. The good governance of Hydro One is essential to our shareholder, the Province of Ontario, our bond holders and the people of Ontario who depend upon Hydro One to operate in their interest. We take our financial obligations seriously. Our financial controls and disclosure practices are solid and under regular external scrutiny. My fellow Board members and I are more focused than ever on ensuring that the Company operates in a way that delivers maximum value to the people of Ontario.

While we've steadfastly carried out our oversight function, we have also put strong emphasis on making a strategic contribution to ensure that the Company benefits from the Board's collective skills and experience.

The Board will continue to provide sound, strategic direction to the Company and is confident in the management team's ability. Hydro One paid its shareholder, the Province of Ontario, dividends of $325 million and recorded $205 million of payments in lieu of income taxes, which helps reduce the legacy-stranded debt held by the Province.

On behalf of the Board of Directors, I would like to thank Hydro One's management and employees for their valuable contribution and dedication to their task. The Board looks forward to continuing the work of the Company in providing a safe, reliable, affordable electricity delivery system for the people of Ontario. After a 35-year career in public service, I leave this post confident that Hydro One and Ontario's electricity delivery system are in capable hands. It has been a great honour to serve.

R. Burak

Rita Burak
Chair

Letter from the President and CEO

Laura Formusa
President and
Chief Executive Officer

The people of Ontario depend upon Hydro One to deliver a precious resource to them. And, as stewards of Ontario's electricity delivery system, our role is clear: we must maintain operational excellence while working with our partners to ensure that electricity can be delivered safely, reliably and affordably for generations to come.

Hydro One is more than just wires, towers and poles traversing this great province. We are good neighbours, safe operators and partners in powerful communities.

Hydro One employees are among the best in North America, and our performance this year reflected that fact. One of the most important measures of our performance is the satisfaction of our customers. And in 2007, our largest customers told us that they were more satisfied with our performance than ever before. Like safety, customer satisfaction is part of every conversation, every project and every day at our Company.

With major refurbishment, growth and construction underway and planned for the years ahead, it's a dynamic and challenging period for our Company. I am confident that Hydro One will continue to successfully deliver the electricity that Ontario needs. I am also confident that our efforts in energy efficiency and demand management will foster a culture of conservation in this province.

In addition to the stations and many thousands of kilometres of lines that we maintain, we have been very busy with major construction projects across Ontario. Our work crews completed the construction of a major underground cable in Toronto to improve supply reliability and flexibility. Significant progress was also made in 2007 on the interconnection with Quebec to improve Ontario's access to clean sources of electricity.

Hydro One is more than just wires, towers and poles traversing this great province. We are good neighbours, safe operators and partners in powerful communities.

The construction of infrastructure projects is only a small part of our task. To be a successful utility requires partnering with the public in a way that was not always part of the model in the past.

I believe that *how* we work with customers, *how* we treat communities and *how* we run our business are just as important as *what* we do.

With a generation of energy workers on the verge of retirement, we have embarked on an ambitious program to renew and enhance our workforce. Our efforts to create value for our shareholder and the people of Ontario are driven by the men and women who work for Hydro One. Maximizing their potential, developing future leaders and recruiting the best and brightest employees will determine Hydro One's strength in the years ahead. In that regard, Hydro One has taken a leadership role by partnering with four Ontario colleges to fund curriculum development to ensure that graduates will leave school with the skills our industry requires.

In 2007, we were also recognized for our focus on diversity. We are proud of receiving an award and believe that creating a diverse workplace is essential to our future and will bring the very best people to Hydro One. Our efforts are ensuring that we're attracting employees who reflect Ontario's communities.

Hydro One's 4,600 employees live and work in almost every community in Ontario. Through employee and pensioner fundraising, they contribute generously to charities of their choice. In 2007, Hydro One launched the PowerPlay grants program to fund projects in our communities for healthy and safe children's sports and play facilities.

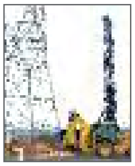
I'd like to thank the Hydro One Board of Directors for its guidance and oversight. Their contribution is critical to the success of our Company. I'm proud to work with the employees of Hydro One, employees who are dedicated, hard-working and aware of how much Ontario counts on them. We all know that the towers, stations, wires and poles we build, operate and maintain are more than just infrastructure, more than just our business. They deliver more than electricity. They deliver light, hope and opportunity.

Laura Formusa
President and Chief Executive Officer

To meet the growing needs of Ontario's communities, Hydro One is engaged in its largest infrastructure renewal initiative in more than two decades.

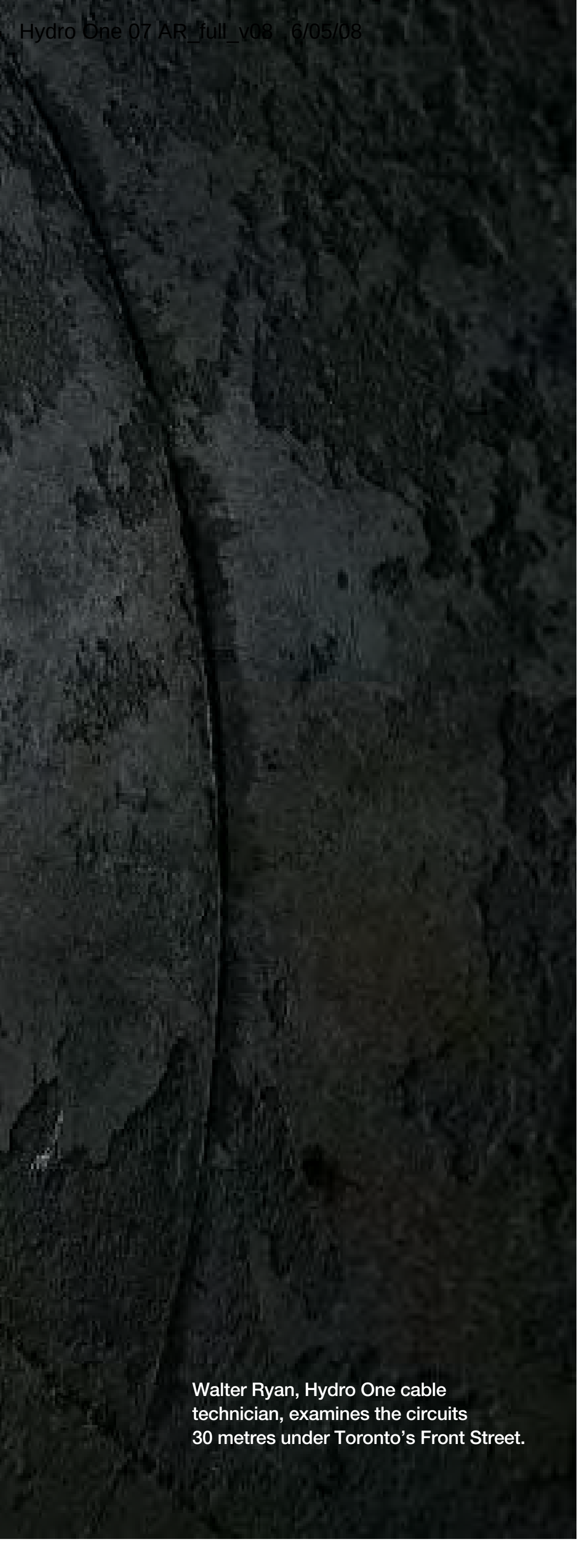
Connecting Clean and New Renewable Energy

To meet southern Ontario's growing energy needs, Hydro One intends to build a 180-km, double-circuit transmission line from the Bruce Power facility near Kincardine to the Milton Switching Station. With a projected in-service date of 2012, the completed line will deliver 3,000 MW of clean electricity. In 2007, Hydro One held a series of public meetings and made a concerted effort to inform and work with communities directly affected by the project.



Connecting Energy in Ontario and Quebec

Hydro One is working with Hydro-Québec TransÉnergie to expand transmission capacity between Ontario and Quebec and provide Ontarians with greater access to a reliable supply of renewable energy. A new line is being built between transformer stations in Ottawa and Masson, Quebec. With an expected in-service date of spring 2009, the new interconnection will increase Ontario's capacity to transfer power from or to Quebec by 1,250 MW.



Walter Ryan, Hydro One cable technician, examines the circuits 30 metres under Toronto's Front Street.

Building infrastructure. Creating opportunity.

To ensure that Ontario's businesses and communities continue to enjoy the benefits of reliable, safe and secure electricity, Hydro One has embarked on a province-wide effort to enhance and expand our transmission infrastructure.

As stewards of the province's transmission system for more than a century, we've learned through experience that the key to a successful construction project is first building a strong relationship with the communities we serve. The recently completed underground transmission line, connecting two transformer stations in downtown Toronto, exemplifies Hydro One's approach of identifying vital needs, seeking stakeholder input and then developing innovative technical solutions.

Downtown Toronto is the heart of Canada's business and financial sectors and its access to a secure, reliable supply of energy has national implications. An analysis of the area's energy requirements made it clear that the existing transmission grid needed improvement. To improve both flexibility and functionality, Hydro One built two underground cables, spanning 2.2 km, between the St. Lawrence Market and the Rogers Centre to connect two transformer stations.

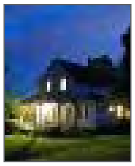
In the past, building a tunnel 30 metres below street level would require tearing up streets and disrupting traffic for months – a particularly unattractive prospect for the country's largest and busiest city. However, an innovative earth-boring machine enabled Hydro One to dig the tunnel without significant disruption to local business activities and with minimal impact on traffic.

Throughout the process, Hydro One kept stakeholders informed through public meetings and regular project updates published on our website. The project was completed on time and the circuit became operational in December 2007.

335 municipalities

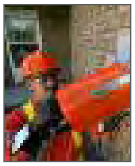
Hydro One's distribution network serves 335 of the 445 municipalities in Ontario.

Hydro One is committed to delivering the clean, reliable, renewable energy Ontario needs to meet the challenges of the 21st century.



Creating a Conservation Culture

Our conservation and demand management programs have reached 1.1 million participants to date. These programs combine to save 272 million kWh annually, enough energy to power 23,000 homes for one year. For more conservation and demand management program results, take a look at the inside back cover.



Doing the Smart Thing Is Rewarding

In September 2007, an international panel of judges named Hydro One the winner of the Utility Planning Network's 2007 Metering Award – Automated Meter Reading Initiative category. The award was given in recognition of Hydro One's efforts to support the province's Smart Meter Program. As of December 31, 2007, Hydro One teams had installed 288,000 smart meters, which allow for the sophisticated metering and management of power use and will ultimately facilitate time-of-use rates when they come into effect.

Linda Heinzle tends to a month-old calf while George keeps on top of feeding time at Terryland Farms in St. Eugene, Ontario.

Sustainable. Renewable. It's our energy future.

Ontario's energy needs are growing and changing. The impact of climate change on the environment has made it clear that the province and its people must take a new approach to energy use and supply management.

Hydro One is partnering with other leaders in the energy sector on a number of innovative measures aimed at reducing energy use and incorporating new sources of renewable energy into Ontario's electricity system.

Over the past year, Hydro One made great strides to deliver on the Province of Ontario's Renewable Energy Standard Offer Program (RESOP). Targeted at small, local suppliers, RESOP supports the development of renewable energy sources, such as solar, wind, biogas, biomass and water power, by offering participants price stability and a 20-year contract. Hydro One reviews the feasibility of all proposals and connects approved suppliers to our distribution system where possible.

In 2007, George and Linda Heinzle became the first suppliers of biomass energy connected to Hydro One's transmission system as part of RESOP.

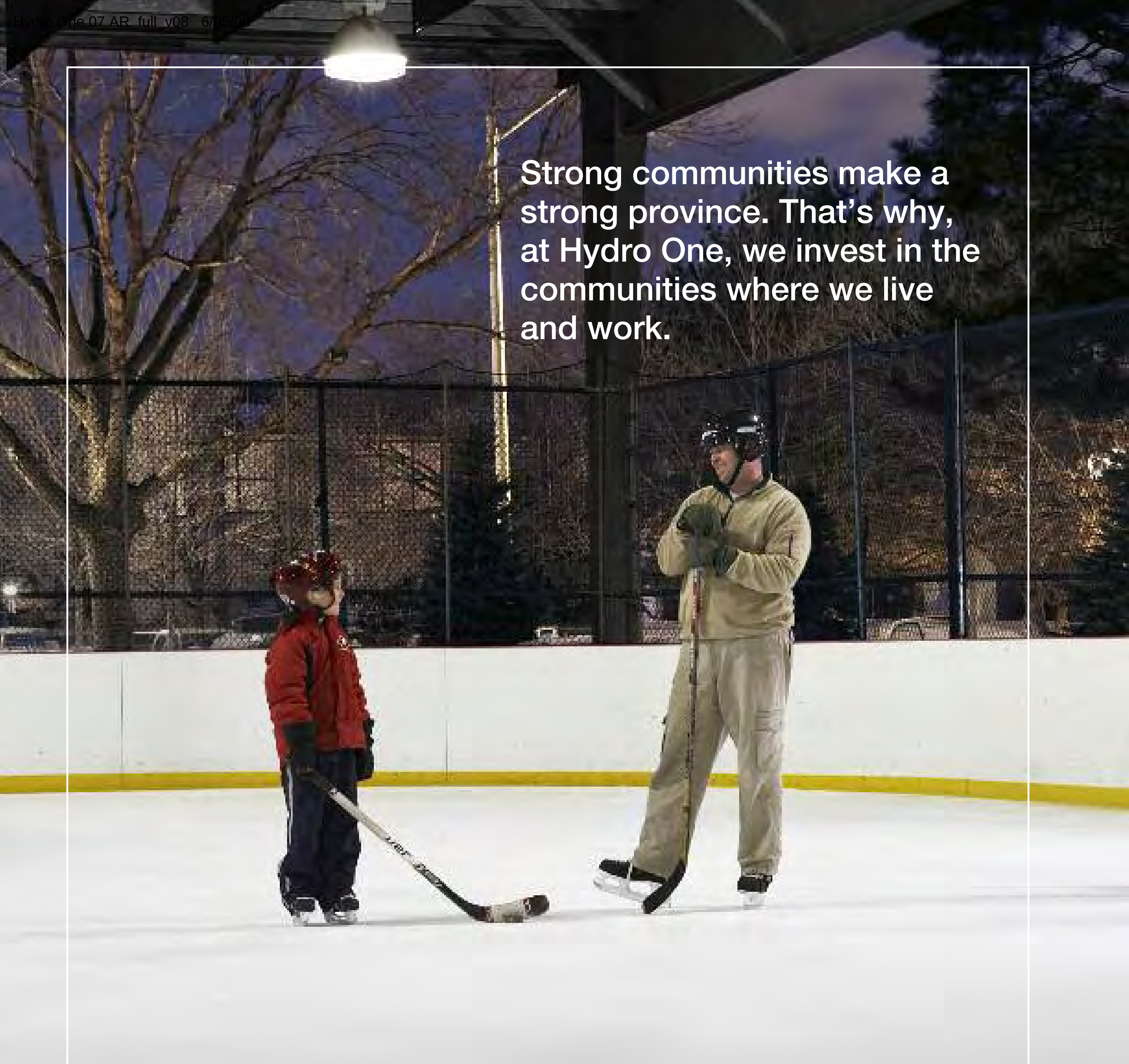
The Heinzles own Terryland Farm, a 130-head dairy operation located east of Ottawa. Like all dairy farms, it produces a significant amount of renewable biomass. But where others saw waste, George and Linda recognized a wasted resource. The Heinzles can generate 700 kWh per day, enough to power an average household for almost one month.

Connecting the Heinzles to the grid was an important first step. As more small providers of renewable energy connect to the electricity system, they will make a big contribution to the system's long-term reliability and diversity of Ontario's power supply.

8,000 MW

In 20 years, Ontario's renewable energy supply is expected to increase by 8,000 MW, enough to meet almost one third of the province's current electricity demand.

– according to the Ontario Power Authority's *Supply Mix Advice Report*.



Strong communities make a strong province. That's why, at Hydro One, we invest in the communities where we live and work.

Supporting First Nations Literacy

In Ontario's north, Hydro One is working with local communities to preserve First Nations' languages and traditions. As a major sponsor of the Kwayaciiwin Literacy Program, we are helping to ensure the ongoing vitality and relevance of aboriginal languages. Offered in seven different northern communities, the program starts in the earliest grades, providing kindergartners and their teachers with special books and teaching materials. The goal of the Kwayaciiwin program is to graduate students who are literate and fluent in both Anihshiniimowin and English.

Powering the International Plowing Match

Since 2001, Hydro One has provided electricity to the International Plowing Match (IPM), Canada's largest agricultural exhibition. The IPM offers an excellent opportunity for Hydro One staff to meet Ontario's agricultural community and discuss smart meters, conservation and other Hydro One programs. By meeting our customers face-to-face, we can better understand their needs and what works for them. This means we can deliver programs and services that help them use electricity as efficiently as possible.

Hydro One is improving children's recreation and play facilities across Ontario through its new PowerPlay grants program.

Partners in powerful communities.

From busy urban centres to the towns and villages of the north, Hydro One and its employees are committed to building strong, healthy communities across Ontario. Through our employees' volunteer efforts and charitable grants and sponsorships, Hydro One supports a wide range of community-building initiatives.

In August 2007, Hydro One announced the launch of PowerPlay, a new grants program to support and enhance children's sports and recreation facilities. PowerPlay offers grants of up to $25,000 for projects for community centres, indoor or outdoor ice rinks, playgrounds, splash pads and sports fields – places where kids can participate in community sports, stay healthy and active and have fun. The program is open to municipalities and registered charities where Hydro One is the local electricity supplier.

Last year, *Corporate Knights*, the world's largest circulation magazine with an explicit focus on corporate responsibility, named Hydro One as one of Canada's Top 50 Corporate Citizens. Rankings are based on a review of environmental, social and governance indicators as well as key performance indicators for specific industry sectors. Hydro One was ranked 26 out of the top 50 and third among utilities in Canada.

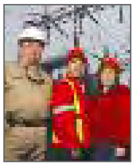
$500,000

Hydro One has committed $500,000 to advance research and treatment of patients with electrical burns, through the Ross Tilley Burn Centre at Sunnybrook Health Sciences Centre.

Hydro One's team of 4,600 employees works together to ensure Ontario has a safe, reliable supply of electricity.

Making Solid Progress in Customer Satisfaction

Customer satisfaction levels increased substantially this year. Overall satisfaction for Large Transmission Customers increased by 10% to 95% this year and overall satisfaction for Large Distribution Customers increased by 6% to reach 90%. These increases are due to a concerted effort by each and every employee in our Company to address customer issues quicker. Our goal is to achieve 90% satisfaction or better for all customers in the next five years.



Building Tomorrow's Workforce

In a few years, more than 30% of Hydro One's workforce can retire. That's why Hydro One is taking action to attract future employees by partnering with four Ontario colleges: Algonquin, Georgian, Mohawk and Northern. In addition to donating equipment and establishing scholarships and bursaries, Hydro One's professionals will help develop curriculum for the program. The partnership will make talented young people aware of the many opportunities available in the electrical transmission and distribution sector. Hydro One is also sponsoring similar programs at the University of Western Ontario, McMaster University and Ryerson University.

Kristy Dennis, controller-trainee, Farooq Qureshy, transmission system planner, and Dean Edwards, line maintainer, don't all work at the Ontario Grid Control Centre, but they do work together to meet Ontario's electricity needs.

Our greatest power is our people.

Every day the women and men of Hydro One go to work with one goal in mind: the safe, reliable operation of Ontario's electricity system. Stewardship of Ontario's electricity delivery system demands a diverse workforce with a wide variety of skills, talents and training. We need people who are not only experts in their respective fields but who are also able to contribute as members of an integrated team. System planners, station maintenance technicians, foresters, line maintainers, system operators and engineers all have to cooperate to keep Ontario strong.

Like many large employers, Hydro One is facing a massive demographic shift. Within five years, 30% of our workforce can retire. In 2007, we focused on strategies to facilitate knowledge transfer to the next generation of employees. Our New Grad initiative recruits top university graduates into an intensive two-year program that rotates them through a range of our operations.

Hydro One's apprenticeship program has steadily expanded in the last four years, with 774 apprentices joining trades such as line maintenance, electrical forestry, station maintenance and others. Hydro One's rigorous training sets the industry standard for the province and produces safe and productive workers that Ontarians can rely on.

Initiatives like our new pilot partnership with the Sioux Lookout Aboriginal Management Board and the Power Workers' Union, launched to attract new Aboriginal employees, demonstrate Hydro One's commitment to reflect the communities where we live and work.

774

Hydro One has taken on 774 apprentices in the last four years.

Hydro One Senior Management

Laura Formusa
President and
Chief Executive Officer,
Hydro One Inc.

Joe Agostino
General Counsel

Myles D'Arcey
Senior Vice-President,
Customer Operations

Steve Dorey
Vice-President,
External Relations

John Fraser
Vice-President, Internal Audit
and Chief Risk Officer

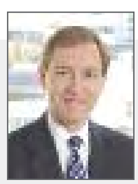
Tom Goldie
Senior Vice-President,
Corporate Services

Peter Gregg
Vice-President,
Corporate and
Regulatory Affairs

Rick Kellestine
Vice-President and
Executive Advisor

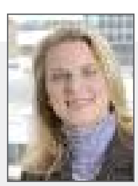
Carmine Marcello
Vice-President,
Corporate Projects

Nairn McQueen
Vice-President,
Engineering and
Construction Services



Geoff Ogram
Vice-President,
Asset Management

Wayne Smith
Vice-President,
Grid Operations



Beth Summers
Executive Vice-President and
Chief Financial Officer

Management's Discussion and Analysis

We prepare our financial statements in Canadian dollars and in accordance with accounting principles generally accepted in Canada. The following discussion is based upon our Consolidated Financial Statements for the years ended December 31, 2007 and 2006.

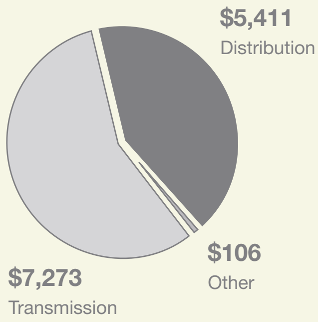
Overview

We are wholly owned by the Province of Ontario (the Province), and our transmission and distribution businesses are regulated by the Ontario Energy Board (OEB). We are the leading electricity transmitter and distributor in Ontario, delivering power safely and reliably to homes and businesses. As stewards of this province's massive and complex transmission and delivery system, our mission is to be an efficient and dynamic transmission and distribution company that is best in North America in the areas of safety, customer service and reliability, while focusing on the development and retention of our employees and creating shareholder value. In 2007, we continued our focus on our core businesses, substantially maintained and improved our performance in various key areas of the business, and made important contributions to the rebuilding of Ontario's core infrastructure.

Transmission

Substantially all of Ontario's electricity transmission system is owned and operated by our company. Our transmission system forms an integrated transmission grid that is monitored, controlled and managed centrally from one location, our Ontario Grid Control Centre in Barrie, Ontario. It operates over relatively long distances and links major sources of generation to transmission stations and larger area load centres. In 2007, we earned total transmission revenues of $1,242 million primarily by transmitting approximately 152 TWh of electricity, directly or indirectly, to substantially all consumers of electricity in Ontario. Our transmission system is one of the largest in North America, and is linked to five adjoining jurisdictions through 26 interconnections. Through these interconnections, we can accommodate imports of about 4,000 MW and exports of approximately 5,800 MW of electricity. In terms of assets, our transmission business is our largest business segment, representing approximately 57% of our total assets.

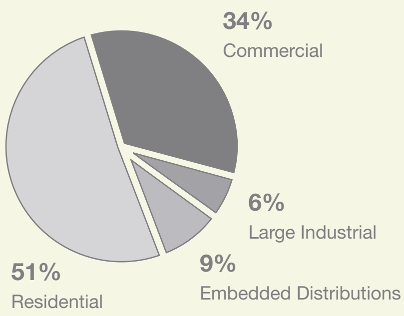
Total Assets
December 31, 2007
(Cdn $ millions)



Distribution

Our distribution system is the largest in Ontario and spans roughly 75% of the province, serving approximately 1.3 million rural and urban customers, and 50 large industrial customers. We also operate small, regulated generation and distribution systems in a number of remote communities across northern Ontario that are not connected to Ontario's electricity grid. As illustrated in the accompanying chart, about half of our distribution revenues are earned from our residential customers.

2007 Distribution Revenues



Other

Our other business segment contributed revenues of $31 million in 2007 and has assets of about $106 million, which constitute less than 1% of our total assets. This segment primarily represents the operations of our wholly owned subsidiary, Hydro One Telecom Inc., which markets fibre-optic capacity to telecommunications carriers and commercial customers with broadband network requirements.

Our Strategy

In 2007, aligned with retaining and building public confidence and trust, we maintained our strategic focus on our core operations and built upon our accomplishments. Consequently, we have moved closer to achieving our goals to be recognized by our customers as their best service provider, by our peers as their benchmark for excellence, and by our shareholder for delivering superior value, while striving to attract, develop and retain productive employees.

We seek to achieve these goals by continuing to implement the following strategies:

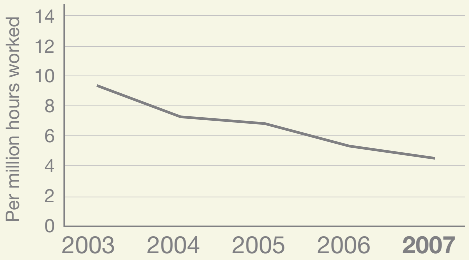
- *Stewardship:* Retain and build the public trust placed in us to ensure the safe, reliable and efficient delivery of electricity.
- *Safety:* Create and maintain an injury-free workplace with a concentrated focus on eliminating serious injury and "near misses" in high potential harm categories of work.
- *Customers:* Become a leading customer-focused company. We intend to maintain our focus and commitment to improving our customers' level of satisfaction. We strive to strengthen relationships with our large and mid-sized customers, acknowledging their commercial requirements. For residential customers, our key focus is on improving the quality of customer services such as billing, call handling, outage management, and meter reading. We also aim to make positive contributions in communities across Ontario through our corporate citizenship programs.
- *Reliability:* Enhance the reliability of our transmission and distribution systems through our productive and cost effective work programs. In transmission, we are proactively developing the system to meet Ontario's power needs. Within distribution, we are focused on reliability while recognizing the challenges in operating a system with low customer density and vast geography.
- *Financial:* Ensure our actions contribute towards maximizing the value of our company, while maintaining effective access to funds on a long-term basis at reasonable rates and delivering appropriate financial returns to our shareholder.
- *Employees:* Manage the challenges of labour demographics by attracting, developing and retaining productive employees.

Performance Measures and Targets

We measure and target our performance in all of the above strategic areas, ensuring that we are recognizing the needs of all of our key stakeholders. We met or exceeded our challenging 2007 objectives, improving in a number of areas over 2006, and are moving towards achieving our strategic goals.

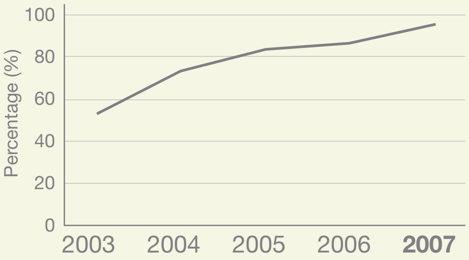
The potentially hazardous nature of our business requires a strong focus on safety. Consequently, one of our goals is to eliminate serious injuries. Accordingly, we measure our Serious Incident Rate to identify possible situations that may increase the risk of injury. These incidents include electrical contacts, preventable motor vehicle accidents and work equipment operations, among others. As shown in the accompanying chart, we had 4.4 serious incidents per million hours worked in 2007, which is 15% lower than 2006, 34% lower than 2005, and 39% lower than 2004. Going forward, we will continue to stress the importance of safety through a sustained cultural change and a continued focus on people and the work environment. This involves an emphasis on strong leadership, understanding and leveraging human factors and the role of human traits in determining safe work performance. Planned initiatives include increased facility and site assessments and further use of decision analysis tools to reduce human error and its consequences.

Serious Incident Rate



Customer satisfaction is also vital to our success. In 2007, we exceeded our overall target for customer satisfaction levels. As shown in the accompanying chart, our Large Transmission Customer Satisfaction Survey results improved from 86% to 95% satisfied, as compared to 2006. Moreover, we have seen continuous improvement over the last five years. We also continue to be conscious of the needs of our residential and small business customers and survey results show an overall satisfaction level of 82%, which remains consistent with 2006 results. We achieved our overall target for generator customer satisfaction. Within this category, we met our satisfaction target for transmission connected generators, but did not achieve our target for distribution connected generators. Addressing the concerns identified will be an area of focus in 2008. We will continue to focus on improving the level of customer satisfaction across all customer segments by targeting our responses to the unique requirements of each segment.

Large Transmission Customer Satisfaction



We aim to retain and build public confidence and trust in our operations, as stewards of the province's electricity grid. In 2007, we continued our focus on this strategic priority by investing in the key assets of the electricity delivery system and by operating the existing system for our customers in a safe, reliable and efficient fashion. We are conscious that businesses of all sizes require reliable service and consequently, we focus on achieving top-quartile reliability in relation to other comparable systems. In 2007, we met our annual reliability targets and achieved improvements over 2006. Our continued commitment to the people of Ontario has been recognized by *Corporate Knights*, an independent media magazine, focused on promoting and reinforcing sustainable development in Canada, as one of Canada's Top 50 Corporate Citizens, ranking third among utilities. The ranking was based on environment, social and governance indicators, and our conservation and demand management (CDM) and Smart Meter Programs were cited as key factors in the recognition. In addition, *Corporate Knights* recognized us as Canada's most diverse utility and ranked us fifth overall in corporate Canada.

Given the retirement profile of our employees, we are entering into a period of significant demographic change. This change is taking place across the electricity sector and we have taken a leadership role to address the transition. As part of a comprehensive strategy to meet our staffing needs well into the future, we entered into a partnership with four community colleges of applied art and technology to attract and educate the future employees of the electricity transmission and distribution sectors. Through this partnership, we will contribute towards scholarships, program development and equipment for programs that will train people for technical, technological and trades positions in the electricity sector.

Our financial performance and the business environment in which we operate are taken into consideration in both our short-term and long-term credit ratings. In March 2007, Standard & Poor's Rating Services Inc. (S&P) assigned a positive outlook to our long-term "A" credit rating from stable, attributing the improvement to lower business risk for the sector as a whole. In November, S&P issued a commentary report which reaffirmed our assigned positive outlook while noting a steady improvement in our business risk profile. Our current credit ratings facilitate ongoing access to debt markets at a reasonable cost to fund the infrastructure requirements of our system.

Regulation

Our electricity transmission and distribution businesses are licensed and regulated by the OEB. The OEB sets rates following oral or written public hearings. Our transmission revenues primarily include our transmission tariff, which is based on the uniform province-wide transmission rates approved by the OEB for all transmitters across Ontario. Our distribution revenues primarily include our distribution tariff, which is also based on OEB-approved rates, and the recovery of the cost of purchased power used by our customers. Consequently, our distribution business does not have commodity price risk. Transmission and distribution tariff rates are set based on an approved revenue requirement that provides for cost recovery and includes a return on deemed common equity. In addition, the OEB approves rate riders to allow for the recovery or disposition of specific regulatory assets and liabilities over a specified timeframe.

Under the current market structure, low-volume and designated consumers pay electricity rates established through the Regulated Price Plan (RPP) and wholesale electricity consumers pay a blend of regulated, contract and wholesale spot market prices. The OEB sets prices for RPP customers based on a two-tiered electricity pricing structure with seasonal consumption thresholds. Unexpected shortfalls or overpayments associated with the RPP are financed by the Ontario Power Authority (OPA). Prices are reviewed every six months and may change based on an updated OEB forecast and any accumulated differences between the amount that customers paid for electricity and the amount paid to generators in the previous period. Customers who are not eligible for the RPP, or wholesale customers, pay the market price for electricity adjusted for the difference between market prices and prices paid to generators under the *Electricity Restructuring Act, 2004*. The Independent Electricity System Operator (IESO) is responsible for overseeing and operating the wholesale market, as well as ensuring the reliability of the integrated power system.

In addition to the oversight role of the OEB, and the market monitoring and coordination role of the IESO, the OPA was created through the *Electricity Restructuring Act, 2004,* to ensure the long-term supply of electricity, facilitate load management and conservation, and assist with the stability of rates for RPP customers, among others. As part of its mandate, and consistent with the Province's direction regarding supply mix, the OPA developed the Integrated Power System Plan (IPSP), which was submitted for OEB review and approval on August 29, 2007. The plan's estimated 20-year capital program will be directed toward initiatives required to deliver electricity to Ontario consumers. OEB approval is expected in the Fall of 2008.

The OPA is also responsible for coordinating the delivery and funding of conservation and demand management programs. This coordination furthers initiatives undertaken by individual local distribution companies (LDCs), including our distribution businesses, as a result of distribution tariff rate increases approved in 2005. Our CDM programs funded through the OPA in 2007 amounted to approximately $6 million and our programs funded through distribution rates since 2005 amounted to approximately $41 million. The overall goal of the CDM programs, under the IPSP, is to reduce provincial demand by 6,300 MW by 2025.

The *Energy Conservation Responsibility Act, 2006* furthers the broad objectives of CDM by providing the framework for the installation of 800,000 smart meters in Ontario homes and businesses by the end of 2007, with installation in all homes and businesses to be completed by the end of 2010. These meters will be capable of measuring and reporting usage over predetermined periods, being read remotely, and when combined with communications systems will be capable of providing customers with access to information about their consumption. In 2007, the Province appointed the IESO as the smart meter entity that will oversee the collection and management of data. LDCs, including our distribution businesses, are accountable for the development of smart meter infrastructure and related technology for communications to meet minimum requirements as defined in regulations, as well as the implementation of time of use rates that are presently voluntary. In 2007, we deployed over 260,000 smart meters, exceeding our 2007 target of approximately 240,000 meters, and bringing the cumulative number of installations under our Smart Meter Program to approximately 288,000. We are continuing the deployment of smart meters (see the Future Capital Expenditures chart on page 30).

Transmission Rates

The IESO facilitates payments to us based on the Ontario Uniform Transmission Rates (UTRs) approved by the OEB for all transmitters across Ontario.

In October 2005, the OEB initiated a proceeding to review our transmission rates and revenue requirements for 2006, 2007, and 2008 based on cost of service regulation. On February 21, 2006, the OEB announced its decision to apply an earnings sharing mechanism (ESM) to equally share, between our shareholder and customers, any transmission earnings in excess of the approved rate of return of 9.88% for the period ending January 1, 2006 until new transmission rates were set. Consequently, 50% of our excess earnings recovered from customers were deferred as a regulatory liability.

In September 2006, we filed a transmission rate application through our subsidiary, Hydro One Networks Inc. (Hydro One Networks). On March 30, 2007, prior to its decision on our transmission rate application, the OEB issued a decision ordering that the ESM cease effective December 31, 2006. The decision also approved the concept of establishing a new revenue difference deferral account (RDDA) to record the revenue differential between existing transmission rates and the new rates that were anticipated to be approved later in the year, for the period commencing January 1, 2007.

On August 16, 2007, the OEB issued its decision in respect of our 2007 and 2008 transmission rate application. The decision, which was effective January 1, 2007, showed confidence in our work programs by approving all of our operating and capital expenditures for 2007 and 2008. However, the decision resulted in an estimated 8% annual reduction in transmission rates primarily due to a reduction in the approved return on equity from 9.88% to 8.35%, based on a formula used by the OEB in the regulation of LDCs. Further, the OEB approved final amounts and disposition treatments for certain regulatory accounts including the RDDA, ESM and export and wheeling fees liabilities, as well as the transmission market ready regulatory asset. The RDDA and ESM will be refunded to customers over the 14-month period from November 1, 2007 to December 31, 2008, while the export and wheeling fees liability and transmission market ready regulatory asset will be factored into rates over the four-year period ending December 31, 2010.

As part of a joint proceeding involving all transmitters in Ontario, on October 17, 2007 the OEB approved new UTRs for implementation on November 1, 2007 through to December 31, 2008. The new rates fully reflect the approved changes to our revenue requirement and charge determinants and are, on average, 12% lower than previously approved rates. The new rates should result in approximately a 1% decrease in the average customer's total electricity bill. We anticipate the OEB will reset UTRs on January 1, 2009, at which time we anticipate our revenue requirement allocation from UTRs will increase to reflect the full repayment to customers of the ESM and RDDA. To achieve the necessary funding in support of the infrastructure required, we plan to submit a transmission rate application for 2009 to 2010 transmission rates in the Summer of 2008.

Distribution Rates

As a distributor, we are responsible for delivering electricity and billing our customers for approved distribution rates, purchased power costs, and other approved regulatory charges.

Distribution Tariffs

In August 2005, we filed a distribution rate application seeking approval for an increase in the 2006 revenue requirements for our distribution businesses operated through Hydro One Networks and Hydro One Brampton Networks Inc. (Hydro One Brampton). On April 12, 2006, the OEB announced its decisions regarding these applications and, on the basis of the written and oral evidence submitted, it approved the requested increases in the revenue requirements based on an approved rate of return of 9.00%, effective May 1, 2006.

In 2006, the OEB commenced the process of establishing an Incentive Regulation Mechanism (IRM) for the years 2007 to 2010. The process includes a formulaic approach to establishing 2007 rates with a rate rebasing approach to be staggered across all Ontario distributors between 2008 and 2010. Our subsidiaries, Hydro One Networks and Hydro One Brampton, applied for marginal distribution rate adjustments in February 2007, based on an OEB-approved formula that considers inflation, efficiency targets and significant events outside the control of management. In April 2007, the OEB approved our submissions on the basis of its cost of capital and second generation IRM policies, and the revised rates were implemented effective May 1, 2007.

As our subsidiary Hydro One Networks was among 25 LDCs selected for rebasing in 2008, we submitted the revenue requirement portion of our 2008 cost of service application in accordance with the OEB's multi-year distribution rate-setting plan on August 15, 2007. This application seeks the approval of a revenue requirement of $1,067 million based on a rate of return of 8.64% for 2008. The requested distribution rate increase amounts to a net average increase of less than 1% on the average customer's total bill. On December 18, 2007, we filed the details of our cost allocation and rate design proposals, which include a plan to reduce the number of customer rate classes and consolidate or harmonize the rates for its existing rate classes to the new proposed rate classes. Based on the OEB's processing guidelines, a decision is anticipated in the latter part of 2008.

On August 2, 2007, the OEB initiated a consultation on the development of the principles and methodology for the third generation IRM. This consultative process will culminate with the issuance of an OEB report expected in mid-2008 that will be used to adjust rates starting in 2009, for those LDCs, including our subsidiary Hydro One Networks, whose 2008 rates will be rebased. On November 1, 2007, Hydro One Brampton filed its application for 2008 rates on the basis of the OEB's cost of capital and second generation IRM policies. The distribution rates of our subsidiary, Hydro One Brampton, will be rebased in 2010.

Smart Meter Program

In March 2006, the OEB approved a monthly rate of 27 cents and 28 cents per metered customer, effective May 1, 2006, as initial funding for the required investment in smart meters for our subsidiaries Hydro One Networks and Hydro One Brampton, respectively. As a result, expenditures in excess of recoveries were recorded as a regulatory asset, with disposition to be established at a later date. In April 2007, as part of the OEB decision regarding the 2007 distribution rate applications made by Hydro One Networks and Hydro One Brampton, the OEB approved an amount of 93 cents and 67 cents, respectively, per month per metered customer for smart meters, for implementation effective May 1, 2007.

On August 8, 2007, the OEB issued a decision on its combined proceeding to determine recoverability of expenditures incurred by distributors. Expenditures associated with the approved minimum functionality for advanced metering infrastructure incurred by our subsidiaries Hydro One Networks and Hydro One Brampton were approved for recovery. As a result of this decision, smart meter expenditures are no longer deferred as regulatory assets, and instead, are now classified as capital or are charged to results of operations. Expenditures determined to be above the minimum functionality for our subsidiary Hydro One Networks have been brought forward for review in our 2008 cost of service rate application. Hydro One Brampton will bring these expenditures forward in its 2010 cost of service application.

Results of Operations

Revenues

Year ended December 31 (Canadian dollars in millions)	**2007**	2006	$ Change	% Change
Transmission	**1,242**	1,245	(3)	–
Distribution	**3,382**	3,273	109	3
Other	**31**	27	4	15
	4,655	4,545	110	2
Average annual Ontario 60-minute peak demand ***(MW)***[1]	**22,988**	22,650	338	1
Distribution – units distributed to customers ***(TWh)***[1]	**30.2**	29.0	1.2	4

1 System-related statistics include preliminary figures for December.

Transmission

Transmission revenues predominantly consist of our transmission tariff, which is based on the monthly peak demand for electricity across our high-voltage network. The tariff is designed to recover revenues necessary to support a transmission system with sufficient capacity to accommodate the maximum expected demand, which is primarily influenced by weather and economic conditions. Transmission revenues also include minor amounts of ancillary revenues which are primarily attributable to maintenance services provided to generators and secondary use of our land rights-of-way.

Revenues for the year were affected by the OEB's August 16, 2007 decision on our transmission rate application. While the OEB approved all of our work program expenditure requirements, our return on equity was reduced from 9.88% to 8.35% and our deemed capital structure was adjusted from one that included common and preferred shares and debt to a deemed capital structure of 60% debt and 40% common shares. This capital structure is consistent with that approved by the OEB in 2006 which established the capital structure for Ontario's LDCs. The OEB's decision was effective January 1, 2007 and new customer rates reflecting the decision were implemented on November 1, 2007. As a result of the OEB decision, we reduced our 2007 transmission revenues to reflect the approved revenue requirement. Excess amounts collected from customers have been recorded in the RDDA and are being returned to customers through lower rates commencing November 1, 2007. On March 30, 2007, the OEB approved cessation of the ESM effective December 31, 2006 and replaced it with the RDDA. The RDDA and ESM liabilities will be drawn down over the period the new rates are in place and will be reflected in revenue over the 14-month period from November 1, 2007 to December 31, 2008.

Our transmission revenues were lower by $3 million, compared to 2006. The OEB's August 16, 2007 transmission rate decision reduced our revenues by about $53 million. This includes the revenue adjustment associated with recording the RDDA liability and the impact of the new OEB-approved rates effective November 1, 2007. Partially offsetting this decrease was the effect of the OEB's earlier decision to end the ESM effective December 31, 2006, which increased our transmission revenues by about $33 million.

Revenues for the year also reflect higher average peak demands compared to last year, resulting in increased transmission revenues of $23 million and lower other revenues of $6 million.

Distribution

Distribution revenues include our distribution tariff, which is based on OEB-approved rates, as well as amounts to recover the cost of purchased power used by our customers. Accordingly, distribution revenues are primarily influenced by our distribution rates, the amount of electricity we distribute, and the cost of purchased power. Distribution revenues also include a minor amount of ancillary distribution services revenues, such as fees related to the use of our poles by the telecommunications and cable television industries, and miscellaneous charges such as those for late payments.

Distribution revenues increased by $109 million, or 3%, in 2007 compared to last year. This change includes the recovery of increased purchased power costs of $19 million as described below under Purchased Power. In addition, the OEB approved increases in distribution tariff rates for our subsidiaries, Hydro One Networks and Hydro One Brampton, effective May 1, 2006 and May 1, 2007, respectively. These tariff rate increases, which support the maintenance and investment requirements of our distribution system and enable the safe and reliable delivery of electricity to our customers through Ontario, resulted in higher distribution revenues of $45 million during the year. In 2006, rates were approved based on a full cost of service hearing. In 2007, rates were approved based on OEB guidelines that included an incentive mechanism to adjust rates. Higher energy consumption, resulting primarily from the colder winter weather this year, increased our distribution revenues by a further $26 million. In addition, as a result of the OEB's decision on August 8, 2007 regarding the combined smart meter proceeding, we recorded smart meter revenues of $17 million reflecting recovery of our investments in this program. We also experienced higher other revenues of $2 million during the year.

Purchased Power

Purchased power costs incurred by our distribution business represent the cost of electricity delivered to customers within our distribution service territory and consist of the wholesale commodity cost of energy, the IESO's wholesale market service charges, and transmission charges levied by the IESO. The commodity cost of energy for certain low-volume and designated customers is based on the OEB's RPP, which consists of a two-tiered pricing structure with seasonal threshold amounts. Customers that are not eligible for the RPP pay the market price for electricity, adjusted for the difference between market prices and the prices paid to generators under the *Electricity Restructuring Act, 2004*. A summary of the RPP affecting the two-year period 2006 and 2007 is provided below.

Summary of RPP

	Tier Threshold (kWh/month)		Tier Rates (cents/kWh)	
Effective Date	Residential	Non-Residential	First Tier	Second Tier
November 1, 2005	1,000	750	5.0	5.8
May 1, 2006	600	750	5.8	6.7
November 1, 2006	1,000	750	5.5	6.4
May 1, 2007	600	750	5.3	6.2
November 1, 2007	1,000	750	5.0	5.9

Purchased power costs increased in 2007 by $19 million, or 1%, to $2,240 million compared to last year. Our increased purchased power costs were primarily due to higher demand for electricity of $57 million, higher wholesale commodity prices of $25 million for customers who are not eligible for the RPP and higher wholesale market service charges levied by the IESO of $7 million. These increases were partially offset by lower costs of $62 million associated with the OEB's RPP for residential and other eligible customers, combined with the impacts of the OEB's August 16, 2007 transmission rate decision of $8 million.

Operation, Maintenance and Administration

Our operation, maintenance and administration costs are comprised primarily of labour, material, equipment and purchased services in support of the operation and maintenance of the transmission and distribution systems. These costs also include property taxes and payments in lieu thereof on our transmission and distribution lines, stations and buildings.

Operation, maintenance and administration costs for each of our three business segments were as follows:

Year ended December 31 (Canadian dollars in millions)	**2007**	2006	$ Change	% Change
Transmission	**415**	390	25	6
Distribution	**549**	460	89	19
Other	**31**	30	1	3
	995	880	115	13

Transmission

Operation, maintenance and administration expenditures incurred to sustain our high-voltage transmission stations, lines and rights-of-way increased by $25 million, or 6%, in 2007 compared to last year. Within our work programs, we continued our investments necessary for the safe and reliable operation of the transmission system. We experienced higher work program expenditures of $24 million primarily related to our planned station maintenance programs for power equipment and transformers and our line clearing and brush control programs, partially offset by lower requirements for unplanned corrective maintenance. We also experienced marginally higher expenditures in support of the transmission system. This increase reflects the commencement of a major business systems and processes project which will enable the adoption of more efficient, standardized business processes, the impact on our transmission regulatory accounts as a result of the OEB's August 16, 2007 transmission rate decision and the impact of a negotiated property tax settlement in 2006. The effect of these increases was partially offset by the impacts of a statutory reduction in our capital taxes and the reassignment of resources to support this year's larger transmission capital program.

Distribution

Operation, maintenance and administration expenditures necessary to maintain our low-voltage distribution system increased by $89 million, or 19%, compared to last year. Increased requirements within our work program of $65 million primarily resulted from the planned expansion of our forestry and line maintenance programs incurred to increase reliability. In addition, we experienced increased customer participation in our conservation and demand management programs. These increases were partially offset by reductions in expenditures incurred to respond to storm damage. In addition, our costs increased due to impacts of last year's OEB rate decision, including the recognition of distribution-related pension costs which had been previously deferred as a regulatory asset. Our operating, maintenance and administration expenditures also increased as a result of the OEB's August 8, 2007 decision on its combined smart meter proceeding due to the recognition of smart meter-related operating expenditures that were incurred in the 2005 to 2007 period but which were previously deferred as regulatory assets. In addition to these increases, our other support expenditures were higher by $24 million as a result of resource requirements in support of the maintenance program and the commencement of a major business systems and processes project, partially offset by the impact of a statutory reduction in our capital taxes.

Depreciation and Amortization

Depreciation and amortization expense increased by $6 million, or 1%, to $521 million this year. This increase was mainly attributable to the placement of new assets in service, consistent with our ongoing capital work program. We also experienced higher amortization of our regulatory assets resulting from an April 12, 2006 OEB distribution rate decision that was effective on May 1, 2006. These increases were partially offset by lower fixed asset removal costs resulting from lower storm damage in the year, compared to 2006.

Financing Charges

Financing charges remain unchanged at $295 million compared to last year. We experienced a lower average effective interest rate on our outstanding debt which was offset by lower capitalized interest on our regulatory assets due to lower prescribed OEB rates and increased regulatory liabilities.

Provision for Payments in Lieu of Corporate Income Taxes

We make payments in lieu of corporate income taxes to the Ontario Electricity Financial Corporation (OEFC) in accordance with the *Electricity Act, 1998* and on the same basis as if we were subject to federal and provincial corporate taxes. In providing for payments in lieu of corporate income taxes relating to our regulated businesses, the taxes payable method is used, whereas the liability method is used in computing the tax provision for our unregulated businesses.

The provision for payments in lieu of corporate income taxes increased by $26 million, or 15%, to $205 million in 2007 compared to 2006. The increase is primarily due to last year's recognition of a $30 million tax benefit related to the recovery of payments in lieu of corporate taxes from prior years, taxes payable on transmission amounts received this year but not recognized as revenue for accounting purposes, and temporary differences associated with certain regulatory accounts. These increases were partially offset this year by lower taxable income and other minor temporary differences.

Net Income

Net income of $399 million was lower by $56 million, or 12%, compared to 2006 results. Net income for the year was impacted by the OEB's August 16, 2007 transmission rate decision. While the OEB approved all of our work program requirements for 2007 and 2008, our return on equity was reduced from 9.88% to 8.35% effective January 1, 2007. Our net income also reflects higher requirements to operate and safely maintain our transmission and distribution systems, including enhanced transmission station maintenance and forestry programs. Our net income was further impacted by OEB decisions, including a 2006 decision affecting our distribution-related pension expenditures, last year's property tax settlement and a higher effective tax rate. These impacts were partially offset by an increase in our distribution revenues resulting from OEB-approved increases to our distribution tariff rates, as well as increased tariff revenue in our transmission and distribution businesses due to increased peak demands and energy consumption, as well as the elimination of last year's ESM.

Quarterly Results of Operations

The following table sets forth unaudited quarterly information for each of the eight quarters from March 31, 2006 through December 31, 2007. This information has been derived from our unaudited interim Consolidated Financial Statements which, in the opinion of our management, have been prepared on a basis consistent with the audited annual Consolidated Financial Statements and which include all adjustments, consisting only of normal recurring adjustments, necessary for fair presentation of our financial position and results of operations for those periods. These operating results are not necessarily indicative of results for any future period and should not be relied upon to predict our future performance.

(Canadian dollars in millions)				**2007**				2006
Quarter ended	**Dec. 31**	**Sep. 30**	**Jun. 30**	**Mar. 31**	Dec. 31	Sep. 30	Jun. 30	Mar. 31
Total revenues[1,2]	**1,129**	**1,128**	**1,120**	**1,278**	1,142	1,165	1,078	1,160
Net income[1,2]	**90**	**67**	**93**	**149**	101	103	99	152
Net income to common shareholder[1,2]	**85**	**63**	**88**	**145**	96	99	94	148

1 The demand for electricity generally follows normal weather-related variations, and therefore our electricity-related revenues and profit, all other things being equal, would tend to be higher in the first and third quarters than in the second and fourth quarters.

2 As a result of the OEB's August 16, 2007 decision on Hydro One Networks' transmission rate application that was effective January 1, 2007, revenues reflect a reduced revenue requirement based on the approved rate of return of 8.35%. Previously, the rate of return was 9.88%.

Liquidity and Capital Resources

Our primary sources of liquidity and capital resources are funds generated from operations, debt capital market borrowings and bank financing. These sources will be used to satisfy our capital resource requirements, which continue to include capital expenditures, servicing and repayment of our debt, payments related to our outsourcing arrangements, investing activities, and dividends.

Summary of Sources and Uses of Cash

Year ended December 31 *(Canadian dollars in millions)*	**2007**	2006
Operating activities	**1,141**	909
Financing activities		
Long-term debt issued	**700**	775
Long-term debt retired	**(355)**	(589)
Short-term notes payable	**(60)**	60
Dividends paid	**(325)**	(350)
Investing activities		
Capital expenditures	**(1,091)**	(823)
Other financing and investing activities	**7**	(2)
Net change in cash and cash equivalents	**17**	(20)

Operating Activities

Net cash from operating activities increased by $232 million to $1,141 million, compared to 2006 results. Our working capital requirements were substantially lower than the comparative period primarily as a result of the impact of the *Ontario Price Credit* that was provided to RPP customers in early 2006, pursuant to regulation. Funding for the credit was received from the IESO in early December 2005. Our working capital requirements were also impacted by lower electricity prices charged to RPP customers in 2007, the impacts of last year's OEB distribution rate decision and increased accounts payable primarily associated with our capital expenditure program.

Financing Activities

Short-term liquidity is provided through funds from operations and our commercial paper program, under which we are authorized to issue up to $1 billion in short-term notes with a term to maturity of less than 365 days. At December 31, 2007, we had no short-term notes payable outstanding. The commercial paper program is supported by a committed revolving credit facility with a syndicate of banks. On January 28, 2008, we increased the facility from $750 million to $1,000 million. The maturity date remains unchanged at August 10, 2010. The short-term liquidity under this program and anticipated levels of funds from operations should be sufficient to fund our normal operating requirements. At December 31, 2007, we had $5,615 million in long-term debt outstanding, including the current portion. Long-term financing is provided by our access to the debt markets, primarily through our Medium-Term Note Program. On June 21, 2007, we filed a $2.5 billion base shelf prospectus to renew our Medium-Term Note Program for another 25 months. Our notes and debentures mature between 2008 and 2046. We currently plan to refinance maturing debt principally through our Medium-Term Note Program. The maximum authorized principal amount of medium-term notes issuable under this program is $2,500 million, of which $2,200 million is remaining and is currently available until July 2009.

Rating Agency	Rating Short-term Debt	Rating Long-term Debt
DBRS Limited	R-1 (middle)	A (high)
Moody's Investors Service Inc.	Prime-1	Aa3
Standard & Poor's Rating Services Inc.	A-1	A

We have the customary covenants normally associated with long-term debt. Among other things, our long-term debt covenants limit our permissible debt as a percentage of our total capitalization, limit our ability to sell assets and impose a negative pledge provision, subject to customary exceptions. The credit agreement related to our $750 million credit facility has no material adverse change clauses that could trigger default. However, the credit agreement requires that we provide notice to the lenders of any material adverse change within three business days of the occurrence. The agreement also provides limitations that debt cannot exceed 75% of total capitalization and that debt issued by our subsidiaries cannot exceed 10% of the total book value of our assets. We are in compliance with all of these covenants and limitations.

During 2007, we issued $700 million in long-term debt under our Medium-Term Note Program and we repaid $355 million in maturing long-term debt. In comparison, during 2006 we issued $775 million in debt under our Medium-Term Note Program and we repaid $589 million in maturing long-term debt. In 2007, we decreased our short-term notes by $60 million compared to an increase of $60 million in 2006.

In 2007, we paid dividends to the Province in the amount of $325 million, consisting of $307 million in common dividends and $18 million in preferred dividends. In the comparative period, we paid common dividends of $332 million and preferred dividends of $18 million. In 2007, cash dividends per common share were $3,070 compared to $3,320 per common share in 2006. Cash dividends per preferred share were $1.375 in each of 2007 and 2006.

Common dividends are declared at the sole discretion of our Board of Directors, and are recommended by management based on results of operations, financial condition, cash requirements and other relevant factors such as industry practice, shareholder expectations. Common dividends pertaining to the quarterly financial results are generally declared and paid in the immediately following quarter.

Investing Activities

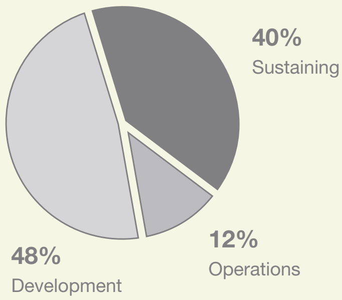
Cash used for investing activities, primarily representing capital expenditures to enhance and reinforce our transmission and distribution infrastructure in the public interest, was as follows:

Year ended December 31 (Canadian dollars in millions)	**2007**	2006	$ Change	% Change
Transmission	**560**	402	158	39
Distribution	**511**	417	94	23
Other	**20**	4	16	400
	1,091	823	268	33

Transmission

Transmission capital expenditures increased by $158 million in 2007 to $560 million, compared to 2006. Expenditures to expand and reinforce the transmission system were $271 million, representing an increase of $92 million over last year. This increase primarily reflects expenditures on our major lines and stations development projects. These projects include our new interconnection with Quebec, which will increase access to emission-free hydroelectric power, our Essa to Stayner connection, which will improve the adequacy and reliability of supply to the Southern Georgian Bay region in recognition of the growing needs of our customers, and the completion of our Downtown Toronto Cable Project. Expenditures on our load and generation connections work have also increased primarily as a result of reconfiguration work at our Lambton Transformer Station and work at our London Talbot, Pleasant, and Holland transformer stations. The impact of these project expenditures was partially offset by last year's expenditure on our Niagara Reinforcement Project. This connection was substantially completed last year but final completion continues to be delayed by the aboriginal land dispute in the Caledonia area. Discussions continue between the involved aboriginal peoples and the various government entities involved. We will complete this project when site access becomes available.

2007 Transmission Capital Expenditures

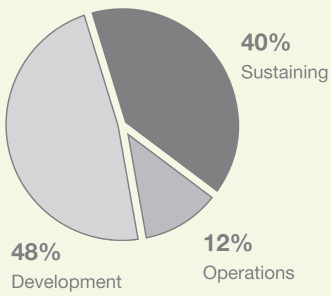


Expenditures to sustain our existing transmission system were $221 million, representing an increase of $31 million compared to 2006. This increase was primarily related to the refurbishment and replacement of end-of-life lines and stations, including work at our Claireville Transformer Station to improve current reliability and to meet growing demands, and protection and control work at our switchyard facility adjoining the Pickering Nuclear Generating Station. Our other transmission capital expenditures were $68 million in 2007, representing an increase of $35 million from last year. This increase included higher information technology expenditures primarily related to a major business systems and processes project.

Distribution

Distribution capital expenditures increased by $94 million to $511 million in 2007, compared to the prior year. Capital expenditures to expand and reinforce our distribution network were $245 million, an increase of $78 million compared to last year. This increase primarily reflects our ongoing investment in smart meters. During the year we installed approximately 260,000 meters, exceeding our 2007 target of approximately 240,000 meters, and bringing our cumulative program total to about 288,000 meters. We also experienced increased expenditures for new customer connections and for planned lines work, partially offset by slightly lower expenditures related to station meters.

2007 Distribution Capital Expenditures



Expenditures to sustain our low-voltage distribution system were $204 million, a reduction of $21 million from 2006. This reduction was primarily a result of lower storm-related expenditures. In 2007, we experienced lower capital expenditures of about $39 million to replace assets and components damaged or destroyed by major storms. Last year an unusual number of violent storms swept through the province and, in particular, a series of severe storms was experienced last summer. This impact was partially offset by higher planned end-of-life replacements of lines assets. Our other distribution capital expenditures were $62 million in 2007, representing an increase of $37 million from last year. This increase included higher information technology expenditures primarily related to a major business systems and processes project.

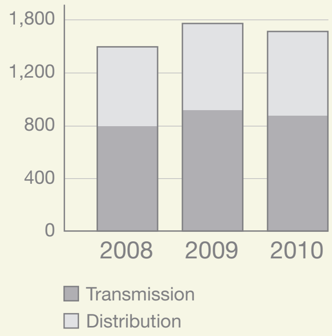
Other

Other capital expenditures made to enhance our telecom infrastructure increased by $16 million to $20 million in 2007. This increase was largely due to construction of a dedicated optical network which will provide secure, high capacity connectivity across numerous health care locations in Ontario.

Future Capital Expenditures

Our capital expenditures in 2008 are budgeted at approximately $1.4 billion. The 2008 capital budgets for our transmission and distribution businesses are about $800 million and $600 million, respectively. Capital expenditures, as shown in the accompanying chart, are expected to exceed $1.5 billion in both 2009 and 2010, primarily reflecting increasing investments to expand, refurbish or replace transmission infrastructure. The overall investment levels reflect transmission infrastructure requirements consistent with government policy, OPA planning information, local area supply requirements and the needs of preventive and corrective maintenance to manage aging assets. These investments will facilitate an adequate and reliable supply of electricity in the public interest. These investment levels also reflect the continued mass deployment of smart meters within our distribution businesses that began in 2007. The replacement of critical information technology systems is also underway. Capital expenditures of our other business segment are budgeted at about $11 million in 2008, about half of the 2007 level, as the implementation of a dedicated fibre-optic network, initiated in 2007, will be completed in 2008.

Future Capital Expenditures
(Cdn $ millions)



Transmission

Transmission system capital expenditures are anticipated to be significant over the period 2008 to 2010, amounting to about $2.5 billion. Our investment plan will address the needs of new generation development and load growth in local areas in the province. The transmission program also continues the focus on sustaining the performance of aging assets through maintenance and refurbishment programs and the replacement of assets that have reached their end of life.

With the primary focus of the recently filed IPSP being on mid- to long-term timeframes, the need justification for most major urgent, short-term transmission investments will continue through Leave-to-Construct (Section 92) proceedings. Referenced in the IPSP as short to mid-term investments is the project to connect redeveloped nuclear generation and wind from the Bruce Peninsula to our Milton Switching Station, other projects of local area supply, and the installation of equipment at our existing transmission stations. OEB and environmental approvals are being sought to build the 500kV line from the Bruce Peninsula, funding for which is included in the investment plan through to 2011. Given the timeframes required for stakeholdering, approvals, and construction, interim measures are being implemented to minimize the impact of generation scheduled to be available in 2009. These are comprised of the enhancement of the protection systems, the installation of Static Var Compensators and shunt capacitor banks in southwestern Ontario, and the upgrade of certain 230kV circuits.

Other projects included in the transmission investment plan include system expansions in northeastern Ontario to accommodate generation on the Mattagami River; transmission reinforcements in the Greater Toronto Area (GTA), Southern Georgian Bay, Woodstock and Windsor; and the interconnection between Ontario and Quebec. Construction of the Toronto third supply is contingent on the OEB approval of the IPSP and the OPA's determination of the need date. This project, for which funding is included in the plan, extends beyond the current planning horizon. This project is required to mitigate the risks associated with having only two major supply corridors to the City of Toronto and as such, to maintain a reliable supply of electricity.

At the local level, we continue to proactively address supply needs with our customers in order to meet load growth. For projects required to provide reliable delivery of electricity to communities, the participation and support of the affected LDCs, as partners in joint planning studies and throughout the consultation and approval processes, continue to be essential. Examples of projects under construction to meet the growing needs of our customers include new transformer stations to serve Essex County and Simcoe County, and expansions of transformer stations serving Brampton, Kingston, York Region and Red Lake. To address local future needs, we are in discussions with customers for major transmission expansions or new transformer stations and, where necessary, line connections in locations such as Woodstock, Mississauga, Oshawa and Brampton. Targeted investments in customer delivery point performance, power quality and our 115kV and 230kV systems are expected to lead to improved reliability.

The investment plan also includes increased program expenditures to manage the replacement and refurbishment of our aging transmission infrastructure to ensure a continued reliable supply of energy to customers throughout the province. Through targeted replacement programs for components, such as gas insulated switchgear, air blast circuit breakers, and 750 MVA autotransformers, improved performance is anticipated, which should reduce system integrity risks.

The timing of many development projects is uncertain as they are dependent upon the final approval of the IPSP and, in some instances, require approvals from various regulatory bodies, as well as negotiations and consultations with customers, neighbouring utilities and other stakeholders. We will not undertake large capital expenditures without a reasonable expectation of recovering them in our rates.

Distribution

Capital expenditures for the period 2008 to 2010 are estimated to be approximately $2 billion, including the Smart Meter Program, and core development and sustainment programs. With approximately 1.3 million customers in our service territory, we anticipate installing about a further one million meters under the program. Consistent with the government policy, all homes and small businesses are to receive a smart meter by 2010. At the Province's request, we will review our implementation plan and associated costs for the period from 2008 to 2010. Smart Network is an initiative that would leverage the smart meter infrastructure to enable functionality across our rural territory. This is currently being piloted and validated, and will be brought forward for consideration if benefits are confirmed.

Our core work will focus on demand programs such as new load connections, trouble calls and storm damage, and system capability reinforcement. The distribution investment plan also includes program expenditures relating to preserving the performance of our aging distribution asset base in order to improve system reliability. These include increased wood pole replacements, feeder sectionalization, and defect management, together with improved maintenance and line clearing practices. Given initiatives to encourage renewable energy technologies, we are experiencing increased distribution generation connection activity. Connection impact assessments are undertaken to determine project feasibility. Under OEB rules, the generator will pay connection costs other than distribution upgrades that also benefit other customers. No provision has been included in the plan for major distribution system modifications to accommodate this growth of new generation.

Summary of Contractual Obligations and Other Commercial Commitments

The following table presents a summary of our debt and other major contractual obligations, as well as other major commercial commitments:

December 31, 2007 *(Canadian dollars in millions)*	Total	2008	2009/2010	2011/2012	After 2012
Contractual obligations *(due by year)*:					
Long-term debt – principal repayments	5,615	540	800	850	3,425
Long-term debt – interest payments	5,211	307	554	488	3,862
Inergi LP (Inergi) outsourcing agreement[1]	396	100	190	106	–
Operating lease commitments	16	6	7	2	1
Total contractual obligations[5]	11,238	953	1,551	1,446	7,288
Other commercial commitments *(by year of expiry)*:					
Bank line[2]	750	–	750	–	–
Letters of credit[3]	99	99	–	–	–
Guarantees[3]	325	325	–	–	–
Pension[4]	196	94	102	–	–
Total other commercial commitments	1,370	518	852	–	–

1 On March 1, 2002, Inergi LP began providing a range of services to us for a 10-year period, including information technology, customer care, supply chain and certain human resources and finance services.

2 As a backstop to our commercial paper program, we have a $750 million revolving standby credit facility with a syndicate of banks which matures in August 2010. On January 28, 2008 this facility was increased to $1,000 million.

3 We currently have bank letters of credit of $95 million outstanding relating to retirement compensation arrangements. We have also provided prudential support to the IESO on behalf of our subsidiaries as required by the IESO's Market Rules, using parental guarantees of up to a maximum of $325 million. The maximum parental guarantee was increased in November 2007 to $325 million as a result of forecast power purchases and the November 1, 2007 change to our transmission rates. Although no letters of credit are currently required for prudential support, we would have to resume providing bank letters of credit if our highest long-term credit rating deteriorated to below the "Aa" category. The remaining amounts included in letters of credit pertain to operating letters of credit and to surety bonds.

4 Contributions to the pension fund are made one month in arrears. Contributions for 2008 are based on an actuarial valuation filed in September 2007 and effective December 31, 2006. Our annual pension contributions for 2008 and 2009 will be about $94 million. Contributions beyond 2009 will be based on an actuarial valuation effective December 31, 2009 and will depend on future investment returns, changes in benefits or actuarial assumptions. Pension contributions beyond 2009 are not estimable at this time.

5 In addition, the Company has entered into various agreements to purchase goods or services in support of our work programs that are enforceable and legally binding. None of these are considered individually material, and the majority will result in payments by our company by December 31, 2008.

The amounts in the above table under long-term debt – principal repayments, are not charged to our results of operations, but are reflected on our Balance Sheet and Statement of Cash Flows. Interest associated with this debt is recorded under financing charges on our Statement of Operations or in our capital programs. Payments in respect of operating leases and our outsourcing agreement with Inergi LP are recorded under operation, maintenance and administration costs on our Statement of Operations or within our capital expenditures.

Related Party Transactions

Related party transactions primarily consist of our transmission revenues received from, and our power purchases payments made to, the IESO, which is a related party by virtue of its status as an agency of our shareholder. The year-over-year changes related to these amounts are described more fully in our discussion of our transmission revenues and purchased power costs. Other significant related party transactions include our dividends which are paid to the Province and our payments in lieu of corporate income taxes which are paid or payable to the OEFC.

Risk Management and Risk Factors

We have an enterprise risk management program that aims at balancing business risks and returns. An enterprise-wide approach enables regulatory, strategic, operational and financial risks to be managed and aligned with our strategic business objectives.

While our philosophy is that risk management is the responsibility of all employees, the Audit and Finance Committee of our Board of Directors annually reviews our company's risk tolerances, our risk profile and the status of our internal control framework. Our President and Chief Executive Officer has ultimate accountability for risk management. Our Leadership Team, comprising direct reports to the President and Chief Executive Officer, provides senior management oversight of risk in our company. Our Chief Risk Officer is responsible for the ongoing monitoring and review of our risk profile and practices, and our Chief Financial Officer is responsible for ensuring that the risk management program is an integral part of our business strategy, planning and objective setting. Each of our subsidiaries, as well as key specialist functions and field services, is required to complete a formal risk assessment and to develop a risk mitigation strategy.

The Audit and Finance Committee, the President and Chief Executive Officer, and the Chief Financial Officer are supported by our Chief Risk Officer. This support includes coordinating risk policies and programs, establishing risk tolerances, preparing risk assessments and profiles and assisting line and functional managers in fulfilling their responsibilities. Our internal audit staff is responsible for performing independent reviews of the effectiveness of risk management policies, processes and systems.

Ownership by the Province

The Province owns all of our outstanding shares. Accordingly, the Province has the power to determine the composition of our Board of Directors and appoint the Chair, and thus influence our major business and corporate decisions. We have entered into a shareholder agreement with the Province relating to certain aspects of the governance of our company.

Conflicts of interest may arise as a result of the Province's obligation to act in the best interests of the residents of Ontario in a broad range of matters, including the regulation of Ontario's electricity industry and environmental matters, any future sale or other transaction by the Province with respect to its ownership interest in our company, the Province's ownership of Ontario Power Generation Inc. (OPG), and the determination of the amount of dividend or payments in lieu of corporate income taxes. We may not be able to resolve any potential conflict with the Province on terms satisfactory to us.

Risk Associated with Transmission Projects

Significant investments have been initiated to increase transmission capacity and enable the reliable delivery of power to Ontario consumers from existing and future generation sources. In many cases, initiating these investments is contingent upon one or more approvals. These can include Section 92, expropriation and environmental approvals, as well as consultation, and possibly accommodation with First Nations where traditional lands or lands subject to land claims are involved. The ability to make such investments may also be impacted by public opposition. If we are unable to make such investments, the reliability of our transmission system and our service quality could be adversely affected.

Workforce Demographic Risk

More than 20% of our employees will be eligible for retirement by the end of 2008. We expect the skilled labour market for our industry to be highly competitive in the future. Consequently, we must continue to advance our training and apprenticeship programs and succession plans to ensure that our future operational staffing needs will be met. If we are unable to attract and retain qualified personnel, our operations could be adversely affected.

Regulatory Risk

We are subject to regulatory risks, including the approval by the OEB of rates for our transmission and distribution businesses that permit a reasonable opportunity to recover the estimated costs of providing service on a timely basis and to earn the approved rate of return.

The OEB approves our transmission and distribution rates based on projected electricity load and consumption levels. If actual load or consumption falls below projected levels, our rate of return for either or both of these businesses could be adversely affected. Also, our current revenue requirements for these businesses are based on cost assumptions that may not materialize. There is no assurance that the OEB would allow rate increases sufficient to offset unfavourable financial impacts from unanticipated changes in electricity demand or in our costs.

Our load could also be negatively impacted by successful CDM programs. Current requirements for CDM call for a 5% reduction in Ontario's projected peak electricity demand by 2010. These expectations are factored into our revenue requirements for OEB approval. There is a risk that our revenues would be reduced if these targets are exceeded. The OEB has recognized the need to compensate utilities for such lost revenue, but the approach, level and timing of such compensation is yet to be determined. We are also subject to risk of revenue loss from other factors. For example, revisions to the OEB's *Transmission System Code* have resulted in customers gaining the right to bypass some of our transformation facilities by constructing their own assets under certain conditions.

As a transmitter, we expect to make significant investment in the coming years in large-scale transmission infrastructure projects and to connect new third-party load and generation assets. Additionally, there is always the possibility that we could incur unexpected capital expenditures to maintain or improve our assets. The risk exists that the OEB may not allow full recovery of such investments. To the extent possible, we try to mitigate this risk by seeking from the regulator clear policy direction on cost responsibility and pre-approval of the need for capital expenditures.

The Province has passed regulations authorizing our subsidiaries, as distributors, to procure smart meters. Of the associated costs in rates, our subsidiaries Hydro One Networks and Hydro One Brampton are only currently authorized to recover 93 cents and 67 cents per metered customer per month, respectively. While we expect all of our expenditures to be fully recoverable after OEB review, any future regulatory decision to disallow or limit the recovery of such costs would lead to potential impairment and charges to results of operations.

Asset Condition

We continually monitor the condition of our assets and maintain, refurbish or replace them to maintain the performance that is needed to support transmission reliability and service quality to our customers. Capital and maintenance programs have been increasing to maintain the performance of our aging asset base. However, execution of these plans is dependent on external factors including limited opportunities to remove equipment from service to accommodate construction due to outage constraints as determined by the IESO and substantially increased lead times for material and equipment due to increased global demand and limited vendor capability. Consequently, the necessary maintenance or replacements may be delayed, which could affect transmission reliability.

Risk of Natural and Other Unexpected Occurrences

Our facilities are exposed to the effects of severe weather conditions, natural disasters and catastrophic events. Although constructed, operated and maintained to industry standards, our facilities may not withstand occurrences of this type in all circumstances. We do not have insurance for damage to our assets located outside our transmission and distribution stations. Lost revenues, repair costs, damage and claims from third parties could be substantial. In the event of a large uninsured loss, we would apply to the OEB for the recovery. However, there is no assurance that the OEB would approve such an application.

Risk from Transfer of Assets Located on Indian Lands

The transfer orders by which we acquired certain of Ontario Hydro's businesses as of April 1, 1999 did not transfer title to some assets located on lands held for bands or bodies of Indians under the *Indian Act* (Canada). Currently, the OEFC holds these assets. Under the terms of the transfer orders, we are required to manage these assets until we have obtained all consents necessary to complete the transfer of title of these assets to us. We cannot predict the aggregate amount that we may have to pay, either on an annual or one-time basis, to obtain the required consents. However, we anticipate having to pay more than the approximately $900,000 per year that we currently are paying to these Indian bands and bodies. If we cannot obtain consents from the Indian bands and bodies, the OEFC will continue to hold these assets for an indefinite period of time. If we cannot reach a satisfactory settlement, we may have to relocate these assets from the Indian lands to other locations or replace them at a cost that could be substantial. These potential costs could have a material adverse effect on our results of operations if we are unable to recover them in future rate orders.

Labour Relations Risk

The substantial majority of our employees are represented by either the Power Workers Union (PWU) or the Society of Energy Professionals. The existing collective agreements with the PWU will expire on March 31, 2008; collective bargaining commenced in January 2008. The Society of Energy Professionals' collective agreement was recently renewed and now expires on March 31, 2013. We face financial risks related to our ability to negotiate collective agreements consistent with our rate orders. In the event of a labour dispute, we could face operational risk related to continued compliance with our license requirements of providing service to customers.

Environmental Risk

We are subject to extensive environmental regulation and failure to comply could subject us to fines and other penalties. In addition, the presence or release of hazardous or other substances could lead to claims by third parties and/or governmental orders requiring us to take specific actions such as investigating, controlling and remediating the effects of these substances. We are currently undertaking a voluntary land assessment and remediation program covering most of our stations and service centres. There is also risk associated with obtaining governmental approvals, permits, or renewals of existing approvals and permits related to constructing our operating facilities. This may require environmental assessment or result in the imposition of conditions, or both, which could mean delays and cost increases.

Future changes in environmental regulations may result in material changes to our estimates of future expenditures to complete this work. On November 4, 2006, Environment Canada published new draft regulations governing the management of polychlorinated biphenyls (PCBs). These draft regulations may be finalized in 2008. We have estimated the non-capital expenditures for complying with these draft regulations to be between $250 million and $375 million in excess of amounts we have already recorded as environmental liabilities on our Balance Sheet. If required, most of these additional expenditures would be incurred in the period from 2013 to 2025. No obligation has been recorded in the financial statements for these increased expenditures due to continued uncertainty regarding the timing and content of the final regulations. In any case, actual future environmental expenditures may vary materially from the estimates used in the calculation of the environmental liabilities on our Balance Sheet. We do not have insurance coverage for these environmental expenditures.

Scientists and public health experts have been studying the possibility that exposure to electric and magnetic fields emanating from power lines and other electric sources may cause health problems. If it were to be concluded that electric and magnetic fields present a health risk, we could face litigation, be required to take costly mitigation measures such as relocating some of our facilities or experience difficulties in locating and building new facilities.

Risk Associated with Information Technology Infrastructure

Our ability to operate effectively in the Ontario electricity market is in part dependent upon us developing, maintaining and managing complex information technology systems that are employed to operate our transmission and distribution facilities, financial and billing systems, and business systems to capture data and to produce timely and accurate information. We are working to transition most of our financial and business processes to an integrated business and financial reporting system which will enable productivity through the adoption of more efficient, standardized business processes. The conversion of these systems and processes may expose us to risk, including risks associated with maintaining internal controls, as new systems are brought online and the data and business processes are transitioned. System failures could have a material adverse effect on our company.

Risk Associated with Outsourcing Arrangement

Consistent with our strategy of reducing operating costs, we entered into an outsourcing services agreement in 2002 with Inergi. If this agreement is terminated for any reason, we could be required to incur significant expenses to re-establish all or some of the outsourced functions, which could have a material adverse effect on our results of operations.

Risk from Provincial Ownership of Transmission Corridors

Although we have the statutory right to use provincially-owned transmission corridors, we may be limited in our ability to expand our systems. Also, other uses of the transmission corridors by third parties in conjunction with the operation of our systems may increase safety or environmental risks.

Pension Plan Risk

We have a defined benefit registered pension plan for the majority of our employees. Contributions to the pension plan are established by actuarial valuations which are filed with the Financial Services Commission of Ontario on a tri-annual basis. The most recently filed valuation was prepared as at December 31, 2006 and was filed in September 2007. Our annual pension contributions for the three-year period 2007 to 2009 are approximately $94 million per year. The next valuation is required to be prepared as at December 31, 2009. The required level of contributions effective January 1, 2010 will depend on future investment returns, changes in benefits and changes in actuarial assumptions. Pension contributions beyond 2009 are not estimable at this time. The recovery of pension costs is subject to approval by the OEB. Failure to attain OEB approval could have an adverse effect on our results of operations.

Risk Associated with Arranging Debt Financing

We expect to borrow to repay our existing indebtedness and to fund capital expenditures. A substantial portion of our existing debt matures between 2008 and 2011. We are also planning a combined total of capital expenditures of approximately $3 billion in 2008 and 2009. Cash generated from operations will not be sufficient to fund the repayment of our existing indebtedness and capital expenditures. Our ability to arrange sufficient and cost effective debt financing could be adversely affected by numerous factors, including the regulatory environment in Ontario, our results of operations and financial position, market conditions, the ratings assigned to our debt securities by credit rating agencies and general economic conditions. Any failure or inability on our part to borrow substantial amounts of debt on satisfactory terms could impair our ability to repay maturing debt, fund capital expenditures and meet other obligations and requirements and, as a result, could have a material adverse effect on our business.

Market and Credit Risk

Market risk refers primarily to risk of loss that results from changes in commodity prices, foreign exchange rates and interest rates. We do not have commodity risk and our foreign exchange risk is currently insignificant, although we could in the future decide to issue foreign currency denominated debt. We are exposed to fluctuations in interest rates as our regulated rate of return is derived using a formula approach which is in part based on the forecast for long-term Government of Canada bond yields. We estimate that a 1% decrease in the forecast long-term Government of Canada bond yield used in determining our rate of return would reduce our transmission business' results of operations by approximately $20 million and our distribution business' results of operations by approximately $13 million. Our results of operations are adversely impacted by rising interest rates as our maturing long-term debt is refinanced at market rates. We periodically utilize interest rate swap agreements to mitigate elements of interest rate risk. We estimate that a 1% increase in interest rates on the refinancing of long-term debt maturing in 2008 and 2009 would reduce our results of operations by approximately $1 million and $4 million, respectively.

Financial assets create a risk that a counter-party will fail to discharge an obligation, causing a financial loss. Derivative financial instruments result in exposure to credit risk, since there is a risk of counter-party default. We monitor and minimize credit risk through various techniques, including dealing with highly rated counter-parties, limiting total exposure levels with individual counter-parties, and by entering into master agreements which enable net settlement. We do not trade in any energy derivatives. We do, however, have interest rate swap contracts outstanding from time to time. Currently, there are no significant concentrations of credit risk with respect to any class of financial assets. We are required to procure electricity on behalf of competitive retailers and embedded LDCs for resale to their customers. The resulting concentrations of credit risk are mitigated through the use of various security arrangements, including letters of credit, which are incorporated into our service agreements with these retailers in accordance with the OEB's Retail Settlements Code.

Critical Accounting Estimates

The preparation of our financial statements requires us to make estimates and judgements that affect the reported amounts of assets, liabilities, revenues and costs, and related disclosures of contingencies. We base our estimates and judgements on historical experience, current conditions and various other assumptions that are believed to be reasonable under the circumstances, the results of which form the basis for making judgements about the carrying values of assets and liabilities as well as identifying and assessing our accounting treatment with respect to commitments and contingencies. Actual results may differ from these estimates and judgements under different assumptions or conditions.

We believe the following critical accounting estimates involve the more significant estimates and judgements used in the preparation of our financial statements:

Regulatory Assets and Liabilities

Regulatory assets as at December 31, 2007 amounted to $213 million and principally relate to regulatory asset recovery accounts (RARAs), employee future benefits other than pension, and environmental costs. We have also recorded regulatory liabilities amounting to $583 million as at December 31, 2007. These amounts pertain primarily to pension, the RDDA, export and wheeling fees, the ESM, and retail settlement variance accounts. These assets and liabilities can be recognized for rate-setting and financial reporting purposes only if the OEB directs the relevant regulatory treatment or if future OEB direction is judged to be probable. Most of our regulatory accounts have already been reviewed by the OEB and confirmed as recoverable or refundable.

If management judges that it is no longer probable that the OEB will include a regulatory asset or liability in the setting of future rates, the relevant regulatory asset or liability would be charged or credited to results of operations in the period in which that judgement is made.

Environmental Liabilities

We record liabilities and related regulatory assets based on the present value of the estimated future expenditures to be made to settle obligations related to legacy environmental contamination inherited upon our de-merger from Ontario Hydro in 1999. These liabilities fall into two main categories: the management of PCB-contaminated assets and mineral oils and the assessment and remediation of contaminated lands. In determining the amounts to be recorded as environmental liabilities, we estimate the current cost of completing mitigation work and make assumptions for when the future expenditures will actually be incurred to generate future cash flow information. A long-term inflation assumption of approximately 2% has been used to express current cost estimates as estimated future expenditures. These future expenditures are discounted using factors ranging from 2.9% to 6.25%. Recording a liability for such long-term expenditures requires that many other assumptions be made, such as the number of contaminated properties and the extent of contamination, and the number and contamination levels of assets with PCBs. All factors used in deriving our environmental liabilities represent management's best estimates. However, it is reasonably possible that numbers or volumes of contaminated assets, current cost estimates, inflation assumptions and assumed pattern of annual cash flows may differ significantly from our assumptions. Estimated environmental liabilities are reviewed annually or more frequently if significant changes in regulation or other relevant facts occur. Estimate changes are accounted for prospectively.

Employee Future Benefits

We provide future benefits to our current and retired employees, including pension, group life insurance, health care and long-term disability.

In accordance with our rate orders, we record pension costs when employer contributions are paid to the pension fund (Fund) in accordance with the *Pension Benefits Act* (Ontario). Our annual pension contributions are approximately $94 million per year over the period 2007 through to 2009. Contributions after 2009 will be based on an actuarial valuation effective December 31, 2009 and will depend on future investment returns, changes in benefits or actuarial assumptions. Pension costs are also disclosed in the notes to the financial statements on an accrual basis. We record employee future benefit costs other than pension on an accrual basis. The accrual costs are determined by independent actuaries using the projected benefit method prorated on service and based on assumptions that reflect management's best estimates. The assumptions were determined by management recognizing the recommendations of our actuaries.

The assumed return on pension plan assets of 6.75% per annum is based on expectations of long-term rates of return at the beginning of the fiscal year and reflects a pension asset mix consistent with the Fund's investment policy. During the year the Fund's target asset mix was changed to 62% exposure to equities, 33% to fixed income and 5% in alternative assets consisting of hedge funds and private equity. Returns on the respective portfolios are determined with reference to published Canadian and U.S. stock indices and long-term bond and treasury bill indices. The assumed rate of return on pension plan assets reflects our long-term expectations. We believe that this assumption is reasonable because, with the Fund's balanced investment approach, the higher volatility of equity investment returns is offset by the greater stability of fixed income and short-term investment returns. The net result, on a long-term basis, is a somewhat lower return than might be expected by investing in equities alone. The return on pension plan assets was lower than this long-term assumption in 2007.

The weighted-average discount rate used to calculate the accrued benefit obligations is determined each year end by referring to the most recently available market interest rates based on AA corporate bond yields reflecting the duration of the applicable employee future benefit plan. The discount rates at December 31, 2007 increased by 0.25% from those at December 31, 2006 in conjunction with an increase in bond yields over this period. The increase in discount rates has resulted in a corresponding reduction in liabilities.

The costs of employee future benefits other than pension are determined at the beginning of the year. The costs are based on assumptions for expected claims experience and future health care cost inflation. A 1% increase in the health care cost trends would result in an increase in service cost and interest cost of about $12 million per year and an increase in the year end obligation of about $167 million.

Employee future benefits are included in labour costs that are either charged to results of operations or capitalized as part of the cost of fixed assets. Changes in assumptions will affect the accrued benefit obligation of the employee future benefits and the future years' amounts that will be charged to our results of operations or capitalized as a cost of fixed assets.

Goodwill

In assessing the recoverability of goodwill, we must make assumptions regarding estimated future cash flows and other factors to determine the fair value of the distribution reporting unit. If these estimates or their related assumptions change in the future, we may be required to record impairment charges related to goodwill. An impairment review of goodwill was carried out during 2007 and we determined that the carrying value of our goodwill has not been impaired.

Emerging Accounting Pronouncements

Transition to International Financial Reporting Standards (IFRS)

The Canadian Accounting Standards Board (AcSB) ratified a new strategic plan for the period of 2006–2011 that entails converging Canadian generally accepted accounting principles (GAAP) with IFRS over the five-year transitional period. The final AcSB decision to proceed on the intended schedule will be made in March 2008. It is generally expected that the decision to adopt IFRS will be confirmed unless some unexpected event occurs. The AcSB has adopted an implementation plan and suggests that companies be in a position to disclose their implementation plans for the IFRS changeover in their 2008 Management's Discussion and Analysis (MD&A). The Canadian Securities Administrators will be defining the MD&A disclosure requirements regarding an enterprise's plans for IFRS conversion. We started planning our transition to IFRS during 2006 and plan to commence convergence work beginning in 2008.

Accounting for Rate Regulated Operations

During 2007, the AcSB issued an exposure draft proposing to remove all specific references to rate regulated accounting from the Handbook of the Canadian Institute of Chartered Accountants (CICA). In August 2007, the AcSB decided to remove a temporary exemption in CICA Handbook Section 1100, retain existing references to rate regulated accounting in the CICA Handbook, require the recognition of future income tax liabilities and assets as well as a separate regulatory asset or liability for the amount of future income taxes, and retain existing requirements to disclose the effects of rate regulation.

The new rules will apply prospectively to interim and annual financial statements relating to fiscal years beginning on or after January 1, 2009 and will result in accrual accounting being followed for payments in lieu of corporate taxes. Such amounts are currently accounted for on a cash basis, consistent with specific OEB rate-setting direction. Commencing the first quarter of 2009, the regulatory impact of the OEB's direction will be reflected through the recognition of regulatory assets and/or liabilities. There will be no impact on results of operations.

Inventories

The AcSB issued new CICA Handbook Section 3031, *Inventories*, which is effective for our company in the first quarter of 2008. The recommendations apply to our materials and supplies inventories and require major spare parts to be classified as future use fixed assets rather than inventory. We anticipate a significant transfer of book value from the materials and supplies category on the Balance Sheet to fixed assets. Additionally, the new handbook section will allow the reversal of prior period write-downs when the net realizable value of impaired inventory subsequently recovers.

Disclosure Controls and Internal Controls over Financial Reporting

As a reporting issuer we are required to comply with the Ontario Securities Commission's Multilateral Instrument 52-109 (Multilateral Instrument) concerning internal control and related certifications, often referred to as Bill 198. During 2005 and 2006, we documented all of our processes, risks and controls, and completed all testing necessary to make the required annual certifications. Commencing with our Consolidated Financial Statements for the year ended December 31, 2005, we certified that our disclosure controls and procedures provide reasonable assurance that all information considered necessary for appropriate disclosure has been accumulated and communicated to management on a timely basis. Commencing with our Consolidated Financial Statements for the year ended December 31, 2006, we also made certifications regarding the design of our internal controls over financial reporting.

Our focus for 2007 has been the ongoing sustainment of our control environment, including communication, evaluation and enhancements, as required to support the certifications of our President and Chief Executive Officer, and Chief Financial Officer (Certifying Officers). We have also carried out a comprehensive plan to test the operational effectiveness of our internal controls over financial reporting.

In compliance with the requirements of the Multilateral Instrument, our Certifying Officers have reviewed and certified the Consolidated Financial Statements for the year ended December 31, 2007, together with other financial information included in our annual securities filings. Our Certifying Officers have also certified that disclosure controls and procedures have been designed to provide reasonable assurance that material information relating to our company is made known within our company and that they operated effectively during the period. Further, our Certifying Officers have also certified that internal controls over financial reporting are designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with GAAP.

Selected Annual Information

The following table sets forth audited annual information for each of the three years ended December 31, 2005, 2006 and 2007. This information has been derived from our audited annual Consolidated Financial Statements.

Consolidated Statement of Operations

Year ended December 31 *(Canadian dollars in millions, except earnings per common share)*	**2007**	2006	2005
Revenues[1]	**4,655**	4,545	4,416
Net income[1]	**399**	455	483
Basic and fully diluted earnings per common share *(Canadian dollars)*	**3,809**	4,366	4,652

Consolidated Balance Sheet

Year ended December 31 *(Canadian dollars in millions, except cash dividends per share)*	**2007**	2006	2005
Total assets[2]	**12,790**	12,210	11,798
Total long-term debt[3]	**5,603**	5,243	5,032
Cash dividends per common share *(Canadian dollars)*	**3,070**	3,320	2,730
Cash dividends per preferred share *(Canadian dollars)*	**1.375**	1.375	1.375

1 As a result of the OEB's August 16, 2007 decision on Hydro One Networks' Transmission rate application that was effective January 1, 2007, revenues reflect a reduced revenue requirement based on the approved rate of return of 8.35%. Previously, the rate of return was 9.88%.

2 Total assets for 2006 and 2005 reflect the reclassification of deferred debt costs in 2007, applied retroactively.

3 Unamortized net losses relating to settled swap agreements were reclassified to AOCI on January 1, 2007 without prior year reclassification.

Outlook

To meet our challenge of being the best transmission and distribution company in North America, we will continue to concentrate on our strategic priorities relating to respect of the public trust, safety, our customers, system reliability, financial stewardship and our employees. Significant improvements have been made toward achieving our customer satisfaction and safety targets, while we maintain our financial profile and reliability performance. Our continued commitment to the people of Ontario has been recognized by the Edison Electric Institute (EEI) and by *Corporate Knights* magazine. Early in the year, EEI honoured us with the "Emergency Recovery Award" for outstanding storm restoration efforts in 2006. This was the first time a non-U.S. utility has won this prestigious award. *Corporate Knights* magazine recognized us as one of Canada's top 50 corporate citizens based on environmental, social and governance indicators. Our CDM program and leadership in the smart metering initiative were cited as key factors contributing to our ranking of third among utilities. This magazine also recognized us as Canada's most diverse utility and ranked us fifth overall in corporate Canada, based on the composition of our Board, senior executives and the company's practices and policies on diversity. In addition, Hydro One was selected as the recipient of the Utility Planning Network's 2007 Metering Award in the category of Automated Meter Reading Initiative – North American Municipal or Cooperative among numerous entries from around the globe.

Consistent with our continued commitment to the public interest and the Province's energy policies, we are planning significant investments in transmission infrastructure and the continued proactive maintenance of our assets to ensure the electricity system's reliability. Our transmission investment plan supports the achievement of the Province's renewable and nuclear objectives, facilitates the development and use of renewable energy resources, promotes system efficiency, sustains equipment performance, meets customers' service quality needs, and facilitates the integration of new supply.

In its transmission rate decision issued on August 16, 2007, the OEB approved our entire operation, maintenance and administration and capital work programs applied for in 2007 and 2008, expressing confidence in our ability and expertise to make an appropriate assessment of what is needed "to maintain a robust, safe, and reliable transmission system." However, the decision was not favourable in other areas such as the approved return on equity. We plan to file a transmission rate application for 2009 and 2010 rates. These rates, if approved, should provide the funding required to maintain and meet the infrastructure requirements of the transmission system in the public interest.

Our investment plan does not include spending for large-scale investments, such as the east-west transmission grid or potential long-term transmission projects identified in the IPSP. For certain long-term projects addressing generation-enabling connection lines and reliability of local area supply, the IPSP recommends that project development work (preliminary engineering, cost estimating, options assessment, and Environmental Assessment and Section 92 approvals, as required) begin upon approval of the IPSP by the OEB. As such, we would be prepared to initiate project development work for these projects to enable expedited construction once a need date is confirmed by the OPA and once we have a reasonable expectation of cost recovery through rates. For some projects such as the transmission connection for generation in the Nipigon area, the IPSP recommends that development work commence in 2008. It is anticipated that the final decision to proceed with the longer term major projects, such as new high voltage transmission lines from north to south, will be made when the next IPSP is prepared in about three years.

The 2006 distribution rate decision has provided a base funding level to build upon. The 2008 Cost of Service application supports the implementation of our Smart Meter Program, and enhances sustainment programs to improve reliability and customer service. In 2007, an OEB decision clarified the recoverability of costs associated with the minimum level of smart meter functionality, thereby reducing the uncertainty of recovery of this program. Smart meter costs in excess of minimum functionality will be reviewed as part of the 2008 Cost of Service hearing. Given the magnitude and unique nature of the Smart Meter Program, recovery of costs will be a key focus. In addition, the distribution investment plan does not provide for the implementation of a Smart Network, which would leverage the smart meter technology to enable further internal productivity initiatives through wireless broadband.

We remain committed to a prudent and measured approach to distribution rationalization. In October 2006, the government announced a two-year exemption of the electricity transfer tax. We will consider and respond to opportunities for acquisitions or divestitures, on a voluntary and commercial basis, where they are consistent with our strategy and direction from our shareholder. The investment plan does not include any funding for any LDC acquisitions or divestitures.

Key enablers of the successful implementation of the work program are our human and material resourcing strategies. Our human resource strategy is focused on hiring through partnering with universities, colleges and our unions, as well as skills development and retention. Significant retirement projections and increasing work volumes will result in an unprecedented number of new hires in the near-term. With regard to materials, we are seeing increasing lead times and costs as market shortages emerge globally. Consequently, sourcing strategies are being developed and implemented to ensure availability of materials to support the work programs.

Through the outlook period, we anticipate no changes to our role within the industry and that our financial returns will be sufficient to maintain our credit quality. In November 2007 the Agency Review Panel issued the second phase of its report on Ontario’s provincially-owned electricity agencies. The report confirmed that, overall, Ontario’s electricity sector and the provincial agencies within it are functioning reasonably well. We do not anticipate any structural changes to our company.

Forward Looking Statements and Information

Our oral and written public communications, including this MD&A, often contain forward-looking statements that are based on current expectations, estimates, forecasts and projections about our business and the industry in which we operate and include beliefs and assumptions made by the management of our company. Such statements include, but are not limited to, statements about our strategy; statements related to the IPSP and projects flowing therefrom; statements about smart meters including costs, cost recovery and deployment and/or implementation plans; expectations regarding the timing, content and impact of future applications and decisions related to our transmission and distribution businesses; the anticipated results on our business processes and productivity as a result of our business systems and processes project; the anticipated impact of CDM programs; statements regarding the reliability of our distribution and transmission systems; expectations regarding load growth and new generation; expectations regarding developments in the statutory and operating framework for electricity distribution and transmission in Ontario including changes to codes, licenses, rates, rate orders, cost recovery, rates of return, rate structures and revenue requirements in both our transmission and distribution businesses and the timing of decisions from the OEB; statements regarding future capital expenditures and our investment plans; expectations regarding the results of our ongoing and planned projects; expectations regarding our strategy for acquisitions or divestitures of distribution assets; expectations regarding future pension contributions; expectations regarding workforce demographics; expectations regarding environmental expenditures and other environmental matters including the need for environmental approvals and assessments; expectations regarding borrowing requirements; expectations regarding anticipated expenditures associated with transferring assets located on Indian lands; statements regarding provincial ownership of our transmission corridors; the estimated impact of changes in the forecast long-term Government of Canada bond yield (used in determining our regulated rate of return) on our results of operations; the estimated impact of changes in interest rates on our results of operations; statements about employee future benefit costs; statements about emerging accounting pronouncements; statements about the outlook period including our expectations regarding our role within the industry, our financial returns, and structural changes to our company. Words such as “expect,” “anticipate,” “intend,” “attempt,” “may,” “plan,” “will”, “believe,” “seek,” “estimate,” and variations of such words and similar expressions are intended to identify such forward-looking statements. These statements are not guarantees of future performance and involve assumptions and risks and uncertainties that are difficult to predict. Therefore, actual outcomes and results may differ materially from what is expressed, implied or forecasted in such forward-looking statements. We do not intend, and we disclaim any obligation to update any forward-looking statements, except as required by law.

These forward-looking statements are based on a variety of factors and assumptions including, but not limited to, the following: no unforeseen changes in the legislative and operating framework for Ontario’s electricity market; no unfavourable decisions from the OEB and other regulatory bodies concerning outstanding rate and other applications; no unforeseen changes in rate orders or rate structures for our distribution and transmission businesses; a stable regulatory environment; and no significant event occurring outside the ordinary course of business. These assumptions are based on information currently available to us, including information obtained from third-party industry analysts. Actual results may differ materially from those predicted by such forward-looking statements. While we do not know what impact any of these differences may have, our business, results of operations, financial condition and our credit stability may be materially adversely affected. Factors that could cause actual results or outcomes to differ materially from the results expressed or implied by forward-looking statements include, among other things:

- the content of the final IPSP, as approved by the OEB;
- delays or denials of the requisite approvals and accommodations for our planned projects;
- the risks associated with being controlled by the Province including potential conflicts of interest that may arise between us, the Province and related parties;
- the risks related to our workforce demographic and our potential inability to attract and retain qualified personnel;
- the risks associated with being subject to extensive regulation including risks associated with OEB action or inaction;
- regulatory decisions regarding our revenue requirements, cost recovery and rates;
- the potential impact of CDM programs on our load and our revenues;
- the potential impact of not being able to recover all of our project costs associated with the installation of smart meters;
- unanticipated changes in electricity demand or in our costs;
- the risks associated with the execution of our capital and operation, maintenance and administration programs necessary to maintain the performance of our aging asset base;
- the risk to our facilities posed by severe weather conditions, natural disasters or catastrophic events and our limited insurance coverage for losses resulting from these events;
- the risk that we may incur significant costs associated with transferring assets located on Indian lands;
- the inability to negotiate collective agreements consistent with our rate orders or in a timely fashion and the potential for labour disputes;
- the potential for substantial and currently undetermined environmental costs and liabilities;
- the risks associated with maintaining a complex information technology systems infrastructure and transitioning most of our financial and business processes to an integrated business and financial reporting system;
- the potential that we may incur significant expenses to replace some or all of the functions currently outsourced if our agreement with Inergi LP is terminated;
- the impact of the ownership by the Province of lands underlying our transmission system;
- the potential impact of not being able to recover our pension costs;
- the risk that we are not able to arrange sufficient cost effective financing to repay maturing debt and to fund capital expenditures and other obligations;
- the risks of counter-party default on our outstanding derivative contracts;
- the risks associated with changes in interest rates; and
- the risks associated with changes in the forecast long-term Government of Canada bond yield.

We caution the reader that the above list of factors is not exhaustive. Some of these and other factors are discussed in more detail under “Risk Management and Risk Factors” in this MD&A, which you should review in detail.

This MD&A is dated as at February 13, 2008. Additional information about our company, including our Annual Information Form, is available on SEDAR at www.sedar.com.

Management's Report

The Consolidated Financial Statements, Management's Discussion and Analysis ("MD&A") and related financial information presented in this Annual Report have been prepared by the management of Hydro One Inc. ("Hydro One" or the "Company"). Management is responsible for the integrity, consistency and reliability of all such information presented. The Consolidated Financial Statements have been prepared in accordance with accounting principles generally accepted in Canada and applicable securities legislation. The MD&A has been prepared in accordance with National Instrument 51-102, Part 5.

The preparation of the Consolidated Financial Statements and information in the MD&A involves the use of estimates and assumptions based on management's judgement, particularly when transactions affecting the current accounting period cannot be finalized with certainty until future periods. Estimates and assumptions are based on historical experience, current conditions and various other assumptions believed to be reasonable in the circumstances, with critical analysis of the significant accounting policies followed by the Company as described in Note 2 to the Consolidated Financial Statements. The preparation of the Consolidated Financial Statements and the MD&A includes information regarding the estimated impact of future events and transactions. The MD&A also includes information regarding sources of liquidity and capital resources, operating trends, risks and uncertainties. Actual results in the future may differ materially from the present assessment of this information because future events and circumstances may not occur as expected. The Consolidated Financial Statements and MD&A have been properly prepared within reasonable limits of materiality and in light of information up to February 13, 2008.

In meeting its responsibility for the reliability of financial information, management maintains and relies on a comprehensive system of internal control and internal audit. The system of internal control includes a written corporate conduct policy; implementation of a risk management framework; effective segregation of duties and delegation of authorities; and sound and conservative accounting policies that are regularly reviewed. This structure is designed to provide reasonable assurance that assets are safeguarded and that reliable information is available on a timely basis. In addition internal and disclosure controls have been documented, evaluated, tested and identified consistent with Multilateral Instrument 52-109 (Bill 198). An internal audit function independently evaluates the effectiveness of these internal controls on an ongoing basis and reports its findings to management and the Audit and Finance Committee of the Hydro One Board of Directors.

The Consolidated Financial Statements have been examined by Ernst & Young LLP, independent external auditors appointed by the Hydro One Board of Directors. The external auditors' responsibility is to express their opinion on whether the Consolidated Financial Statements are fairly presented in accordance with accounting principles generally accepted in Canada. The Auditors' Report, which appears on page 48, outlines the scope of their examination and their opinion.

The Hydro One Board of Directors, through its Audit and Finance Committee, is responsible for ensuring that management fulfills its responsibilities for financial reporting and internal controls. The Audit and Finance Committee of Hydro One met periodically with management, the internal auditors, and the external auditors to satisfy itself that each group had properly discharged its respective responsibility and to review the Consolidated Financial Statements before recommending approval by the Board of Directors. The external auditors had direct and full access to the Audit and Finance Committee, with and without the presence of management, to discuss their audit and their findings as to the integrity of the financial reporting and the effectiveness of the system of internal controls.

The Company's President and Chief Executive Officer, and Chief Financial Officer have certified Hydro One's annual Consolidated Financial Statements and annual MD&A filed under provincial securities legislation, related disclosure controls and procedures, and the design of related internal controls over financial reporting pursuant to Multilateral Instrument 52-109.

On behalf of Hydro One Inc.'s management:

Laura Formusa
President and Chief Executive Officer

Beth Summers
Executive Vice-President and
Chief Financial Officer

Auditors' Report

To the Shareholder of Hydro One Inc.

We have audited the Consolidated Balance Sheets of Hydro One Inc. (the Company) as at December 31, 2007 and December 31, 2006, and the Consolidated Statements of Operations, Retained Earnings and Cash Flows of the Company for each of the years in the two-year period ended December 31, 2007. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these Consolidated Financial Statements present fairly, in all material respects, the financial position of the Company as at December 31, 2007 and December 31, 2006 and the results of its operations and its cash flows for each of the years in the two-year period ended December 31, 2007 in accordance with Canadian generally accepted accounting principles.

Ernst & Young LLP

Ernst & Young LLP
Chartered Accountants

Licensed Public Accountants
Toronto, Canada
February 13, 2008

Consolidated Statements of Operations

Year ended December 31 *(Canadian dollars in millions)*	**2007**	2006
Revenues		
Transmission (Notes 7 and 13)	**1,242**	1,245
Distribution (Note 13)	**3,382**	3,273
Other	**31**	27
	4,655	4,545
Costs		
Purchased power (Note 13)	**2,240**	2,221
Operation, maintenance and administration (Note 13)	**995**	880
Depreciation and amortization (Note 3)	**521**	515
	3,756	3,616
Income before financing charges and provision for payments in lieu of corporate income taxes	**899**	929
Financing charges (Note 4)	**295**	295
Income before provision for payments in lieu of corporate income taxes	**604**	634
Provision for payments in lieu of corporate income taxes (Notes 5 and 13)	**205**	179
Net income	**399**	455
Other comprehensive income	**3**	–
Comprehensive income	**402**	455
Basic and fully diluted earnings per common share *(Canadian dollars)* (Note 12)	**3,809**	4,366

Consolidated Statements of Retained Earnings

Year ended December 31 *(Canadian dollars in millions)*	**2007**	2006
Retained earnings, January 1	**1,184**	1,079
Net income	**399**	455
Dividends (Note 12)	**(325)**	(350)
Retained earnings, December 31	**1,258**	1,184

See accompanying notes to Consolidated Financial Statements.

Consolidated Balance Sheets

December 31 *(Canadian dollars in millions)*	**2007**	2006
Assets		
Current assets:		
Accounts receivable (net of allowance for doubtful accounts – $21 million; 2006 – $19 million) (Note 13)	**759**	777
Regulatory assets (Note 7)	**103**	121
Materials and supplies	**67**	56
Other	**17**	13
	946	967
Fixed assets (Note 6):		
Fixed assets in service	**16,812**	16,238
Less: accumulated depreciation	**6,220**	6,180
	10,592	10,058
Construction in progress	**622**	468
	11,214	10,526
Other long-term assets:		
Deferred pension asset (Note 10)	**380**	382
Regulatory assets (Note 7)	**110**	190
Goodwill	**133**	133
Other assets	**7**	12
	630	717
Total assets	**12,790**	12,210

See accompanying notes to Consolidated Financial Statements.

Consolidated Balance Sheets (continued)

December 31 *(Canadian dollars in millions)*	**2007**	2006
Liabilities		
Current liabilities:		
Bank indebtedness	**12**	29
Accounts payable and accrued charges (Notes 11 and 13)	**731**	661
Regulatory liabilities (Note 7)	**114**	–
Accrued interest	**55**	49
Short-term notes payable (Note 8)	**–**	60
Long-term debt payable within one year (Note 8)	**540**	395
	1,452	1,194
Long-term debt (Note 8)	**5,063**	4,848
Other long-term liabilities:		
Employee future benefits other than pension (Note 10)	**855**	803
Regulatory liabilities (Note 7)	**469**	473
Environmental liabilities (Note 11)	**52**	55
Long-term accounts payable and accrued charges	**13**	16
	1,389	1,347
Total liabilities	**7,904**	7,389
Contingencies and commitments (Notes 9, 15 and 16)		
Shareholder's equity (Note 12)		
Preferred shares (authorized: unlimited; issued: 12,920,000)	**323**	323
Common shares (authorized: unlimited; issued: 100,000)	**3,314**	3,314
Retained earnings	**1,258**	1,184
Accumulated other comprehensive income	**(9)**	–
Total shareholder's equity	**4,886**	4,821
Total liabilities and shareholder's equity	**12,790**	12,210

See accompanying notes to Consolidated Financial Statements.

On behalf of the Board of Directors:

R. Burak

Rita Burak
Chair

Walter Murray
Chair, Audit and Finance Committee

Consolidated Statements of Cash Flows

Year ended December 31 *(Canadian dollars in millions)*	**2007**	2006
Operating activities		
Net income	**399**	455
Adjustments for non-cash items:		
Depreciation and amortization (net of removal costs)	**482**	474
Revenue difference deferral account	**73**	–
Retail settlement variance accounts	**46**	7
Other regulatory asset and liability accounts	**1**	19
Transmission earnings sharing mechanism	**–**	33
Amortization of debt discount	**5**	27
	1,006	1,015
Changes in non-cash balances related to operations (Note 14)	**135**	(106)
Net cash from operating activities	**1,141**	909
Financing activities		
Long-term debt issued	**700**	775
Long-term debt retired	**(355)**	(589)
Short-term notes payable	**(60)**	60
Dividends paid	**(325)**	(350)
Other	**(1)**	(4)
Net cash used in financing activities	**(41)**	(108)
Investing activities		
Capital expenditures	**(1,091)**	(823)
Other assets	**8**	2
Net cash used in investing activities	**(1,083)**	(821)
Net change in cash and cash equivalents	**17**	(20)
Cash and cash equivalents, January 1	**(29)**	(9)
Cash and cash equivalents, December 31 (Note 14)	**(12)**	(29)

See accompanying notes to Consolidated Financial Statements.

Notes to Consolidated Financial Statements

Note 1.
Description of the Business

Hydro One Inc. (Hydro One or the Company) was incorporated on December 1, 1998, under the *Business Corporations Act* (Ontario) and is wholly owned by the Province of Ontario (the Province). The principal businesses of Hydro One are the transmission and distribution of electricity to customers within Ontario. These businesses are regulated by the Ontario Energy Board (OEB).

Note 2.
Significant Accounting Policies

Basis of Consolidation

The Consolidated Financial Statements include the accounts of the Company and its wholly owned subsidiaries: Hydro One Networks Inc. (Hydro One Networks), Hydro One Remote Communities Inc., Hydro One Brampton Inc., Hydro One Brampton Networks Inc. (Hydro One Brampton), Hydro One Telecom Inc., Hydro One Delivery Services Company Inc. and Hydro One Network Services Inc.

Hydro One Brampton Inc. was dissolved on January 30, 2007. Hydro One Network Services Inc. was dissolved on December 14, 2006. Hydro One Delivery Services Inc. will be dissolved pursuant to the *Business Corporations Act* (Ontario).

Basis of Accounting

The Consolidated Financial Statements are prepared in accordance with accounting principles generally accepted in Canada (Canadian GAAP).

Rate-Setting

The rates of the Company's electricity transmission and distribution businesses are subject to regulation by the OEB. In October 2005, the OEB initiated a proceeding to review Hydro One Network's transmission rates and to approve revenue requirements for 2006, 2007 and 2008 based on cost of service regulation. On February 21, 2006, the OEB announced a decision to apply an earnings sharing mechanism (ESM) to equally share, between Hydro One's shareholder and its customers, any transmission earnings in excess of the approved rate of return of 9.88% for the period ending January 1, 2006 until new transmission rates were set.

In September 2006, Hydro One Networks filed a transmission rate application. On March 30, 2007, prior to its decision on our transmission rate application, the OEB issued a decision ordering that the transmission ESM cease effective December 31, 2006. The decision also approved the concept of establishing a new revenue difference deferral account (RDDA) to record the revenue differential between existing transmission rates and the new rates that were anticipated to be approved later in the year, for the period commencing January 1, 2007.

On August 16, 2007, the OEB issued its decision in respect of Hydro One Networks' 2007 and 2008 transmission rate application. The decision, which was effective January 1, 2007, approved all operating and capital expenditures for 2007 and 2008. However, the decision resulted in a reduction in the approved return on equity from 9.88% to 8.35%. The OEB also approved final amounts and disposition treatments for certain regulatory liabilities including the RDDA, the ESM and export and wheeling fees, as well as the transmission market ready regulatory asset.

The Company's distribution rates are also based on a revenue requirement that includes a rate of return. On April 12, 2006, the OEB announced its decision regarding the Company's rate applications in respect of the distribution businesses of Hydro One Networks and Hydro One Brampton. On the basis of the written evidence submitted, the OEB approved the requested increase in the revenue requirement based on a reduction in the approved rate of return, from a targeted 9.88% to 9.00%, effective May 1, 2006.

In 2006, the OEB commenced a process of establishing an Incentive Regulation Mechanism (IRM) for the years 2007 to 2010. The process includes a formulaic approach to establishing 2007 rates with a rate rebasing approach to be staggered across all Ontario distributors between 2008 and 2010. Hydro One Networks and Hydro One Brampton applied for marginal distribution rate adjustments in February 2007, based on an OEB-approved formula that considers inflation, efficiency targets and significant events outside the control of management. In April 2007, the OEB approved the Company's submissions on the basis of its cost of capital and second generation IRM policies, and the revised rates were implemented effective May 1, 2007.

Hydro One Networks submitted the revenue requirement portion of its 2008 cost of service application in accordance with the OEB's multi-year distribution rate-setting plan on August 15, 2007. This application seeks the approval of a revenue requirement of $1,067 million based on a return of 8.64% for 2008. On December 18, 2007, Hydro One Networks filed the details of its cost allocation and rate design proposals, which include a plan to reduce the number of rate classes for its customers and consolidate or harmonize the rates for its existing rate classes to the new proposed rate classes. Based on the OEB's processing guidelines, a decision is anticipated in the Fall of 2008. On November 1, 2007, Hydro One Brampton filed an application for 2008 rates on the basis of the OEB's cost of capital and second generation IRM policies.

The OEB has the general power to include or exclude costs, revenues, losses or gains in the rates of a specific period, resulting in a change in the timing of accounting recognition from that which would have applied in an unregulated company. Such change in timing involves the application of rate regulated accounting, giving rise to the recognition of regulatory assets and liabilities. The Company's regulatory assets represent certain amounts receivable from future customers and costs that have been deferred for accounting purposes because it is probable that they will be recovered in future rates. In addition, the Company has recorded regulatory liabilities which represent amounts for expenses incurred in different periods than would be the case had the Company been unregulated. The Company continually assesses the likelihood of recovery of each of its regulatory assets and continues to believe that it is probable that the OEB will factor its regulatory assets and liabilities into the setting of future rates. If, at some future date, the Company judges that it is no longer probable that the OEB will include a regulatory asset or liability in future rates, the appropriate carrying amount will be reflected in results of operations in the period that the assessment is made. Specific regulatory assets and liabilities are disclosed in Note 7.

Revenue Recognition and Allocation

Transmission revenues are collected through OEB-approved rates, which are based on an approved revenue requirement that includes a rate of return. Such revenue is recognized as power is transmitted and delivered to customers.

Distribution revenues attributable to the delivery of electricity are based on OEB-approved distribution rates and are recognized as electricity is delivered to customers. The Company estimates the monthly revenue for the period based on wholesale power purchases because customer meters are not generally read at the end of each month. Unbilled revenue included within accounts receivable as at December 31, 2007 amounted to $413 million (2006 – $386 million).

Distribution revenue also includes an amount relating to rate protection for rural residential and remote customers, which is received from the Independent Electricity System Operator (IESO) based on a standardized customer rate that is approved by the OEB. The current legislation provides rate protection for prescribed classes of rural residential and remote consumers by reducing the electricity rates that would otherwise apply.

Segment revenues for transmission, distribution and other also include revenue related to sales of other services and equipment. Such revenue is recognized as services are rendered or as equipment is delivered.

Corporate Income and Capital Taxes

Under the *Electricity Act, 1998*, Hydro One is required to make payments in lieu of corporate taxes to the Ontario Electricity Financial Corporation (OEFC). These payments are calculated in accordance with the rules for computing income and taxable capital and other relevant amounts contained in the *Income Tax Act* (Canada) and the *Corporations Tax Act* (Ontario) as modified by the *Electricity Act, 1998*, and related regulations.

The Company provides for payments in lieu of corporate income taxes relating to its regulated businesses using the taxes payable method as directed by the OEB. Under the taxes payable method, no provisions are made for future income taxes as a result of temporary differences between the tax basis of assets and liabilities and their carrying amounts for accounting purposes. When unrecorded future income taxes become payable, it is expected that they will be included in the rates approved by the OEB and recovered from the customers of Hydro One at that time. The Company provides for payments in lieu of corporate income taxes relating to its unregulated businesses using the liability method.

Materials and Supplies

Materials and supplies represent spare parts and construction material held for internal construction and maintenance of fixed assets. These assets are carried at lower of average cost or net realizable value.

Fixed Assets

Fixed assets are capitalized at cost which comprises materials, labour, engineering costs, overheads, depreciation on service equipment and the OEB-approved allowance for funds used during construction applicable to capital construction activities within regulated businesses, or interest applicable to capital construction activities within unregulated businesses.

Fixed assets in service consist of transmission, distribution, communication, administration and service assets and easements. Fixed assets also include future use assets such as land and capitalized development costs associated with deferred capital projects.

Some of the Company's transmission and distribution assets, particularly those located on unowned easements and rights-of-way, may have asset retirement obligations, conditional or otherwise. The majority of the Company's easements and rights-of-way are either of perpetual duration or are automatically renewed annually. Land rights with finite terms are generally subject to extension or renewal. As the Company expects to use the majority of its installed assets for an indefinite period, no removal date can be determined and consequently a reasonable estimate of the fair value of most asset retirement obligations cannot be made at this time. If, at some future date, it becomes possible to estimate the fair value cost of disposing of assets that the Company is legally required to remove, a related asset retirement obligation will be recognized at that time.

Transmission

Transmission assets include assets used for the transmission of high-voltage electricity, such as transmission lines, support structures, foundations, insulators, connecting hardware and grounding systems, and assets used to step up the voltage of electricity from generating stations for transmission and to step down voltages for distribution, such as transformers, circuit breakers and switches.

Distribution

Distribution assets comprise assets related to the distribution of low-voltage electricity, including lines, poles, switches, transformers, protective devices and metering systems.

Communication

Communication assets include the fibre-optic and microwave radio system, optical ground wire, towers, telephone equipment and associated buildings.

Administration and Service

Administration and service assets include administrative buildings, major computer systems, personal computers, transport and work equipment, tools, vehicles and minor fixed assets.

Easements

Easements include statutory rights of use to transmission corridors and abutting lands granted under the *Reliable Energy and Consumer Protection Act, 2002*, as well as other amounts related to access rights.

Construction in Progress

Overhead costs, including corporate functions and services costs, are capitalized on a fully allocated basis, consistent with an OEB-approved methodology. Financing costs are capitalized on fixed assets under construction based on the OEB's approved allowance for funds used during construction (2007 – 5.20%; 2006 – 6.39%).

Depreciation

The capital costs of fixed assets are depreciated on a straight-line basis, except for transport and work equipment, which are depreciated on a declining balance basis.

Effective January 1, 2007, the Company prospectively revised its fixed asset depreciation rates resulting from a periodic external review required by the OEB. The estimated impact of the change in rates is a reduction in depreciation expense of approximately $7 million per annum. A summary of the new rates for the various classes of assets is included below:

	Depreciation Rates (%)	
	Range	Average
Transmission	1%–4%	2%
Distribution	1%–13%	2%
Communication	1%–13%	5%
Administration and service	1%–20%	8%

Depreciation rates for easements are based on their contract life. The majority of easements are held in perpetuity and are not depreciated.

In accordance with group depreciation practices, the original cost of normal fixed asset retirements is charged to accumulated depreciation, with no gain or loss reflected in results of operations. Gains and losses on sales of fixed assets and losses on premature retirements are charged to results of operations as adjustments to depreciation expense. Depreciation expense also includes the costs incurred to remove fixed assets.

The estimated service lives of fixed assets are subject to periodic review. Any changes arising from such a review are implemented on a remaining service life basis consistent with their inclusion in rates.

Goodwill

Goodwill represents the cost of acquired local distribution companies in excess of fair value of the net identifiable assets purchased and is evaluated for impairment on an annual basis, or more frequently if circumstances require. Goodwill impairment is assessed based on a comparison of the fair value of the reporting unit to the underlying carrying value of the reporting unit's net assets, including goodwill, with any write-down of the carrying value of goodwill being charged against the results of operations.

The Company has determined that goodwill is not impaired. All of the goodwill is attributable to the distribution business segment.

Discounts and Premiums on Debt

Discounts and premiums are amortized over the period of the related debt using the effective interest method.

Financial Instruments

Effective January 1, 2007, the Company adopted four new accounting standards comprising the following sections of the Handbook of the Canadian Institute of Chartered Accountants (CICA): 1530, *Comprehensive Income*; *3855, Financial Instruments – Recognition and Measurement*; 3861, *Financial Instruments – Disclosure and Presentation*; and 3865, *Hedges*. The adoption of these new standards required changes in the accounting for financial instruments and hedges, and the recognition of certain transition adjustments that were recorded in opening accumulated other comprehensive income (AOCI) as described below, consistent with the CICA Handbook sections. The comparative annual Consolidated Financial Statements have not been restated. The principal changes in the accounting for financial instruments and hedges due to the adoption of these accounting standards are described below.

Comprehensive Income

Comprehensive income is composed of the Company's net income and other comprehensive income (OCI). OCI includes the amortization of net unamortized hedging losses on discontinued cash flow hedges, and the change in fair value on existing cash flow hedges. The impact of the amortization of net hedging losses that were discontinued prior to the transition date was immaterial to the Statement of Operations.

Financial Assets and Liabilities

Under the new standards, all financial instruments are classified into one of the following five categories: held-to-maturity investments, loans and receivables, held-for-trading, other liabilities or available-for-sale. All financial instruments, including derivatives, are carried at fair value on the Consolidated Balance Sheet except for loans and receivables, held-to-maturity investments and other financial liabilities, which are measured at amortized cost. Held-for-trading financial instruments are measured at fair value and all gains and losses are included in financing charges in the period in which they arise. Available-for-sale financial instruments are measured at fair value with revaluation gains and losses included in OCI until the instrument is derecognized or impaired. The Company has classified its financial instruments as follows:

Short-term investments	Held-to-maturity
Long-term accounts receivable	Loans and receivables
Bank indebtedness	Other liabilities
Short-term notes payable	Other liabilities
Long-term debt (excluding MTN Series 8 Note)	Other liabilities
MTN Series 8 Note	Designated as held-for-trading

The MTN Series 8 Note is a step-up coupon note with extendable maturity dates up to 2011 (see Notes 8 and 9).

Where there is an economic hedge, as in the case of the MTN Series 8 Note and associated interest rate swap, the Company has applied the fair value option without hedge accounting. The impact was not material.

All financial instrument transactions are recorded at trade date.

Derivatives and Hedge Accounting

All derivative instruments, including embedded derivatives, are carried at fair value on the Consolidated Balance Sheet unless exempted from derivative treatment as a normal purchase and sale. All changes in fair value are recorded in financing charges unless cash flow hedge accounting is used, in which case changes in fair value are recorded in OCI to the extent that the hedge is effective. The impact of the change in the accounting policy related to embedded derivatives was not material.

The Company does not engage in derivative trading or speculative activities.

The Company periodically develops hedging strategies for execution taking into account risk management objectives. At the inception of a hedging relationship, the Company documents the relationship between the hedging instrument and the hedged item. This would include linking all derivatives to specific assets and liabilities on the Consolidated Balance Sheet or to specific firm commitments or forecasted transactions. The Company would also assess, both at the inception of the hedge and on an ongoing basis, whether the derivatives that are used are effective in offsetting changes in fair values or cash flows of hedged items.

Upon adoption of the new standards, the Company reclassified unamortized hedging losses on cash flow hedges that had been discontinued prior to the transition date to AOCI. The hedging losses are amortized to financing charges using the effective interest method over the term of the hedged debt.

Transaction Costs

Transaction costs for financial assets and liabilities that are other than held-for-trading are added to the carrying value of the asset or liability and then amortized over the expected life of the instrument using the effective interest method. The impact of the change in amortization basis from an annuity method to the effective interest method was not material.

Employee Future Benefits

Employee future benefits provided by Hydro One include pension, group life insurance, health care and long-term disability.

In accordance with the OEB's rate orders, pension costs are recorded when employer contributions are paid to the pension fund in accordance with the *Pension Benefits Act* (Ontario). Actuarial valuations are conducted at least every three years. Pension costs are also calculated on an accrual basis. Pension costs are actuarially determined using the projected benefit method prorated on service and based on assumptions that reflect management's best estimate of the effect of future events, including future compensation increases, on the actuarial present value of accrued pension benefits. Pension plan assets, consisting primarily of listed equity securities as well as corporate and government debt securities, are valued using fair values. Past service costs from plan amendments and all actuarial gains or losses are amortized on a straight-line basis over the expected average remaining service life of the employees covered.

Employee future benefits other than pension are recorded on an accrual basis. Costs are determined by independent actuaries using the projected benefit method prorated on service and based on assumptions that reflect management's best estimates. Past service costs from plan amendments and actuarial gains or losses are amortized on a straight-line basis over the expected average remaining service life of the employees covered.

Employee future benefit costs are attributed to labour and charged to operations or capitalized as part of the cost of fixed assets.

Environmental Costs

Hydro One recognizes a liability for estimated future expenditures associated with the assessment and remediation of contaminated lands and for the phase-out and destruction of polychlorinated biphenyl (PCB) contaminated mineral oil from electrical equipment, based on the net present value of these estimated future expenditures. As the Company anticipates that the related expenditures will continue to be recoverable in future rates, a regulatory asset has been recognized to reflect the future recovery of these costs from customers. Hydro One reviews its estimates of future environmental expenditures on an ongoing basis.

Use of Estimates

The preparation of financial statements in conformity with Canadian GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities at the date of the financial statements, and the reported amounts of revenues and expenses for the year. Actual results could differ from estimates, including changes as a result of future decisions made by the OEB or the Province.

Note 3.
Depreciation and Amortization

Year ended December 31 *(Canadian dollars in millions)*	**2007**	2006
Depreciation of fixed assets in service	**384**	379
Fixed asset removal costs	**39**	41
Amortization of regulatory and other assets	**98**	95
	521	515

Note 4.
Financing Charges

Year ended December 31 *(Canadian dollars in millions)*	**2007**	2006
Interest on short-term notes payable	**4**	2
Interest on long-term debt payable	**308**	296
Amortization of debt discount	**5**	27
Other	**7**	9
Less:		
Interest capitalized on construction in progress	**(24)**	(28)
Interest accreted on regulatory accounts	**–**	(7)
Interest earned on investments	**(5)**	(4)
	295	295

Note 5.
Provision for Payments in Lieu of Corporate Income Taxes

The provision for payments in lieu of corporate income taxes (PILs) differs from the amount that would have been recorded using the combined Canadian Federal and Ontario statutory income tax rate. A reconciliation between the statutory and effective tax rates is provided as follows:

Year ended December 31 *(Canadian dollars in millions)*	**2007**	2006
Income before provision for PILs	**604**	634
Federal and Ontario statutory income tax rate	**36.12%**	36.12%
Provision for PILs at statutory rate	**218**	229
Increase (decrease) resulting from:		
Net temporary differences:		
Transmission amounts received but not recognized for accounting purposes	**25**	12
Retail settlement variance accounts	**17**	2
Pension contributions in excess of pension expense	**(13)**	(16)
Overheads capitalized for accounting but deducted for tax purposes	**(12)**	(11)
Interest capitalized for accounting purposes but deducted for tax purposes	**(9)**	(13)
Capital cost allowance in excess of depreciation and amortization	**(9)**	(3)
Employee future benefits other than pension expense in excess of cash payments	**7**	14
Environmental expenditures	**(4)**	(6)
Recovery of PILs related to prior years	**–**	(30)
Other	**(5)**	2
Net temporary differences	**(3)**	(49)
Net permanent differences	**(10)**	(1)
Provision for PILs	**205**	179
Effective income tax rate	**33.94%**	28.23%

In 2006, Hydro One recognized a tax benefit of approximately $30 million in respect of a recovery of PILs from prior years following a successful appeal allowing a deduction for certain overhead costs that had been previously capitalized.

Future income taxes relating to the regulated businesses have not been recorded in the accounts as they are expected to be recovered through future revenues. As at December 31, 2007, future income tax liabilities of $253 million (2006 – $281 million), based on substantively enacted income tax rates, have not been recorded. In the absence of rate regulated accounting, the Company's provision for PILs would have been recognized using the liability method rather than the taxes payable method. As a result, the provision for PILs would have been lower by approximately $28 million (2006 – higher by $16 million), including the impact of a change in substantively enacted tax rates.

Future income taxes relating to the non-regulated businesses have also not been recorded in the accounts as they have not met the criterion of "more likely than not" to be realized. As at December 31, 2007, future income tax assets of $4 million (2006 – $4 million), based on substantively enacted income tax rates, have not been recorded.

Note 6.
Fixed Assets

December 31 (Canadian dollars in millions)	Fixed Assets in Service	Accumulated Depreciation	Construction in Progress	Total
2007				
Transmission	**8,708**	**3,152**	**370**	**5,926**
Distribution	**5,902**	**2,133**	**115**	**3,884**
Communication	**739**	**305**	**58**	**492**
Administration and service	**978**	**556**	**79**	**501**
Easements	**485**	**74**	**–**	**411**
	16,812	**6,220**	**622**	**11,214**
2006				
Transmission	8,293	3,024	359	5,628
Distribution	5,651	2,129	86	3,608
Communication	822	383	18	457
Administration and service	989	583	5	411
Easements	483	61	–	422
	16,238	6,180	468	10,526

Financing costs are capitalized on fixed assets under construction, including allowance for funds used during construction on regulated assets and interest on unregulated assets, and were $24 million in 2007 (2006 – $28 million).

Note 7.
Regulatory Assets and Liabilities

Regulatory assets and liabilities arise as a result of the rate-making process. Hydro One has recorded the following regulatory assets and liabilities:

December 31 *(Canadian dollars in millions)*	**2007**	2006
Regulatory assets:		
Regulatory asset recovery account II	**66**	87
Environmental	**65**	70
Employee future benefits other than pension	**42**	84
Regulatory asset recovery account I	**19**	58
Market ready	**13**	–
Smart meters	**4**	10
Other	**4**	2
Total regulatory assets	**213**	311
Less: current portion	**103**	121
	110	190
Regulatory liabilities:		
Deferred pension	**380**	382
Revenue difference deferral account	**73**	–
Retail settlement variance accounts	**50**	2
Export and wheeling fees	**38**	49
Transmission earnings sharing mechanism	**28**	34
Other	**14**	6
Total regulatory liabilities	**583**	473
Less: current portion	**114**	–
	469	473

Regulatory Assets

Regulatory Asset Recovery Account II (RARA II)

On April 12, 2006, the OEB announced its decision regarding the Company's rate application in respect of the distribution business of Hydro One Networks. As part of this decision, the OEB also approved the distribution-related deferral account balances sought by Hydro One. The OEB ordered that the approved balances be recovered on a straight-line basis over a four-year period from May 1, 2006 to April 30, 2010. The RARA II includes retail settlement and cost variance amounts and distribution low-voltage service amounts, plus accrued interest. In the absence of rate regulated accounting, amortization expense in 2007 would have been lower by $23 million (2006 – $16 million). In addition, related financing charges would have been higher by $3 million (2006 – $5 million).

Environmental

Hydro One records a liability for the estimated future expenditures required to remediate past environmental contamination. Because such expenditures are expected to be recoverable in future rates, the Company has recognized an equivalent amount as a regulatory asset. This regulatory asset is expected to be amortized to results of operations on a basis consistent with the pattern of actual expenditures expected to be incurred up to the year 2030. The OEB has the discretion to examine and assess the prudence and the timing of recovery of all of Hydro One's future regulatory expenditures. In the absence of rate regulated accounting, amortization expense in 2007 would have been lower by $12 million (2006 – $17 million).

Employee Future Benefits Other Than Pension

Employee future benefits other than pension are recorded using the accrual method as required by Canadian GAAP. The OEB has allowed for the recovery of past service costs, which arose on the adoption of the accrual method, in the revenue requirement on a straight-line basis over a 10-year period. As a result, in 1999 Hydro One recorded a regulatory asset, with an original balance of $419 million, to reflect this regulatory treatment. This regulatory asset has a remaining recovery period of one year (2006 – two years) and does not earn a return. In the absence of rate regulated accounting, amortization expense in 2007 would have been lower by $42 million (2006 – $42 million).

Regulatory Asset Recovery Account I (RARA I)

On December 9, 2004, the OEB issued a decision on the prudence of the distribution related deferral account balances for which recovery was sought by Hydro One in its May 31, 2004 application. Amounts for which recovery was approved represented balances incurred prior to December 31, 2003, plus associated interest. The OEB ordered that the approved amounts be aggregated into a single regulatory account to be recovered on a straight-line basis over the period ending April 30, 2008. Hydro One Networks has requested an extension of the period for the RARA I recovery until such time as new rates are implemented. The RARA I includes distribution business low-voltage services amounts, deferred environmental expenditures incurred in 2001 and 2002, deferred market ready expenditures, retail settlement variance amounts, and other amounts primarily consisting of accrued interest. Any over- or under-recovery of the RARA I due to continuance of the rate rider will be tracked for disposition at a future date. In the absence of rate regulated accounting, amortization expense in 2007 would have been lower by $20 million (2006 – $20 million). In addition, related financing charges would have been higher by $1 million (2006 – $3 million).

Market Ready

In September 2006, as part of its transmission rate application, Hydro One Networks applied for the recovery of various regulatory deferral accounts including the transmission market ready costs incurred in connection with market opening. The transmission related transition costs were incurred to meet IESO requirement associated with registration and authorization activities. On August 16, 2007, as a result of the oral and written evidence the OEB approved the recovery of substantially all of these costs. Consequently, the market ready regulatory asset was established and recovery is being factored into rates over the four-year period ending December 31, 2010. In the absence of rate regulated accounting, operation, maintenance and administration expense would have been higher by $16 million (2006 – $nil) and revenue would have been higher by $4 million (2006 – $nil).

Smart Meters

On March 21, 2006, the OEB approved the establishment of regulatory deferral accounts for smart meter-related expenditures and a monthly customer charge of 27 cents and 28 cents per metered customer for Hydro One Networks and Hydro One Brampton, respectively, was reflected in Hydro One's revenue requirement. Consistent with the OEB's direction and pending further guidance, the Company recognized a regulatory asset consisting of the net balance of capital and operating expenditures for smart meters less recoveries received from customers. In April 2007, as part of its decision regarding the Company's 2007 distribution rate applications, the OEB increased the monthly customer charge effective May 1, 2007 to 93 cents and 67 cents per metered customer for Hydro One Networks and Hydro One Brampton, respectively.

On August 8, 2007, the OEB issued a decision on its combined proceeding to determine recoverability of expenditures incurred by distributors. Expenditures associated with the minimum functionality for advanced metering infrastructure incurred by Hydro One Networks and Hydro One Brampton were approved for recovery. As a result of this decision, smart meter expenditures are no longer deferred as regulatory assets. Such expenditures are now classified as capital or are charged to results of operations consistent with the Company's standard accounting practices. Expenditures determined to be above the minimum functionality have been brought forward for review in Hydro One Networks' cost of service rate application filed in 2007.

The OEB decision also required that related revenues be based upon a calculated revenue requirement specific to smart meters. As a result, the carrying value of the smart meter regulatory asset account represents the difference between revenue recorded on this basis and actual recoveries received under existing rate adders. In the absence of rate regulated accounting, year-to-date operation, maintenance and administration expense would have been lower by $3 million (2006 – higher by $4 million) and revenues would have been lower by $2 million (2006 – higher by $2 million).

Regulatory Liabilities

Deferred Pension

In accordance with the OEB's 1999 transitional rate order, pension costs are recorded in results of operations when employer contributions are paid into the pension plan. The Company's deferred pension asset represents the cumulative difference between employer contributions and pension costs and the deferred pension regulatory liability results from the Company's recognition, as the result of OEB direction, of revenues and expenses in different periods than would be the case for an unregulated enterprise. In the absence of rate regulated accounting, operating, maintenance and administration expense would have been higher by $1 million (2006 – $50 million).

Revenue Difference Deferral Account (RDDA)

On March 30, 2007, the OEB issued a decision approving the establishment of the RDDA to record the revenue differential between existing transmission rates and the new rates that were anticipated to be approved later in the year. The new deferral account was to represent the revenue differential between existing and future rates for the period commencing January 1, 2007. On August 16, 2007, in its decision on Hydro One Networks' 2007 and 2008 transmission rates, the OEB approved final amounts and disposition treatments for the RDDA liability, which will be returned to customers over the 14-month period ending December 31, 2008.

Retail Settlement Variance Accounts (RSVA)

Hydro One has deferred certain retail settlement variance amounts under the provisions of Article 490 of the OEB's *Accounting Procedures Handbook*. The OEB's December 9, 2004 decision allowed for recovery of retail settlement variance amounts accumulated prior to December 31, 2003, inclusive of interest, within the RARA I. The OEB's April 12, 2006 decision allowed for recovery of retail settlement variance amounts accumulated since January 1, 2004 and forecasted through to April 30, 2006, inclusive of interest, within the RARA II. The Company has accumulated a net liability in its RSVA since May 1, 2006 which was taken into consideration in the revenue requirement of Hydro One Networks as part of the 2008 distribution rate application filed with the OEB in December 2007.

Export and Wheeling Fees

Consistent with the IESO's Market Rules, an export and wheeling fee is collected by the IESO and remitted to Hydro One at the rate of $1 per MWh on electricity exported outside of Ontario. The amounts collected in respect of these export and wheeling fees, plus interest, were taken into consideration in the revenue requirement of Hydro One's transmission business as part of the Company's transmission rate application filed with the OEB in September 2006. In August 2007, the OEB issued its decision in respect of the Company's transmission rate application and approved final amounts and disposition treatments for the export wheeling fees. The export wheeling fees will be factored into rates over a four-year period ending December 31, 2010.

Transmission Earnings Sharing Mechanism (ESM)

On February 21, 2006, the OEB issued a decision that established an ESM to equally share, between the Company's shareholder and ratepayers, any transmission earnings in excess of the approved rate of return of 9.88%, for the period ending January 1, 2006 until new transmission rates were set. Consequently, 50% of the Company's excess earnings were deferred as a regulatory liability. On March 30, 2007, the OEB issued a decision ordering that the transmission ESM cease effective December 31, 2006. The ESM was taken into consideration in setting the revenue requirement of Hydro One Networks for 2007 and 2008. On August 16, 2007, in its decision on Hydro One Networks 2007 and 2008 transmission rates, the OEB approved final amounts and disposition treatments for the ESM which will be returned to customers over a 14-month period ending December 31, 2008.

Note 8.
Debt

December 31 *(Canadian dollars in millions)*	2007	2006
Short-term notes payable	–	60
Long-term debt:		
4.45% notes due 2007	–	282
4.55% notes due 2007	–	73
4.70% (2006 – 4.10%) notes due 2008[1]	40	40
4.00% notes due 2008	500	500
3.95% notes due 2009	400	400
7.15% debentures due 2010	400	400
6.40% notes due 2011	250	250
5.77% notes due 2012	600	600
4.64% notes due 2016	450	450
5.18% notes due 2017	300	–
7.35% debentures due 2030	400	400
6.93% notes due 2032	500	500
6.35% notes due 2034	385	385
5.36% notes due 2036	600	600
4.89% notes due 2037	400	–
6.59% notes due 2043	315	315
5.00% notes due 2046	75	75
	5,615	5,270
Less:		
Long-term debt payable within one year	(540)	(395)
Net unamortized premiums	13	9
Unamortized hedging losses[2]	–	(12)
Unamortized debt issuance costs	(25)	(24)
Long-term debt	5,063	4,848

1 Step-up coupon from 4.10% to 6.40%, extendable to 2011.

2 Unamortized net losses relating to settled swap agreements were reclassified to AOCI on January 1, 2007 without prior year reclassification.

Short-term debt represents promissory notes issued pursuant to the Company's Commercial Paper Program. The notes are denominated in Canadian dollars with varying maturities not exceeding 365 days. In 2007, the notes had a weighted-average interest rate of 5.7%.

Hydro One has a $750 million committed and unused revolving standby credit facility with a syndicate of banks maturing in August 2010. If used, interest on the facility would apply based on Canadian benchmark rates. This credit facility supports the Company's Commercial Paper Program.

The Company issues notes for long-term financing under the Medium-Term Note Program. The maximum authorized principal amount of medium-term notes issuable under this program is $2,500 million of which $2,200 million is remaining and is currently available until July 2009.

The long-term debt is subject to covenants that, among other things, limit permissible debt as a percentage of total capitalization, limit ability to sell assets and impose a negative pledge provision, subject to customary exceptions. At December 31, 2007, the Company was in compliance with these covenants.

The long-term debt is unsecured and denominated in Canadian dollars. Such debt is summarized by the number of years to maturity in the following table:

Years to Maturity	Principal Outstanding on Notes and Debentures *(Canadian dollars in millions)*	Weighted Average Interest Rate *(Percent)*
1 year	540	4.1
2 years	400	4.0
3 years	400	7.2
4 years	250	6.4
5 years	600	5.8
	2,190	5.3
6–10 years	750	4.9
Over 10 years	2,675	6.2
	5,615	5.7

Note 9.
Fair Value of Financial Instruments and Risk Management

The carrying amounts of all financial instruments, except long-term debt, approximate fair value. The fair value of derivative financial instruments reflects the estimated amount that the Company, if required to settle an outstanding contract, would have been required to pay or would be entitled to receive at year end. The fair value of long-term debt, based on year end quoted market prices for the same or similar debt of the same remaining maturities, is provided in the following table:

December 31 *(Canadian dollars in millions)*	**2007**		2006	
	Carrying Value	Fair Value	Carrying Value	Fair Value
Long-term debt[1]	**5,615**	**6,005**	5,270	5,831

[1] The carrying value of long-term debt represents the par value of the notes and debentures, other than the step-up note, which is marked to market.

Hydro One may enter into derivative agreements, such as forward starting pay fixed interest rate swap agreements, to hedge against the effect of future interest rate movements on long-term fixed rate borrowing requirements. These transactions are accounted for as cash flow hedges of anticipated transactions. In October 2007, upon issuance of debt under the Company's Medium-Term Note Program, Hydro One terminated two forward interest rate swap agreements having a total notional principal amount of $200 million, resulting in a net gain of $0.4 million. The net gain was recorded as other comprehensive income and is being amortized to financing charges over the term of the related debt. In late 2007, Hydro One entered into two new forward starting pay fixed interest rate swap agreements with a notional amount of $140 million.

As at December 31, 2007, the Company had a pay floating interest rate swap agreement related to a step-up coupon note issuance with an initial maturity date in 2007, and with extended maturity dates up to 2011. In 2006, the interest rate swap was accounted for as a fair value hedge. In 2007, the interest rate swap was accounted for using the fair value option without hedge accounting. This agreement has a notional principal amount of $40 million and a fair value of $nil (2006 – $nil).

The Company has no significant counter-party credit risk exposure as the fair value of the interest rate swap contracts was not significant in 2007 or in 2006.

Financial assets create a risk that a counter-party will fail to discharge an obligation, causing a financial loss. As at December 31, 2007, there were no significant concentrations of credit risk with respect to any class of financial assets. The Company's revenue is earned from a broad base of customers. As a result, Hydro One did not earn a significant amount of revenue from any single customer. As at December 31, 2007, there were no significant balances of accounts receivable due from any single customer.

The Company will continue to use derivative instruments to manage interest rate risk. Derivative financial instruments result in exposure to credit risk, since there is a risk of counter-party default. Hydro One monitors and minimizes credit risk through various techniques including dealing with highly rated counter-parties, limiting total exposure levels with individual counter-parties and entering into master agreements which enable net settlement.

Note 10.
Employee Future Benefits

Hydro One has a contributory defined benefit pension plan covering all regular employees of Hydro One and its subsidiaries, except Hydro One Brampton. Employees of Hydro One Brampton participate in the Ontario Municipal Employees Retirement System (OMERS), a multi-employer public sector pension fund. Current contributions by Hydro One Brampton are approximately $1 million annually.

Plan Asset Mix

Hydro One's pension plan asset mix at December 31, 2007 and 2006 was as follows:

	% of Plan Assets	
December 31	**2007**	2006
Equity securities	**62.5**	64.6
Debt securities	**34.1**	32.0
Other	**3.4**	3.4
	100.0	100.0

Supplementary Information

The Hydro One pension plan does not hold any direct securities of the Company, but did hold debt securities of the Province of $90 million and $92 million at December 31, 2007 and 2006, respectively.

The Company's pension plan provides benefits based on the highest three-year average pensionable earnings. For new management employees who commenced employment on or after January 1, 2004, and for new Society of Energy Professionals hired after November 17, 2005, benefits are based on the highest five-year average pensionable earnings. After retirement, pensions are indexed to inflation. The measurement date used to determine plan assets and the accrued benefit obligation is December 31. Based on the actuarial valuation filed with the Financial Services Commission of Ontario on September 20, 2007, effective for December 31, 2006, the Company contributed $95 million to its pension plan in respect of 2007 (2006 – $86 million), all of which is required to satisfy minimum funding requirements. Contributions are payable one month in arrears. All of the contributions are expected to be in the form of cash. Contributions after 2009 will be based on an actuarial valuation effective December 31, 2009 and will depend on future investment returns, and changes in benefits or actuarial assumptions.

Total cash payments for employee future benefits made in 2007, consisting of cash contributed by the Company to its funded pension plan and cash paid directly to beneficiaries for its unfunded other benefit plans, was $137 million in 2007 (2006 – $122 million).

Year ended December 31 (Canadian dollars in millions)	Pension **2007**	Pension 2006	Employee Future Benefits Other Than Pension **2007**	Employee Future Benefits Other Than Pension 2006
Change in accrued benefit obligation				
Accrued benefit obligation, January 1	**5,411**	5,355	**1,100**	1,143
Current service cost	**105**	106	**23**	33
Interest cost	**282**	267	**57**	58
Benefits paid	**(264)**	(253)	**(42)**	(36)
Plan amendments	**–**	6	**–**	22
Net actuarial gain	**(457)**	(70)	**(44)**	(120)
Accrued benefit obligation, December 31	**5,077**	5,411	**1,094**	1,100
Change in plan assets				
Fair value of plan assets, January 1	**5,123**	4,713	**–**	–
Actual return on plan assets	**142**	571	**–**	–
Benefits paid	**(264)**	(253)	**–**	–
Employer's contributions[1]	**95**	86	**–**	–
Employees' contributions	**17**	17	**–**	–
Administrative expenses	**(13)**	(11)	**–**	–
Fair value of plan assets, December 31	**5,100**	5,123	**–**	–
Funded status				
Funded excess (unfunded benefit obligation)	**23**	(288)	**(1,094)**	(1,100)
Unamortized net actuarial losses	**336**	645	**178**	236
Unamortized past service costs	**21**	25	**21**	25
Deferred pension asset (accrued benefit liability)	**380**	382	**(895)**	(839)
Less: current portion	**–**	–	**40**	36
Deferred pension asset (long-term liability)	**380**	382	**(855)**	(803)

[1] In January 2008, the Company made a contribution of $8 million in respect of 2007 (2007 – $8 million in respect of 2006).

Year ended December 31 *(Canadian dollars in millions)*	Pension 2007	Pension 2006	Employee Future Benefits Other Than Pension 2007	Employee Future Benefits Other Than Pension 2006
Components of net periodic benefit cost				
Current service cost, net of employee contributions	**88**	89	**23**	33
Interest cost	**282**	267	**57**	58
Actual return on plan asset net of expenses	**(129)**	(560)	**–**	–
Actuarial gain	**(457)**	(70)	**(44)**	(120)
Plan amendments	**–**	6	**–**	22
Other	**–**	(1)	**–**	(1)
Costs arising in the period	**(216)**	(269)	**36**	(8)
Differences between costs arising in the period and costs recognized in the period in respect of:				
Return on plan assets	**(212)**	248	**–**	–
Actuarial loss (gain)	**522**	177	**59**	149
Plan amendments	**3**	(3)	**4**	(19)
Net periodic benefit cost[2]	**97**	153	**99**	122
Charged to results of operations[2]	**58**	42	**60**	75
Effect of 1% increase in health care cost trends on:				
Accrued benefit obligation, December 31	**–**	–	**167**	156
Service cost and interest cost	**–**	–	**12**	13
Effect of 1% decrease in health care cost trends on:				
Accrued benefit obligation, December 31	**–**	–	**(132)**	(124)
Service cost and interest cost	**–**	–	**(9)**	(10)
Significant assumptions				
For net periodic benefit cost:				
Expected rate of return on plan assets	**6.75%**	6.75%	**–**	–
Weighted-average discount rate	**5.25%**	5.00%	**5.24%**	4.98%
Rate of compensation scale escalation (without merit)	**3.25%**	3.25%	**3.25%**	3.25%
Rate of cost of living increase	**2.50%**	2.50%	**2.50%**	2.50%
Average remaining service life of employees *(years)*	**10**	10	**9**	10
Rate of increase in health care cost trend[3]	**–**	–	**4.40%**	4.40%
For accrued benefit obligation, December 31:				
Weighted-average discount rate	**5.50%**	5.25%	**5.50%**	5.24%
Rate of compensation scale escalation (without merit)	**3.00%**	3.25%	**3.00%**	3.25%
Rate of cost of living increase	**2.25%**	2.50%	**2.25%**	2.50%
Rate of increase in health care cost trend[4]	**–**	–	**4.40%**	4.40%

2 The Company follows the cash basis of accounting. During 2007, pension costs of $95 million (2006 – $86 million) were attributed to labour, of which $58 million (2006 – $42 million) was charged to operations, $37 million (2006 – $34 million) was capitalized as part of the cost of fixed assets, and $nil (2006 – $10 million) was attributed to regulatory asset.

3 8.69% in 2007 grading down to 4.40% per annum in and after 2018 (2006 – 7.87% in 2006 grading down to 4.40% per annum in and after 2014).

4 8.33% in 2008 grading down to 4.40% per annum in and after 2018 (2006 – 8.69% in 2007 grading down to 4.40% per annum in and after 2014).

Note 11.
Environmental Liabilities

December 31 *(Canadian dollars in millions)*	**2007**	2006
Environmental liabilities, January 1	**70**	79
Interest accretion	**4**	5
Expenditures	**(12)**	(17)
Revaluation adjustment	**3**	3
Environmental liabilities, December 31	**65**	70
Less: current portion	**(13)**	(15)
	52	55

Estimated future environmental expenditures for each of the five years subsequent to December 31, 2007 and in total thereafter are as follows: 2008 – $13 million; 2009 – $12 million; 2010 – $10 million; 2011 – $8 million; 2012 – $6 million and thereafter – $35 million.

There are uncertainties in estimating future environmental costs due to potential external events such as changing regulations and advances in remediation technologies. Hydro One continuously reviews factors affecting its cost estimates as well as the environmental condition of the various properties. The actual cost of investigation or remediation may differ from current estimates.

Note 12.
Share Capital

Common and Preferred Shares

On March 31, 2000, the Company issued to the Province 12,920,000 5.5% cumulative preferred shares with a redemption value of $25.00 per share, and 99,990 common shares, bringing the total number of outstanding common shares to 100,000. The Company is authorized to issue an unlimited number of preferred and common shares.

The preferred shares are entitled to an annual cumulative dividend of $18 million, which is payable on a quarterly basis. The preferred shares are redeemable at the option of the Province at a price of $25 per share, representing the stated value, plus any accrued and unpaid dividends if the Province sells a number of the common shares which it owns to the public such that the Province’s holdings are reduced to less than 50% of the common shares of the Company. Hydro One may elect, without condition, to pay all or part of this redemption price by issuing additional common shares to the Province. If the Province does not exercise its redemption right, the Company would have the ability to adjust the dividend on the preferred shares to produce a yield that is 0.50% less than the then-current dividend market yield for similarly rated preferred shares. The preferred shares do not carry voting rights, except in limited circumstances, and would rank in priority over the common shares upon liquidation.

Dividends

Common dividends are declared at the sole discretion of the Hydro One Board of Directors, and are recommended by management based on results of operations, financial condition, cash requirements and other relevant factors such as industry practice and shareholder expectations.

In 2007, preferred dividends in the amount of $18 million (2006 – $18 million) and common dividends in the amount of $307 million (2006 – $332 million) were declared.

Earnings per Share

Earnings per share is calculated as net income during the year, after cumulative preferred dividends, divided by the weighted-average number of common shares outstanding during the year.

Note 13.
Related Party Transactions

The Province, OEFC, IESO, OPA and Ontario Power Generation Inc. (OPG) are related parties of Hydro One. In addition the OEB is related to the Company by virtue of its status as a Provincial Crown Corporation. Transactions between these parties and Hydro One were as follows:

Hydro One received revenue for transmission services from IESO, based on uniform transmission rates approved by the OEB. Transmission revenue for 2007 includes $1,203 million (2006 – $1,206 million) related to these services.

Hydro One receives amounts for rural rate protection from the IESO. Distribution revenue for 2007 includes $127 million (2006 – $127 million) related to this program. Hydro One also received revenue related to the supply of electricity to remote northern communities from the IESO. Distribution revenue for 2007 includes $21 million (2006 – $21 million) related to these services.

In 2007, Hydro One purchased power in the amount of $2,213 million (2006 – $2,183 million) from the IESO administered electricity market and $27 million (2006 – $38 million) from OPG.

Under the *Ontario Energy Board Act, 1998*, the OEB is required to recover all of its annual operating costs from gas and electricity distributors and electricity transmitters. In 2007, Hydro One incurred $10 million (2006 – $9 million) in OEB fees.

Hydro One has service level agreements with the other successor corporations. These services include field, engineering, logistics and telecommunications services. Revenues related to the provision of construction and equipment maintenance services to the other successor corporations were $12 million (2006 – $15 million), primarily for the transmission business. Operation, maintenance and administration costs related to the purchase of services from the other successor corporations were less than $1 million in each of 2007 and 2006.

Consistent with the OPA mandate, the OPA is responsible for some of our CDM programs. The funding includes program costs, incentives and management fees and bonuses. In 2007, Hydro One received $3 million (2006 – $nil) from the OPA in respect of the CDM programs and had a net accounts receivable of $3 million (2006 – $nil).

The provision for payments in lieu of corporate income taxes was paid or payable to the OEFC and dividends were paid or payable to the Province.

The amounts due to and from related parties as a result of the transactions referred to above are as follows:

December 31 *(Canadian dollars in millions)*	**2007**	2006
Accounts receivable	**97**	114
Accounts payable and accrued charges	**(234)**	(230)

Included in accounts payable and accrued charges are amounts owing to the IESO in respect of power purchases of $202 million (2006 – $195 million).

Note 14.
Consolidated Statements of Cash Flows

For the purposes of the Consolidated Statements of Cash Flows, "cash and cash equivalents" refers to the Balance Sheet item "bank indebtedness."

The changes in non-cash balances related to operations consist of the following:

Year ended December 31 *(Canadian dollars in millions)*	**2007**	2006
Accounts receivable decrease (increase)	**18**	(149)
Materials and supplies increase	**(11)**	–
Accounts payable and accrued charges increase (decrease)	**70**	(39)
Accrued interest increase	**6**	6
Long-term accounts payable and accrued charges decrease	**(3)**	(7)
Employee future benefits other than pension increase	**52**	87
Other	**3**	(4)
	135	(106)
Supplementary information:		
Interest paid	**306**	302
Payments in lieu of corporate income taxes	**230**	252

Note 15.
Contingencies

Legal Proceedings

Hydro One is involved in various lawsuits, claims and regulatory proceedings in the normal course of business. In the opinion of management, the outcome of such matters, except as noted below, will not have a materially adverse effect on the Company's consolidated financial position, results of operations or cash flows.

On March 29, 1999, the Whitesand First Nation Band commenced an action in the Ontario Court (General Division), now the Superior Court Justice, naming as defendants the Province, the Attorney General of Canada, Ontario Hydro, OEFC, OPG and the Company. On May 24, 2001, the Whitesand First Nation Band issued an almost identical claim against the same parties. The reason for the second claim is the procedural defence of the Province that proper notice of the first claim was not given under the *Proceedings Against the Crown Act* (Ontario). These actions seek declaratory relief, injunctive relief and damages in an unspecified amount. The Whitesand Band alleges that since at least the first half of the 20th century, Ontario Hydro has erected dams, generating stations and other facilities within or affecting the band's traditional lands and that those facilities have caused damage to band members and the lands, including substantial flooding and erosion. The Whitesand Band also claims treaty rights to a share of the profits arising from the activities of these Ontario Hydro facilities, an entitlement to increases in annuity payments established by treaty and for breach of an alleged contract to reimburse the band for negotiation costs with Ontario Hydro. The Whitesand Band asserts multiple causes of action, including trespass, breach of fiduciary duty, nuisance and negligence. The May 24, 2001 case was consolidated in 2004 with a similar claim by Red Rock First Nation Band which commenced on September 7, 2001 as all procedural issues in both matters were the same. There is now one action in which the claims of both Whitesand and Red Rock are set out. The claims relating to activities of Ontario Hydro (i.e., flooding) are the matters for which OPG would have responsibility pursuant to Transfer Orders under the *Electricity Act, 1998*. In the consolidated claim, Whitesand and Red Rock seek to tie Hydro One into the flooding allegations on the alleged basis of the integrated nature of the transmission system with the entire electricity system, which includes the method of generating power. To date, Hydro One has not filed a defence. Hydro One believes that it is unlikely that the outcome of this litigation will have a material adverse effect on its consolidated financial position, results of operations or cash flows.

Transfer of Assets

The transfer orders by which Hydro One acquired certain of Ontario Hydro's businesses as of April 1, 1999 did not transfer title to some assets located on lands held for bands or bodies of Indians under the *Indian Act* (Canada). Currently, the OEFC holds these assets. Under the terms of the transfer orders, Hydro One is required to manage these assets until it has obtained all consents necessary to complete the transfer of title of these assets to itself. The Company cannot predict the aggregate amount that it may have to pay, either on an annual or one-time basis, to obtain the required consents. However, it anticipates having to pay more than the approximately $900,000 per year than it currently is paying to these Indian bands and bodies. If the Company cannot obtain consents from the Indian bands and bodies, OEFC will continue to hold these assets for an indefinite period of time. If the Company cannot reach a satisfactory settlement, it may have to relocate these assets from the Indian lands to other locations at a cost that could be substantial or, in a limited number of cases, to abandon a line and replace it with diesel generation facilities. The costs relating to these assets could have a material adverse effect on the Company's results of operations if it is not able to recover them in future rate orders.

Draft PCB Regulations

Future changes in environmental regulations may result in material changes to the Company's estimated liability related to the management of PCBs. On November 4, 2006, Environment Canada published new draft regulations governing the management of PCBs. These draft regulations may be finalized in 2008. The Company has estimated its operating expenditures for complying with these draft regulations to be between $250 million and $375 million in excess of amounts already recorded as environmental liabilities on its Balance Sheet. If required, most of these additional expenditures are expected to be incurred between 2013 and 2025. No obligation has been recorded in the financial statements for these increased expenditures due to continued uncertainty regarding the timing and content of the final regulations. In the event that an obligation related to new regulations is recorded, the Company expects to simultaneously record a regulatory asset of equivalent value.

Note 16.
Commitments

Agreement with Inergi

Effective March 1, 2002, Cap Gemini Canada Inc. began providing services to Hydro One through Inergi. As a result of this initiative, Hydro One receives from Inergi a range of services including information technology, customer care, supply chain and certain human resources and finance services for a 10-year period. The initial service level price ranged between $90 million and $130 million per year, subject to external benchmarking every three years to ensure Hydro One is receiving a defined competitive and continuously improved price. In connection with this agreement, on March 1, 2002 the Company transferred approximately 900 employees to Inergi, including about 130 non-regular employees.

The annual commitments under the agreement in each of the five years subsequent to December 31, 2007, and in total thereafter are as follows: 2008 – $100 million; 2009 – $97 million; 2010 – $93 million; 2011 – $90 million; 2012 – $16 million and thereafter – $nil.

Prudential Support

Purchasers of electricity in Ontario, through the IESO, are required to provide security to mitigate the risk of their default based on their expected activity in the market. The IESO could draw on these guarantees if Hydro One Networks or Hydro One Brampton fails to make a payment required by a default notice issued by the IESO. The maximum potential payment is the face value of any bank letters of credit plus the nominal amount of the parental guarantee. As at December 31, 2007, the Company provided prudential support using only parental guarantees, reflecting a change from 2006. If Hydro One's highest long-term credit rating deteriorated to below the "Aa" category, the Company would be required to resume providing letters of credit as prudential support. Prudential support at December 31, 2007 was provided using bank letters of credit of $nil million (2006 – $22 million) and parental guarantees of $325 million (2006 – $275 million).

Retirement Compensation Arrangements

Bank letters of credit have been issued to provide security for the Company's liability under the terms of a trust fund established pursuant to the supplementary pension plan for the employees of Hydro One and its subsidiaries. The trustee is required to draw upon the letters of credit if Hydro One is in default of its obligations under the terms of this plan. Such obligations include the requirement to provide the trustee with an annual actuarial report as well as letters of credit sufficient to secure the Company's liability under the plan, to pay benefits payable under the plan and to pay the letter of credit fee. The maximum potential payment is the face value of the bank letters of credit. As at December 31, 2007, Hydro One had bank letters of credit of $95 million (2006 – $93 million) outstanding relating to retirement compensation arrangements.

Operating Leases

The future minimum lease payments under operating leases for each of the five years subsequent to December 31, 2007 and in total thereafter are as follows: 2008 – $6 million; 2009 – $5 million; 2010 – $2 million; 2011 – $1 million; 2012 – $1 million and thereafter – $1 million.

Note 17.
Segment Reporting

Hydro One has three reportable segments:

- The transmission business, which comprises the core business of providing transportation and connection services, is responsible for transmitting electricity throughout the Ontario electricity grid;
- The distribution business, which comprises the core business of delivering and selling electricity to customers; and
- The "other" segment, which primarily consists of the telecommunications business.

The designation of segments is based on a combination of regulatory status and the nature of the products and services provided. The accounting policies followed by the segments are the same as those described in the summary of significant accounting policies (see Note 2). Segment information on the above basis is as follows:

Year ended December 31 (Canadian dollars in millions)	Transmission	Distribution	Other	Consolidated
2007				
Segment profit				
Revenues	**1,242**	**3,382**	**31**	**4,655**
Purchased power	**–**	**2,240**	**–**	**2,240**
Operation, maintenance and administration	**415**	**549**	**31**	**995**
Depreciation and amortization	**242**	**273**	**6**	**521**
Income (loss) before financing charges and provision for payments in lieu of corporate income taxes	**585**	**320**	**(6)**	**899**
Financing charges				**295**
Income before provision for payments in lieu of corporate income taxes				**604**
Capital expenditures	**560**	**511**	**20**	**1,091**
2006				
Segment profit				
Revenues	1,245	3,273	27	4,545
Purchased power	–	2,221	–	2,221
Operation, maintenance and administration	390	460	30	880
Depreciation and amortization	241	269	5	515
Income (loss) before financing charges and provision for payments in lieu of corporate income taxes	614	323	(8)	929
Financing charges				295
Income before provision for payments in lieu of corporate income taxes				634
Capital expenditures	402	417	4	823

December 31 *(Canadian dollars in millions)*	**2007**	2006
Total assets		
Transmission	**7,273**	6,950
Distribution	**5,411**	5,161
Other	**106**	99
	12,790	12,210

All revenues, costs and assets, as the case may be, are earned, incurred or held in Canada.

Note 18.
Subsequent Events

On January 21, 2008, the Company entered into a forward starting pay fixed interest rate swap agreement to hedge against the effect of future interest rate movements on long-term fixed rate borrowing requirements. This transaction had a notional amount of $60 million and is used to lock in the interest rate of a forecasted debt issuance planned for later in 2008. This transaction is being accounted for as a cash flow hedge of a forecasted transaction.

On January 28, 2008 the Company increased its committed revolving credit facility, which supports its commercial paper program, by $250 million to $1,000 million. The maturity date remains unchanged at August 10, 2010.

Note 19.
Comparative Figures

The comparative Consolidated Financial Statements have been reclassified from statements previously presented to conform to the presentation of the December 31, 2007 Consolidated Financial Statements.

Five-Year Summary of Financial and Operating Statistics

Year ended December 31 *(Canadian dollars in millions)*	**2007**	2006	2005	2004	2003
Statement of operations data					
Revenues					
Transmission	**1,242**	1,245	1,310	1,262	1,298
Distribution	**3,382**	3,273	3,085	2,874	2,734
Other	**31**	27	21	17	26
	4,655	4,545	4,416	4,153	4,058
Costs					
Purchased power	**2,240**	2,221	2,131	1,987	1,872
Operation, maintenance and administration	**995**	880	792	771	795
Depreciation and amortization	**521**	515	487	480	454
	3,756	3,616	3,410	3,238	3,121
Regulatory recovery[1]	**–**	–	–	91	–
Income before financing charges and provision for payments in lieu of corporate income taxes	**899**	929	1,006	1,006	937
Financing charges	**295**	295	325	331	348
Income before provision for payments in lieu of corporate income taxes	**604**	634	681	675	589
Provision for payments in lieu of corporate income taxes	**205**	179	198	177	193
Net income	**399**	455	483	498	396
Basic and fully diluted earnings per common share *(Canadian dollars)*	**3,809**	4,366	4,652	4,798	3,779

Five-Year Summary of Financial and Operating Statistics (continued)

Year ended December 31 (Canadian dollars in millions)	**2007**	2006	2005	2004	2003
Balance sheet data					
Assets					
Transmission	**7,273**	6,950	6,813	6,771	6,576
Distribution	**5,411**	5,161	4,893	4,836	4,614
Other	**106**	99	92	95	94
Total assets	**12,790**	12,210	11,798	11,702	11,284
Liabilities					
Current liabilities					
(including current portion of long-term debt)	**1,452**	1,194	1,341	1,262	1,192
Long-term debt	**5,063**	4,848	4,443	4,590	4,517
Other long-term liabilities	**1,389**	1,347	1,298	1,326	1,284
Shareholder's equity					
Share capital	**3,637**	3,637	3,637	3,637	3,637
Retained earnings	**1,258**	1,184	1,079	887	654
Accumulated other comprehensive income	**(9)**	–	–	–	–
Total liabilities and shareholder's equity	**12,790**	12,210	11,798	11,702	11,284

Five-Year Summary of Financial and Operating Statistics (continued)

Year ended December 31 (Canadian dollars in millions)	2007	2006	2005	2004	2003
Other financial data					
Capital expenditures					
Transmission	**560**	402	349	432	289
Distribution	**511**	417	338	288	292
Other	**20**	4	4	7	16
Total capital expenditures	**1,091**	823	691	727	597
Ratios					
Net asset coverage on long-term debt[2]	**1.87**	1.92	1.93	1.88	1.86
Earnings coverage ratio[3]	**2.67**	2.67	2.69	2.70	2.43
Operating statistics					
Transmission					
Units transmitted *(TWh)*[4]	**152.2**	151.1	157.0	153.4	151.7
Ontario 20-minute system peak demand *(MW)*[4]	**25,809**	27,056	26,219	25,204	24,849
Ontario 60-minute system peak demand *(MW)*[4]	**25,737**	27,005	26,160	24,979	24,753
Total transmission lines *(circuit-kilometres)*	**28,915**	28,600	28,547	28,643	28,621
Distribution					
Units distributed to Hydro One customers *(TWh)*[4]	**30.2**	29.0	29.7	28.5	27.9
Units distributed through Hydro One lines *(TWh)*[4, 5]	**45.7**	44.7	45.6	44.8	44.7
Total distribution lines *(circuit-kilometres)*	**122,933**	122,460	122,118	121,736	121,285
Customers	**1,311,714**	1,293,396	1,273,768	1,258,925	1,238,748
Total regular employees	**4,602**	4,295	4,189	4,118	3,967

1 As a result of the oral and written evidence submitted by Hydro One, on December 9, 2004, the OEB issued a ruling, citing prudence, and approving recovery of amounts previously delayed by the *Electricity Pricing, Conservation and Supply Act, 2002*, relating to regulatory deferral account balances sought by Hydro One in its May 31, 2004 submission. Consequently, a one-time regulatory recovery of $91 million was recorded.

2 The net asset coverage on long-term debt ratio is calculated as total assets minus total liabilities excluding long-term debt (including current portion) divided by long-term debt (including current portion).

3 The earnings coverage ratio has been calculated as the sum of net income, financing charges and provision for payments in lieu of corporate income taxes divided by the sum of financing charges, capitalized interest and cumulative preferred dividends.

4 System-related statistics include preliminary figures for December.

5 Units distributed through Hydro One lines represent total distribution system requirements and include electricity distributed to consumers who purchased power directly from the IESO.

Board of Directors (as at December 31, 2007)

Rita Burak[2*]
Chair of the Board of Directors, Hydro One Inc.

Sami Bébawi[5, 6]
Advisor to the President, SNC-Lavalin Group Inc.
President, Geracon Inc.

Kathryn A. Bouey[3, 4, 6]
President, Kathryn Bouey & Associates Ltd.
Corporate Director

Murray J. Elston[1, 5]
President and CEO, Canadian Nuclear Association

Laura Formusa
President and CEO, Hydro One Inc.

Don MacKinnon[5, 6]
President, Power Workers' Union

Michael J. Mueller[2, 4]
Corporate Director

Walter Murray[1, 3, 4]
Corporate Director

Robert L. Pace[1, 3]
President and CEO, The Pace Group Ltd.

Gale Rubenstein[1, 2, 5]
Partner, Goodmans LLP

Douglas E. Speers[3, 4, 6]
Chairman and Director, Emco Corporation

Board Committees

1 **Audit and Finance Committee**
The Audit and Finance Committee oversees the integrity of accounting policies and financial reporting, internal controls, internal audit, significant corporate risk exposures and financial compliance. The committee met six times in 2007.

2 **Corporate Governance Committee**
The Corporate Governance Committee is responsible for the Board's governance of the Company. It recommends issues to be discussed at meetings of the Board of Directors, reviews the mandate of the Board and each committee of the Board, conducts Board Assessments, monitors the quality of management's relationship with the Board and recommends suitable nominees for election to the Board of Directors. The committee met four times in 2007.

3 **Human Resources and Public Policy Committee**
The Human Resources and Public Policy Committee is responsible for reviewing the appropriateness of our current and future organizational structure, succession plans for corporate and divisional officers, the code of business conduct, the performance and remuneration of our senior executives, including recommending to the Board the remuneration of the President and CEO and for identifying, assessing and providing advice to the Board of Directors on public affairs issues that have a significant impact on us. The committee met 11 times in 2007.

4 **Business Transformation Committee (Formerly the Information Technology Committee)**
The Business Transformation Committee is an advisory committee of the Board established to assist the Board in its oversight responsibility on matters related to the Company's enterprise application systems replacement strategy. The committee met five times in 2007.

5 **Regulatory and Environment Committee**
The Regulatory and Environment Committee monitors the Company's compliance with applicable regulatory requirements and environmental legislation. The committee oversees compliance programs, policies, standards and procedures, reviews the Company's proposals for rate applications and reviews compliance actions and reports. The committee met six times in 2007.

6 **Health and Safety Committee**
The Health and Safety Committee is responsible for reviewing occupational health and safety policies, standards, and programs, compliance with occupational health and safety legislation, policies and standards, and public health and safety issues. The committee met four times in 2007.

* Effective March 31, 2008, James Arnett was elected as Chair of the Board of Directors of Hydro One Inc. by our shareholder following the resignation of Rita Burak, who did not seek reappointment.

Corporate Information

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Residential, farm &
small business accounts:
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Business accounts:
1-877-447-4412

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Ernst & Young LLP

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Concept and Design: THE WORKS www.worksdesign.com Principal Photography: Lorne Bridgman

Something To Smile About.

Hydro One customers have saved more than 272 million kWh of energy since our Conservation and Demand Management program was launched in 2005.

Our Conservation and Demand Management (CDM) initiatives have helped Hydro One customers substantially reduce their energy consumption. To date, they have saved an astonishing 272 million kWh of energy – that's enough electricity to power 23,000 homes for an entire year. This also reduces carbon emissions to the environment by 178,000 tonnes.

Our Conservation and Demand Management programs have had more than 1.1 million participants and that number continues to grow daily.

Over the five-year average life span of efficiency measures installed, the expected electrical savings are almost 1.5 billion kWh – that is equivalent to powering 120,000 homes for one year.

$3.40 in societal benefits

Every dollar we've spent on CDM is worth $3.40 of societal benefits, as measured through the Total Resource Cost test.

10,000 smart stats

We installed 10,000 web-enabled thermostats that allow central air conditioners to be remotely turned down during peak demand hours.

2,200 traffic signals

2,200 traffic signals in 16 municipalities were replaced with LED technologies, saving 1.7 million kWh annually.

31,000 monitors

We installed 31,000 real-time electricity use monitors in northern Ontario. Seeing real-time data on a daily basis can reduce electricity consumption by up to 15%.

11,000 recycled appliances

We picked up more than 11,000 old refrigerators, freezers and room air conditioners and disposed of them in an environmentally responsible manner.

www.HydroOne.com

483 Bay Street
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(416) 345-5000
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HYDRO ONE INC. – BRIDGE YEAR (2007) AND TEST YEAR (2008) QUARTERLY REPORTS

Included in this exhibit are Hydro One Inc.'s first, second, third and fourth quarterly reports for the year 2007 and first quarterly report for 2008.

RESULTS OF OPERATIONS

As used in this section, references to increases and decreases, whether in terms of amounts or percentages, are made by comparison of the three months ended March 31, 2007 to the three months ended March 31, 2006.

Revenues

Three months ended March 31 (Canadian dollars in millions)	**2007**	**2006**	**$ Change**	**% Change**
Transmission	327	298	29	10
Distribution	944	856	88	10
Other	7	6	1	17
	1,278	1,160	118	10
Average Ontario 60-minute peak demand *(MW)* [1]	23,480	22,382	1,098	5
Distribution - units distributed to customers *(TWh)* [1]	8.6	8.0	0.6	8

[1]System-related statistics are preliminary

The demand for electricity generally follows normal weather-related variations and therefore, our energy-related revenues tend to be higher in the first and third quarters than in the second and fourth quarters.

Transmission

Transmission revenues consist predominantly of our transmission tariff, which is based on the monthly peak demand for electricity across our high-voltage network. The tariff is designed to recover revenues necessary to support a transmission system with sufficient capacity to accommodate maximum expected demand, which is primarily influenced by weather as well as economic conditions. Transmission revenues also include minor amounts of ancillary revenues which are primarily attributable to maintenance services provided to generators and secondary use of our land rights-of-way.

Our transmission tariff revenues increased by $29 million, or 10%, during the first quarter of 2007 compared to the same period last year. On March 30, 2007, the Ontario Energy Board (OEB) issued a decision ordering that the transmission earnings sharing mechanism cease effective January 1, 2007. This decision had the effect of increasing transmission revenues by $15 million in the quarter as compared to the same period last year. In addition, the monthly peak demands were higher during the first quarter of 2007, reflecting the colder weather experienced in the winter. Consequently, tariff revenues increased by $14 million compared to the same period last year.

Distribution

Distribution revenues include our distribution tariff, which is based on OEB-approved rates, as well as amounts to recover the cost of purchased power used by our customers. Accordingly, distribution revenues are primarily influenced by our distribution rates, the amount of electricity we distribute, and the cost of purchased power. Distribution revenues also include a minor amount of ancillary distribution services revenues, such as fees related to the use of our poles by the telecommunications and cable television industries, and miscellaneous charges such as those for late payments.

Distribution revenues increased by $88 million, or 10%, during the first quarter of 2007 compared to the same period last year, primarily as a result of the recovery of increased purchased power costs of $43 million, as described below under "Purchased Power." In addition, on April 12, 2006, after reviewing our oral and written evidence, the OEB approved increases in tariff rates for the distribution businesses conducted by our subsidiaries, Hydro One Networks Inc. (Hydro One Networks) and Hydro One Brampton Networks Inc. (Hydro One Brampton Networks), effective May 1, 2006. We also received OEB approval for low-voltage rates for services provided to local distribution companies that are embedded within our service territory. These tariff rate increases support the maintenance and investment requirements of our distribution system, enabling the safe and reliable delivery of electricity to our customers throughout Ontario, and resulted in higher distribution revenues of $33 million. Higher energy consumption resulting from the colder winter weather this year increased distribution revenues by an additional $8 million. The remaining increase reflects marginally higher ancillary revenues.

Purchased Power

Purchased power costs incurred by our distribution business represent the cost of electricity delivered to customers within our distribution service territory and consist of the wholesale commodity cost of energy, the Independent Electricity System Operator's (IESO's) wholesale market service charges, and transmission charges levied by the IESO. The commodity cost of energy for certain low-volume and designated customers is based on the OEB's Regulated Price Plan (RPP) which consists of a two-tiered pricing structure with threshold amounts adjusted twice annually. Customers who are not eligible for the RPP pay the market price for electricity, adjusted for the difference between market prices and the prices paid to generators under the *Electricity Restructuring Act, 2004*. A summary of the RPP is provided below.

Summary of RPP

	Tier Threshold (kWh)		Tier Rates (cents/kWh)	
Effective Date	**Residential**	**Non-Residential**	**First Tier**	**Second Tier**
November 1, 2005	1,000	750	5.0	5.8
May 1, 2006	600	750	5.8	6.7
November 1, 2006	1,000	750	5.5	6.4

Purchased power costs increased by $43 million, or 7%, to $641 million compared to the first quarter of 2006. This increase primarily reflects higher demand for electricity of $34 million due to the colder weather experienced during the winter, an increase in wholesale market service charges levied by the IESO of $8 million, and an increase associated with the OEB's RPP for residential and other eligible customers of $2 million, partially offset lower wholesale commodity prices of $1 million for customers who are not eligible for the RPP.

Operation, Maintenance and Administration

Our operation, maintenance and administration costs are comprised primarily of labour, material, equipment and purchased services in support of the operation and maintenance of the transmission and distribution systems. These costs also include property taxes and payments in lieu thereof on our transmission and distribution lines, stations and buildings.

Operation, maintenance and administration costs for each of our three business segments were as follows:

Three months ended March 31 (Canadian dollars in millions)	**2007**	**2006**	**$ Change**	**% Change**
Transmission	99	93	6	6
Distribution	128	86	42	49
Other	7	6	1	17
	234	185	49	26

Transmission

Operation, maintenance and administration expenditures incurred to sustain our high-voltage transmission stations, lines and rights-of-way increased by $6 million, or by 6%, in the quarter compared to the same period last year. Within our work programs, we continued our investments to ensure the operation of a safe and reliable transmission system. We experienced higher work program expenditures of approximately $4 million, primarily related to increased maintenance within our stations resulting from an earlier commencement of planned program work. This increase was partially offset by lower line clearing and brush control expenditures. In addition, we experienced marginally higher support expenditures this quarter, primarily related to the commencement of a major business systems and processes project.

Distribution

Operation, maintenance and administration expenditures necessary to maintain our low-voltage system increased by $42 million, or 49%, relative to the comparative period in 2006. Our work program increased by $40 million, primarily due to higher line clearing and brush control expenditures, consistent with our increased focus on these activities within our distribution business in the current period, as well as higher conservation and demand management (CDM) expenditures. In addition, pension costs within our distribution business were impacted by a 2006 OEB rate decision. Prior to May 1, 2006, all of our distribution-related pension costs were deferred as a regulatory asset. In addition to the increase in our work program, our other support expenditures increased marginally, primarily as a result of the commencement of a major business systems and processes project.

Depreciation and Amortization

Depreciation and amortization expense for the first quarter increased by $7 million, or 6%, to $125 million compared to the same period last year. This increase was primarily due to higher amortization of our regulatory assets resulting from the April 12, 2006 OEB rate decision, effective May 1, 2006. In addition, our depreciation expense was higher this year due to increased assets in-service, consistent with our capital expenditures programs.

Financing Charges

Financing charges for the first three months of the year were unchanged from the same period last year at $73 million. Our interest on long-term debt was lower by approximately $5 million, reflecting lower interest rates. This impact was offset by lower interest capitalization on our regulatory assets combined with the impact of interest on our refund of payments in lieu of property taxes in the first quarter of last year.

Provision for Payments in Lieu of Corporate Income Taxes

The provision for payments in lieu of corporate income taxes increased by $22 million, or 65%, to $56 million in the first three months of this year compared to last year. This increase was primarily due to last year's recognition of a $30 million tax benefit related to the recovery of payments in lieu of corporate taxes from prior years, combined with higher pre-tax income this year. These impacts were partially offset by increased temporary differences, primarily related to higher capital cost allowance.

Net Income

Net income of $149 million was lower by $3 million, or 2%, compared to 2006 first quarter results. We experienced higher tariff revenues this year, primarily as a result of OEB decisions removing the transmission earnings sharing mechanism effective January 1, 2007 and approving new distribution rates effective May 1, 2006. However, these increases were more than offset by the impact of an increase in our effective tax rate in the period due to the recognition of a tax benefit in the first quarter of last year, combined with higher operation, maintenance and administration expenditures on our work programs and the impact of a 2006 OEB decision on our distribution-related pension expenditures.

Quarterly Results of Operations

The following table sets forth unaudited quarterly information for each of the eight quarters from June 30, 2005 through March 31, 2007. This information has been derived from our unaudited interim Consolidated Financial Statements which, in the opinion of our management, have been prepared on a basis consistent with the audited annual Consolidated Financial Statements and which include all adjustments, consisting only of normal recurring adjustments, necessary for fair presentation of our financial position and results of operations for those periods. These operating results are not necessarily indicative of results for any future period and should not be relied upon to predict our future performance.

(Canadian dollars in millions)	**2007**	**2006**				**2005**		
Quarter ended	**Mar. 31**	**Dec. 31**	**Sep. 30**	**Jun. 30**	**Mar. 31**	**Dec. 31**	**Sep. 30**	**Jun. 30**
Total revenues[1,2,3]	1,278	1,142	1,165	1,078	1,160	1,025	1,179	1,018
Net income[1,2,3]	149	101	103	99	152	104	133	115
Net income to common shareholder[1,2,3]	145	96	99	94	148	99	129	110

[1] The demand for electricity generally follows normal weather-related variations, and therefore our electricity-related revenues and net income, all other things being equal, would tend to be higher in the first and third quarters than in the second and fourth quarters.

[2] Under a new regulation issued in October 2005, RPP customers received a one-time credit reflecting a lower cost of power than the fixed commodity price between April 1, 2004 and March 31, 2005. In the fourth quarter of 2005, revenue and cost of power were both reduced by approximately $140 million. The application of the one-time credit did not result in any adjustment to net income.

[3] During 2006, the OEB applied an earnings sharing mechanism to any transmission earnings in excess of the approved rate of return of 9.88% until new rates are set. This is expected to occur later in 2007.

LIQUIDITY AND CAPITAL RESOURCES

Our primary sources of liquidity and capital resources are funds generated from operations, debt capital market borrowings and bank financing. These resources will be used to satisfy our capital resource requirements, which continue to include capital expenditures, servicing and repayment of our debt, payments related to our outsourcing arrangements, investing activities, and dividends.

Summary of Sources and Uses of Cash

Three months ended March 31 (Canadian dollars in millions)	**2007**	**2006**
Operating activities	299	146
Financing activities		
Long-term debt issued	400	300
Short-term notes payable	(60)	-
Dividends paid	(107)	(159)
Investing activities		
Capital expenditures	(187)	(177)
Other financing and investing activities	(1)	8
Net change in cash and cash equivalents	344	118

Operating Activities

Net cash generated from operating activities increased in the first quarter by $153 million to $299 million relative to the comparative period. This increase reflects lower working capital requirements this year, primarily attributable to the impact of issuing the *Ontario Price Credit* to RPP customers in early 2006, pursuant to regulation. Our working capital requirements in the quarter also decreased as a result of the timing of tax installment payments.

Financing Activities

Short-term liquidity is provided through funds from operations and our Commercial Paper Program, under which we are authorized to issue up to $1 billion in short-term notes with a term to maturity of less than 365 days. As at March 31, 2007, we had no short-term notes outstanding. The commercial paper program is supported by a $750 million committed revolving credit facility with a syndicate of banks, which matures in August 2007 and has a two-year extension option. The short-term liquidity under this program and anticipated levels of funds from operations should be sufficient to fund our normal operating requirements. Long-term financing is provided by our access to the debt markets, including our Medium-Term Note Program. Our notes and debentures mature between 2007 and 2046. We currently plan to refinance maturing debt principally through our Medium-Term Note Program. The maximum authorised principal amount of medium-term notes issuable under this program is $2,500 million. As at March 31, 2007, $1,325 million remained available until July 2007.

	Rating	
Rating Agency	**Short-term Debt**	**Long-term Debt**
Standard & Poor's Rating Services Inc. [1]	A-1	A
Dominion Bond Rating Service Inc.	R-1 (middle)	A (high)
Moody's Investors Service Inc.	Prime-1	Aa3

[1] On March 26, 2007, Standard & Poor's Ratings Services Inc. affirmed our "A" long-term debt rating and revised its outlook on the company to positive from stable.

We have customary covenants normally associated with long-term debt. Among other things, our long-term debt covenants limit our permissible debt as a percentage of our total capitalization, limit our ability to sell assets and impose a negative pledge provision, subject to customary exceptions. The credit agreement related to our $750 million credit facility has no material adverse change clauses that could trigger default. However, the credit agreement requires that we provide notice to the lenders of any material adverse change within three business days of the occurrence. The agreement also provides limitations that debt cannot exceed 75% of total capitalization and that debt issued by our subsidiaries cannot exceed 10% of the total book value of our assets. We are in compliance with all of these covenants and limitations.

During the first quarter of 2007, we issued $400 million in long-term debt under our Medium-Term Note Program and had no maturities and no short-term notes outstanding at the balance sheet date. During the same period in 2006, we issued $300 million in long-term debt and also had no maturities or short-term notes outstanding.

In the first quarter of 2007, we paid dividends to the Province of Ontario in the amount of $107 million, consisting of $103 million in common dividends and $4 million in preferred dividends. In the comparative period, we paid common dividends of $155 million and preferred dividends of $4 million.

Common dividends are declared at the sole discretion of our Board of Directors and are recommended by management based on results of operations, financial condition, cash requirements and other relevant factors such as industry practice and shareholder expectations. Common dividends pertaining to the quarterly financial results are generally declared and paid in the immediately following quarter.

Investing Activities

Cash used for investing activities primarily represents capital expenditures for each of our three business segments as follows:

Three months ended March 31 (Canadian dollars in millions)	**2007**	**2006**	**$ Change**	**% Change**
Transmission	95	100	(5)	(5)
Distribution	91	75	16	21
Other	1	2	(1)	(50)
	187	177	10	6

Transmission

Transmission capital expenditures decreased by $5 million, or 5%, to $95 million, compared to the first quarter of 2006. Expenditures made to expand and reinforce our transmission system were $48 million, a reduction of $6 million from the comparative period in 2006. This reduction primarily reflects last year's substantive completion of our Niagara Reinforcement Project. Final completion continues to be delayed by the aboriginal land dispute in the Caledonia area. Discussions continue between the affected aboriginal peoples and the various government entities involved. This impact was partially offset by increased development work related to the construction of our new inter-connection with Quebec, a major reconfiguration of our Lambton Transformer Station, and the continued construction of our downtown Toronto Cable Project. Expenditures to sustain our existing transmission system were relatively unchanged in the first three months compared to the same period last year at $41 million, an increase of $1 million. Our other transmission capital expenditures were unchanged compared to the first three months last year at $6 million.

Distribution

Distribution business capital expenditures made during the first three months of this year were $91 million, representing a $16 million, or 21%, increase over last year's levels for the same period. Expenditures to sustain our distribution system were moderately higher at $40 million, an increase of $5 million in the quarter. This increase was primarily due to higher end of life planned replacement expenditures in our lines work program. Capital investments to expand and reinforce our distribution network were $38 million, $5 million higher than the comparative period. This increase primarily reflects our investments in smart meters. During the quarter, we installed about 29,000 smart meters, for a cumulative total of approximately 57,000. We plan to install approximately 240,000 smart meters in 2007. Other capital expenditures increased by $6 million to $13 million in the quarter as a result of higher information technology expenditures, including expenditures related to a significant business systems and processes project, and increased purchases of minor support assets.

Future Capital Expenditures

Our capital expenditures are planned to be about $1.25 billion in 2007 and $1.35 billion in 2008. These planned investments will address new development and supply enhancement initiatives, including system expansions, generation requirements and load connections, and the needs of our aging transmission system under continued challenging conditions of generation supply. Our transmission rate application, which was filed in the third quarter of 2006, reflected these prudent transmission infrastructure project investments in a secure and reliable transmission system, consistent with the public interest. Within our distribution business, we plan to continue the mass deployment of smart meters begun in the first quarter of this year.

The Ontario Power Authority (OPA) is responsible for developing the Integrated Power System Plan (IPSP) and submitting it to the OEB for review and approval. The OPA is expected to submit the IPSP to the OEB in 2007. We intend to proceed with some transmission projects in the short-term because of pressing need, consistent with our transmission rate application. The IPSP is expected to influence the amount of our future capital expenditures. The timing of many of our development projects is dependent upon the final IPSP, the requirement for approvals from various regulatory bodies, and requirements for negotiations and consultations with customers, neighbouring utilities and other stakeholders and our ability to effectively resource these projects. We will not undertake large capital expenditures without a reasonable expectation of recovering them in our rates.

Our distribution investment plan includes the mass rollout of the smart metering program. Over the period 2007 to 2010, we anticipate installing over 1 million meters throughout our service territory. Consistent with the government policy, all homes and small businesses are to receive a smart meter by 2010. Total project costs are anticipated to be significant. In 2007, we plan to invest approximately $75 million under our smart meter program. At the Province's request, we will review our implementation plan and associated costs for the period 2008 to 2010.

Summary of Contractual Obligations and Other Commercial Commitments

The following table presents a summary of our debt and other major contractual obligations as well as other major commercial commitments.

March 31, 2007 (Canadian dollars in millions)	**Total**	**2007**[1]	**2008/2009**	**2010/2011**	**After 2011**
Contractual Obligations *(due by year)*					
Long-term debt – principal repayments	5,670	395	900	650	3,725
Long-term debt – interest payments	5,324	269	563	487	4,005
Inergi LP outsourcing agreement[2]	469	83	192	179	15
Operating lease commitments	15	4	9	1	1
Total Contractual Obligations	11,478	751	1,664	1,317	7,746
Other Commercial Commitments *(by year of expiry)*					
Bank line[3]	750	750	-	-	-
Letters of credit[4]	113	113	-	-	-
Guarantees[4]	275	275	-	-	-
Pension[5]	283	75	200	8	-
Total Other Commercial Commitments	1,421	1,213	200	8	-

[1] The amounts disclosed represent the balances due over the period April 1, 2007 to December 31, 2007.

[2] On March 1, 2002, Inergi began providing a range of services to us for a 10-year period, including information technology, customer care, supply chain and certain human resources and finance services.

[3] As a backstop to our commercial paper program, we have a $750 million, 364-day revolving standby credit facility with a syndicate of banks that matures in August 2007, with a two-year extension option.

[4] We currently have bank letters of credit of $93 million outstanding relating to retirement compensation arrangements. We have also provided prudential support to the IESO as required by the Market Rules, using a combination of bank letters of credit of $17 million and parental guarantees of $275 million. Currently, the amount of prudential support that we provide in the form of bank letters of credit to the IESO is based on our highest long-term credit rating which is in the “Aa” category. The amount of bank letters of credit provided would need to increase if our highest credit rating deteriorated. For example, if our credit rating declined to the “A” category, the amount of bank letters of credit required to meet our prudential support obligation would be 1.7 times our current amount, and if our credit ratings declined to “BBB” category, the amount of bank letters of credit required to meet our prudential support obligation would be 3.3 times the current amount. The remaining amounts included in letters of credit pertain to operating letters of credit and to surety bonds.

[5] Contributions to the pension fund are made one month in arrears. Contributions for 2007 will be based on an actuarial valuation effective December 31, 2006 and will depend on future investment returns, changes in benefits or actuarial assumptions. Based on current factors, we currently estimate our annual pension contributions for 2007 and beyond to be up to $100 million.

The amounts in the above table under long-term debt are not charged to our results of operations, but are reflected on our balance sheet and statement of cash flows. Interest associated with this debt is recorded under financing charges on our statement of operations or in our capital programs, but these financing charges are not reflected in the above table. Payments in respect of operating leases and our outsourcing agreement with Inergi LP are recorded under operation, maintenance and administration costs on our statement of operations or in our capital programs.

RELATED PARTY TRANSACTIONS

Related party transactions primarily consist of our transmission revenues received from, and our power purchases payments made to, the IESO, which is a related party by virtue of its status as an agency of our shareholder the Province of Ontario. The year-over-year changes in these amounts are described more fully in our discussion of our transmission revenues and purchased power costs. Other significant related party transactions include our dividends which are paid to the Province and our payments in lieu of corporate income taxes which are paid or payable to the Ontario Electricity Financial Corporation.

RECENT DEVELOPMENTS

Bruce to Milton Transmission Reinforcement

On March 26, 2007, the OPA recommended commencement of the planning and approval process required to build a new 500kV transmission line on an existing transmission corridor that is to be widened between the Bruce region and our Milton Switching Station. The new line will provide transmission capability to reliably deliver an additional 3,000 MW of generation capacity. This project is the largest expansion of Ontario's transmission system in almost 20 years, and is critical to securing Ontario's clean and renewable energy future. On March 29, 2007, we filed a leave-to-construct application with the OEB. This project represents an investment of approximately $635 million in Ontario's transmission system and is expected to be complete in late 2011.

Other Applications to Construct Facilities

On January 26, 2007 and January 31, 2007, the OEB issued decisions approving our leave-to-construct applications for our Southern Georgian Bay Transmission Line Reinforcement and Hurontario Station and Transmission Line Reinforcement projects, respectively. These facilities are required to maintain reliability and improve system performance.

On February 28, 2007, we filed an application with the OEB to build approximately three kilometers of 230kV underground transmission circuits to be located on an existing transmission line right of way between Jim Yarrow Transformer Station in Brampton and the proposed Hurontario Switching Station. The new circuits are required to improve the reliability and quality of service to consumers in the Western Brampton area.

On March 9, 2007, we filed an application with the OEB to build transmission line facilities in the Woodstock area. These facilities are required to increase transmission capacity to ensure the availability and quality of electricity supply to consumers in the area.

Transmission and Distribution Rate Applications

On March 26 and 27, 2007, a settlement conference was held in connection with Hydro One Networks' application seeking the approval of transmission rates and revenue requirement for implementation in 2007. On March 30, 2007, the OEB issued a decision ordering that the transmission earnings sharing mechanism cease effective January 1, 2007. After OEB review, the approved balance of this account, including interest, is expected to be incorporated into future rates to be set later in 2007. In its recent decision, the OEB also ordered Hydro One Networks to establish a new regulatory deferral account, effective January 1 2007, to record the revenue differential between existing transmission rates and the new rates that will be approved later in the year.

On April 20, 2007, the OEB released its decision regarding the 2007 rate application made by Hydro One Networks. The OEB approved the submission on the basis of its cost of capital and second generation incentive regulation mechanism policies. The revised rates, including an amount of 93 cents per month per metered customer for smart meters, were approved for implementation effective May 1, 2007. On April 12, 2007, the OEB issued a decision on the same basis in respect of the 2007 rate application made by our subsidiary Hydro One Brampton Networks. The new rates include an amount of 67 cents per month per metered customer for smart meters and were also approved for implementation effective May 1, 2007.

On April 4, 2007, the OEB announced that Hydro One Networks has been selected to have 2008 distribution rates rebased under the OEB's multi-year distribution rate-setting plan. Hydro One Brampton Networks filed a letter with the OEB requesting to be included in the 2010 distribution rate group for their cost of service review.

OEB RPP Price Change

On April 12, 2007, the OEB announced a decrease in electricity prices for RPP customers for the period May 1 to October 31, 2007. The electricity price has been reduced from 5.5 cents to 5.3 cents per kilowatt hour for customers consuming up to certain thresholds, depending on the type of customer, and from 6.4 cents to 6.2 cents for kilowatt hours exceeding the thresholds.

Conservation and Demand Management (CDM)

On April 2, 2007, we filed our 2006 CDM Annual Report with the OEB which highlights our results since the program's inception in 2005. To date, approximately 880,000 of our customers have participated in one or more of our 20 CDM initiatives and programs. The results of this participation include expected electricity savings over the lifetime of installed energy efficient equipment of 635 million kWh, or the annual consumption of over 53,000 homes. In addition to energy savings, the demand for electricity during peak periods has been reduced by almost 11 MW.

Purchases and Sales of Electricity Distributors

On October 17, 2006, the government of Ontario lifted the moratorium on the purchase and sale of our electricity distribution assets and customer service territories and required us to submit a rationalization strategy for approval. On March 19, 2007, the government approved our proposed rationalization strategy.

Debt Issue

On March 13, 2007, we issued $400 million of 30-year notes at a coupon rate of 4.89% and with a maturity date of March 13, 2037 at a yield of 4.89%. This is our first issue under the Medium-Term Note Program in 2007.

Credit Rating

On March 26, 2007, Standard & Poor's Ratings Services Inc. affirmed our "A" long-term debt rating and revised its outlook on the company to positive from stable.

Society Negotiations

We commenced early bargaining for the next collective agreement with the Society of Energy Professionals to proactively address a number of operational challenges at this point in time. Discussions will continue through May with a mutually agreed deadline of May 31, 2007 set for reaching an agreement.

SELECTED FINANCIAL HIGHLIGHTS AND RATIOS

Three months ended March 31 (Canadian dollars in millions) (except as otherwise noted)	**2007**	**2006**
Net income	149	152
Net cash from operations	299	146
Capital expenditures	187	177
Earnings per common share *(Canadian dollars)*	1,446	1,474
Earnings coverage ratio[1]	2.74	2.69
Net asset coverage on long-term debt ratio[2]	1.86	1.92
Total debt to capitalization ratio[3]	54%	52%

[1]The earnings coverage ratio has been presented for the twelve months ended March 31, 2007 and March 31, 2006, respectively and has been calculated as the sum of net income, provision for payments in lieu of corporate income taxes and financing charges divided by the sum of financing charges, capitalized interest and cumulative preferred dividends.

[2]The net asset coverage on long-term debt ratio has been presented as at March 31, 2007 and December 31, 2006 and has been calculated as total assets minus total liabilities excluding long-term debt (including current portion) divided by long-term debt (including current portion).

[3]Total debt to capitalization ratio has been presented as at March 31, 2007 and December 31, 2006 and has been calculated as total debt divided by total debt plus total shareholder's equity.

FORWARD-LOOKING STATEMENTS AND INFORMATION

Our oral and written public communications, including this Management's Discussion and Analysis, often contain forward looking statements that are based on current expectations, estimates, forecasts and projections about our business and the industry in which we operate and include beliefs and assumptions made by the management of our company. Such statements include, but are not limited to statements regarding future capital expenditures; statements about the installation and cost of smart meters; expectations surrounding future pension contributions; statements regarding potential incremental environmental expenditures; and expectations concerning the impact of new accounting standards. Words such as "expect," "anticipate," "intend," "attempt," "may," "plan," "will", "believe," "seek," "estimate," and variations of such words and similar expressions are intended to identify such forward-looking statements. These statements are not guarantees of future performance and involve assumptions and risks and uncertainties that are difficult to predict. Therefore, actual outcomes and results may differ materially from what is expressed, implied or forecasted in such forward-looking statements. We do not intend, and we disclaim any obligation to update any forward looking statements, whether written or oral, or whether as a result of new information, future events or otherwise, except as required by law.

These forward looking statements are based on a variety of factors and assumptions including, but not limited to the following: no unforeseen changes in the legislative and operating framework for Ontario's electricity market; favourable decisions from the OEB and other regulatory bodies concerning outstanding rate and other applications; and no significant events occurring outside the ordinary course of business. These assumptions are based on information currently available to us, including information obtained from third-party industry analysts. Actual results may differ materially from those predicted by such forward-looking statements. While we do not know what impact any of these differences may have, our business, results of operations, financial condition and our credit stability may be materially adversely affected. Factors that could cause actual results or outcomes to differ materially from the results expressed or implied by forward-looking statements include, among other things:

- the content of the final IPSP, as approved by the OEB;
- delays or denials of the requisite approvals for planned future capital expenditures;
- regulatory decisions regarding our revenue requirements and tariff rates; and
- future interest rates, inflation, changes in benefits and changes in actuarial assumptions.

We caution the reader that the above list of factors is not exhaustive.

This management's discussion and analysis is dated as at May10, 2007. Additional information about our company, including our annual information form, is available on SEDAR at www.sedar.com.

HYDRO ONE INC.
CONSOLIDATED STATEMENTS OF OPERATIONS (unaudited)

Three months ended March 31 (Canadian dollars in millions)	**2007**	**2006**
Revenues		
Transmission *(Note 3)*	327	298
Distribution	944	856
Other	7	6
	1,278	1,160
Costs		
Purchased power	641	598
Operation, maintenance and administration	234	185
Depreciation and amortization *(Note 2)*	125	118
	1,000	901
Income before financing charges and provision for payments in lieu of corporate income taxes	278	259
Financing charges	73	73
Income before provision for payments in lieu of corporate income taxes	205	186
Provision for payments in lieu of corporate income taxes	56	34
Net income and comprehensive income *(Note 2)*	149	152
Basic and fully diluted earnings per common share *(Canadian dollars)*	1,446	1,474

CONSOLIDATED STATEMENTS OF RETAINED EARNINGS (unaudited)

Three months ended March 31 (Canadian dollars in millions)	**2007**	**2006**
Retained earnings, beginning of period	1,184	1,079
Net income	149	152
Dividends *(Note 4)*	(107)	(159)
Retained earnings, end of period	1,226	1,072

See accompanying notes to Consolidated Financial Statements.

HYDRO ONE INC.
CONSOLIDATED BALANCE SHEETS (unaudited)

(Canadian dollars in millions)	**March 31, 2007**	**December 31, 2006**
Assets		
Current assets		
Short-term investments	331	-
Accounts receivable (net of allowance for doubtful accounts)	842	777
Materials and supplies	61	56
Other	6	13
	1,240	846
Fixed assets		
Fixed assets in service	16,146	16,238
Less: accumulated depreciation	6,078	6,180
	10,068	10,058
Construction in progress	541	468
	10,609	10,526
Other long-term assets		
Deferred pension asset	382	382
Regulatory assets	289	311
Goodwill	133	133
Long-term accounts receivable and other assets	8	12
	812	838
Total assets	12,661	12,210
Liabilities		
Current liabilities		
Bank indebtedness	16	29
Accounts payable and accrued charges	663	661
Accrued interest	91	49
Short-term notes payable	-	60
Long-term debt payable within one year	395	395
	1,165	1,194
Long-term debt *(Note 5)*	5,262	4,848
Other long-term liabilities		
Regulatory liabilities *(Note 3)*	494	473
Employee future benefits other than pension *(Note 6)*	820	803
Environmental liabilities	53	55
Long-term accounts payable and other liabilities	16	16
	1,383	1,347
Total liabilities	7,810	7,389
Shareholder's equity		
Preferred shares (authorized: unlimited; issued: 12,920,000)	323	323
Common shares (authorized: unlimited; issued: 100,000)	3,314	3,314
Retained earnings	1,226	1,184
Accumulated other comprehensive income *(Note 2)*	(12)	-
Total shareholder's equity	4,851	4,821
Total liabilities and shareholder's equity	12,661	12,210

See accompanying notes to Consolidated Financial Statements.

HYDRO ONE INC.
CONSOLIDATED STATEMENTS OF CASH FLOWS (unaudited)

Three months ended March 31 (Canadian dollars in millions)	**2007**	**2006**
Operating activities		
Net income	149	152
Adjustments for non-cash items:		
Depreciation and amortization (net of removal costs)	115	109
Retail settlement variance accounts	16	3
Amortization of discount	3	11
Transmission earnings sharing	-	15
Low-voltage services	-	(6)
	283	284
Changes in non-cash balances related to operations	16	(138)
Net cash from operating activities	299	146
Financing activities		
Long-term debt issued	400	300
Short-term notes payable	(60)	-
Dividends paid	(107)	(159)
Other	(1)	-
Net cash from financing activities	232	141
Investing activities		
Capital expenditures	(187)	(177)
Other assets	-	8
Net cash used in investing activities	(187)	(169)
Net change in cash and cash equivalents	344	118
Cash and cash equivalents, beginning of period	(29)	(9)
Cash and cash equivalents, end of period	315	109

See accompanying notes to Consolidated Financial Statements.

1. BASIS OF PRESENTATION

The unaudited interim Consolidated Financial Statements do not conform in all respects to the disclosure requirements of Canadian generally accepted accounting principles for annual financial statements and should, therefore, be read in conjunction with the annual Consolidated Financial Statements of Hydro One Inc. (Hydro One or the Company) for the year ending December 31, 2006, which includes information necessary or useful to understanding the Company's business and financial statement presentation. In particular, the Company's significant accounting policies and practices are presented as Note 2 to the annual Consolidated Financial Statements, and have been consistently applied in the preparation of these interim Consolidated Financial Statements, except as described below in Note 2.

The demand for electricity generally follows normal weather-related variations, and therefore the Company's energy-related revenues, all other things being equal, will tend to be higher in the first and third quarters than in the second and fourth quarters.

2. ACCOUNTING CHANGES

Change in Accounting Policy – Financial Instruments, Hedges and Comprehensive Income

Effective January 1, 2007, the Company adopted four new accounting standards comprising the Canadian Institute of Chartered Accountants' (CICA) Handbook Sections 1530, *Comprehensive Income*; 3855, *Financial Instruments – Recognition and Measurement*; 3861, *Financial Instruments – Disclosure and Presentation;* and 3865, *Hedges*. The adoption of these new standards required changes in the accounting for financial instruments and hedges, and the recognition of certain transition adjustments that are recorded in opening accumulated other comprehensive income (AOCI) as described below, consistent with the CICA Handbook sections. The comparative interim Consolidated Financial Statements have not been restated. The principal changes in the accounting for financial instruments and hedges due to the adoption of these accounting standards are described below.

(a) Comprehensive Income

Comprehensive income is composed of the Company's net income and other comprehensive income (OCI). OCI includes the amortization of unamortized hedging losses on cash flow hedges that had been discontinued prior to the transition date. The impact of this amortization is immaterial to the Statement of Operations.

(b) Financial Assets and Liabilities

Under the new standards, all financial instruments are classified into one of the following five categories: held-to-maturity investments, loans and receivables, held-for-trading, other liabilities or available-for-sale. All financial instruments, including derivatives, are carried at fair value on the consolidated balance sheet except for loans and receivables, held-to-maturity investments and other financial liabilities, which are measured at amortized cost. Held-for-trading financial instruments are measured at fair value and all gains and losses are included in financing charges in the period which they arise. Available-for-sale financial instruments are measured at fair value with revaluation gains and losses included in OCI until the instrument is derecognized or impaired. The Company has classified its financial instruments as follows:

Short-term investments	Held-to-maturity
Long-term accounts receivable	Loans and receivables
Bank indebtedness	Other liabilities
Short-term notes payable	Held-to-maturity
Long-term debt (excluding MTN Series 8 Note)	Held-to-maturity
MTN Series 8 Note	Designated as held-for-trading

The MTN Series 8 Note is a step-up coupon note issuance with an initial maturity date in 2007, and with extended maturity dates up to 2011.

Where there is an economic hedge, as in the case of the MTN Series 8 note and associated interest rate swap, we have applied the fair value option without hedge accounting and the impact is not material.

All financial instrument transactions are recorded at trade date.

(c) Derivatives and Hedge Accounting

Derivatives

All derivative instruments, including embedded derivatives, are carried at fair value on the balance sheet unless exempted from derivative treatment as a normal purchase and sale. All changes in fair value are recorded in financing charges unless cash flow hedge accounting is used, in which case changes in fair value are recorded in OCI to the extent that the hedge is effective. The impact of the change in the accounting policy related to embedded derivatives was not material.

Hedge Accounting

The Company periodically develops hedging strategies for execution taking into account risk management objectives. At the inception of a hedging relationship, the Company documents the relationship between the hedging instrument and the hedged item. This would include linking all derivatives to specific assets and liabilities on the consolidated balance sheet or to specific firm commitments or forecasted transactions. The Company would also assess, both at the inception of the hedge and on an ongoing basis, whether the derivatives that are used are effective in offsetting changes in fair values or cash flows of hedged items.

Upon adoption of the new standards, the Company reclassified unamortized hedging losses on cash flow hedges that had been discontinued prior to the transition date to accumulated other comprehensive income. The hedging losses are amortized through OCI using the effective interest method over the term of the hedged debt.

(d) Transaction Costs

Transaction costs for financial assets and liabilities, classified as other than held-for-trading, are added to the carrying value of the asset or liability and then amortized over the expected life of the instrument using the effective interest method. The impact of the change in amortization method from an annuity basis to the effective interest method was not material.

Change in Accounting Estimate – Depreciation

Effective January 1, 2007, the Company prospectively revised its fixed asset depreciation rates resulting from a periodic external review required by the Ontario Energy Board (OEB). Capital costs of fixed assets are depreciated on a straight-line basis, except for transport and work equipment, which is depreciated on a declining balance basis. The estimated impact of the change in rates is a reduction in depreciation expense of approximately $7 million per annum. A summary of the new rates for the various classes of assets is included below:

	Depreciation rates (%)	
	Range	Average
Transmission	1% - 4%	2%
Distribution	1% - 13%	2%
Communication	1% - 13%	5%
Administration and service	1% - 20%	8%

3. TRANSMISSION EXCESS EARNINGS SHARING MECHANISM

On March 30, 2007, the OEB issued a decision ordering that the transmission earnings sharing mechanism cease effective January 1, 2007. The balance of the account was $35 million. After OEB review, the approved balance of this account, including interest, is expected to be incorporated into future rates to be set later in 2007. In its decision, the OEB also ordered that the Company establish a new regulatory deferral account to record the revenue differential between existing transmission rates and the new rates that are anticipated to be approved later in the year. The new deferral account will represent the revenue differential between existing and future rates for the period between January 1, 2007 and the date of the OEB's upcoming transmission rate decision. As the specifics of this decision cannot be foreseen, the value of this account cannot reasonably be determined at this time. Appropriate accounting recognition will be given to any revenue differential once the OEB renders its decision on our transmission rates.

4. DIVIDENDS

During the three months ended March 31, 2007, preferred dividends in the amount of $4 million (2006 - $4 million) and common dividends in the amount of $103 million (2006 - $155 million) were declared.

5. LONG-TERM DEBT

On March 13, 2007, Hydro One issued notes under the Company's medium term note program. The issue was comprised of medium term notes with a principal amount of $400 million having a 30-year term with a coupon rate of 4.89%. The notes are due March 13, 2037.

6. EMPLOYEE FUTURE BENEFITS

Total benefit costs are as follows:

Three months ended March 31 (Canadian dollars in millions)	**2007**	**2006**
Pension		
Net periodic benefit cost	25	38
Pension fund contribution	25	22
Less: Portion attributable to labour and capitalized as part of the cost of fixed assets	10	8
Portion attributable to regulatory assets	-	8
Charged to results of operations	15	6
Employee Future Benefits Other than Pension		
Net periodic benefit cost	27	30
Less: Portion attributable to labour and capitalized as part of the cost of fixed assets	10	10
Charged to results of operations	17	20

7. SEGMENTED REPORTING

Hydro One has three reportable segments:

- The transmission business, which comprises the core business of providing transportation and connection services, is responsible for transmitting electricity throughout the Ontario electricity grid;
- The distribution business, which comprises the core business of delivering and selling electricity to customers; and
- An "other" segment primarily consisting of telecommunication.

The designation of segments has been based on a combination of regulatory status and the nature of the products and services provided. Segment information on the above basis is as follows:

Three months ended March 31 *(Canadian dollars in millions)*	Transmission	Distribution	Other	Consolidated
2007				
Segment profit				
Revenues	327	944	7	1,278
Purchased power	-	641	-	641
Operation, maintenance and administration	99	128	7	234
Depreciation and amortization	60	64	1	125
Income (loss) before financing charges and provision for payments in lieu of corporate income taxes	168	111	(1)	278
Financing charges				73
Income before provision for payments in lieu of corporate income taxes				205
Capital expenditures	95	91	1	187

Three months ended March 31 *(Canadian dollars in millions)*	Transmission	Distribution	Other	Consolidated
2006				
Segment profit				
Revenues	298	856	6	1,160
Purchased power	-	598	-	598
Operation, maintenance and administration	93	86	6	185
Depreciation and amortization	59	58	1	118
Income (loss) before financing charges and provision for payments in lieu of corporate income taxes	146	114	(1)	259
Financing charges				73
Income before provision for payments in lieu of corporate income taxes				186
Capital expenditures	100	75	2	177

(Canadian dollars in millions)	**March 31, 2007**	**December 31, 2006**
Total assets		
Transmission	6,978	6,950
Distribution	5,264	5,161
Other	419	99
	12,661	12,210

All revenues, costs and assets, as the case may be, are earned, incurred or held in Canada.

8. SUBSEQUENT EVENTS

On April 20, 2007 and April 12, 2007, the OEB released its decision regarding the 2007 rate applications made by the Company's subsidiaries Hydro One Networks Inc. and Hydro One Brampton Inc. respectively. The OEB approved the submissions on the basis of its cost of capital and second generation incentive regulation mechanism policies. The revised rates, including an amount of 93 cents and 67 cents per month per metered customer for smart meters, were approved for implementation effective May 1, 2007.

On April 12, 2007, the OEB announced a decrease in electricity prices for Regulated Price Plan customers. Beginning May 1, 2007, the electricity price has been reduced from 5.5 cents to 5.3 cents per kilowatt hour for customers consuming up to certain thresholds, depending on the type of customer, and from 6.4 cents to 6.2 cents for kilowatt hours exceeding the thresholds.

9. COMPARATIVE FIGURES

The comparative interim Consolidated Financial Statements have been reclassified from statements previously presented to conform to the presentation of the March 31, 2007 unaudited interim Consolidated Financial Statements.

RESULTS OF OPERATIONS

As used in this section, references to increases and decreases, whether in terms of amounts or percentages are made by comparison of the three and six months ended June 30, 2007 to the three and six months ended June 30, 2006.

Revenues

	Three months ended June 30				Six months ended June 30			
(Canadian dollars in millions)	2007	2006	$ Change	% Change	2007	2006	$ Change	% Change
Transmission	315	316	(1)	-	642	614	28	5
Distribution	798	757	41	5	1,742	1,613	129	8
Other	7	5	2	40	14	11	3	27
	1,120	1,078	42	4	2,398	2,238	160	7
Average Ontario 60-minute peak demand *(MW)*[1]	22,414	22,596	(182)	(1)	22,947	22,489	458	2
Distribution - units distributed to customers *(TWh)*[1]	6.9	6.6	0.3	5	15.5	14.6	0.9	6

[1]System-related statistics are preliminary

The demand for electricity generally follows normal weather-related variations, and, therefore, our energy-related revenues, all other things being equal, will tend to be higher in the first and third quarters than in the second and fourth quarters.

Transmission

Transmission revenues predominantly consist of our transmission tariff, which is based on the monthly peak demand for electricity across our high-voltage network. The tariff is designed to recover revenues necessary to support a transmission system with sufficient capacity to accommodate the maximum expected demand, which is primarily influenced by weather and economic conditions. Transmission revenues also include minor amounts of ancillary revenues, which are primarily attributable to maintenance services provided to generators, and secondary use of our land rights-of-way.

Our transmission tariff revenues were marginally lower during the second quarter of 2007, but increased by $28 million, or 5%, in the first six months compared to the same period last year. Both the three and six month periods reflect a decision issued by the Ontario Energy Board (OEB) on March 30, 2007 ordering that the transmission earnings sharing mechanism cease effective December 31, 2006. This decision had the effect of increasing transmission revenues by $3 million in the quarter and $18 million in the first six months compared to last year. In addition, revenues for the second quarter increased marginally as peak demands were comparable to the same period last year. However, the average monthly peak demand was higher during the first six months of 2007, resulting in increased transmission revenues of $16 million in the year-to-date period. We also experienced lower other revenues of $4 million in the quarter and $6 million on a year-to-date basis.

We are currently awaiting a decision on our transmission rate application which was initially filed in September 2006. On March 30, 2007, the OEB issued an order that we establish a new regulatory deferral account to record any revenue differential between existing transmission rates and the new rates that are anticipated to be approved later this year, effective January 1, 2007. The specifics of this decision cannot be estimated at this time. Appropriate accounting recognition, including an increase or decrease to current revenue levels, will be given to any revenue differential once the OEB renders its decision on our rates.

Distribution

Distribution revenues include our distribution tariff, which is based on OEB-approved rates, as well as amounts to recover the cost of purchased power used by our customers. Accordingly, distribution revenues are primarily influenced by our distribution rates, the amount of electricity we distribute, and the cost of purchased power. Distribution revenues also include a minor amount of ancillary distribution services revenue, such as fees related to the use of our poles by the telecommunications and cable television industries, and miscellaneous charges such as those for late payments.

Distribution revenues increased by $41 million, or 5%, to $798 million in the second quarter and by $129 million, or 8%, to $1,742 million during the first six months compared to the same periods last year. These increases were primarily a result of the recovery of increased purchased power costs of $17 million in the quarter and $60 million in the first six months, as described below under "Purchased Power." In addition, the OEB approved increases in distribution tariff rates for our subsidiaries, Hydro One Networks Inc. (Hydro One Networks) and Hydro One Brampton Networks Inc. (Hydro One Brampton Networks), effective May 1, 2006 and May 1, 2007 respectively. These tariff rate increases of $8 million in the quarter and $42 million in the first six months support the maintenance and investment requirements of our distribution system, enabling the safe and reliable delivery of electricity to our customers throughout Ontario, resulted in higher distribution revenues. In 2006, rates were based on a full cost of service hearing and in 2007, rates were adjusted based on the OEB's Second Generation Incentive Regulation mechanism. Higher energy consumption, resulting primarily from the colder winter weather this year, increased our distribution revenues by a further $6 million in the quarter and $15 million in the year-to-date period. In addition, as a result of the OEB's decision on August 8, 2007 regarding the combined smart meter proceeding, we recognized an additional $10 million in revenue. We also experienced marginally higher ancillary revenues of $2 million in the first six months of 2007 compared to the same period last year.

Purchased Power

Purchased power costs incurred by our distribution business represent the cost of electricity delivered to customers within our distribution service territory and consist of the wholesale commodity cost of energy, the Independent Electricity System Operator's (IESO's) wholesale market service charges, and transmission charges levied by the IESO. The commodity cost of energy for certain low-volume and designated customers is based on the OEB's Regulated Price Plan (RPP), which consists of a two-tiered pricing structure with threshold amounts adjusted twice annually. Customers who are not eligible for the RPP pay the market price for electricity, adjusted for the difference between market prices and the prices paid to generators under the *Electricity Restructuring Act, 2004*. A summary of the RPP is provided below.

Summary of RPP

	Tier Threshold (kWh)		Tier Rates (cents/kWh)	
Effective Date	**Residential**	**Non-Residential**	**First Tier**	**Second Tier**
November 1, 2005	1,000	750	5.0	5.8
May 1, 2006	600	750	5.8	6.7
November 1, 2006	1,000	750	5.5	6.4
May 1, 2007	600	750	5.3	6.2

Purchased power costs increased by $17 million, or 3%, to $522 million in the second quarter and by $60 million, or 5%, to $1,163 million during the first six months compared to last year. These increases primarily reflect higher demand for electricity of $14 million in the quarter and $48 million in the first six months, and higher wholesale commodity prices for customers who are not eligible for the RPP of $10 million, both in the quarter and during the first six months. For the quarter, these increases were partially offset by the impact of the May 1, 2007 RPP rate change for residential and other eligible customers and a reduction in wholesale market service charges levied by the IESO.

Operation, Maintenance and Administration

Our operation, maintenance and administration costs are comprised primarily of labour, material, equipment and purchased services in support of the operation and maintenance of the transmission and distribution systems. These costs also include property taxes and payments in lieu thereof on our transmission and distribution lines, stations and buildings.

Operation, maintenance and administration costs for each of our three business segments were as follows:

	Three months ended June 30				Six months ended June 30			
(Canadian dollars in millions)	**2007**	**2006**	**$ Change**	**% Change**	**2007**	**2006**	**$ Change**	**% Change**
Transmission	107	109	(2)	(2)	206	202	4	2
Distribution	145	120	25	21	273	206	67	33
Other	7	5	2	40	14	11	3	27
	259	234	25	11	493	419	74	18

Transmission

Operation, maintenance and administration expenditures incurred to sustain our high-voltage transmission stations, lines and rights-of-way decreased by $2 million, or by 2%, in the quarter and increased by $4 million, or 2%, on a year-to-date basis compared to the same periods last year. Within our work programs, we continued our investments that support the safe and reliable operation of the transmission system. We experienced higher work program expenditures in the quarter of approximately $7 million and year-to-date of about $9 million, primarily due to the early mobilization of resources for our planned station maintenance program. For the year-to-date period, these expenditures were partially offset by lower line clearing and brush control expenditures experienced in the first quarter. In addition, expenditures incurred in support of the transmission system increased marginally during the first six months as we commenced a major business systems and processes project. These increases were substantially offset in the quarter and in the year-to-date periods by the impact of reassigning resources in support of our larger capital work program.

Distribution

Operation, maintenance and administration expenditures necessary to maintain our low-voltage system increased by $25 million, or 21%, in the second quarter and by $67 million, or 33%, on a year-to-date basis, relative to the comparative periods. Higher expenditures within our work program of $16 million in the quarter and $49 million for the first six months resulted from higher line clearing and brush control expenditures, customer participation in our conservation and demand management programs and higher planned maintenance in our lines work program. In addition, pension costs within our distribution business for the quarterly and year-to-date periods were impacted by a 2006 OEB rate decision. Prior to May 1, 2006, all of our distribution-related pension costs were deferred as a regulatory asset. Also, as a result of the OEB's decision on August 8, 2007 regarding the combined smart meter proceeding, we recognized an additional $10 million in expenditures associated with this program. In addition to these increases, our other support expenditures for the first six months increased marginally, as a result of the commencement of a major business systems and processes project.

Depreciation and Amortization

Depreciation and amortization increased by $2 million, or 2%, to $129 million in the second quarter and by $9 million, or 4%, to $254 million in the first six months compared to the same periods last year. These increases were primarily the result of higher fixed asset removal costs related to storm recovery work in our lines work program and, for the year-to-date period, higher amortization of our regulatory assets resulting from the April 12, 2006 OEB rate decision that was effective on May 1, 2006.

Financing Charges

Financing charges in both the second quarter and year-to-date periods increased by $1 million to $74 million and to $147 million respectively, compared to the same periods last year. These increases were primarily due to reduced capitalization of financing costs on our regulatory accounts of $4 million in the quarter and $6 million for the first six months. Interest related to a first quarter 2006 recovery of payments in lieu of corporate income taxes also contributed to the increase in year-over-year financing costs for the six month period. The impact of these increases was almost offset by lower interest on long-term debt reflecting the impact of lower average borrowing costs, partially offset by a higher average level of debt outstanding.

Provision for Payments in Lieu of Corporate Income Taxes

The provision for payments in lieu of corporate income taxes increased by $3 million, or 8%, to $43 million in the second quarter and increased by $25 million, or 34%, to $99 million on a year-to-date basis, compared to the same periods last year. The increase in the quarter was primarily attributable to minor temporary differences. The year-to-date increase primarily reflects higher pre-tax income in the first six months of this year and the impact of last year's first quarter recognition of a $30 million tax benefit related to the recovery of payments in lieu of corporate taxes from prior years.

Net Income

Net income of $93 million was lower by $6 million, or 6% in the second quarter, and lower by $9 million, or 4% in the first six months compared to 2006 results. These reductions reflect increased expenditures within our distribution work program to maintain system reliability and the impact of a 2006 OEB decision on our distribution-related pension expenditures. In addition, our effective tax rate was higher in the year-to-date period due to a recovery of payments in lieu of corporate income taxes in the first quarter of last year. These increases were partially offset by increased tariff revenues within our transmission and distribution businesses.

QUARTERLY RESULTS OF OPERATIONS

The following table sets forth unaudited quarterly information for each of the eight quarters from September 30, 2005 through June 30, 2007. This information has been derived from our unaudited interim Consolidated Financial Statements which, in the opinion of our management, have been prepared on a basis consistent with the audited annual Consolidated Financial Statements and which include all adjustments, consisting only of normal recurring adjustments, necessary for fair presentation of our financial position and results of operations for those periods. These operating results are not necessarily indicative of results for any future period and should not be relied upon to predict our future performance.

(Canadian dollars in millions)	**2007**		**2006**				**2005**	
Quarter ended	**Jun. 30**	**Mar. 31**	**Dec. 31**	**Sep. 30**	**Jun. 30**	**Mar. 31**	**Dec. 31**	**Sep. 30**
Total revenue[1, 2, 3,4]	1,120	1,278	1,142	1,165	1,078	1,160	1,025	1,179
Net income [1, 2, 3]	93	149	101	103	99	152	104	133
Net income to common shareholder [1, 2, 3]	88	145	96	99	94	148	99	129

[1] The demand for electricity generally follows normal weather-related variations, and therefore our electricity-related revenues and profit, all other things being equal, would tend to be higher in the first and third quarters than in the second and fourth quarters.

[2] Under a new regulation issued in October 2005, RPP customers received a one-time credit reflecting a lower cost of power than the fixed commodity price between April 1, 2004 and March 31, 2005. In the fourth quarter of 2005, revenue and cost of power were both reduced by approximately $140 million. The application of the one-time credit did not result in any adjustment to net income.

[3] Effective January 1, 2006, the OEB applied an earnings sharing mechanism (ESM) to any transmission earnings in excess of the approved rate of return of 9.88%. On March 30, 2007 the OEB issued a decision ordering that the ESM cease effective December 31, 2006. The approved balance of the ESM account is expected to be incorporated into future rates to be set later in 2007.

[4] As a result of the OEB's decision on August 8, 2007 regarding the combined smart meter proceeding, we recognized an additional $10 million in revenue and cost as at June 30, 2007.

LIQUIDITY AND CAPITAL RESOURCES

Our primary sources of liquidity and capital resources are funds generated from operations, debt capital market borrowings and bank financing. These resources will be used to satisfy our capital resource requirements, which continue to include capital expenditures, servicing and repayment of our debt, payments related to our outsourcing arrangements, investing activities, and dividends.

Summary of Sources and Uses of Cash	**Three months ended June 30**		**Six months ended June 30**	
(Canadian dollars in millions)	**2007**	**2006**	**2007**	**2006**
Operating activities	238	218	537	364
Financing activities				
Long-term debt issued	-	250	400	550
Long-term debt retired	(282)	(448)	(282)	(448)
Short-term notes payable	75	130	15	130
Dividends paid	(73)	(64)	(180)	(223)
Investing activities				
Capital expenditures	(303)	(198)	(490)	(375)
Other financing and investing activities	15	(3)	14	5
Net change in cash and cash equivalents	(330)	(115)	14	3

Operating Activities

Net cash generated from operating activities increased by $20 million to $238 million in the second quarter, and by $173 million to $537 million in the first six months compared to 2006 results, primarily due to lower working capital requirements during the quarter and year-to-date periods. In the quarter, our working capital requirements were impacted by a first quarter 2006 recovery of payments in lieu of corporate income taxes. For the year-to-date period, our working capital requirements also increased as a result of the *Ontario Price Credit* that was provided to RPP customers in early 2006, pursuant to regulation. Funding for the credit was received from the IESO in early December 2005.

Financing Activities

Short-term liquidity is provided through funds from operations and our Commercial Paper Program, under which we are authorized to issue up to $1 billion in short-term notes with a term to maturity of less than 365 days. As at June 30, 2007, we had $75 million of short-term notes outstanding. The commercial paper program is supported by a $750 million committed revolving credit facility with a syndicate of banks. The term of this facility has been extended as of August 10th, 2007 to August 10th, 2010. The short-term liquidity under this program and anticipated levels of funds from operations should be sufficient to fund our normal operating requirements. Long-term financing is provided by our access to the debt markets, including our Medium-Term Note Program. On June 21, 2007, we filed a $2.5 billion base shelf prospectus to renew our Medium-Term Note Program for another 25 months. Our notes and debentures mature between 2007 and 2046. We currently plan to refinance maturing debt principally through our Medium-Term Note Program. The maximum authorised principal amount of medium-term notes issuable under this program is $2,500 million, all of which currently remains available until July 2009.

	Rating	
Rating Agency	**Short-term Debt**	**Long-term Debt**
DBRS Inc.	R-1 (middle)	A (high)
Moody's Investors Service Inc.	Prime-1	Aa3
Standard & Poor's Rating Services Inc.	A-1	A

We have customary covenants normally associated with long-term debt. Among other things, our long-term debt covenants limit our permissible debt as a percentage of our total capitalization, limit our ability to sell assets and impose a negative pledge provision, subject to customary exceptions. The credit agreement related to our $750 million credit facility has no material adverse change clauses that could trigger default. However, the credit agreement requires that we provide notice to the lenders of any material adverse change within three business days of the occurrence. The agreement also provides limitations that debt cannot exceed 75% of total capitalization and that debt issued by our subsidiaries cannot exceed 10% of the total book value of our assets. We are in compliance with all of these covenants and limitations.

During the second quarter of 2007, we repaid $282 million in maturing long term debt and increased our short-term notes by $75 million. During the same period in 2006, we issued $250 million in long-term debt under our Medium-Term Note Program, repaid $448 million in maturing long-term debt, and increased our short-term notes by $130 million.

During the first six months of 2007, we issued $400 million in long-term debt under our Medium-Term Note Program, repaid $282 million in maturing long-term debt, and increased our short-term notes by $15 million. In comparison, during the same period in 2006, we issued $550 million in long-term debt under our medium term note program, repaid $448 million in maturing long-term debt and increased our short-term notes by $130 million.

In the second quarter of 2007, we paid dividends to the Province of Ontario in the amount of $73 million, consisting of $68 million in common dividends and $5 million in preferred dividends. In the comparative period, we paid common dividends of $59 million and preferred dividends of $5 million. Year-to-date, we have paid common and preferred dividends totaling $180 million, compared to $223 million in 2006.

Common dividends are declared at the sole discretion of our Board of Directors, and are recommended by management based on results of operations, financial condition, cash requirements and other relevant factors such as industry practice and shareholder expectations. Common dividends pertaining to the quarterly financial results are generally declared and paid in the immediately following quarter.

Investing Activities

Cash used for investing activities primarily represents capital expenditures for each of our three business segments as follows:

(Canadian dollars in millions)	Three months ended June 30 2007	2006	$ Change	% Change	Six months ended June 30 2007	2006	$ Change	% Change
Transmission	155	97	58	60	250	197	53	27
Distribution	138	100	38	38	229	175	54	31
Other	10	1	9	900	11	3	8	267
	303	198	105	53	490	375	115	31

Transmission

Transmission capital expenditures increased by $58 million, or 60%, to $155 million in the second quarter, and increased by $53 million, or 27%, to $250 million in the first six months, compared to the same periods in 2006. Expenditures made to expand and reinforce our transmission system were $89 million in the quarter and $136 million for the first six months of the year, representing increases over the comparative periods of $58 million and $52 million, respectively. These increases primarily reflect load and generation connections work at our Whitby and London Talbot transformer stations, and the reconfiguration of our Lambton Transformer Station. Our expenditures on major lines and stations development projects have also increased as a result of construction on our new inter-connection with Quebec, which will increase access to emission-free hydroelectric power, work at our Cambridge Preston Transformer Station, and the continued construction of our Downtown Toronto Cable Project. The impact of these increases was partially offset by expenditures on our Niagara Reinforcement Project, which was substantively completed last year. Final completion continues to be delayed by the aboriginal land dispute in the Caledonia area. Discussions continue between the affected aboriginal peoples and the various government entities involved. Expenditures to sustain our existing transmission system were $51 million in the quarter and $92 million on a year-to-date basis, representing reductions of $4 million and $2 million respectively, compared to the same periods last year. Our other transmission capital expenditures were $15 million in the quarter and $22 million for the first six months, representing respective increases of $4 million and $3 million, primarily due to expenditures on a major business systems and processes project.

Distribution

Distribution capital expenditures increased by $38 million, or 38%, to $138 million in the quarter and by $54 million, or 31%, to $229 million for the first six months, compared to the same periods in 2006. Capital investments to expand and reinforce our distribution network were $71 million in the quarter and $109 million for the first six months, representing increases of $32 million and $37 million over the comparable periods. These increases primarily reflect our ongoing investments in smart meters. During the quarter, we installed about 60,000 smart meters, for a year-to-date total of approximately 89,000 and a cumulative program total of approximately 117,000. We plan to install about 240,000 smart meters in 2007. Expenditures to sustain our distribution system of $56 million in the quarter and $96 million year-to-date, increased by $3 million and $7 million respectively compared to last year. These increases were primarily due to higher end-of-life planned replacement expenditures in our lines work program and the impact of replacing storm damaged components in the second quarter. Other capital expenditures increased to $11 million and $24 million for the three and six month periods compared to $8 million and $14 million in the same periods last year as a result of higher information technology expenditures, including expenditures on a major business systems and processes project.

Other

Other capital expenditures made to enhance our telecom infrastructure increased by $9 million in the second quarter and by $8 million in the first six months compared to the same periods in 2006. These increases were largely due to construction of a dedicated optical network which will provide secure, high capacity connectivity across numerous healthcare locations in Ontario.

Future Capital Expenditures

Our capital expenditures are planned to be about $1.25 billion in 2007 and $1.35 billion in 2008. These planned investments will address new development and supply enhancement initiatives, including system expansions, generation requirements and load connections, and the needs of our aging transmission system under continued challenging conditions of generation supply. Our transmission rate application, which was filed in the third quarter of 2006, reflected these prudent transmission infrastructure project investments in a secure and reliable transmission system, consistent with the public interest. Within our distribution business, the mass deployment of smart meters is underway and we are currently on track to meet the 2007 year-end target. Our future capital expenditures also include a major business systems and processes project, which incorporates the replacement of end of life information systems.

The Ontario Power Authority (OPA) is responsible for developing the Integrated Power System Plan (IPSP) and submitting it to the OEB for review and approval. The OPA is expected to submit the IPSP to the OEB in 2007. We intend to proceed with some transmission projects in the short-term because of pressing need, consistent with our transmission rate application. The IPSP is expected to influence the amount of our future capital expenditures. The timing of many of our development projects is dependent upon the final IPSP, the requirement for approvals from various regulatory bodies, and requirements for negotiations and consultations with customers, neighbouring utilities and other stakeholders and our ability to effectively resource these projects. We will not undertake large capital expenditures without a reasonable expectation of recovering them in our rates.

Our distribution investment plan includes the mass rollout of the smart metering program. Over the period 2007 to 2010, we anticipate installing 1.3 million meters throughout our service territory. Consistent with the government policy, all homes and small businesses are to receive a smart meter by the end of 2010. Total project costs are anticipated to be significant. In 2007, we plan to invest approximately $75 million under our smart meter program. At the Province’s request, we will review our implementation plan and associated costs for the period 2008 to 2010.

Summary of Contractual Obligations and Other Commercial Commitments

The following table presents a summary of our debt and other major contractual obligations as well as other major commercial commitments.

June 30, 2007 (Canadian dollars in millions)	**Total**	**2007**[1]	**2008/2009**	**20010/2011**	**After 2011**
Contractual Obligations *(due by year)*					
Short-term note payable	75	75	-	-	-
Long-term debt – principal repayments	5,388	113	900	650	3,725
Long-term debt – interest payments	5,208	153	563	487	4,005
Inergi LP outsourcing agreement[2]	448	56	195	181	16
Operating lease commitments	16	3	10	2	1
Total Contractual Obligations	11,135	400	1,668	1,320	7,747
Other Commercial Commitments *(by year of expiry)*					
Bank line[3]	750	750	-	-	-
Letters of credit[4]	107	97	10	-	-
Guarantees[4]	275	275	-	-	-
Pension[5]	257	49	200	8	-
Total Other Commercial Commitments	1,389	1,171	210	8	-

[1] The amounts disclosed represent the balance due over the period July 1, 2007 to December 31, 2007.

[2] On March 1, 2002, Inergi LP began providing a range of services to us for a 10-year period, including information technology, customer care, supply chain and certain human resources and finance services.

[3] As a backstop to our commercial paper program, we have a $750 million, 364-day revolving standby credit facility with a syndicate of banks. The term of this facility has been extended as of August 10th, 2007 to August 10th, 2010.

[4] We currently have bank letters of credit of $93 million outstanding relating to retirement compensation arrangements. We have also provided prudential support to the IESO as required by the Market Rules, using a combination of bank letters of credit of $10 million and parental guarantees of $275 million. Pursuant to Market Rule changes which became effective August 1, 2007, we are now able to meet our entire prudential support obligation using only parental guarantees based on our highest long-term credit rating which is in the “Aa” category. Although no letters of credit are required for prudential support as of August 1, 2007, we would have to resume providing bank letters of credit if our credit rating deteriorated. The remaining amounts included in letters of credit pertain to operating letters of credit and to surety bonds.

[5] Contributions to the pension fund are made one-month in arrears. Contributions for 2007 will be based on an actuarial valuation effective December 31, 2006 and will depend on future investment returns, changes in benefits or actuarial assumptions. Based on current factors, we currently estimate our annual pension contributions for 2007 and beyond to be up to $100 million.

The amounts in the above table under long-term debt are not charged to our results of operations, but are reflected on our balance sheet and statement of cash flows. Interest associated with this debt is recorded under financing charges on our statement of operations or in our capital programs, but these financing charges are not reflected in the above table. Payments in respect of operating leases and our outsourcing agreement with Inergi LP are recorded under operation, maintenance and administration costs on our statement of operations or in our capital programs.

RELATED PARTY TRANSACTIONS

Related party transactions primarily consist of our transmission revenues received from, and our power purchases payments made to, the IESO, which is a related party by virtue of its status as an agency of our shareholder the Province of Ontario. The year-over-year changes in these amounts are described more fully in our discussion of our transmission revenues and purchased power costs. Other significant related party transactions include our dividends which are paid to the Province and our payments in lieu of corporate income taxes which are paid or payable to the Ontario Electricity Financial Corporation.

RECENT DEVELOPMENTS

Transmission and Distribution Rate Applications

During the second quarter, the evidentiary phase of the transmission rate hearing was completed and we filed our final argument with the OEB on June 13, 2007. Based on the OEB's processing guidelines, a decision is anticipated shortly.

We are currently in the process of preparing our 2008 distribution rate application for our subsidiary Hydro One Networks. On July 18, 2007, we held a stakeholder session which was attended by interested parties and we highlighted some of the key aspects of our application. We are required to file our application with the OEB by August 15, 2007.

Combined Smart Meter Proceeding

On May 2, 2007, the OEB issued a notice for a combined proceeding to determine certain general principles related to the prudence and recovery of costs associated with smart metering activities. Our subsidiaries, Hydro One Networks and Hydro One Brampton Networks participated in this proceeding. During June 2007, evidence was filed by our subsidiaries and an oral hearing was held. On August 8, 2007, the OEB issued a decision approving the recovery of expenditures associated with the minimum functionality for advanced metering infrastructure.

Society Negotiations

In April 2007, we commenced early bargaining for the next collective agreement with the Society of Energy Professionals (Society) and on May 31, 2007 we successfully reached a tentative agreement with a five-year term effective April 1, 2008. In June 2007, the collective agreement was ratified by our Board of Directors and the Society.

Application to Construct Facilities

On June 6, 2007, the Minister of the Environment issued a letter confirming an individual environmental assessment (EA) is not required for the Holland Transformer Station Project which proposes construction of a new transformer to address ongoing load growth in northern York Region. The letter grants approval of the EA subject to certain conditions. We anticipate the project to be in-service in Spring 2009.

In the first quarter, we filed leave-to-construct applications for our Western Brampton Line Reinforcement and our Supply to Woodstock projects. These applications are awaiting OEB review pursuant to the Transmission System Code in relation to the treatment of capital contributions for local area supply connection facilities. Decisions are anticipated in August 2007.

Purchase of Assets

On July 9, 2007, we entered into an agreement with the Township of Terrace Bay to purchase the assets of Terrace Bay Superior Wires Inc. (TBSW) for approximately $1 million. TBSW is located on the north shore of Lake Superior and has approximately 950 customers. The transaction is subject to OEB approval and on July 11, 2007 we submitted a joint application, with the Township of Terrace Bay, to the OEB. The transaction is anticipated to close in Fall 2007.

SELECTED FINANCAL HIGHLIGHTS AND RATIOS

	Three months ended June 30		Six months ended June 30	
(Canadian dollars in millions) (except as otherwise noted)	**2007**	**2006**	**2007**	**2006**
Net income	93	99	242	251
Net cash from operating activities	238	218	537	364
Capital expenditures	303	198	490	375
Earnings per common share *(Canadian dollars)*	888	943	2,334	2,417
Earnings coverage ratio[1]			2.77	2.71
Net asset coverage on long-term debt[2]			1.91	1.92
Total debt to capitalization[3]			52%	52%

[1]The earnings coverage ratio has been presented for the twelve months ended June 30, 2007 and June 30, 2006, respectively and has been calculated as the sum of net income, provision for payments in lieu of corporate income taxes and financing charges divided by the sum of financing charges, capitalized interest and cumulative preferred dividends.

[2]The net asset coverage on long-term debt ratio has been presented as at June 30, 2007 and December 31, 2006 and has been calculated as total assets minus total liabilities excluding long-term debt (including current portion) divided by long-term debt including current portion.

[3]Total debt to capitalization ratio has been presented as at June 30, 2007 and December 31, 2006 and has been calculated as total debt divided by total debt plus total shareholder's equity.

FORWARD-LOOKING STATEMENTS AND INFORMATION

Our oral and written public communications, including this Management's Discussion and Analysis, often contain forward looking statements that are based on current expectations, estimates, forecasts and projections about our business and the industry in which we operate and include beliefs and assumptions made by the management of our company. Such statements include, but are not limited to statements regarding future capital expenditures; statements about the installation and cost of smart meters; expectations surrounding future pension contributions; statements regarding potential incremental environmental expenditures; and expectations concerning the impact of new accounting standards. Words such as "expect," "anticipate," "intend," "attempt," "may," "plan," "will", "believe," "seek," "estimate," and variations of such words and similar expressions are intended to identify such forward-looking statements. These statements are not guarantees of future performance and involve assumptions and risks and uncertainties that are difficult to predict. Therefore, actual outcomes and results may differ materially from what is expressed, implied or forecasted in such forward-looking statements. We do not intend, and we disclaim any obligation to update any forward looking statements, whether written or oral, or whether as a result of new information, future events or otherwise, except as required by law.

These forward looking statements are based on a variety of factors and assumptions including, but not limited to the following: no unforeseen changes in the legislative and operating framework for Ontario's electricity market; favourable decisions from the OEB and other regulatory bodies concerning outstanding rate and other applications; and no significant events occurring outside the ordinary course of business. These assumptions are based on information currently available to us, including information obtained from third-party industry analysts. Actual results may differ materially from those predicted by such forward-looking statements. While we do not know what impact any of these differences may have, our business, results of operations, financial condition and our credit stability may be materially adversely affected. Factors that could cause actual results or outcomes to differ materially from the results expressed or implied by forward-looking statements include, among other things:

- the content of the final IPSP, as approved by the OEB;
- delays or denials of the requisite approvals for planned future capital expenditures;
- regulatory decisions regarding our revenue requirements and tariff rates;
- significant changes to Environment Canada's draft PCB regulations issued on November 4, 2006; and
- future interest rates, inflation, changes in benefits and changes in actuarial assumptions.

We caution the reader that the above list of factors is not exhaustive.

This management's discussion and analysis is dated as at August 10, 2007. Additional information about our company, including our annual information form, is available on SEDAR at www.sedar.com.

HYDRO ONE INC.
CONSOLIDATED STATEMENTS OF OPERATIONS (unaudited)

(Canadian dollars in millions)	Three months ended June 30 2007	Three months ended June 30 2006	Six months ended June 30 2007	Six months ended June 30 2006
Revenues				
Transmission *(Note 3)*	315	316	642	614
Distribution *(Note 4)*	798	757	1,742	1,613
Other	7	5	14	11
	1,120	1,078	2,398	2,238
Costs				
Purchased power	522	505	1,163	1,103
Operation, maintenance and administration *(Note 4)*	259	234	493	419
Depreciation and amortization *(Note 2)*	129	127	254	245
	910	866	1,910	1,767
Income before financing charges and provision for payments in lieu of corporate income taxes	210	212	488	471
Financing charges	74	73	147	146
Income before provision for payments in lieu of corporate income taxes	136	139	341	325
Provision for payments in lieu of corporate income taxes	43	40	99	74
Net income	93	99	242	251
Other comprehensive income	1	-	1	-
Comprehensive income *(Note 2)*	94	99	243	251
Basic and fully diluted earnings per common share *(Canadian dollars)*	888	943	2,334	2,417

CONSOLIDATED STATEMENTS OF RETAINED EARNINGS (unaudited)

(Canadian dollars in millions)	Three months ended June 30 2007	Three months ended June 30 2006	Six months ended June 30 2007	Six months ended June 30 2006
Retained earnings, beginning of period	1,226	1,072	1,184	1,079
Net income	93	99	242	251
Dividends *(Note 5)*	(73)	(64)	(180)	(223)
Retained earnings, end of period	1,246	1,107	1,246	1,107

See accompanying notes to Consolidated Financial Statements.

HYDRO ONE INC.
CONSOLIDATED BALANCE SHEETS (unaudited)

(Canadian dollars in millions)	**June 30, 2007**	**December 31, 2006**
Assets		
Current assets		
Accounts receivable (net of allowance for doubtful accounts)	769	777
Materials and supplies	62	56
Other	7	13
	838	846
Fixed assets		
Fixed assets in service	16,322	16,238
Less: accumulated depreciation	6,164	6,180
	10,158	10,058
Construction in progress	667	468
	10,825	10,526
Long-term assets		
Deferred pension asset	383	382
Regulatory assets	251	311
Goodwill	133	133
Long-term accounts receivable and other assets	7	12
	774	838
Total assets	12,437	12,210
Liabilities		
Current liabilities		
Bank indebtedness	15	29
Accounts payable and accrued charges	649	661
Accrued interest	52	49
Short-term notes payable	75	60
Long-term debt payable within one year *(Note 6)*	612	395
	1,403	1,194
Long-term debt *(Note 6)*	4,764	4,848
Other long-term liabilities		
Regulatory liabilities *(Note 3)*	502	473
Employee future benefits other than pension *(Note 7)*	830	803
Environmental liabilities	51	55
Long-term accounts payable and other liabilities	15	16
	1,398	1,347
Total liabilities	7,565	7,389
Shareholder's equity		
Preferred shares (authorized: unlimited; issued: 12,920,000)	323	323
Common shares (authorized: unlimited; issued: 100,000)	3,314	3,314
Retained earnings	1,246	1,184
Accumulated other comprehensive income *(Note 2)*	(11)	-
Total shareholder's equity	4,872	4,821
Total liabilities and shareholder's equity	12,437	12,210

See accompanying notes to Consolidated Financial Statements.

HYDRO ONE INC.
CONSOLIDATED STATEMENTS OF CASH FLOWS (unaudited)

(Canadian dollars in millions)	Three months ended June 30 2007	Three months ended June 30 2006	Six months ended June 30 2007	Six months ended June 30 2006
Operating activities				
Net income	93	99	242	251
Adjustments for non-cash items:				
Depreciation and amortization (net of removal costs)	116	118	231	227
Retail settlement variance accounts	-	3	16	6
Transmission earnings sharing	-	3	-	18
Amortization of discount	3	7	6	18
Low-voltage services	-	(2)	-	(8)
	212	228	495	512
Changes in non-cash balances related to operations	26	(10)	42	(148)
Net cash from operating activities	238	218	537	364
Financing activities				
Long-term debt issued	-	250	400	550
Long-term debt retired	(282)	(448)	(282)	(448)
Short-term notes payable	75	130	15	130
Dividends paid	(73)	(64)	(180)	(223)
Other	-	(4)	(1)	(4)
Net cash (used in) from financing activities	(280)	(136)	(48)	5
Investing activities				
Fixed assets	(303)	(198)	(490)	(375)
Other assets	15	1	15	9
Net cash used in investing activities	(288)	(197)	(475)	(366)
Net change in cash and cash equivalents	(330)	(115)	14	3
Cash and cash equivalents, beginning of period	315	109	(29)	(9)
Cash and cash equivalents, end of period	(15)	(6)	(15)	(6)

See accompanying notes to Consolidated Financial Statements.

1. BASIS OF PRESENTATION

These interim Consolidated Financial Statements do not conform in all respects to the disclosure requirements of Canadian generally accepted accounting principles for annual financial statements and should, therefore, be read in conjunction with the annual Consolidated Financial Statements of Hydro One Inc. (Hydro One or the Company) for the year ending December 31, 2006 which includes information necessary or useful to understanding the Company's business and financial statement presentation. In particular, the Company's significant accounting policies and practices are presented as Note 2 to the annual Consolidated Financial Statements, and have been consistently applied in the preparation of these interim Consolidated Financial Statements, except as described below in note 2.

The demand for electricity generally follows normal weather-related variations, and therefore the Company's energy-related revenues, all other things being equal, will tend to be higher in the first and third quarters than in the second and fourth quarters.

2. ACCOUNTING CHANGES

Change in Accounting Policy – Financial Instruments, Hedges and Comprehensive Income

Effective January 1, 2007, the Company adopted four new accounting standards comprising the Canadian Institute of Chartered Accountants' (CICA) Handbook Sections 1530, *Comprehensive Income*; 3855, *Financial Instruments – Recognition and Measurement*; 3861, *Financial Instruments – Disclosure and Presentation;* and 3865, *Hedges*. The adoption of these new standards required changes in the accounting for financial instruments and hedges, and the recognition of certain transition adjustments that are recorded in opening accumulated other comprehensive income (AOCI) as described below, consistent with the CICA Handbook sections. The comparative interim Consolidated Financial Statements have not been restated. The principal changes in the accounting for financial instruments and hedges due to the adoption of these accounting standards are described below.

(a) Comprehensive Income

Comprehensive income is composed of the Company's net income and other comprehensive income (OCI). OCI includes the amortization of unamortized hedging losses on cash flow hedges that had been discontinued prior to the transition date. The impact of this amortization is immaterial to the Statement of Operations.

(b) Financial Assets and Liabilities

Under the new standards, all financial instruments are classified into one of the following five categories: held-to-maturity investments, loans and receivables, held-for-trading, other liabilities or available-for-sale. All financial instruments, including derivatives, are carried at fair value on the consolidated balance sheet except for loans and receivables, held-to-maturity investments and other financial liabilities, which are measured at amortized cost. Held-for-trading financial instruments are measured at fair value and all gains and losses are included in financing charges in the period which they arise. Available-for-sale financial instruments are measured at fair value with revaluation gains and losses included in OCI until the instrument is derecognized or impaired. The Company has classified its financial instruments as follows:

Short-term investments	Held-to-maturity
Long-term accounts receivable	Loans and receivables
Bank indebtedness	Other liabilities
Short-term notes payable	Other liabilities
Long-term debt (excluding MTN Series 8 Note)	Other liabilities
MTN Series 8 Note	Designated as held-for-trading

The MTN Series 8 Note is a step-up coupon note with a maturity date in 2007, and with extended maturity dates up to 2011.

Where there is an economic hedge, as in the case of the MTN Series 8 note and associated interest rate swap, we have applied the fair value option without hedge accounting. The impact is not material.

All financial instrument transactions are recorded at trade date.

(c) Derivatives and Hedge Accounting

Derivatives

All derivative instruments, including embedded derivatives, are carried at fair value on the balance sheet unless exempted from derivative treatment as a normal purchase and sale. All changes in fair value are recorded in financing charges unless cash flow hedge accounting is used, in which case changes in fair value are recorded in OCI to the extent that the hedge is effective. The impact of the change in the accounting policy related to embedded derivatives was not material.

Hedge Accounting

The Company periodically develops hedging strategies for execution taking into account risk management objectives. At the inception of a hedging relationship, the Company documents the relationship between the hedging instrument and the hedged item. This would include linking all derivatives to specific assets and liabilities on the consolidated balance sheet or to specific firm commitments or forecasted transactions. The Company would also assess, both at the inception of the hedge and on an ongoing basis, whether the derivatives that are used are effective in offsetting changes in fair values or cash flows of hedged items.

Upon adoption of the new standards, the Company reclassified unamortized hedging losses on cash flow hedges that had been discontinued prior to the transition date to accumulated other comprehensive income. The hedging losses are amortized through OCI using the effective interest method over the term of the hedged debt.

(d) Transaction Costs

Transaction costs for financial assets and liabilities that are other than held-for-trading, are added to the carrying value of the asset or liability and then amortized over the expected life of the instrument using the effective interest method. The impact of the change in amortization method from an annuity basis to the effective interest method was not material.

Change in Accounting Estimate – Depreciation

Effective January 1, 2007, the Company prospectively revised its fixed asset depreciation rates resulting from a periodic external review required by the Ontario Energy Board (OEB). Capital costs of fixed assets are depreciated on a straight-line basis, except for transport and work equipment, which is depreciated on a declining balance basis. The estimated impact of the change in rates is a reduction in depreciation expense of approximately $7 million per annum. A summary of the new rates for the various classes of assets is included below:

	Depreciation rates (%)	
	Range	Average
Transmission	1% - 4%	2%
Distribution	1% - 13%	2%
Communication	1% - 13%	5%
Administration and service	1% - 20%	8%

3. TRANSMISSION EXCESS EARNINGS SHARING MECHANISM

On March 30, 2007, the OEB issued a decision ordering that the transmission earnings sharing mechanism cease effective December 31, 2006. The balance of the account was $35 million. After OEB review, the approved balance of this account, including interest, is expected to be incorporated into future rates to be set later in 2007. In its decision, the OEB also ordered that the Company establish a new regulatory deferral account to record the revenue differential between existing transmission rates and the new rates that are anticipated to be approved later in the year. The new deferral account will represent the revenue differential between existing and future rates for the period between January 1, 2007 and the date of the OEB's upcoming transmission rate decision. As the specifics of this decision cannot be foreseen, the value of this account cannot reasonably be determined at this time. Appropriate accounting recognition will be given to any revenue differential once the OEB renders its decision on Hydro One's transmission rates.

4. SMART METER COST RECOVERY

On August 8, 2007, the OEB issued a decision on its combined proceeding to determine the recovery of costs incurred by distributors. Expenditures associated with the minimum functionality for advanced metering infrastructure were approved for recovery. Consequently, as at June 30, 2007, the Company reduced its net smart meter regulatory asset and recorded fixed assets of $41 million. In addition, the Company recognized revenues of $10 million and an equivalent amount of costs incurred in support of the program which were deferred in previous periods. Costs determined to be above the minimum functionality will be brought forward for review in a subsequent cost of service rate application.

5. DIVIDENDS

During the three months ended June 30, 2007, preferred dividends in the amount of $5 million (2006 - $5 million) and common dividends in the amount of $68 million (2006 - $59 million) were declared. During the six months ended June 30, 2007, preferred dividends in the amount of $9 million (2006 - $9 million) and common dividends in the amount of $171 million (2006 - $214 million) were declared.

6. LONG-TERM DEBT

On March 13, 2007, Hydro One issued notes under the Company's medium term note program. The issue was comprised of medium term notes with a principal amount of $400 million having a 30-year term with a coupon rate of 4.89%. The notes are due March 13, 2037.

In the second quarter, Hydro One extended the maturity date of its $40 million extendible step-up note from May 15, 2007 to November 15, 2007.

The Company has a $750 million, 364-day revolving standby credit facility with a syndicate of banks. The term of this facility has been extended as of August 10th, 2007 to August 10th, 2010.

7. EMPLOYEE FUTURE BENEFITS

Total benefit costs are as follows:

	Three months ended June 30		Six months ended June 30	
(Canadian dollars in millions)	**2007**	**2006**	**2007**	**2006**
Pension				
Net periodic benefit cost	25	39	50	77
Pension fund contribution	26	22	51	44
Less: Portion attributable to labour and capitalized as part of the cost of fixed assets	10	9	20	17
Portion attributable to regulatory assets	-	3	-	11
Charged to results of operations	16	10	31	16
Employee Future Benefits Other than Pension				
Net periodic benefit cost	26	31	53	61
Less: Portion attributable to labour and capitalized as part of the cost of fixed assets	11	9	21	19
Charged to results of operations	15	22	32	42

8. SEGMENTED REPORTING

Hydro One has three reportable segments:

- The transmission business, which comprises the core business of providing transportation and connection services, is responsible for transmitting electricity throughout the Ontario electricity grid;
- The distribution business, which comprises the core business of delivering and selling electricity to customers; and
- An "other" segment primarily consisting of telecommunications business.

The designation of segments has been based on a combination of regulatory status and the nature of the products and services provided. Segment information on the above basis is as follows:

Three months ended June 30 (Canadian dollars in millions)	Transmission	Distribution	Other	Consolidated
2007				
Segment profit				
Revenues	315	798	7	1,120
Purchased power	-	522	-	522
Operation, maintenance and administration	107	145	7	259
Depreciation and amortization	60	67	2	129
Income (loss) before financing charges and provision for payments in lieu of corporate income taxes	148	64	(2)	210
Financing charges				74
Income before provision for payments in lieu of corporate income taxes				136
Capital expenditures	155	138	10	303
2006				
Segment profit				
Revenues	316	757	5	1,078
Purchased power	-	505	-	505
Operation, maintenance and administration	109	120	5	234
Depreciation and amortization	61	64	2	127
Income (loss) before financing charges and provision for payments in lieu of corporate income taxes	146	68	(2)	212
Financing charges				73
Income before provision for payments in lieu of corporate income taxes				139
Capital expenditures	97	100	1	198

Six months ended June 30 (Canadian dollars in millions)	**Transmission**	**Distribution**	**Other**	**Consolidated**
2007				
Segment profit				
Revenues	642	1,742	14	2,398
Purchased power	-	1,163	-	1,163
Operation, maintenance and administration	206	273	14	493
Depreciation and amortization	120	131	3	254
Income (loss) before financing charges and provision for payments in lieu of corporate income taxes	316	175	(3)	488
Financing charges				147
Income before provision for payments in lieu of corporate income taxes				341
Capital expenditures	250	229	11	490
2006				
Segment profit				
Revenues	614	1,613	11	2,238
Purchased power	-	1,103	-	1,103
Operation, maintenance and administration	202	206	11	419
Depreciation and amortization	120	122	3	245
Income (loss) before financing charges and provision for payments in lieu of corporate income taxes	292	182	(3)	471
Financing charges				146
Income before provision for payments in lieu of corporate income taxes				325
Capital expenditures	197	175	3	375

(Canadian dollars in millions)	**June 30, 2007**	**December 31, 2006**
Total assets		
Transmission	7,085	6,950
Distribution	5,256	5,161
Other	96	99
	12,437	12,210

All revenues, costs and assets, as the case may be, are earned, incurred or held in Canada.

9. COMMITMENTS

Purchasers of electricity in Ontario, through the Independent Electricity System Operator (IESO), are required to provide security to mitigate the risk of their default based on their expected activity in the market. The IESO could draw on these guarantees should the Company's subsidiaries, Hydro One Networks Inc. or Hydro One Brampton Networks Inc., fail to make a payment required by a default notice issued by the IESO.

On June 28, 2007, the IESO approved revisions to the prudential support obligations under the market rules. Previously, prudential support was provided to the IESO using a combination of bank letters of credit and parental guarantees. Under the new rules, effective August 1, 2007 the Company can meet its prudential support requirements using only parental guarantees, as long as it maintains a long-term credit rating in the "Aa" category. Consequently, the Company will reduce its bank letters of credit by $10 million.

10. SUBSEQUENT EVENT

On August 2, 2007, the Company entered into a forward starting pay fixed interest rate swap agreements to hedge against the effect of future interest rate movements on long-term fixed rate borrowing requirements. This transaction had a notional amount of $150 million and is used to lock in the interest rate of a forecasted debt issuance planned for later in 2007. This transaction is being accounted for as a cash flow hedge of a forecasted transaction.

11. COMPARATIVE FIGURES

The comparative unaudited interim Consolidated Financial Statements have been reclassified from statements previously presented to conform to the presentation of the June 30, 2007 unaudited interim Consolidated Financial Statements.

RESULTS OF OPERATIONS

As used in this section, references to increases and decreases, whether in terms of amounts or percentages are made by comparison of the three and nine months ended September 30, 2007 to the three and nine months ended September 30, 2006.

Revenues

	Three months ended September 30				Nine months ended September 30			
(Canadian dollars in millions)	**2007**	**2006**	**$ Change**	**% Change**	**2007**	**2006**	**$ Change**	**% Change**
Transmission	307	331	(24)	(7)	949	945	4	-
Distribution	813	828	(15)	(2)	2,555	2,441	114	5
Other	8	6	2	33	22	17	5	29
	1,128	1,165	(37)	(3)	3,526	3,403	123	4
Average Ontario 60-minute peak demand *(MW)*[1]	24,730	24,358	372	2	23,542	23,112	430	2
Distribution - units distributed to customers *(TWh)*[1]	7.1	7.0	0.1	1	22.5	21.6	0.9	4

[1]System-related statistics are preliminary

The demand for electricity generally follows normal weather-related variations, and, therefore, our energy-related revenues, all other things being equal, will tend to be higher in the first and third quarters than in the second and fourth quarters.

Transmission

Transmission revenues predominantly consist of our transmission tariff, which is based on the monthly peak demand for electricity across our high-voltage network. The tariff is designed to recover revenues necessary to support a transmission system with sufficient capacity to accommodate the maximum expected demand, which is primarily influenced by weather and economic conditions. Transmission revenues also include minor amounts of ancillary revenues, which are primarily attributable to maintenance services provided to generators, and secondary use of our land rights-of-way.

Revenues for the quarter and for the year-to-date periods were affected by the Ontario Energy Board's (OEB's) August 16, 2007 decision on our transmission rate application. The OEB approved all of our work program expenditure requirements. Our return on equity was reduced from 9.88% to 8.35% and our deemed capital structure was adjusted from one that included common and preferred shares and debt to a deemed capital structure split of 60% debt and 40% common shares. This capital structure is consistent with that approved by the OEB in its December 2006 report which established the capital structure for Ontario's electricity distributors. The OEB's decision was effective January 1, 2007 and new customer rates reflecting the decision were implemented on November 1, 2007. As a result of the OEB decision, we reduced our 2007 transmission revenues in the third quarter to reflect the approved revenue requirement. These amounts are being returned to customers through lower rates commencing November 1, 2007. This liability has been recorded in the Revenue Difference Deferral Account (RDDA). On March 30, 2007, the OEB approved cessation of the 2006 transmission Earnings Sharing Mechanism (ESM) effective December 31, 2006 and replaced it with the RDDA. The RDDA liability will be drawn down over the period the new rates are in place and revenue will be recorded based on the approved revenue requirement throughout the remainder of 2007 and during 2008.

Our transmission tariff revenues decreased by $24 million, or 7%, during the third quarter of 2007, but increased by $4 million in the first nine months compared to the same period last year. Our transmission revenues reflect the impacts of the OEB's August 16, 2007 transmission rate decision, which had the effect of reducing our quarterly and year-to-date revenues by about $38 million. This reduction includes the revenue adjustment associated with recording the RDDA liability, as well as other decision-related revenue adjustments related to the disposition of regulatory asset and liability accounts and the recording of export and wheeling fees revenue. In addition, our transmission revenues were higher than the comparative periods by $6 million in the quarter and $23 million year-to-date as a result of the OEB's earlier decision to end the ESM effective December 31, 2006.

Revenues for the third quarter and year-to-date also reflect higher average peak demands compared to the same periods last year, resulting in increased transmission revenues of $5 million in the quarter and $21 million for the year-to-date period. We also experienced increased other revenues of $3 million in the quarter and decreased other revenues of $2 million on a year-to-date basis.

Distribution

Distribution revenues include our distribution tariff, which is based on OEB-approved rates, as well as amounts to recover the cost of purchased power used by our customers. Accordingly, distribution revenues are primarily influenced by our distribution rates, the amount of electricity we distribute, and the cost of purchased power. Distribution revenues also include a minor amount of ancillary distribution services revenue, such as fees related to the use of our poles by the telecommunications and cable television industries, and miscellaneous charges such as those for late payments.

Distribution revenues decreased by $15 million, or 2%, to $813 million in the third quarter but increased by $114 million, or 5%, to $2,555 million during the first nine months compared to the same periods last year. These changes include the recovery of lower purchased power costs of $31 million in the quarter and higher purchased power costs of $29 million in the first nine months, as described below under "Purchased Power." In addition, the OEB approved increases in distribution tariff rates for our subsidiaries, Hydro One Networks Inc. (Hydro One Networks) and Hydro One Brampton Networks Inc. (Hydro One Brampton Networks), effective May 1, 2006 and May 1, 2007 respectively. These tariff rate increases, which support the maintenance and investment requirements of our distribution system, enabling the safe and reliable delivery of electricity to our customers throughout Ontario, resulted in higher distribution revenues of $1 million in the quarter and $44 million in the first nine months. In 2006, rates were based on a full cost of service hearing and in 2007, rates were adjusted based on OEB guidelines. Higher energy consumption, resulting primarily from the colder winter weather this year, increased our distribution revenues by a further $4 million in the quarter and $18 million in the year-to-date period. In addition, as a result of the OEB's decision on August 8, 2007 regarding the combined smart meter proceeding, we recorded smart meter revenues of $6 million in the quarter and $16 million in the first nine months. We also experienced higher other revenues of $5 million in the quarter and $7 million in the first nine months of 2007 compared to the same periods last year.

Purchased Power

Purchased power costs incurred by our distribution business represent the cost of electricity delivered to customers within our distribution service territory and consist of the wholesale commodity cost of energy, the Independent Electricity System Operator's (IESO's) wholesale market service charges, and transmission charges levied by the IESO. The commodity cost of energy for certain low-volume and designated customers is based on the OEB's Regulated Price Plan (RPP), which consists of a two-tiered pricing structure with threshold amounts adjusted twice annually. Customers who are not eligible for the RPP pay the market price for electricity, adjusted for the difference between market prices and the prices paid to generators under the *Electricity Restructuring Act, 2004*. A summary of the RPP is provided below.

Summary of RPP				
	Tier Threshold (kWh)		Tier Rates (cents/kWh)	
Effective Date	**Residential**	**Non-Residential**	**First Tier**	**Second Tier**
November 1, 2005	1,000	750	5.0	5.8
May 1, 2006	600	750	5.8	6.7
November 1, 2006	1,000	750	5.5	6.4
May 1, 2007	600	750	5.3	6.2

Purchased power costs decreased by $31 million, or 5%, to $533 million in the third quarter but increased by $29 million, or 2%, to $1,696 million during the first nine months compared to the last year. The decrease for the quarter primarily reflects the impact of the May 1, 2007 reduction in RPP rates for residential and other eligible customers of $36 million, partially offset by higher wholesale commodity prices for customers who are not eligible for the RPP of $2 million, higher demand for electricity of $2 million, and higher wholesale market service charges levied by the IESO of $1 million. For the nine-month period, higher demand for electricity of $49 million, higher wholesale commodity prices for customers who are not eligible for the RPP of $12 million, and higher wholesale market service charges levied by the IESO of $3 million, more than offset the impact of the May 1, 2007 RPP rate change for residential and other eligible customers of $35 million.

Operation, Maintenance and Administration

Our operation, maintenance and administration costs are comprised primarily of labour, material, equipment and purchased services in support of the operation and maintenance of the transmission and distribution systems. These costs also include property taxes and payments in lieu thereof on our transmission and distribution lines, stations and buildings.

Operation, maintenance and administration costs for each of our three business segments were as follows:

	Three months ended September 30				Nine months ended September 30			
(Canadian dollars in millions)	2007	2006	$ Change	% Change	2007	2006	$ Change	% Change
Transmission	117	105	12	11	323	307	16	5
Distribution	137	122	15	12	410	328	82	25
Other	9	6	3	50	23	17	6	35
	263	233	30	13	756	652	104	16

Transmission

Operation, maintenance and administration expenditures incurred to sustain our high-voltage transmission stations, lines and rights-of-way increased by $12 million, or by 11%, in the quarter and increased by $16 million, or 5%, on a year-to-date basis compared to the same periods last year. Within our work programs, we continued our investments that support the safe and reliable operation of the transmission system. We experienced higher work program expenditures of approximately $13 million in the quarter and about $24 million year-to-date, primarily due to the enhancement of our planned station maintenance program. Higher expenditures on line clearing and brush control were experienced in the quarter. In addition, we experienced a one-time $6 million cost related to revaluing some of our transmission regulatory accounts as a result of the OEB's August 16, 2007 transmission rate decision. Our expenditures incurred in support of the transmission system increased marginally during the first nine months as we commenced a major business systems and processes project. The impact of these increases was offset by the impact of reassigning resources to support our larger transmission capital program.

Distribution

Operation, maintenance and administration expenditures necessary to maintain our low-voltage system increased by $15 million, or 12%, in the third quarter and by $82 million, or 25%, on a year-to-date basis, relative to the comparative periods. Higher expenditures within our work program of $8 million in the quarter and $51 million for the first nine months resulted from higher line clearing expenditures and customer participation in our conservation and demand management programs. These impacts were partially offset in the quarter by a reduction in our lines maintenance work program, predominantly as a result of higher storm activity in 2006. In addition, pension costs within our distribution business for the quarterly and year-to-date periods were higher than in 2006 as a result of last year's OEB rate decision. Prior to May 1, 2006, all of our distribution-related pension costs were deferred as a regulatory asset. As a result of the OEB's August 8, 2007 decision on the combined smart meter proceeding, we have recorded increased operation, maintenance and administration expense related to smart meter expenditures incurred in the 2005 to 2007 period that were previously deferred as regulatory assets. In addition to these increases, our other support expenditures for the first nine months increased marginally as a result of the commencement of a major business systems and processes project.

Depreciation and Amortization

Depreciation and amortization decreased by $4 million, or 3%, to $128 million in the third quarter and increased by $5 million, or 1%, to $382 million in the first nine months compared to the same periods last year. The reduction in the quarter is primarily due to lower amortization of regulatory assets of $3 million. The remainder of the reduction in the quarter is due to lower fixed asset removal costs resulting from lower storm damage. The year-to-date increase is primarily due to higher year-over-year amortization of our regulatory assets of $2 million resulting from an April 12, 2006 OEB distribution rate decision that was effective on May 1, 2006, combined with higher fixed asset removal costs of $2 million as a result of increased storm work performed in the first and second quarters.

Financing Charges

Financing charges increased by $2 million, or 3%, to $76 million in the quarter and by $3 million, or 1%, to $223 million in the first nine months of the year, compared to the same periods last year. These increases were primarily due to reduced capitalization of financing costs of $4 million in the quarter and $10 million for the first nine months. Interest capitalization on our fixed and regulatory assets was lower as a result of lower OEB-prescribed rates and higher net regulatory liability balances resulting from recording the RDDA. Interest related to a first quarter 2006 recovery of payments in lieu of corporate income taxes also contributed to the increase in year-over-year financing costs for the nine month period. The impact of these increases was partially offset by lower interest on long-term debt of about $2 million in the quarter and $9 million for the first nine months, reflecting the impact of lower average borrowing costs partially offset by a higher average level of debt outstanding.

Provision for Payments in Lieu of Corporate Income Taxes

The provision for payments in lieu of corporate income taxes increased by $2 million, or 3%, to $61 million in the third quarter and by $27 million, or 20%, to $160 million on a year-to-date basis compared to last year. The year-to-date increase primarily reflects last year's first quarter recognition of a $30 million tax benefit related to the recovery of payments in lieu of corporate taxes from prior years. These impacts were partially offset by higher capital cost allowance in excess of depreciation this year and other temporary differences.

Net Income

Net income of $67 million was lower by $36 million, or 35%, in the third quarter and was lower by $45 million, or 13%, in the first nine months compared to 2006 results. Net income, both in the quarter and year-to-date, was impacted by the OEB's August 16, 2007 transmission rate decision. While the OEB approved all of our work program requirements for 2007 and 2008, our return on equity was reduced from 9.88% to 8.35%. Our net income levels in both the quarterly and year-to-date periods were also affected by higher distribution work program expenditures to maintain system reliability, the impact of a 2006 OEB decision on our distribution-related pension expenditures and by higher effective tax rates. The increased rates are related to temporary differences associated with amounts to be returned to customers as part of the OEB's transmission rate decision and a recovery of payments in lieu of corporate income taxes in the first quarter of last year. These impacts were partially offset by increased transmission revenues due to a higher average peak demand and distribution tariff revenues for the first nine months of 2007.

QUARTERLY RESULTS OF OPERATIONS

The following table sets forth unaudited quarterly information for each of the eight quarters from December 31, 2005 through September 30, 2007. This information has been derived from our unaudited interim Consolidated Financial Statements which, in the opinion of our management, have been prepared on a basis consistent with the audited annual Consolidated Financial Statements and which include all adjustments, consisting only of normal recurring adjustments, necessary for fair presentation of our financial position and results of operations for those periods. These operating results are not necessarily indicative of results for any future period and should not be relied upon to predict our future performance.

(Canadian dollars in millions)		**2007**			**2006**			**2005**
Quarter ended	**Sep. 30**	**Jun. 30**	**Mar. 31**	**Dec. 31**	**Sep. 30**	**Jun. 30**	**Mar. 31**	**Dec. 31**
Total revenue[1, 2, 3]	1,128	1,120	1,278	1,142	1,165	1,078	1,160	1,025
Net income [1, 2, 3]	67	93	149	101	103	99	152	104
Net income to common shareholder [1, 2, 3]	63	88	145	96	99	94	148	99

[1] The demand for electricity generally follows normal weather-related variations, and therefore our electricity-related revenues and profit, all other things being equal, would tend to be higher in the first and third quarters than in the second and fourth quarters.

[2] Under a new regulation issued in October 2005, RPP customers received a one-time credit reflecting a lower cost of power than the fixed commodity price between April 1, 2004 and March 31, 2005. In the fourth quarter of 2005, revenue and cost of power were both reduced by approximately $140 million. The application of the one-time credit did not result in any adjustment to net income.

[3] As a result of the OEB's August 16, 2007 decision on Hydro One Networks' Transmission rate application that was effective January 1, 2007, year-to-date revenues have been adjusted to reflect a reduced revenue requirement based on the approved rate of return of 8.35%.

LIQUIDITY AND CAPITAL RESOURCES

Our primary sources of liquidity and capital resources are funds generated from operations, debt capital market borrowings and bank financing. These resources will be used to satisfy our capital resource requirements, which continue to include capital expenditures, servicing and repayment of our debt, payments related to our outsourcing arrangements, investing activities, and dividends.

Summary of Sources and Uses of Cash	**Three months ended September 30**		**Nine months ended September 30**	
(Canadian dollars in millions)	**2007**	**2006**	**2007**	**2006**
Operating activities	331	351	868	715
Financing activities				
Long-term debt issued	-	150	400	700
Long-term debt retired	(73)	-	(355)	(448)
Short-term notes payable	85	(130)	100	-
Dividends paid	(72)	(63)	(252)	(286)
Investing activities				
Capital expenditures	(275)	(218)	(765)	(593)
Other financing and investing activities	4	4	18	9
Net change in cash and cash equivalents	-	94	14	97

Operating Activities

Net cash generated from operating activities decreased by $20 million to $331 million in the third quarter, but increased by $153 million to $868 million in the first nine months. The decrease for the quarter was primarily due to marginally higher working capital requirements compared to the third quarter last year. Our working capital requirements in the year-to-date period were substantially lower than the comparative period primarily as a result of a first quarter 2006 recovery of payments in lieu of corporate income taxes and the impact of the *Ontario Price Credit* that was provided to RPP customers in early 2006, pursuant to regulation. Funding for the credit was received from the IESO in early December 2005.

Financing Activities

Short-term liquidity is provided through funds from operations and our Commercial Paper Program, under which we are authorized to issue up to $1 billion in short-term notes with a term to maturity of less than 365 days. As at September 30, 2007, we had $161 million of short-term notes payable. The Commercial Paper Program is supported by a $750 million committed revolving credit facility with a syndicate of banks which matures on August 10, 2010. The short-term liquidity under this program and anticipated levels of funds from operations should be sufficient to fund our normal operating requirements. Long-term financing is provided by our access to the debt markets, primarily through our Medium-Term Note Program. On June 21, 2007, we filed a $2.5 billion base shelf prospectus to renew our Medium-Term Note Program for another 25 months. Our notes and debentures mature between 2007 and 2046. We currently plan to refinance maturing debt principally through our Medium-Term Note Program. The maximum authorised principal amount of medium-term notes issuable under this program is $2,500 million, all of which currently remains available until July 2009.

	Rating	
Rating Agency	**Short-term Debt**	**Long-term Debt**
DBRS Inc.	R-1 (middle)	A (high)
Moody's Investors Service Inc.	Prime-1	Aa3
Standard & Poor's Rating Services Inc.	A-1	A

We have the customary covenants normally associated with long-term debt. Among other things, our long-term debt covenants limit our permissible debt as a percentage of our total capitalization, limit our ability to sell assets and impose a negative pledge provision, subject to customary exceptions. The credit agreement related to our $750 million credit facility has no material adverse change clauses that could trigger default. However, the credit agreement requires that we provide notice to the lenders of any material adverse change within three business days of the occurrence. The agreement also provides limitations that debt cannot exceed 75% of total capitalization and that debt issued by our subsidiaries cannot exceed 10% of the total book value of our assets. We are in compliance with all of these covenants and limitations.

During the third quarter of 2007, we repaid $73 million in maturing long term debt and increased our short-term notes by $86 million. During the same period in 2006, we issued $150 million in long-term debt under our Medium-Term Note Program and decreased our short-term notes by $130 million.

During the first nine months of 2007, we issued $400 million in long-term debt under our Medium-Term Note Program, repaid $355 million in maturing long-term debt, and increased our short-term notes by $101 million. In comparison, during the same period in 2006, we issued $700 million in long-term debt under our Medium Term Note Program and repaid $448 million in maturing long-term debt.

In the third quarter of 2007, we paid dividends to the Province of Ontario in the amount of $72 million, consisting of $68 million in common dividends and $4 million in preferred dividends. In the comparative period, we paid common dividends of $59 million and preferred dividends of $4 million. Year-to-date, we have paid common and preferred dividends totaling $252 million, compared to $286 million in 2006.

Common dividends are declared at the sole discretion of our Board of Directors, and are recommended by management based on results of operations, financial condition, cash requirements and other relevant factors such as industry practice and shareholder expectations. Common dividends pertaining to the quarterly financial results are generally declared and paid in the immediately following quarter.

Investing Activities

Cash used for investing activities primarily represents capital expenditures for each of our three business segments as follows:

	Three months ended September 30				**Nine months ended September 30**			
(Canadian dollars in millions)	**2007**	**2006**	**$ Change**	**% Change**	**2007**	**2006**	**$ Change**	**% Change**
Transmission	144	93	51	55	394	290	104	36
Distribution	126	123	3	2	355	298	57	19
Other	5	2	3	150	16	5	11	220
	275	218	57	26	765	593	172	29

Transmission

Transmission capital expenditures increased by $51 million, or 55%, to $144 million in the third quarter, and increased by $104 million, or 36%, to $394 million in the first nine months, compared to the same periods in 2006. Expenditures made to expand and reinforce our transmission system were $72 million in the quarter and $208 million for the first nine months of the year, representing increases over the comparative periods of $26 million and $78 million, respectively. These increases primarily reflect expenditures on major lines and stations development projects. These expenditures have increased primarily as a result of our construction on a new inter-connection with Quebec, which will increase access to emission-free hydroelectric power, work on our Cambridge Preston Transformer Station and on our Essa to Stayner connection, and the continued construction of our Downtown Toronto Cable Project. The impact of these increases was partially offset by last year’s expenditures on our Niagara Reinforcement Project. This project was substantially completed last year but final completion continues to be delayed by the aboriginal land dispute in the Caledonia area. Discussions continue between the affected aboriginal peoples and the various government entities involved. Expenditures on our load and generation connections work have also increased as a result of work at our London Talbot, Holland and Whitby transformer stations, as well as the reconfiguration of our Lambton Transformer Station. Expenditures to sustain our existing transmission system were $55 million in the quarter and $147 million on a year-to-date basis, representing increases of $11 million and $8 million respectively, compared to the same periods last year. Our other transmission capital expenditures increased to $17 million and $39 million for the three and nine month periods, compared to $3 million and $21 million in the same periods last year, primarily due to higher information technology expenditures, including expenditures on a major business systems and processes project.

Distribution

Distribution capital expenditures increased by $3 million, or 2%, to $126 million in the quarter and by $57 million, or 19%, to $355 million for the first nine months, compared to the same periods in 2006. Capital investments to expand and reinforce our distribution network were $57 million in the quarter and $166 million for the first nine months, representing increases of $10 million and $46 million, respectively over the comparable periods. These increases primarily reflect our ongoing investments in smart meters. During the quarter, we installed about 83,000 smart meters, for a year-to-date total of approximately 172,000 and a cumulative program total of approximately 200,000. We plan to install about 240,000 smart meters in 2007. Expenditures to sustain our distribution system were $56 million in the quarter and $152 million year-to-date, representing decreases of $17 million and $9 million, respectively compared to last year. These decreases were primarily due to reduced storm activity this year compared to the summer of 2006. This impact was partially offset by higher planned end-of-life asset component replacement expenditures in our lines work program this year. Our other distribution capital expenditures increased to $13 million and $37 million for the three and nine month periods, compared to $3 million and $17 million in the same periods last year primarily due to higher information technology expenditures, including expenditures on a major business systems and processes project.

Other

Other capital expenditures made to enhance our telecom infrastructure increased by $3 million in the third quarter and by $11 million in the first nine months compared to the same periods in 2006. These increases were largely due to construction of a dedicated optical network which will provide secure, high capacity connectivity across numerous healthcare locations in Ontario.

Future Capital Expenditures

Our capital expenditures are planned to be about $1.2 billion in 2007 and $1.4 billion in 2008. These planned investments will address new development and supply enhancement initiatives, including system expansions, generation requirements and load connections, and the needs of our aging transmission system under continued challenging conditions of generation supply. The OEB approved the transmission-related investments for both 2007 and 2008 in its decision of August 16, 2007. Within our distribution business, the mass deployment of smart meters is underway and we are currently on track to meet our 2007 year-end target. Our future capital expenditures also include a major business systems and processes project, which incorporates the replacement of end of life information systems.

The Ontario Power Authority (OPA) has completed its Integrated Power System Plan (IPSP), focusing primarily on the mid- to long-term time frames, and submitted it to the OEB at the end of August 2007. Consequently, we will be required to justify the need for many of our key projects. We have initiated section 92 leave-to-construct filings with the OEB for our pre-IPSP projects. No significant changes have been noted between the IPSP and our business plan, although the IPSP recommends commencement of project development work on certain large and immediate projects. The IPSP is a key driver for the amount of our future capital expenditures. The timing of many of our development projects is also dependent on the requirement to seek and attain approvals from various regulatory bodies, requirements for negotiations and consultations with customers, neighbouring utilities and other stakeholders, and our ability to effectively resource these projects. We will not undertake large capital expenditures without a reasonable expectation of recovering them in our rates.

Our distribution investment plan includes the mass rollout of the smart metering program. Over the period 2007 to 2010, we anticipate installing 1.3 million meters throughout our service territory. Consistent with the government policy, all homes and small businesses are to receive a smart meter by the end of 2010. Total project costs are anticipated to be significant. In 2007, we plan to invest approximately $75 million under our smart meter program. At the Province’s request, we will review our implementation plan and associated costs for the period 2008 to 2010.

Summary of Contractual Obligations and Other Commercial Commitments

The following table presents a summary of our debt and other major contractual obligations as well as other major commercial commitments.

September 30, 2007 (Canadian dollars in millions)	**Total**	**2007[1]**	**2008/2009**	**20010/2011**	**After 2011**
Contractual Obligations *(due by year)*					
Short-term note payable	161	161	-	-	-
Long-term debt – principal repayments	5,315	40	900	650	3,725
Long-term debt – interest payments	5,166	111	563	487	4,005
Inergi LP outsourcing agreement[2]	419	28	195	181	15
Operating lease commitments	18	2	11	3	2
Total Contractual Obligations	11,079	342	1,669	1,321	7,747
Other Commercial Commitments *(by year of expiry)*					
Bank line[3]	750	-	-	750	-
Letters of credit[4]	97	96	1	-	-
Guarantees[4]	275	275	-	-	-
Pension[5]	214	18	188	8	-
Total Other Commercial Commitments	1,336	389	189	758	-

[1] The amounts disclosed represent the balance due over the period October 1, 2007 to December 31, 2007.

[2] On March 1, 2002, Inergi LP began providing a range of services to us for a 10-year period, including information technology, customer care, supply chain and certain human resources and finance services.

[3] As a backstop to our commercial paper program, we have a $750 million revolving standby credit facility with a syndicate of banks which matures in August 2010.

[4] We currently have bank letters of credit of $93 million outstanding relating to retirement compensation arrangements. We have also provided prudential support to the IESO on behalf of our subsidiaries as required by the Market Rules, using parental guarantees up to a maximum of $275 million. The maximum parental guarantee is expected to increase in November 2007 to $325 million as a result of forecast power purchases and the November 1, 2007 change to our transmission rates. Although no letters of credit are currently required for prudential support, we would have to resume providing bank letters of credit if our highest long-term credit rating deteriorated to below the "Aa" category. The remaining amounts included in letters of credit pertain to operating letters of credit and to surety bonds.

[5] Contributions to the pension fund are made one-month in arrears. Contributions for 2007 are based on an actuarial valuation filed in September 2007 and effective December 31, 2006. Our annual pension contributions for 2007 - 2009 will be about $94 million. Contributions beyond 2009 will be based on an actuarial valuation effective December 31, 2009 and will depend on future investment returns, changes in benefits or actuarial assumptions. Pension contributions beyond 2009 are not estimable at this time.

The amounts in the above table under long-term debt are not charged to our results of operations, but are reflected on our balance sheet and statement of cash flows. Interest associated with this debt is recorded under financing charges on our statement of operations or in our capital programs, but these financing charges are not reflected in the above table. Payments in respect of operating leases and our outsourcing agreement with Inergi LP are recorded under operation, maintenance and administration costs on our statement of operations or in our capital programs.

RELATED PARTY TRANSACTIONS

Our related party transactions primarily consist of our transmission revenues received from, and our power purchases payments made to, the IESO, which is a related party by virtue of its status as an agency of our shareholder, the Province of Ontario. The year-over-year changes related to these amounts are described more fully in our discussion of transmission revenues and purchased power costs. Other significant related party transactions include our dividends which are paid to the Province of Ontario and our payments in lieu of corporate income taxes which are paid or payable to the Ontario Electricity Financial Corporation.

RECENT DEVELOPMENTS

Transmission Rate Decision

On August 16, 2007, the OEB issued its decision in respect of our 2007 and 2008 transmission rate application. The decision, which is effective January 1, 2007, showed confidence in our work programs by approving all of our operating and capital expenditures for 2007 and 2008. The decision resulted in an estimated 8% annual reduction in transmission rates primarily due to a reduction in the approved return on equity from 9.88% to 8.35%, based on a formula used by the OEB in the regulation of local distribution companies. With the rate adjustment taking effect November 1, 2007, there is an estimated one-time reduction in transmission rates of about 13%, resulting in a reduction of approximately 1% on an average customer's total bill.

As part of a joint proceeding involving all Transmitters in Ontario, on October 17, 2007, the OEB approved new Ontario Uniform Transmission Rates for implementation on November 1, 2007 noting that these Uniform Transmission Rates will be in effect until December 31, 2008.

IPSP

On August 29, 2007, the OPA submitted its application to the OEB for review and approval of the IPSP for Ontario. The plan's estimated 20-year, $60-billion capital cost will be directed toward initiatives required to deliver electricity to Ontario consumers. The IPSP focused on the medium to long term, recommending that project development work on certain major transmission projects, including generation enabling connection lines and projects addressing reliability of local area supply, commence once the IPSP is approved. OEB approval is expected in the Fall of 2008. Any development work commencing until at least the next IPSP is submitted, will continue to require us to prove project need as part of our section 92 leave-to-construct proceedings.

Decision on Combined Transmission Connection Procedures Proceeding

On September 6, 2007, the OEB issued its decision related to our August 20, 2006 application for transmission connection procedures. The OEB noted that the connection procedures that we filed drew no substantial criticism or comment from intervening parties or OEB staff as evidence of our commitment to a fair, transparent and effective connection process. The OEB's decision, however, was inconsistent with our position on the need for capital contributions for Local Area Supply facilities. The OEB determined that capital contributions should generally be required. On October 9, 2007, we filed a motion to request a review of parts the decision.

Applications to Construct Facilities

On August 20, 2007, the OEB issued its decision granting us early access to lands expected to be used in the proposed Bruce to Milton transmission line project so we could conduct certain survey, testing, appraisal and investigative activities. The interim order, which is effective through to April 1, 2009, is subject to conditions that establish the parameters by which we are to conduct our work in order to ensure minimal disruption to landowners. We commenced early access activities in September.

On October 9, 2007 and October 11, 2007, the OEB issued two decisions approving our leave-to-construct applications for electricity transmission facilities in the western Brampton and Woodstock areas, respectively. These facilities are required to maintain reliability and improve system performance.

2008 Distribution Rate Applications

On August 15, 2007, we filed the revenue requirement component of our cost of service application with the OEB for our distribution business operated through Hydro One Networks. The cost allocation and rate design components of our application is expected to be filed later in the year. Our proposed revenue requirement for 2008 results in a net distribution rate increase of about 4%. This translates into an average annual increase on total customer bills of less than 2%.

On September 28, 2007, the OEB issued its filing requirements for 2008 Incentive Regulation Mechanism applications to set distribution rates effective May 1, 2008 for all electricity distributors not filing a cost of service application. Our subsidiary Hydro One Brampton Networks filed its application with the OEB on November 1, 2007.

Distribution System Acquisition

On October 10, 2007, the OEB issued its decision approving our acquisition of the distribution system assets of Terrace Bay Superior Wires Inc. The acquisition closed on October 25, 2007.

OEB RPP Price Change

On October 12, 2007, the OEB announced a scheduled change in electricity prices for RPP customers. Beginning November 1, 2007, the electricity price has been reduced from 5.3 cents to 5.0 cents per kilowatt hour for customers consuming up to certain thresholds, depending on the type of customer, and from 6.2 cents to 5.9 cents for kilowatt hours exceeding the thresholds.

Debt Issue

On October 18, 2007, we issued $300 million of 10-year notes under our Medium-Term Note Program at a coupon rate of 5.18% and with a maturity date of October 18, 2017. The proceeds of the issue were temporarily invested in money market instruments, including asset backed commercial paper sponsored by the five major Canadian chartered banks. We do not hold any non-bank or third party sponsored commercial paper.

SELECTED FINANCAL HIGHLIGHTS AND RATIOS

	Three months ended September 30		Nine months ended September 30	
(Canadian dollars in millions) (except as otherwise noted)	**2007**	**2006**	**2007**	**2006**
Net income	67	103	309	354
Net cash from operating activities	331	351	868	715
Capital expenditures	275	218	765	593
Earnings per common share *(Canadian dollars)*	618	991	2,952	3,407
Earnings coverage ratio[1]			2.68	2.66
Net asset coverage on long-term debt[2]			1.92	1.92
Total debt to capitalization[3]			52%	52%

[1]The earnings coverage ratio has been presented for the twelve months ended September 30, 2007 and September 30, 2006, respectively and has been calculated as the sum of net income, provision for payments in lieu of corporate income taxes and financing charges divided by the sum of financing charges, capitalized interest and cumulative preferred dividends.

[2]The net asset coverage on long-term debt ratio has been presented as at September 30, 2007 and December 31, 2006 and has been calculated as total assets minus total liabilities excluding long-term debt (including current portion) divided by long-term debt including current portion.

[3]Total debt to capitalization ratio has been presented as at September 30, 2007 and December 31, 2006 and has been calculated as total debt divided by total debt plus total shareholder's equity.

FORWARD-LOOKING STATEMENTS AND INFORMATION

Our oral and written public communications, including this Management's Discussion and Analysis, often contain forward looking statements that are based on current expectations, estimates, forecasts and projections about our business and the industry in which we operate and include beliefs and assumptions made by the management of our company. Such statements include, but are not limited to statements regarding future capital expenditures; statements about the installation and cost of smart meters; expectations surrounding future pension contributions; statements regarding potential incremental environmental expenditures; and expectations concerning the impact of new accounting standards. Words such as "expect," "anticipate," "intend," "attempt," "may," "plan," "will," "believe," "seek," "estimate," and variations of such words and similar expressions are intended to identify such forward-looking statements. These statements are not guarantees of future performance and involve assumptions and risks and uncertainties that are difficult to predict. Therefore, actual outcomes and results may differ materially from what is expressed, implied or forecasted in such forward-looking statements. We do not intend, and we disclaim any obligation to update any forward looking statements, whether written or oral, or whether as a result of new information, future events or otherwise, except as required by law.

These forward looking statements are based on a variety of factors and assumptions including, but not limited to the following: no unforeseen changes in the legislative and operating framework for Ontario's electricity market; favourable decisions from the OEB and other regulatory bodies concerning outstanding rate and other applications; and no significant events occurring outside the ordinary course of business. These assumptions are based on information currently available to us, including information obtained from third-party industry analysts. Actual results may differ materially from those predicted by such forward-looking statements. While we do not know what impact any of these differences may have, our business, results of operations, financial condition and our credit stability may be materially adversely affected. Factors that could cause actual results or outcomes to differ materially from the results expressed or implied by forward-looking statements include, among other things:

- the content of the final IPSP, once it is approved by the OEB;
- delays or denials of the requisite approvals for planned future capital expenditures;
- regulatory decisions regarding our revenue requirements and tariff rates;
- significant changes to Environment Canada’s draft polychlorinated biphenyl (PCB) regulations issued on November 4, 2006; and
- future interest rates, inflation, changes in benefits and changes in actuarial assumptions.

We caution the reader that the above list of factors is not exhaustive.

This management’s discussion and analysis is dated as at November 8, 2007. Additional information about our company, including our annual information form, is available on SEDAR at www.sedar.com.

HYDRO ONE INC.
CONSOLIDATED STATEMENTS OF OPERATIONS (unaudited)

(Canadian dollars in millions)	Three months ended September 30 2007	2006	Nine months ended September 30 2007	2006
Revenues				
Transmission *(Note 3)*	307	331	949	945
Distribution *(Note 4)*	813	828	2,555	2,441
Other	8	6	22	17
	1,128	1,165	3,526	3,403
Costs				
Purchased power	533	564	1,696	1,667
Operation, maintenance and administration *(Note 4)*	263	233	756	652
Depreciation and amortization *(Note 2)*	128	132	382	377
	924	929	2,834	2,696
Income before financing charges and provision for payments in lieu of corporate income taxes	204	236	692	707
Financing charges	76	74	223	220
Income before provision for payments in lieu of corporate income taxes	128	162	469	487
Provision for payments in lieu of corporate income taxes	61	59	160	133
Net income	67	103	309	354
Other comprehensive income	(1)	-	-	-
Comprehensive income *(Note 2)*	66	103	309	354
Basic and fully diluted earnings per common share *(Canadian dollars)*	618	991	2,952	3,407

CONSOLIDATED STATEMENTS OF RETAINED EARNINGS (unaudited)

(Canadian dollars in millions)	Three months ended September 30 2007	2006	Nine months ended September 30 2007	2006
Retained earnings, beginning of period	1,246	1,107	1,184	1,079
Net income	67	103	309	354
Dividends *(Note 5)*	(72)	(63)	(252)	(286)
Retained earnings, end of period	1,241	1,147	1,241	1,147

See accompanying notes to Consolidated Financial Statements.

HYDRO ONE INC.
CONSOLIDATED BALANCE SHEETS (unaudited)

(Canadian dollars in millions)	**September 30, 2007**	**December 31, 2006**
Assets		
Current assets		
Accounts receivable (net of allowance for doubtful accounts)	748	777
Materials and supplies	64	56
Other	12	13
	824	846
Fixed assets		
Fixed assets in service	16,358	16,238
Less: accumulated depreciation	6,121	6,180
	10,237	10,058
Construction in progress	764	468
	11,001	10,526
Long-term assets		
Deferred pension asset	382	382
Regulatory assets	238	311
Goodwill	133	133
Long-term accounts receivable and other assets	7	12
	760	838
Total assets	12,585	12,210
Liabilities		
Current liabilities		
Bank indebtedness	15	29
Accounts payable and accrued charges	674	661
Accrued interest	86	49
Regulatory liabilities *(Note 3)*	102	-
Short-term notes payable	160	60
Long-term debt payable within one year *(Note 6)*	540	395
	1,577	1,194
Long-term debt *(Note 6)*	4,764	4,848
Other long-term liabilities		
Regulatory liabilities *(Note 3)*	468	473
Employee future benefits other than pension *(Note 7)*	848	803
Environmental liabilities	48	55
Long-term accounts payable and other liabilities	14	16
	1,378	1,347
Total liabilities	7,719	7,389
Shareholder's equity		
Preferred shares (authorized: unlimited; issued: 12,920,000)	323	323
Common shares (authorized: unlimited; issued: 100,000)	3,314	3,314
Retained earnings	1,241	1,184
Accumulated other comprehensive income *(Note 2)*	(12)	-
Total shareholder's equity	4,866	4,821
Total liabilities and shareholder's equity	12,585	12,210

See accompanying notes to Consolidated Financial Statements.

HYDRO ONE INC.
CONSOLIDATED STATEMENTS OF CASH FLOWS **(unaudited)**

(Canadian dollars in millions)	**Three months ended September 30**		**Nine months ended September 30**	
	2007	**2006**	**2007**	**2006**
Operating activities				
Net income	67	103	309	354
Adjustments for non-cash items:				
Depreciation and amortization (net of removal costs)	119	120	350	347
Revenue difference deferral account *(Note 3)*	76		76	
Retail settlement variance accounts	8	(5)	24	1
Disposition of deferral accounts *(Note 3)*	(28)	-	(28)	-
Transmission earnings sharing	-	6	-	24
Amortization of discount	-	5	6	23
Low-voltage services	-	-	-	(8)
	242	229	737	741
Changes in non-cash balances related to operations	89	122	131	(26)
Net cash from operating activities	331	351	868	715
Financing activities				
Long-term debt issued	-	150	400	700
Long-term debt retired	(73)	-	(355)	(448)
Short-term notes payable	85	(130)	100	-
Dividends paid	(72)	(63)	(252)	(286)
Other	-	-	(1)	(4)
Net cash used in financing activities	(60)	(43)	(108)	(38)
Investing activities				
Fixed assets	(275)	(218)	(765)	(593)
Other assets	4	4	19	13
Net cash used in investing activities	(271)	(214)	(746)	(580)
Net change in cash and cash equivalents	-	94	14	97
Cash and cash equivalents, beginning of period	(15)	(6)	(29)	(9)
Cash and cash equivalents, end of period	(15)	88	(15)	88

See accompanying notes to Consolidated Financial Statements.

1. BASIS OF PRESENTATION

These interim Consolidated Financial Statements do not conform in all respects to the disclosure requirements of Canadian generally accepted accounting principles for annual financial statements and should, therefore, be read in conjunction with the annual Consolidated Financial Statements of Hydro One Inc. (Hydro One or the Company) for the year ending December 31, 2006 which includes information necessary or useful to understanding the Company's business and financial statement presentation. In particular, the Company's significant accounting policies and practices are presented as Note 2 to the annual Consolidated Financial Statements, and have been consistently applied in the preparation of these interim Consolidated Financial Statements, except as described below in Note 2.

The demand for electricity generally follows normal weather-related variations, and therefore the Company's energy-related revenues, all other things being equal, will tend to be higher in the first and third quarters than in the second and fourth quarters.

2. ACCOUNTING CHANGES

Change in Accounting Policy – Financial Instruments, Hedges and Comprehensive Income

Effective January 1, 2007, the Company adopted four new accounting standards comprising the Canadian Institute of Chartered Accountants' (CICA) Handbook Sections 1530, *Comprehensive Income*; 3855, *Financial Instruments – Recognition and Measurement*; 3861, *Financial Instruments – Disclosure and Presentation;* and 3865, *Hedges*. The adoption of these new standards required changes in the accounting for financial instruments and hedges, and the recognition of certain transition adjustments that are recorded in opening accumulated other comprehensive income (AOCI) as described below, consistent with the CICA Handbook sections. The comparative interim Consolidated Financial Statements have not been restated. The principal changes in the accounting for financial instruments and hedges due to the adoption of these accounting standards are described below.

(a) Comprehensive Income

Comprehensive income is composed of the Company's net income and other comprehensive income (OCI). OCI includes the amortization of unamortized hedging losses on cash flow hedges that had been discontinued prior to the transition date. The impact of this amortization is immaterial to the Statement of Operations.

(b) Financial Assets and Liabilities

Under the new standards, all financial instruments are classified into one of the following five categories: held-to-maturity investments, loans and receivables, held-for-trading, other liabilities or available-for-sale. All financial instruments, including derivatives, are carried at fair value on the consolidated balance sheet except for loans and receivables, held-to-maturity investments and other financial liabilities, which are measured at amortized cost. Held-for-trading financial instruments are measured at fair value and all gains and losses are included in financing charges in the period which they arise. Available-for-sale financial instruments are measured at fair value with revaluation gains and losses included in OCI until the instrument is derecognized or impaired. The Company has classified its financial instruments as follows:

Short-term investments	Held-to-maturity
Long-term accounts receivable	Loans and receivables
Bank indebtedness	Other liabilities
Short-term notes payable	Other liabilities
Long-term debt (excluding MTN Series 8 Note)	Other liabilities
MTN Series 8 Note	Designated as held-for-trading

The MTN Series 8 Note is a step-up coupon note with extendable maturity dates up to 2011.

Where there is an economic hedge, as in the case of the MTN Series 8 note and associated interest rate swap, we have applied the fair value option without hedge accounting. The impact is not material.

All financial instrument transactions are recorded at trade date.

(c) Derivatives and Hedge Accounting

Derivatives

All derivative instruments, including embedded derivatives, are carried at fair value on the balance sheet unless exempted from derivative treatment as a normal purchase and sale. All changes in fair value are recorded in financing charges unless cash flow hedge accounting is used, in which case changes in fair value are recorded in OCI to the extent that the hedge is effective. The impact of the change in the accounting policy related to embedded derivatives was not material.

Hedge Accounting

The Company periodically develops hedging strategies for execution taking into account risk management objectives. At the inception of a hedging relationship, the Company documents the relationship between the hedging instrument and the hedged item. This would include linking all derivatives to specific assets and liabilities on the consolidated balance sheet or to specific firm commitments or forecasted transactions. The Company would also assess, both at the inception of the hedge and on an ongoing basis, whether the derivatives that are used are effective in offsetting changes in fair values or cash flows of hedged items.

Upon adoption of the new standards, the Company reclassified unamortized hedging losses on cash flow hedges that had been discontinued prior to the transition date to accumulated other comprehensive income. The hedging losses are amortized through OCI using the effective interest method over the term of the hedged debt.

(d) Transaction Costs

Transaction costs for financial assets and liabilities that are other than held-for-trading, are added to the carrying value of the asset or liability and then amortized over the expected life of the instrument using the effective interest method. The impact of the change in amortization method from an annuity basis to the effective interest method was not material.

Change in Accounting Estimate – Depreciation

Effective January 1, 2007, the Company prospectively revised its fixed asset depreciation rates resulting from a periodic external review required by the Ontario Energy Board (OEB). Capital costs of fixed assets are depreciated on a straight-line basis, except for transport and work equipment, which is depreciated on a declining balance basis. The estimated impact of the change in rates is a reduction in depreciation expense of approximately $7 million per annum. A summary of the new rates for the various classes of assets is included below:

	Depreciation rates (%)	
	Range	Average
Transmission	1% - 4%	2%
Distribution	1% - 13%	2%
Communication	1% - 13%	5%
Administration and service	1% - 20%	8%

3. TRANSMISSION RATE DECISION

On August 16, 2007, the OEB issued its decision on the Transmission rate application made by the Company's subsidiary, Hydro One Networks Inc. The OEB decision is effective January 1, 2007 with resultant rates being implemented on November 1, 2007. On the basis of written and oral evidence submitted, the OEB approved substantially all of the Company's proposed capital and non-capital work programs, as well as a targeted rate of return on deemed common equity of 8.35% for the Company's Transmission business for the rate years 2007 and 2008. Previously, the approved rate of return was 9.88% on deemed common equity and was set in 1999. With this reduction in the rate of return, the OEB decision will result in a reduction in revenue over the remainder of 2007 and in 2008. In addition, the Company's transmission revenues reflect the impacts of the OEB's August 16, 2007 transmission rate decision, which had the effect of reducing its quarterly and year-to-date revenues by about $38 million. This reduction includes the revenue adjustment associated with recording a new regulatory liability, termed the Revenue Difference Deferral Account (RDDA), as well as other decision-related revenue adjustments related to the disposition of regulatory asset and liability accounts and the recording of export and wheeling fees revenue.

The OEB decision also resulted in an increase in the aggregate carrying value of the Company's regulatory assets and liabilities of approximately $46 million, representing an increase in regulatory liabilities of $60 million and an increase in regulatory assets of $14 million. The RDDA liability was approved in concept in the OEB's March 30, 2007 decision that terminated the Transmission Earnings Sharing Mechanism (ESM) effective December 31, 2006. In its August decision, the OEB approved final amounts and disposition treatments for the RDDA liability, the ESM liability, the export and wheeling fees liability, and a new Transmission market ready regulatory asset. The RDDA and ESM will be returned to customers over the two-year period ending December 31, 2008, while the export and wheeling fees liability and Transmission market ready regulatory asset will be factored into rates over the four-year period ending December 31, 2010. In the absence of rate regulated accounting, year-to-date operation, maintenance and administration expense would have been higher by approximately $16 million and revenue would have been lower by approximately $3 million.

4. SMART METER COST RECOVERY

On August 8, 2007, the OEB issued a decision on its combined proceeding to determine recoverability of expenditures incurred by distributors. Expenditures associated with the minimum functionality for advanced metering infrastructure incurred by the Company's subsidiaries Hydro One Networks Inc. and Hydro One Brampton Networks Inc. were approved for recovery. As a result of this decision, smart meter expenditures are no longer deferred as regulatory assets. Such expenditures are now classified as capital or are charged to results of operations consistent with the Company's standard accounting practices. Expenditures determined to be above the minimum functionality will be brought forward for review in a subsequent cost of service rate application.

The OEB decision also required that related revenues be based upon a calculated revenue requirement specific to smart meters. As a result, the carrying value of the smart meter regulatory asset account represents the difference between revenue recorded on this basis and actual recoveries received under existing rate adders. In the absence of rate regulated accounting, year-to-date operation, maintenance and administration expense would have been lower by approximately $4 million.

5. DIVIDENDS

During the three months ended September 30, 2007, preferred dividends in the amount of $4 million (2006 - $4 million) and common dividends in the amount of $68 million (2006 - $59 million) were declared. During the nine months ended September 30, 2007, preferred dividends in the amount of $13 million (2006 - $13 million) and common dividends in the amount of $239 million (2006 - $273 million) were declared.

6. LONG-TERM DEBT

On March 13, 2007, Hydro One issued notes under the Company's medium term note program. The issue was comprised of medium term notes with a principal amount of $400 million having a 30-year term with a coupon rate of 4.89%. The notes are due March 13, 2037.

In the second quarter, Hydro One extended the maturity date of its $40 million extendible step-up note from May 15, 2007 to November 15, 2007. On October 17, 2007, the maturity date of the note was extended again to May 15, 2008 with a new coupon rate of 4.70% per annum.

The Company has a $750 million, revolving standby credit facility with a syndicate of banks. The term of this facility has been extended as of August 10, 2007 to August 10, 2010.

In the third quarter, the Company entered into two forward starting pay fixed interest rate swap agreements to hedge against the effect of future interest rate movements on long-term fixed rate borrowing requirements. The transactions, with notional amounts of $150 million and $50 million respectively, are used to fix the interest rate of a forecasted debt issuance planned for later in 2007 and are being accounted for as cash flow hedges of a forecasted transaction.

7. EMPLOYEE FUTURE BENEFITS

Total benefit costs are as follows:

(Canadian dollars in millions)	Three months ended September 30 2007	2006	Nine months ended September 30 2007	2006
Pension				
Net periodic benefit cost	26	38	76	116
Pension fund contribution	25	22	76	66
Less: Portion attributable to labour and capitalized as part of the cost of fixed assets	10	8	30	25
Portion attributable to regulatory assets	-	-	-	11
Charged to results of operations	15	14	46	30
Employee Future Benefits Other than Pension				
Net periodic benefit cost	27	30	80	91
Less: Portion attributable to labour and capitalized as part of the cost of fixed assets	10	10	31	29
Charged to results of operations	17	20	49	62

8. SEGMENTED REPORTING

Hydro One has three reportable segments:

- The transmission business, which comprises the core business of providing transportation and connection services, is responsible for transmitting electricity throughout the Ontario electricity grid;
- The distribution business, which comprises the core business of delivering and selling electricity to customers; and
- An "other" segment primarily consisting of telecommunications business.

The designation of segments has been based on a combination of regulatory status and the nature of the products and services provided. Segment information on the above basis is as follows:

Three months ended September 30 (Canadian dollars in millions)	Transmission	Distribution	Other	Consolidated
2007				
Segment profit				
Revenues	307	813	8	1,128
Purchased power	-	533	-	533
Operation, maintenance and administration	117	137	9	263
Depreciation and amortization	56	71	1	128
Income (loss) before financing charges and provision for payments in lieu of corporate income taxes	134	72	(2)	204
Financing charges				76
Income before provision for payments in lieu of corporate income taxes				128
Capital expenditures	144	126	5	275

Three months ended September 30 (Canadian dollars in millions)	**Transmission**	**Distribution**	**Other**	**Consolidated**
2006				
Segment profit				
Revenues	331	828	6	1,165
Purchased power	-	564	-	564
Operation, maintenance and administration	105	122	6	233
Depreciation and amortization	64	67	1	132
Income (loss) before financing charges and provision for payments in lieu of corporate income taxes	162	75	(1)	236
Financing charges				74
Income before provision for payments in lieu of corporate income taxes				162
Capital expenditures	93	123	2	218

Nine months ended September 30 (Canadian dollars in millions)	**Transmission**	**Distribution**	**Other**	**Consolidated**
2007				
Segment profit				
			2	
Revenues	949	2,555	2	3,526
Purchased power	-	1,696	-	1,696
Operation, maintenance and administration	323	410	23	756
Depreciation and amortization	176	202	4	382
Income (loss) before financing charges and provision for payments in lieu of corporate income taxes	450	247	(5)	692
Financing charges				223
Income before provision for payments in lieu of corporate income taxes				469
Capital expenditures	394	355	16	765
2006				
Segment profit				
Revenues	945	2,441	17	3,403
Purchased power	-	1,667	-	1,667
Operation, maintenance and administration	307	328	17	652
Depreciation and amortization	184	189	4	377
Income (loss) before financing charges and provision for payments in lieu of corporate income taxes	454	257	(4)	707
Financing charges				220
Income before provision for payments in lieu of corporate income taxes				487
Capital expenditures	290	298	5	593

(Canadian dollars in millions)	**September 30, 2007**	**December 31, 2006**
Total assets		
Transmission	7,180	6,950
Distribution	5,304	5,161
Other	101	99
	12,585	12,210

All revenues, costs and assets, as the case may be, are earned, incurred or held in Canada.

9. COMMITMENTS

Purchasers of electricity in Ontario, through the Independent Electricity System Operator (IESO), are required to provide security to mitigate the risk of their default based on their expected activity in the market. The IESO could draw on these guarantees should the Company's subsidiaries, Hydro One Networks Inc. or Hydro One Brampton Networks Inc., fail to make a payment required by a default notice issued by the IESO.

On June 28, 2007, the IESO approved revisions to the prudential support obligations under the market rules. Previously, prudential support was provided to the IESO using a combination of bank letters of credit and parental guarantees. Under the new rules, effective August 1, 2007 the Company can meet its prudential support requirements using only parental guarantees, as long as it maintains a long-term credit rating in the "Aa" category. Consequently, the Company has reduced its bank letters of credit by $10 million, having met the credit rating criteria.

10. SUBSEQUENT EVENTS

On October 12, 2007, the OEB announced a decrease in electricity prices for Regulated Price Plan customers. Beginning November 1, 2007, the electricity price has been reduced from 5.3 cents to 5.0 cents per kilowatt hour for customers consuming up to certain thresholds, depending on the type of customer, and from 6.2 cents to 5.9 cents for kilowatt hours exceeding the thresholds.

On October 18, 2007, Hydro One issued notes under the Company's medium term note program. The issue was comprised of medium term notes with a principal amount of $300 million having a 10-year term with a coupon rate of 5.18%. The notes are due on October 18, 2017. In relation to this debt issuance, the Company terminated on October 18, 2007 the two forward starting pay fixed interest rate swaps entered into on August 2, 2007 and September 10, 2007. The transactions had been accounted for as cash flow hedges of a forecasted debt issue for the purpose of fixing the interest rate for the debt issuance. The net gain realized on terminating the swaps was $0.4 million.

11. COMPARATIVE FIGURES

The comparative unaudited interim Consolidated Financial Statements have been reclassified from statements previously presented to conform to the presentation of the September 30, 2007 unaudited interim Consolidated Financial Statements.

HYDRO ONE INC.
ANNUAL CONSOLIDATED FINANCIAL STATEMENTS

We prepare our financial statements in Canadian dollars and in accordance with accounting principles generally accepted in Canada. The following discussion is based upon our Consolidated Financial Statements for the years ended December 31, 2007 and 2006.

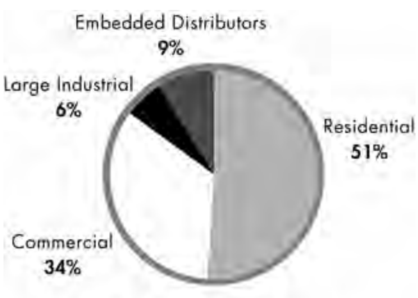
OVERVIEW

We are wholly owned by the Province of Ontario (the Province), and our transmission and distribution businesses are regulated by the Ontario Energy Board (OEB). We are the leading electricity transmitter and distributor in Ontario, delivering power safely and reliably to homes and businesses. As stewards of this province's massive and complex transmission and delivery system, our mission is to be an efficient and dynamic transmission and distribution company that is best in North America in the areas of safety, customer service and reliability, while focusing on the development and retention of our employees and creating shareholder value. In 2007, we continued our focus on our core businesses, substantially maintained and improved our performance in various key areas of the business, and made important contributions to the rebuilding of Ontario's core infrastructure.

Transmission

Substantially all of Ontario's electricity transmission system is owned and operated by our company. Our transmission system forms an integrated transmission grid that is monitored, controlled and managed centrally from one location, our Ontario Grid Control Centre in Barrie, Ontario. It operates over relatively long distances and links major sources of generation to transmission stations and larger area load centers. In 2007, we earned total transmission revenues of $1,242 million primarily by transmitting approximately 152 TWhs of electricity, directly or indirectly, to substantially all consumers of electricity in Ontario. Our transmission system is one of the largest in North America, and is linked to five adjoining jurisdictions through 26 interconnections. Through these interconnections, we can accommodate imports of about 4,000 MWs and exports of approximately 5,800 MWs of electricity. In terms of assets, our transmission business is our largest business segment, representing approximately 57% of our total assets.

Total Assets
December 31, 2007
(Cdn $ millions)



2007 Distribution Revenues

Distribution

Our distribution system is the largest in Ontario and spans roughly 75% of the province, serving approximately 1.3 million rural and urban customers, and 50 large industrial customers. We also operate small, regulated generation and distribution systems in a number of remote communities across Northern Ontario that are not connected to Ontario's electricity grid. As illustrated in the accompanying chart, about half of our distribution revenues are earned from our residential customers.

Other

Our other business segment contributed revenues of $31 million in 2007 and has assets of about $106 million, which constitute less than 1% of our total assets. This segment primarily represents the operations of our wholly owned subsidiary, Hydro One Telecom Inc., which markets fibre-optic capacity to telecommunications carriers and commercial customers with broadband network requirements.

Our Strategy

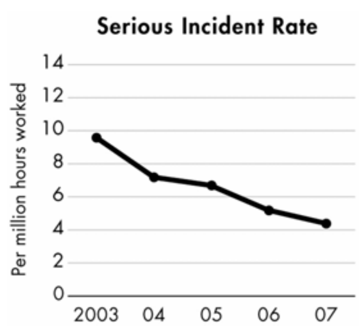
In 2007, aligned with retaining and building public confidence and trust, we maintained our strategic focus on our core operations and built upon our accomplishments. Consequently, we have moved closer to achieving our goals to be recognized by our customers as their best service provider, by our peers as their benchmark for excellence, and by our shareholder as delivering superior value, while striving to attract, develop and retain productive employees.

We seek to achieve these goals by continuing to implement the following strategies:

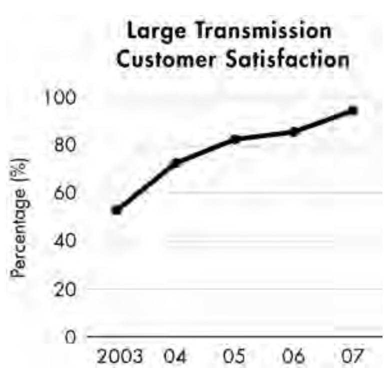
- *Stewardship:* Retain and build the public trust placed in us to ensure the safe, reliable and efficient delivery of electricity.
- *Safety:* Create and maintain an injury-free workplace with a concentrated focus on eliminating serious injury and "near misses" in high potential harm categories of work.
- *Customers:* Become a leading customer-focused company. We intend to maintain our focus and commitment to improving our customers' level of satisfaction. We strive to strengthen relationships with our large and mid-sized customers, acknowledging their commercial requirements. For residential customers, our key focus is on improving the quality of customer services such as billing, call handling, outage management, and meter reading. We also aim to make positive contributions in communities across Ontario through our corporate citizenship programs.
- *Reliability:* Enhance the reliability of our transmission and distribution systems through our productive and cost effective work programs. In transmission, we are proactively developing the system to meet Ontario's power needs. Within distribution, we are focused on reliability while recognizing the challenges in operating a system with low customer density and vast geography.
- *Financial:* Ensure our actions contribute towards maximizing the value of our company, while maintaining effective access to funds on a long-term basis at reasonable rates and delivering appropriate financial returns to our shareholder.
- *Employees*: Manage the challenges of labour demographics by attracting, developing and retaining productive employees.

Performance Measures and Targets

We measure and target our performance in all of the above strategic areas, ensuring that we are recognizing the needs of all of our key stakeholders. We met or exceeded our challenging 2007 objectives, improving in a number of areas over 2006, and are moving towards achieving our strategic goals.



The potentially hazardous nature of our business requires a strong focus on safety. Consequently, one of our goals is to eliminate serious injuries. Accordingly, we measure our Serious Incident Rate to identify possible situations that may increase the risk of injury. These incidents include electrical contacts, preventable motor vehicle accidents and work equipment operations, among others. As shown in the accompanying chart, we had 4.4 serious incidents per million hours worked in 2007, which is 15% lower than 2006, 34% lower than 2005, and 39% lower than 2004. Going forward, we will continue to stress the importance of safety through a sustained cultural change and a continued focus on people and the work environment. This involves an emphasis on strong leadership, understanding and leveraging human factors and the role of human traits in determining safe work performance. Planned initiatives include increased facility and site assessments and further use of decision analysis tools to reduce human error and its consequences.



Customer satisfaction is also vital to our success. In 2007, we exceeded our overall target for customer satisfaction levels. As shown in the accompanying chart, our Large Transmission Customer Satisfaction Survey results improved from 86% to 95% satisfied, as compared to 2006. Moreover, we have seen continuous improvement over the last five years. We also continue to be conscious of the needs of our residential and small business customers and survey results show an overall satisfaction level of 82%, which remains consistent with 2006 results. We achieved our overall target for generator customer satisfaction. Within this category, we met our satisfaction target for transmission connected generators, but did not achieve our target for distribution connected generators. Addressing the concerns identified will be an area of focus in 2008. We will continue to focus on improving the level of customer satisfaction across all customer segments by targeting our responses to the unique requirements of each segment.

We aim to retain and build public confidence and trust in our operations, as stewards of the province's electricity grid. In 2007, we continued our focus on this strategic priority by investing in the key assets of the electricity delivery system and by operating the existing system for our customers in a safe, reliable and efficient fashion. We are conscious that businesses of all sizes require reliable service and consequently, we focus on achieving top-quartile reliability in relation to other comparable systems. In 2007, we met our annual reliability targets and achieved improvements over 2006. Our continued commitment to the people of Ontario has been recognized by Corporate Knights, an independent media company focused on promoting and reinforcing sustainable development in Canada, as one of Canada's Top 50 Corporate Citizens, ranking third among utilities. The ranking was based on environment, social and governance indicators, and our conservation and demand management and smart meter programs were cited as key factors in the recognition. In addition, Corporate Knights recognized us as Canada's most diverse utility and ranked us fifth overall in corporate Canada.

Given the retirement profile of our employees, we are entering into a period of significant demographic change. This change is taking place across the electricity sector and we have taken a leadership role to address the transition. As part of a comprehensive strategy to meet our staffing needs well into the future, we entered into a partnership with four community colleges of applied art and technology to attract and educate the future employees of the electricity transmission and distribution sectors. Through this partnership, we will contribute towards scholarships, program development and equipment for programs that will train people for technical, technological and trades positions in the electricity sector.

Our financial performance and the business environment in which we operate are taken into consideration in both our short-term and long-term credit ratings. In March 2007, Standard & Poor's Rating Services Inc. (S&P) assigned a positive outlook to our long-term "A" credit rating from stable, attributing the improvement to lower business risk for the sector as a whole. In November, S&P issued a commentary report which reaffirmed our assigned positive outlook while noting a steady improvement in our business risk profile. Our current credit ratings facilitate ongoing access to debt markets at a reasonable cost to fund the infrastructure requirements of our system.

REGULATION

Our electricity transmission and distribution businesses are licensed and regulated by the OEB. The OEB sets rates following oral or written public hearings. Our transmission revenues primarily include our transmission tariff, which is based on the uniform province-wide transmission rates approved by the OEB for all transmitters across Ontario. Our distribution revenues primarily include our distribution tariff, which is also based on OEB-approved rates, and the recovery of the cost of purchased power used by our customers. Consequently, our distribution business does not have commodity price risk. Transmission and distribution tariff rates are set based on an approved revenue requirement that provides for cost recovery and includes a return on deemed common equity. In addition, the OEB approves rate riders to allow for the recovery or disposition of specific regulatory assets and liabilities over a specified timeframe.

Under the current market structure, low-volume and designated consumers pay electricity rates established through the Regulated Price Plan (RPP) and wholesale electricity consumers pay a blend of regulated, contract and wholesale spot market prices. The OEB sets prices for RPP customers based on a two-tiered electricity pricing structure with seasonal consumption thresholds. Unexpected shortfalls or overpayments associated with the RPP are financed by the Ontario Power Authority (OPA). Prices are reviewed every six months and may change based on an updated OEB forecast and any accumulated differences between the amount that customers paid for electricity and the amount paid to generators in the previous period. Customers who are not eligible for the RPP, or wholesale customers, pay the market price for electricity adjusted for the difference between market prices and prices paid to generators under the *Electricity Restructuring Act, 2004*. The Independent Electricity System Operator (IESO) is responsible for overseeing and operating the wholesale market, as well as ensuring the reliability of the integrated power system.

In addition to the oversight role of the OEB, and the market monitoring and coordination role of the IESO, the OPA was created through the *Electricity Restructuring Act, 2004* to ensure the long-term supply of electricity, facilitate load management and conservation, and assist with the stability of rates for RPP customers, among others. As part of its mandate, and consistent with the Province's direction regarding supply mix, the OPA developed the Integrated Power System Plan (IPSP), which was submitted for OEB review and approval on August 29, 2007. The plan's estimated 20-year capital program will be directed toward initiatives required to deliver electricity to Ontario consumers. OEB approval is expected in the Fall of 2008.

The OPA is also responsible for coordinating the delivery and funding of conservation and demand management (CDM) programs. This coordination furthers initiatives undertaken by individual local distribution companies (LDCs), including our distribution businesses, as a result of distribution tariff rate increases approved in 2005. Our CDM programs funded through the OPA in 2007 amounted to approximately $6 million and our programs funded through distribution rates since 2005 amounted to approximately $41 million. The overall goal of the CDM programs, under the IPSP, is to reduce provincial demand by 6,300 MW by 2025.

The *Energy Conservation Responsibility Act, 2006* furthers the broad objectives of CDM by providing the framework for the installation of 800,000 smart meters in Ontario homes and businesses by the end of 2007, with installation in all homes and businesses to be completed by the end of 2010. These meters will be capable of measuring and reporting usage over predetermined periods, being read remotely, and when combined with communications systems will be capable of providing customers with access to information about their consumption. In 2007, the Province appointed the IESO as the smart meter entity that will oversee the collection and management of data. LDCs, including our distribution businesses, are accountable for the development of smart meter infrastructure and related technology for communications to meet minimum requirements as defined in regulations, as well as the implementation of time of use rates that are presently voluntary. In 2007, we deployed over 260,000 smart meters, exceeding our 2007 target of approximately 240,000 meters, and bringing the cumulative number of installations under our Smart Meter Program to approximately 288,000. We are continuing the deployment of smart meters (see Future Capital Expenditures).

Transmission Rates

The IESO facilitates payments to us based on the Ontario Uniform Transmission Rates (UTRs) approved by the OEB for all transmitters across Ontario.

In October 2005, the OEB initiated a proceeding to review our transmission rates and revenue requirements for 2006, 2007, and 2008 based on cost of service regulation. On February 21, 2006, the OEB announced its decision to apply an earnings sharing mechanism (ESM) to equally share, between our shareholder and customers, any transmission earnings in excess of the approved rate of return of 9.88% for the period January 1, 2006 until new transmission rates were set. Consequently, 50% of our excess earnings recovered from customers were deferred as a regulatory liability.

In September 2006, we filed a transmission rate application through our subsidiary, Hydro One Networks Inc. (Hydro One Networks). On March 30, 2007, prior to their decision on our transmission rate application, the OEB issued a decision ordering that the ESM cease effective December 31, 2006. The decision also approved the concept of establishing a new revenue difference deferral account (RDDA) to record the revenue differential between existing transmission rates and the new rates that were anticipated to be approved later in the year, for the period commencing January 1, 2007.

On August 16, 2007, the OEB issued its decision in respect of our 2007 and 2008 transmission rate application. The decision, which was effective January 1, 2007, showed confidence in our work programs by approving all of our operating and capital expenditures for 2007 and 2008. However, the decision resulted in an estimated 8% annual reduction in transmission rates primarily due to a reduction in the approved return on equity from 9.88% to 8.35%, based on a formula used by the OEB in the regulation of LDCs. Further, the OEB approved final amounts and disposition treatments for certain regulatory accounts including the: RDDA, ESM and export and wheeling fees liabilities, as well as the transmission market ready regulatory asset. The RDDA and ESM will be refunded to customers over the fourteen-month period from November 1, 2007 to December 31, 2008, while the export and wheeling fees liability and transmission market ready regulatory asset will be factored into rates over the four-year period ending December 31, 2010.

As part of a joint proceeding involving all transmitters in Ontario, on October 17, 2007 the OEB approved new UTRs for implementation on November 1, 2007 through to December 31, 2008. The new rates fully reflect the approved changes to our revenue requirement and charge determinants and are, on average, 12% lower than previously approved rates. The new rates should result in approximately a 1% decrease in the average customer's total electricity bill. We anticipate the OEB will reset UTRs on January 1, 2009, at which time we anticipate our revenue requirement allocation from UTRs will increase to reflect the full repayment to customers of the ESM and RDDA. To achieve the necessary funding in support of the infrastructure required, we plan to submit a transmission rate application for 2009 to 2010 transmission rates in the Summer of 2008.

Distribution Rates

As a distributor, we are responsible for delivering electricity and billing our customers for approved distribution rates, purchased power costs, and other approved regulatory charges.

Distribution Tariffs

In August 2005, we filed a distribution rate application seeking approval for an increase in the 2006 revenue requirements for our distribution businesses operated through Hydro One Networks and Hydro One Brampton Networks Inc. (Hydro One Brampton). On April 12, 2006, the OEB announced its decisions regarding these applications and, on the basis of the written and oral evidence submitted, it approved the requested increases in the revenue requirements based on an approved rate of return of 9.00%, effective May 1, 2006.

In 2006, the OEB commenced the process of establishing an Incentive Regulation Mechanism (IRM) for the years 2007 to 2010. The process includes a formulaic approach to establishing 2007 rates with a rate rebasing approach to be staggered across all Ontario distributors between 2008 and 2010. Our subsidiaries, Hydro One Networks and Hydro One Brampton, applied for marginal distribution rate adjustments in February 2007, based on an OEB-approved formula that considers inflation, efficiency targets and significant events outside the control of management. In April 2007, the OEB approved our submissions on the basis of its cost of capital and second generation IRM policies, and the revised rates were implemented effective May 1, 2007.

As our subsidiary Hydro One Networks was among 25 LDCs selected for rebasing in 2008, we submitted the revenue requirement portion of our 2008 cost of service application in accordance with the OEB's multi-year distribution rate-setting plan on August 15, 2007. This application seeks the approval of a revenue requirement of $1,067 million based on a rate of return of 8.64% for 2008. The requested distribution rate increase amounts to a net average increase of less than 1% on the average customer's total bill. On December 18, 2007, we filed the details of our cost allocation and rate design proposals, which include a plan to reduce the number of customer rate classes and consolidate or harmonize the rates for its existing rate classes to the new proposed rate classes. Based on the OEB's processing guidelines, a decision is anticipated in the latter part of 2008.

On August 2, 2007, the OEB initiated a consultation on the development of the principles and methodology for the third generation IRM. This consultative process will culminate with the issuance of an OEB report expected in mid-2008 that will be used to adjust rates starting in 2009, for those LDCs, including our subsidiary Hydro One Networks, whose 2008 rates will be rebased. On November 1, 2007, Hydro One Brampton filed its application for 2008 rates on the basis of the OEB's cost of capital and second generation IRM policies. The distribution rates of our subsidiary, Hydro One Brampton, will be rebased in 2010.

Smart Meter Program

In March 2006, the OEB approved a monthly rate of 27 cents and 28 cents per metered customer, effective May 1, 2006, as initial funding for the required investment in smart meters for our subsidiaries Hydro One Networks and Hydro One Brampton, respectively. As a result, expenditures in excess of recoveries were recorded as a regulatory asset, with disposition to be established at a later date. In April 2007, as part of the OEB decision regarding the 2007 distribution rate applications made by Hydro One Networks and Hydro One Brampton, the OEB approved an amount of 93 cents and 67 cents, respectively, per month per metered customer for smart meters, for implementation effective May 1, 2007.

On August 8, 2007, the OEB issued a decision on its combined proceeding to determine recoverability of expenditures incurred by distributors. Expenditures associated with the approved minimum functionality for advanced metering infrastructure incurred by our subsidiaries Hydro One Networks and Hydro One Brampton were approved for recovery. As a result of this decision, smart meter expenditures are no longer deferred as regulatory assets, and instead, are now classified as capital or are charged to results of operations. Expenditures determined to be above the minimum functionality for our subsidiary Hydro One Networks have been brought forward for review in our 2008 cost of service rate application. Hydro One Brampton will bring these expenditures forward in its 2010 cost of service application.

RESULTS OF OPERATIONS

Revenues

Year ended December 31 (Canadian dollars in millions)	**2007**	**2006**	**$ Change**	**% Change**
Transmission	1,242	1,245	(3)	-
Distribution	3,382	3,273	109	3
Other	31	27	4	15
	4,655	4,545	110	2
Average annual Ontario 60-minute peak demand *(MW)* [1]	22,988	22,650	338	1
Distribution – units distributed to customers *(TWh)*[1]	30.2	29.0	1.2	4

[1] System related statistics include preliminary figures for December.

Transmission

Transmission revenues predominantly consist of our transmission tariff, which is based on the monthly peak demand for electricity across our high-voltage network. The tariff is designed to recover revenues necessary to support a transmission system with sufficient capacity to accommodate the maximum expected demand, which is primarily influenced by weather and economic conditions. Transmission revenues also include minor amounts of ancillary revenues which are primarily attributable to maintenance services provided to generators and secondary use of our land rights-of-way.

Revenues for the year were affected by the OEB’s August 16, 2007 decision on our transmission rate application. While the OEB approved all of our work program expenditure requirements, our return on equity was reduced from 9.88% to 8.35% and our deemed capital structure was adjusted from one that included common and preferred shares and debt to a deemed capital structure of 60% debt and 40% common shares. This capital structure is consistent with that approved by the OEB in 2006 which established the capital structure for Ontario’s LDCs. The OEB’s decision was effective January 1, 2007 and new customer rates reflecting the decision were implemented on November 1, 2007. As a result of the OEB decision, we reduced our 2007 transmission revenues to reflect the approved revenue requirement. Excess amounts collected from customers have been recorded in the RDDA and are being returned to customers through lower rates commencing November 1, 2007. On March 30, 2007, the OEB approved cessation of the ESM effective December 31, 2006 and replaced it with the RDDA. The RDDA and ESM liabilities will be drawn down over the period the new rates are in place and will be reflected in revenue over the fourteen month period from November 1, 2007 to December 31, 2008.

Our transmission revenues were lower by $3 million, compared to 2006. The OEB’s August 16, 2007 transmission rate decision reduced our revenues by about $53 million. This includes the revenue adjustment associated with recording the RDDA liability and the impact of the new OEB-approved rates effective November 1, 2007. Partially offsetting this decrease was the effect of the OEB’s earlier decision to end the ESM effective December 31, 2006, which increased our transmission revenues by about $33 million.

Revenues for the year also reflect higher average peak demands compared to last year, resulting in increased transmission revenues of $23 million and lower other revenues of $6 million.

Distribution

Distribution revenues include our distribution tariff, which is based on OEB-approved rates, as well as amounts to recover the cost of purchased power used by our customers. Accordingly, distribution revenues are primarily influenced by our distribution rates, the amount of electricity we distribute, and the cost of purchased power. Distribution revenues also include a minor amount of ancillary distribution services revenues, such as fees related to the use of our poles by the telecommunications and cable television industries, and miscellaneous charges such as those for late payments.

Distribution revenues increased by $109 million, or 3%, in 2007 compared to last year. This change includes the recovery of increased purchased power costs of $19 million as described below under "Purchased Power." In addition, the OEB approved increases in distribution tariff rates for our subsidiaries, Hydro One Networks and Hydro One Brampton, effective May 1, 2006 and May 1, 2007 respectively. These tariff rate increases, which support the maintenance and investment requirements of our distribution system, enabling the safe and reliable delivery of electricity to our customers through Ontario, resulted in higher distribution revenues of $45 million during the year. In 2006, rates were approved based on a full cost of service hearing. In 2007, rates were approved based on OEB guidelines that included an incentive mechanism to adjust rates. Higher energy consumption, resulting primarily from the colder winter weather this year, increased our distribution revenues by a further $26 million. In addition, as a result of the OEB's decision on August 8, 2007 regarding the combined smart meter proceeding, we recorded smart meter revenues of $17 million reflecting recovery of our investments in this program. We also experienced higher other revenues of $2 million during the year.

Purchased Power

Purchased power costs incurred by our distribution business represent the cost of electricity delivered to customers within our distribution service territory and consist of the wholesale commodity cost of energy, the IESO's wholesale market service charges, and transmission charges levied by the IESO. The commodity cost of energy for certain low-volume and designated customers is based on the OEB's RPP, which consists of a two-tiered pricing structure with seasonal threshold amounts. Customers that are not eligible for the RPP pay the market price for electricity, adjusted for the difference between market prices and the prices paid to generators under the *Electricity Restructuring Act, 2004*. A summary of the RPP affecting the two-year period 2006 and 2007 is provided below.

Summary of RPP

	Tier Threshold (kWh/month)		Tier Rates (cents/kWh)	
Effective Date	**Residential**	**Non-Residential**	**First Tier**	**Second Tier**
November 1, 2005	1,000	750	5.0	5.8
May 1, 2006	600	750	5.8	6.7
November 1, 2006	1,000	750	5.5	6.4
May 1, 2007	600	750	5.3	6.2
November 1, 2007	1,000	750	5.0	5.9

Purchased power costs increased in 2007 by $19 million, or 1%, to $2,240 million compared to last year. Our increased purchased power costs were primarily due to higher demand for electricity of $57 million, higher wholesale commodity prices of $25 million for customers who are not eligible for the RPP and higher wholesale market service charges levied by the IESO of $7 million. These increases were partially offset by lower costs of $62 million associated with the OEB's RPP for residential and other eligible customers, combined with the impacts of the OEB's August 16, 2007 transmission rate decision of $8 million.

Operation, Maintenance and Administration

Our operation, maintenance and administration costs are comprised primarily of labour, material, equipment and purchased services in support of the operation and maintenance of the transmission and distribution systems. These costs also include property taxes and payments in lieu thereof on our transmission and distribution lines, stations and buildings.

Operation, maintenance and administration costs for each of our three business segments were as follows:

Year ended December 31 (Canadian dollars in millions)	**2007**	**2006**	**$ Change**	**% Change**
Transmission	415	390	25	6
Distribution	549	460	89	19
Other	31	30	1	3
	995	880	115	13

Transmission

Operation, maintenance and administration expenditures incurred to sustain our high-voltage transmission stations, lines and rights-of-way increased by $25 million, or 6%, in 2007 compared to last year. Within our work programs, we continued our investments necessary for the safe and reliable operation of the transmission system. We experienced higher work program expenditures of $24 million primarily related to our planned station maintenance programs for power equipment and transformers and our line clearing and brush control programs, partially offset by lower requirements for unplanned corrective maintenance. We also experienced marginally higher expenditures in support of the transmission system. This increase reflects the commencement of a major business systems and processes project which will enable the adoption of more efficient, standardized business processes, the impact on our transmission regulatory accounts as a result of the OEB's August 16, 2007 transmission rate decision and the impact of a negotiated property tax settlement in 2006. The effect of these increases was partially offset by the impacts of a statutory reduction in our capital taxes and the reassignment of resources to support this year's larger transmission capital program.

Distribution

Operation, maintenance and administration expenditures necessary to maintain our low-voltage distribution system increased by $89 million, or 19%, compared to last year. Increased requirements within our work program of $65 million primarily resulted from the planned expansion of our forestry and line maintenance programs incurred to increase reliability. In addition, we experienced increased customer participation in our conservation and demand management programs. These increases were partially offset by reductions in expenditures incurred to respond to storm damage. In addition, our costs increased due to impacts of last year's OEB rate decision, including the recognition of distribution-related pension costs which had been previously deferred as a regulatory asset. Our operating, maintenance and administration expenditures also increased as a result of the OEB's August 8, 2007 decision on its combined smart meter proceeding due to the recognition of smart meter-related operating expenditures that were incurred in the 2005 to 2007 period but which were previously deferred as regulatory assets. In addition to these increases, our other support expenditures were higher by $24 million as a result of resource requirements in support of the maintenance program and the commencement of a major business systems and processes project, partially offset by the impact of a statutory reduction in our capital taxes.

Depreciation and Amortization

Depreciation and amortization expense increased by $6 million, or 1%, to $521 million this year. This increase was mainly attributable to the placement of new assets in service, consistent with our ongoing capital work program. We also experienced higher amortization of our regulatory assets resulting from an April 12, 2006 OEB distribution rate decision that was effective on May 1, 2006. These increases were partially offset by lower fixed asset removal costs resulting from lower storm damage in the year, compared to 2006.

Financing Charges

Financing charges remain unchanged at $295 million compared to last year. We experienced a lower average effective interest rate on our outstanding debt which was offset by lower capitalized interest on our regulatory assets due to lower prescribed OEB rates and increased regulatory liabilities.

Provision for Payments in Lieu of Corporate Income Taxes

We make payments in lieu of corporate income taxes to the Ontario Electricity Financial Corporation (OEFC) in accordance with the *Electricity Act, 1998* and on the same basis as if we were subject to federal and provincial corporate taxes. In providing for payments in lieu of corporate income taxes relating to our regulated businesses, the taxes payable method is used, whereas the liability method is used in computing the tax provision for our unregulated businesses.

The provision for payments in lieu of corporate income taxes increased by $26 million, or 15%, to $205 million in 2007 compared to 2006. The increase is primarily due to last year's recognition of a $30 million tax benefit related to the recovery of payments in lieu of corporate taxes from prior years, taxes payable on transmission amounts received this year but not recognized as revenue for accounting purposes, and temporary differences associated with certain regulatory accounts. These increases were partially offset this year by lower taxable income and other minor temporary differences.

Net Income

Net income of $399 million was lower by $56 million, or 12%, compared to 2006 results. Net income for the year was impacted by the OEB's August 16, 2007 transmission rate decision. While the OEB approved all of our work program requirements for 2007 and 2008, our return on equity was reduced from 9.88% to 8.35% effective January 1, 2007. Our net income also reflects higher requirements to operate and safely maintain our transmission and distribution systems, including enhanced transmission station maintenance and forestry programs. Our net income was further impacted by OEB decisions, including a 2006 decision affecting our distribution-related pension expenditures, last year's property tax settlement and a higher effective tax rate. These impacts were partially offset by an increase in our distribution revenues resulting from OEB-approved increases to our distribution tariff rates, as well as increased tariff revenue in our transmission and distribution businesses due to increased peak demands and energy consumption, as well as the elimination of last year's ESM.

Quarterly Results of Operations

The following table sets forth unaudited quarterly information for each of the eight quarters from March 31, 2006 through December 31, 2007. This information has been derived from our unaudited interim Consolidated Financial Statements which, in the opinion of our management, have been prepared on a basis consistent with the audited annual Consolidated Financial Statements and which include all adjustments, consisting only of normal recurring adjustments, necessary for fair presentation of our financial position and results of operations for those periods. These operating results are not necessarily indicative of results for any future period and should not be relied upon to predict our future performance.

(Canadian dollars in millions)	**2007**				**2006**			
Quarter ended	**Dec. 31**	**Sep. 30**	**Jun. 30**	**Mar. 31**	**Dec. 31**	**Sep. 30**	**Jun. 30**	**Mar. 31**
Total revenues[1,2]	1,129	1,128	1,120	1,278	1,142	1,165	1,078	1,160
Net income[1,2]	90	67	93	149	101	103	99	152
Net income to common shareholder[1,2]	85	63	88	145	96	99	94	148

[1] The demand for electricity generally follows normal weather-related variations, and therefore our electricity-related revenues and profit, all other things being equal, would tend to be higher in the first and third quarters than in the second and fourth quarters.

[2] As a result of the OEB's August 16, 2007 decision on Hydro One Networks' Transmission rate application that was effective January 1, 2007, revenues reflect a reduced revenue requirement based on the approved rate of return of 8.35%. Previously, the rate of return was 9.88%.

LIQUIDITY AND CAPITAL RESOURCES

Our primary sources of liquidity and capital resources are funds generated from operations, debt capital market borrowings and bank financing. These sources will be used to satisfy our capital resource requirements, which continue to include capital expenditures, servicing and repayment of our debt, payments related to our outsourcing arrangements, investing activities, and dividends.

Summary of Sources and Uses of Cash

Year ended December 31 (Canadian dollars in millions)	**2007**	**2006**
Operating activities	1,141	909
Financing activities		
Long-term debt issued	700	775
Long-term debt retired	(355)	(589)
Short-term notes payable	(60)	60
Dividends paid	(325)	(350)
Investing activities		
Capital expenditures	(1,091)	(823)
Other financing and investing activities	7	(2)
Net change in cash and cash equivalents	17	(20)

Operating Activities

Net cash from operating activities increased by $232 million, to $1,141 million, compared to 2006 results. Our working capital requirements were substantially lower than the comparative period primarily as a result of the impact of the *Ontario Price Credit* that was provided to RPP customers in early 2006, pursuant to regulation. Funding for the credit was received from the IESO in early December 2005. Our working capital requirements were also impacted by lower electricity prices charged to RPP customers in 2007, the impacts of last year's OEB distribution rate decision and increased accounts payable primarily associated with our capital expenditure program.

Financing Activities

Short-term liquidity is provided through funds from operations and our commercial paper program, under which we are authorized to issue up to $1 billion in short-term notes with a term to maturity of less than 365 days. At December 31, 2007, we had no short-term notes payable outstanding. The commercial paper program is supported by a committed revolving credit facility with a syndicate of banks. On January 28, 2008, we increased the facility from $750 million to $1,000 million. The maturity date remains unchanged at August 10, 2010. The short-term liquidity under this program and anticipated levels of funds from operations should be sufficient to fund our normal operating requirements. At December 31, 2007, we had $5,615 million in long-term debt outstanding, including the current portion. Long-term financing is provided by our access to the debt markets, primarily through our Medium-Term Note Program. On June 21, 2007, we filed a $2.5 billion base shelf prospectus to renew our Medium-Term Note Program for another 25 months. Our notes and debentures mature between 2008 and 2046. We currently plan to refinance maturing debt principally through our Medium-Term Note Program. The maximum authorized principal amount of medium-term notes issuable under this program is $2,500 million, of which $2,200 million is remaining and is currently available until July 2009.

	Rating	
Rating Agency	**Short-term Debt**	**Long-term Debt**
DBRS Limited	R-1 (middle)	A (high)
Moody's Investors Service Inc.	Prime-1	Aa3
Standard & Poor's Rating Services Inc.	A-1	A

We have the customary covenants normally associated with long-term debt. Among other things, our long-term debt covenants limit our permissible debt as a percentage of our total capitalization, limit our ability to sell assets and impose a negative pledge provision, subject to customary exceptions. The credit agreement related to our $750 million credit facility has no material adverse change clauses that could trigger default. However, the credit agreement requires that we provide notice to the lenders of any material adverse change within three business days of the occurrence. The agreement also provides limitations that debt cannot exceed 75% of total capitalization and that debt issued by our subsidiaries cannot exceed 10% of the total book value of our assets. We are in compliance with all of these covenants and limitations.

During 2007, we issued $700 million in long-term debt under our Medium-Term Note Program and we repaid $355 million in maturing long-term debt. In comparison, during 2006 we issued $775 million in debt under our medium-term note program and we repaid $589 million in maturing long-term debt. In 2007, we decreased our short-term notes by $60 million compared to an increase of $60 million in 2006.

In 2007, we paid dividends to the Province in the amount of $325 million, consisting of $307 million in common dividends and $18 million in preferred dividends. In the comparative period, we paid common dividends of $332 million and preferred dividends of $18 million. In 2007, cash dividends per common share were $3,070 compared to $3,320 per common share in 2006. Cash dividends per preferred share were $1.375 in each of 2007 and 2006.

Common dividends are declared at the sole discretion of our Board of Directors, and are recommended by management based on results of operations, financial condition, cash requirements and other relevant factors such as industry practice, shareholder expectations. Common dividends pertaining to the quarterly financial results are generally declared and paid in the immediately following quarter.

Investing Activities

Cash used for investing activities, primarily representing capital expenditures to enhance and reinforce our transmission and distribution infrastructure in the public interest, was as follows:

Year ended December 31 (Canadian dollars in millions)	**2007**	**2006**	**$ Change**	**% Change**
Transmission	560	402	158	39
Distribution	511	417	94	23
Other	20	4	16	400
	1,091	823	268	33

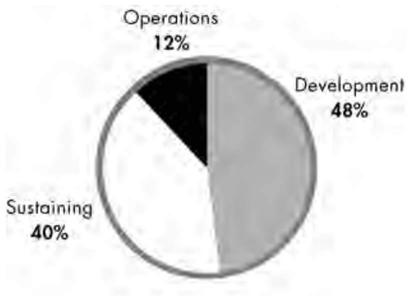
Transmission

2007 Transmission Capital Expenditures

Transmission capital expenditures increased by $158 million in 2007 to $560 million, compared to 2006. Expenditures to expand and reinforce the transmission system were $271 million, representing an increase of $92 million over last year. This increase primarily reflects expenditures on our major lines and stations development projects. These projects include our new interconnection with Québec, which will increase access to emission-free hydroelectric power, our Essa to Stayner connection, which will improve the adequacy and reliability of supply to the Southern Georgian Bay region in recognition of the growing needs of our customers, and the completion of our Downtown Toronto Cable Project. Expenditures on our load and generation connections work have also increased primarily as a result of reconfiguration work at our Lambton Transformer Station and work at our London Talbot, Pleasant, and Holland transformer stations. The impact of these project expenditures was partially offset by last year's expenditure on our Niagara Reinforcement Project. This connection was substantially completed last year but final completion continues to be delayed by the aboriginal land dispute in the Caledonia area. Discussions continue between the involved aboriginal peoples and the various government entities involved. We will complete this project when site access becomes available.

Expenditures to sustain our existing transmission system were $221 million, representing an increase of $31 million compared to 2006. This increase was primarily related to the refurbishment and replacement of end-of-life lines and stations, including work at our Claireville Transformer Station to improve current reliability and to meet growing demands, and protection and control work at our switchyard facility adjoining the Pickering Nuclear Generating Station. Our other transmission capital expenditures were $68 million in 2007, representing an increase of $35 million from last year. This increase included higher information technology expenditures primarily related to a major business systems and processes project.

Distribution



2007 Distribution
Capital Expenditures

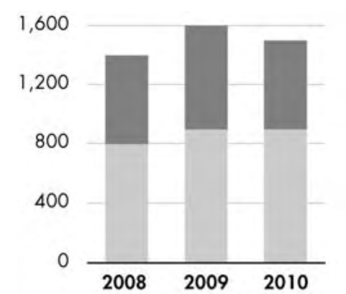
Distribution capital expenditures increased by $94 million to $511 million in 2007, compared to the prior year. Capital expenditures to expand and reinforce our distribution network were $245 million, an increase of $78 million compared to last year. This increase primarily reflects our ongoing investment in smart meters. During the year we installed approximately 260,000 meters, exceeding our 2007 target of approximately 240,000 meters, and bringing our cumulative program total to about 288,000 meters. We also experienced increased expenditures for new customer connections and for planned lines work, partially offset by slightly lower expenditures related to station meters.

Expenditures to sustain our low-voltage distribution system were $204 million, a reduction of $21 million from 2006. This reduction was primarily a result of lower storm-related expenditures. In 2007, we experienced lower capital expenditures of about $39 million to replace assets and components damaged or destroyed by major storms. Last year an unusual number of violent storms swept through the province and, in particular, a series of severe storms was experienced last summer. This impact was partially offset by higher planned end-of-life replacements of lines assets. Our other distribution capital expenditures were $62 million in 2007, representing an increase of $37 million from last year. This increase included higher information technology expenditures primarily related to a major business systems and processes project.

Other

Other capital expenditures made to enhance our telecom infrastructure increased by $16 million to $20 million in 2007. This increase was largely due to construction of a dedicated optical network which will provide secure, high capacity connectivity across numerous healthcare locations in Ontario.

Future Capital Expenditures



Future Capital Expenditures
(Cdn $ millions)

Our capital expenditures in 2008 are budgeted at approximately $1.4 billion. The 2008 capital budgets for our transmission and distribution businesses are about $800 million and $600 million, respectively. Capital expenditures, as shown in the accompanying chart, are expected to exceed $1.5 billion in both 2009 and 2010, primarily reflecting increasing investments to expand, refurbish or replace transmission infrastructure. The overall investment levels reflect transmission infrastructure requirements consistent with government policy, OPA planning information, local area supply requirements and the needs of preventive and corrective maintenance to manage aging assets. These investments will facilitate an adequate and reliable supply of electricity in the public interest. These investment levels also reflect the continued mass deployment of smart meters within our distribution businesses that began in 2007. The replacement of critical information technology systems is also underway. Capital expenditures of our other business segment are budgeted at about $11 million in 2008, about half of the 2007 level, as the implementation of a dedicated fibre optic network, initiated in 2007, will be completed in 2008.

Transmission

Transmission system capital expenditures are anticipated to be significant over the period 2008 to 2010, amounting to about $2.5 billion. Our investment plan will address the needs of new generation development and load growth in local areas in the province. The transmission program also continues the focus on sustaining the performance of aging assets through maintenance and refurbishment programs and the replacement of assets that have reached their end of life.

With the primary focus of the recently filed IPSP being on mid to long-term timeframes, the need justification for most major urgent, short-term transmission investments will continue through Leave-to-Construct (Section 92) proceedings. Referenced in the IPSP as short to mid-term investments is the project to connect redeveloped nuclear generation and wind from the Bruce Peninsula to our Milton Switching Station, other projects of local area supply, and the installation of equipment at our existing transmission stations. OEB and environmental approvals are being sought to build the 500kV line from the Bruce Peninsula, funding for which is included in the investment plan through to 2011. Given the timeframes required for stakeholdering, approvals, and construction, interim measures are being implemented to minimize the impact of generation scheduled to be available in 2009. These are comprised of the enhancement of the protection systems, the installation of Static Var Compensators and shunt capacitor banks in Southwestern Ontario, and the upgrade of certain 230kV circuits.

Other projects included in the transmission investment plan include system expansions in Northeastern Ontario to accommodate generation on the Mattagami River; transmission reinforcements in the Greater Toronto Area (GTA), Southern Georgian Bay, Woodstock and Windsor; and the interconnection between Ontario and Québec. Construction of the Toronto third supply is contingent on the OEB approval of the IPSP and the OPA’s determination of the need date. This project, for which funding is included in the plan, extends beyond the current planning horizon. This project is required to mitigate the risks associated with having only two major supply corridors to the City of Toronto and as such, to maintain a reliable supply of electricity.

At the local level, we continue to proactively address supply needs with our customers in order to meet load growth. For projects required to provide reliable delivery of electricity to communities, the participation and support of the affected LDCs as partners in joint planning studies and throughout the consultation and approval processes, continue to be essential. Examples of projects under construction to meet the growing needs of our customers include new transformer stations to serve Essex County and Simcoe County, and expansions of transformer stations serving Brampton, Kingston, York Region and Red Lake. To address local future needs, we are in discussions with customers for major transmission expansions or new transformer stations and, where necessary, line connections in locations such as Woodstock, Mississauga, Oshawa and Brampton. Targeted investments in customer delivery point performance, power quality and our 115kV and 230kV systems are expected to lead to improved reliability.

The investment plan also includes increased program expenditures to manage the replacement and refurbishment of our aging transmission infrastructure to ensure a continued reliable supply of energy to customers throughout the province. Through targeted replacement programs for components, such as gas insulated switchgear, air blast circuit breakers, and 750 MVA autotransformers, improved performance is anticipated, which should reduce system integrity risks.

The timing of many development projects is uncertain as they are dependent upon the final approval of the IPSP and, in some instances, require approvals from various regulatory bodies, as well as negotiations and consultations with customers, neighbouring utilities and other stakeholders. We will not undertake large capital expenditures without a reasonable expectation of recovering them in our rates.

Distribution

Capital expenditures for the period 2008 to 2010 are estimated to be approximately $2 billion, including the Smart Meter Program, and core development and sustainment programs. With approximately 1.3 million customers in our service territory, we anticipate installing about a further 1 million meters under the program. Consistent with the government policy, all homes and small businesses are to receive a smart meter by 2010. At the Province’s request, we will review our implementation plan and associated costs for the period from 2008 to 2010. Smart Network is an initiative that would leverage the smart meter infrastructure to enable functionality across our rural territory. This is currently being piloted and validated, and will be brought forward for consideration if benefits are confirmed.

Our core work will focus on demand programs such as new load connections, trouble calls and storm damage, and system capability reinforcement. The distribution investment plan also includes program expenditures relating to preserving the performance of our aging distribution asset base in order to improve system reliability. These include increased wood pole replacements, feeder sectionalization, and defect management, together with improved maintenance and line clearing practices. Given initiatives to encourage renewable energy technologies, we are experiencing increased distribution generation connection activity. Connection impact assessments are undertaken to determine project feasibility. Under OEB rules, the generator will pay connection costs other than distribution upgrades that also benefit other customers. No provision has been included in the plan for major distribution system modifications to accommodate this growth of new generation.

Summary of Contractual Obligations and Other Commercial Commitments

The following table presents a summary of our debt and other major contractual obligations, as well as other major commercial commitments:

December 31, 2007 (Canadian dollars in millions)	Total	2008	2009/2010	2011/2012	After 2012
Contractual Obligations *(due by year):*					
Long-term debt – principal repayments	5,615	540	800	850	3,425
Long-term debt – interest payments	5,211	307	554	488	3,862
Inergi LP (Inergi) outsourcing agreement[1]	396	100	190	106	-
Operating lease commitments	16	6	7	2	1
Total Contractual Obligations[5]	11,238	953	1,551	1,446	7,288
Other Commercial Commitments *(by year of expiry)*:					
Bank line[2]	750	-	750	-	-
Letters of credit[3]	99	99	-	-	-
Guarantees[3]	325	325	-	-	-
Pension[4]	196	94	102	-	-
Total Other Commercial Commitments	1,370	518	852	-	-

[1] On March 1, 2002, Inergi LP began providing a range of services to us for a 10-year period, including information technology, customer care, supply chain and certain human resources and finance services.

[2] As a backstop to our commercial paper program, we have a $750 million revolving standby credit facility with a syndicate of banks which matures in August 2010. On January 28, 2008 this facility was increased to $1,000 million.

[3] We currently have bank letters of credit of $95 million outstanding relating to retirement compensation arrangements. We have also provided prudential support to the IESO on behalf of our subsidiaries as required by the IESO's Market Rules, using parental guarantees of up to a maximum of $325 million. The maximum parental guarantee was increased in November 2007 to $325 million as a result of forecast power purchases and the November 1, 2007 change to our transmission rates. Although no letters of credit are currently required for prudential support, we would have to resume providing bank letters of credit if our highest long-term credit rating deteriorated to below the "Aa" category. The remaining amounts included in letters of credit pertain to operating letters of credit and to surety bonds.

[4] Contributions to the pension fund are made one-month in arrears. Contributions for 2008 are based on an actuarial valuation filed in September 2007 and effective December 31, 2006. Our annual pension contributions for 2008 and 2009 will be about $94 million. Contributions beyond 2009 will be based on an actuarial valuation effective December 31, 2009 and will depend on future investment returns, changes in benefits or actuarial assumptions. Pension contributions beyond 2009 are not estimable at this time.

[5] In addition, the Company has entered into various agreements to purchase goods or services in support of our work programs that are enforceable and legally binding. None of these are considered individually material, and the majority will result in payments by our Company by December 31, 2008.

The amounts in the above table under long-term debt – principal repayments, are not charged to our results of operations, but are reflected on our Balance Sheet and Statement of Cash Flows. Interest associated with this debt is recorded under financing charges on our Statement of Operations or in our capital programs. Payments in respect of operating leases and our outsourcing agreement with Inergi LP are recorded under operation, maintenance and administration costs on our Statement of Operations or within our capital expenditures.

RELATED PARTY TRANSACTIONS

Related party transactions primarily consist of our transmission revenues received from, and our power purchases payments made to, the IESO, which is a related party by virtue of its status as an agency of our shareholder. The year-over-year changes related to these amounts are described more fully in our discussion of our transmission revenues and purchased power costs. Other significant related party transactions include our dividends which are paid to the Province and our payments in lieu of corporate income taxes which are paid or payable to the OEFC.

RISK MANAGEMENT AND RISK FACTORS

We have an enterprise risk management program that aims at balancing business risks and returns. An enterprise-wide approach enables regulatory, strategic, operational and financial risks to be managed and aligned with our strategic business objectives.

While our philosophy is that risk management is the responsibility of all employees, the Audit and Finance Committee of our Board of Directors annually reviews our company's risk tolerances, our risk profile and the status of our internal control framework. Our President and Chief Executive Officer has ultimate accountability for risk management. Our Leadership Team, comprising direct reports to the President and Chief Executive Officer, provides senior management oversight of risk in our company. Our Chief Risk Officer is responsible for the ongoing monitoring and review of our risk profile and practices, and our Chief Financial Officer is responsible for ensuring that the risk management program is an integral part of our business strategy, planning and objective setting. Each of our subsidiaries, as well as key specialist functions and field services, is required to complete a formal risk assessment and to develop a risk mitigation strategy.

The Audit and Finance Committee, the President and Chief Executive Officer, and the Chief Financial Officer are supported by our Chief Risk Officer. This support includes coordinating risk policies and programs, establishing risk tolerances, preparing risk assessments and profiles and assisting line and functional managers in fulfilling their responsibilities. Our internal audit staff is responsible for performing independent reviews of the effectiveness of risk management policies, processes and systems.

Ownership by the Province

The Province owns all of our outstanding shares. Accordingly, the Province has the power to determine the composition of our Board of Directors and appoint the Chair, and thus influence our major business and corporate decisions. We have entered into a shareholder agreement with the Province relating to certain aspects of the governance of our company.

Conflicts of interest may arise as a result of the Province’s obligation to act in the best interests of the residents of Ontario in a broad range of matters, including the regulation of Ontario’s electricity industry and environmental matters, any future sale or other transaction by the Province with respect to its ownership interest in our company, the Province’s ownership of Ontario Power Generation Inc. (OPG), and the determination of the amount of dividend or payments in lieu of corporate income taxes. We may not be able to resolve any potential conflict with the Province on terms satisfactory to us.

Risk Associated with Transmission Projects

Significant investments have been initiated to increase transmission capacity and enable the reliable delivery of power to Ontario consumers from existing and future generation sources. In many cases, initiating these investments is contingent upon one or more approvals. These can include Section 92, expropriation and environmental approvals, as well as consultation, and possibly accommodation with First Nations where traditional lands or lands subject to land claims are involved. The ability to make such investments may also be impacted by public opposition. If we are unable to make such investments, the reliability of our transmission system and our service quality could be adversely affected.

Work Force Demographic Risk

More than 20% of our employees will be eligible for retirement by the end of 2008. We expect the skilled labour market for our industry to be highly competitive in the future. Consequently, we must continue to advance our training and apprenticeship programs and succession plans to ensure that our future operational staffing needs will be met. If we are unable to attract and retain qualified personnel, our operations could be adversely affected.

Regulatory Risk

We are subject to regulatory risks, including the approval by the OEB of rates for our transmission and distribution businesses that permit a reasonable opportunity to recover the estimated costs of providing service on a timely basis and to earn the approved rate of return.

The OEB approves our transmission and distribution rates based on projected electricity load and consumption levels. If actual load or consumption falls below projected levels, our rate of return for either or both of these businesses could be adversely affected. Also, our current revenue requirements for these businesses are based on cost assumptions that may not materialize. There is no assurance that the OEB would allow rate increases sufficient to offset unfavourable financial impacts from unanticipated changes in electricity demand or in our costs.

Our load could also be negatively impacted by successful CDM programs. Current requirements for CDM call for a 5% reduction in Ontario's projected peak electricity demand by 2010. These expectations are factored into our revenue requirements for OEB approval. There is a risk that our revenues would be reduced if these targets are exceeded. The OEB has recognized the need to compensate utilities for such lost revenue, but the approach, level and timing of such compensation is yet to be determined. We are also subject to risk of revenue loss from other factors. For example, revisions to the OEB's *Transmission System Code* have resulted in customers gaining the right to bypass some of our transformation facilities by constructing their own assets under certain conditions.

As a transmitter, we expect to make significant investment in the coming years in large-scale transmission infrastructure projects, and to connect new third-party load and generation assets. Additionally, there is always the possibility that we could incur unexpected capital expenditures to maintain or improve our assets. The risk exists that the OEB may not allow full recovery of such investments. To the extent possible, we try to mitigate this risk by seeking from the regulator clear policy direction on cost responsibility, and pre-approval of the need for capital expenditures.

The Province has passed regulations authorizing our subsidiaries, as distributors, to procure smart meters. Of the associated costs in rates, our subsidiaries Hydro One Networks and Hydro One Brampton are only currently authorized to recover 93 cents and 67 cents per metered customer per month, respectively. While we expect all of our expenditures to be fully recoverable after OEB review, any future regulatory decision to disallow or limit the recovery of such costs would lead to potential impairment and charges to results of operations.

Asset Condition

We continually monitor the condition of our assets and maintain, refurbish or replace them to maintain the performance that is needed to support transmission reliability and service quality to our customers. Capital and maintenance programs have been increasing to maintain the performance of our aging asset base. However, execution of these plans is dependent on external factors including limited opportunities to remove equipment from service to accommodate construction due to outage constraints as determined by the IESO and substantially increased lead times for material and equipment due to increased global demand and limited vendor capability. Consequently, the necessary maintenance or replacements may be delayed, which could affect transmission reliability.

Risk of Natural and Other Unexpected Occurrences

Our facilities are exposed to the effects of severe weather conditions, natural disasters and catastrophic events. Although constructed, operated and maintained to industry standards, our facilities may not withstand occurrences of this type in all circumstances. We do not have insurance for damage to our assets located outside our transmission and distribution stations. Lost revenues, repair costs, damage and claims from third parties could be substantial. In the event of a large uninsured loss, we would apply to the OEB for the recovery. However, there is no assurance that the OEB would approve such an application.

Risk from Transfer of Assets Located on Indian Lands

The transfer orders by which we acquired certain of Ontario Hydro's businesses as of April 1, 1999 did not transfer title to some assets located on lands held for bands or bodies of Indians under the *Indian Act* (Canada). Currently, the OEFC holds these assets. Under the terms of the transfer orders, we are required to manage these assets until we have obtained all consents necessary to complete the transfer of title of these assets to us. We cannot predict the aggregate amount that we may have to pay, either on an annual or one-time basis, to obtain the required consents. However, we anticipate having to pay more than the approximately $900,000 per year that we currently are paying to these Indian bands and bodies. If we cannot obtain consents from the Indian bands and bodies, the OEFC will continue to hold these assets for an indefinite period of time. If we cannot reach a satisfactory settlement, we may have to relocate these assets from the Indian lands to other locations or replace them at a cost that could be substantial. These potential costs could have a material adverse effect on our results of operations if we are unable to recover them in future rate orders.

Labour Relations Risk

The substantial majority of our employees are represented by either the Power Workers Union (PWU) or the Society of Energy Professionals. The existing collective agreements with the PWU will expire on March 31, 2008; collective bargaining commenced in January 2008. The Society of Energy Professionals collective agreement was recently renewed and now expires on March 31, 2013. We face financial risks related to our ability to negotiate collective agreements consistent with our rate orders. In the event of a labour dispute, we could face operational risk related to continued compliance with our license requirements of providing service to customers.

Environmental Risk

We are subject to extensive environmental regulation and failure to comply could subject us to fines and other penalties. In addition, the presence or release of hazardous or other substances could lead to claims by third parties and/or governmental orders requiring us to take specific actions such as investigating, controlling and remediating the effects of these substances. We are currently undertaking a voluntary land assessment and remediation program covering most of our stations and service centers. There is also risk associated with obtaining governmental approvals, permits, or renewals of existing approvals and permits related to constructing or operating facilities. This may require environmental assessment or result in the imposition of conditions, or both, which could mean delays and cost increases.

Future changes in environmental regulations may result in material changes to our estimates of future expenditures to complete this work. On November 4, 2006, Environment Canada published new draft regulations governing the management of polychlorinated biphenyls (PCBs). These draft regulations may be finalized in 2008. We have estimated the non-capital expenditures for complying with these draft regulations to be between $250 million and $375 million in excess of amounts we have already recorded as environmental liabilities on our Balance Sheet. If required, most of these additional expenditures would be incurred in the period from 2013 to 2025. No obligation has been recorded in the financial statements for these increased expenditures due to continued uncertainty regarding the timing and content of the final regulations. In any case, actual future environmental expenditures may vary materially from the estimates used in the calculation of the environmental liabilities on our Balance Sheet. We do not have insurance coverage for these environmental expenditures.

Scientists and public health experts have been studying the possibility that exposure to electric and magnetic fields emanating from power lines and other electric sources may cause health problems. If it were to be concluded that electric and magnetic fields present a health risk, we could face litigation, be required to take costly mitigation measures such as relocating some of our facilities or experience difficulties in locating and building new facilities.

Risk Associated with Information Technology Infrastructure

Our ability to operate effectively in the Ontario electricity market is in part dependent upon us developing, maintaining and managing complex information technology systems that are employed to operate our transmission and distribution facilities, financial and billing systems, and business systems to capture data and to produce timely and accurate information. We are working to transition most of our financial and business processes to an integrated business and financial reporting system which will enable productivity through the adoption of more efficient, standardized business processes. The conversion of these systems and processes may expose us to risk, including risks associated with maintaining internal controls, as new systems are brought online and the data and business processes are transitioned. System failures could have a material adverse effect on our company.

Risk Associated with Outsourcing Arrangement

Consistent with our strategy of reducing operating costs, we entered into an outsourcing services agreement in 2002 with Inergi. If this agreement is terminated for any reason, we could be required to incur significant expenses to re-establish all or some of the outsourced functions, which could have a material adverse effect on our results of operations.

Risk from Provincial Ownership of Transmission Corridors

Although we have the statutory right to use provincially-owned transmission corridors, we may be limited in our ability to expand our systems. Also, other uses of the transmission corridors by third parties in conjunction with the operation of our systems may increase safety or environmental risks.

Pension Plan Risk

We have a defined benefit registered pension plan for the majority of our employees. Contributions to the pension plan are established by actuarial valuations which are filed with the Financial Services Commission of Ontario on a tri-annual basis. The most recently filed valuation was prepared as at December 31, 2006 and was filed in September 2007. Our annual pension contributions for the three year period 2007 to 2009 are approximately $94 million per year. The next valuation is required to be prepared as at December 31, 2009. The required level of contributions effective January 1, 2010 will depend on future investment returns, changes in benefits and changes in actuarial assumptions. Pension contributions beyond 2009 are not estimable at this time. The recovery of pension costs is subject to approval by the OEB. Failure to attain OEB approval could have an adverse effect on our results of operations.

Risk Associated with Arranging Debt Financing

We expect to borrow to repay our existing indebtedness and to fund capital expenditures. A substantial portion of our existing debt matures between 2008 and 2011. We are also planning a combined total of capital expenditures of approximately $3 billion in 2008 and 2009. Cash generated from operations will not be sufficient to fund the repayment of our existing indebtedness and capital expenditures. Our ability to arrange sufficient and cost effective debt financing could be adversely affected by numerous factors, including the regulatory environment in Ontario, our results of operations and financial position, market conditions, the ratings assigned to our debt securities by credit rating agencies and general economic conditions. Any failure or inability on our part to borrow substantial amounts of debt on satisfactory terms could impair our ability to repay maturing debt, fund capital expenditures and meet other obligations and requirements and, as a result, could have a material adverse effect on our business.

Market and Credit Risk

Market risk refers primarily to risk of loss that results from changes in commodity prices, foreign exchange rates and interest rates. We do not have commodity risk and our foreign exchange risk is currently insignificant, although we could in future decide to issue foreign currency denominated debt. We are exposed to fluctuations in interest rates as our regulated rate of return is derived using a formula approach which is in part based on the forecast for long-term Government of Canada bond yields. We estimate that a 1% decrease in the forecast long-term Government of Canada bond yield used in determining our rate of return would reduce our transmission business' results of operations by approximately $20 million and our distribution business' results of operations by approximately $13 million. Our results of operations are adversely impacted by rising interest rates as our maturing long-term debt is refinanced at market rates. We periodically utilize interest rate swap agreements to mitigate elements of interest rate risk. We estimate that a 1% increase in interest rates on the refinancing of long-term debt maturing in 2008 and 2009 would reduce our results of operations by approximately $1 million and $4 million, respectively.

Financial assets create a risk that a counter-party will fail to discharge an obligation, causing a financial loss. Derivative financial instruments result in exposure to credit risk, since there is a risk of counter-party default. We monitor and minimize credit risk through various techniques, including dealing with highly rated counter-parties, limiting total exposure levels with individual counter-parties, and by entering into master agreements which enable net settlement. We do not trade in any energy derivatives. We do, however, have interest rate swap contracts outstanding from time to time. Currently, there are no significant concentrations of credit risk with respect to any class of financial assets. We are required to procure electricity on behalf of competitive retailers and embedded LDCs for resale to their customers. The resulting concentrations of credit risk are mitigated through the use of various security arrangements, including letters of credit, which are incorporated into our service agreements with these retailers in accordance with the OEB's *Retail Settlements Code*.

CRITICAL ACCOUNTING ESTIMATES

The preparation of our financial statements requires us to make estimates and judgements that affect the reported amounts of assets, liabilities, revenues and costs, and related disclosures of contingencies. We base our estimates and judgements on historical experience, current conditions and various other assumptions that are believed to be reasonable under the circumstances, the results of which form the basis for making judgements about the carrying values of assets and liabilities as well as identifying and assessing our accounting treatment with respect to commitments and contingencies. Actual results may differ from these estimates and judgements under different assumptions or conditions.

We believe the following critical accounting estimates involve the more significant estimates and judgements used in the preparation of our financial statements:

Regulatory Assets and Liabilities

Regulatory assets as at December 31, 2007 amounted to $213 million and principally relate to regulatory asset recovery accounts (RARAs), employee future benefits other than pension, and environmental costs. We have also recorded regulatory liabilities amounting to $583 million as at December 31, 2007. These amounts pertain primarily to pension, the RDDA, export and wheeling fees, the ESM, and retail settlement variance accounts. These assets and liabilities can be recognized for rate-setting and financial reporting purposes only if the OEB directs the relevant regulatory treatment or if future OEB direction is judged to be probable. Most of our regulatory accounts have already been reviewed by the OEB and confirmed as recoverable or refundable.

If management judges that it is no longer probable that the OEB will include a regulatory asset or liability in the setting of future rates, the relevant regulatory asset or liability would be charged or credited to results of operations in the period in which that judgement is made.

Environmental Liabilities

We record liabilities and related regulatory assets based on the present value of the estimated future expenditures to be made to settle obligations related to legacy environmental contamination inherited upon our de-merger from Ontario Hydro in 1999. These liabilities fall into two main categories: the management of PCB-contaminated assets and mineral oils and the assessment and remediation of contaminated lands. In determining the amounts to be recorded as environmental liabilities, we estimate the current cost of completing mitigation work and make assumptions for when the future expenditures will actually be incurred to generate future cash flow information. A long-term inflation assumption of approximately 2% has been used to express current cost estimates as estimated future expenditures. These future expenditures are discounted using factors ranging from 2.9% to 6.25%. Recording a liability for such long-term future expenditures requires that many other assumptions be made, such as the number of contaminated properties and the extent of contamination, and the number and contamination levels of assets with PCBs. All factors used in deriving our environmental liabilities represent management's best estimates. However, it is reasonably possible that numbers or volumes of contaminated assets, current cost estimates, inflation assumptions and assumed pattern of annual cash flows may differ significantly from our assumptions. Estimated environmental liabilities are reviewed annually or more frequently if significant changes in regulation or other relevant facts occur. Estimate changes are accounted for prospectively.

Employee Future Benefits

We provide future benefits to our current and retired employees, including pension, group life insurance, health care and long-term disability.

In accordance with our rate orders, we record pension costs when employer contributions are paid to the pension fund (Fund) in accordance with the *Pension Benefits Act* (Ontario). Our annual pension contributions are approximately $94 million per year over the period 2007 through to 2009. Contributions after 2009 will be based on an actuarial valuation effective December 31, 2009 and will depend on future investment returns, changes in benefits or actuarial assumptions. Pension costs are also disclosed in the notes to the financial statements on an accrual basis. We record employee future benefit costs other than pension on an accrual basis. The accrual costs are determined by independent actuaries using the projected benefit method prorated on service and based on assumptions that reflect management's best estimates. The assumptions were determined by management recognizing the recommendations of our actuaries.

The assumed return on pension plan assets of 6.75% per annum is based on expectations of long-term rates of return at the beginning of the fiscal year and reflects a pension asset mix consistent with the Fund's investment policy. During the year the Fund's target asset mix was changed to 62% exposure to equities, 33% to fixed income and 5% in alternative assets consisting of hedge funds and private equity. Returns on the respective portfolios are determined with reference to published Canadian and U.S. stock indices and long-term bond and treasury bill indices. The assumed rate of return on pension plan assets reflects our long-term expectations. We believe that this assumption is reasonable because, with the fund's balanced investment approach, the higher volatility of equity investment returns is offset by the greater stability of fixed income and short-term investment returns. The net result, on a long-term basis, is a somewhat lower return than might be expected by investing in equities alone. The return on pension plan assets was lower than this long-term assumption in 2007.

The weighted-average discount rate used to calculate the accrued benefit obligations is determined each year end by referring to the most recently available market interest rates based on AA corporate bond yields reflecting the duration of the applicable employee future benefit plan. The discount rates at December 31, 2007 increased by 0.25% from those at December 31, 2006 in conjunction with increase in bond yields over this period. The increase in discount rates has resulted in a corresponding reduction in liabilities.

The costs of employee future benefits other than pension are determined at the beginning of the year. The costs are based on assumptions for expected claims experience and future health care cost inflation. A 1% increase in the health care cost trends would result in an increase in service cost and interest cost of about $12 million per year and an increase in the year end obligation of about $167 million.

Employee future benefits are included in labour costs that are either charged to results of operations or capitalized as part of the cost of fixed assets. Changes in assumptions will affect the accrued benefit obligation of the employee future benefits and the future years' amounts that will be charged to our results of operations or capitalized as a cost of fixed assets.

Goodwill

In assessing the recoverability of goodwill, we must make assumptions regarding estimated future cash flows and other factors to determine the fair value of the distribution reporting unit. If these estimates or their related assumptions change in the future, we may be required to record impairment charges related to goodwill. An impairment review of goodwill was carried out during 2007 and we determined that the carrying value of our goodwill has not been impaired.

EMERGING ACCOUNTING PRONOUNCEMENTS

Transition to International Financial Reporting Standards (IFRS)

The Canadian Accounting Standards Board (AcSB) ratified a new strategic plan for the period of 2006-2011 that entails converging Canadian generally accepted accounting principles (GAAP) with IFRS over the five-year transitional period. The final AcSB decision to proceed on the intended schedule will be made in March 2008. It is generally expected that the decision to adopt IFRS will be confirmed unless some unexpected event occurs. The AcSB has adopted an implementation plan and suggests that companies be in a position to disclose their implementation plans for the IFRS changeover in their 2008 Management, Discussion and Analysis (MD&A). The Canadian Securities Administrators will be defining the MD&A disclosure requirements regarding an enterprise's plans for IFRS conversion. We started planning our transition to IFRS during 2006 and plan to commence convergence work beginning in 2008.

Accounting for Rate Regulated Operations

During 2007, the AcSB issued an exposure draft proposing to remove all specific references to rate regulated accounting from the Handbook of the Canadian Institute of Chartered Accountants (CICA). In August 2007, the AcSB decided to remove a temporary exemption in CICA Handbook Section 1100, retain existing references to rate regulated accounting in the CICA Handbook, require the recognition of future income tax liabilities and assets as well as a separate regulatory asset or liability for the amount of future income taxes, and retain existing requirements to disclose the effects of rate regulation.

The new rules will apply prospectively to interim and annual financial statements relating to fiscal years beginning on or after January 1, 2009 and will result in accrual accounting being followed for payments in lieu of corporate taxes. Such amounts are currently accounted for on a cash basis, consistent with specific OEB rate-setting direction. Commencing the first quarter of 2009, the regulatory impact of the OEB's direction will be reflected through the recognition of regulatory assets and/or liabilities. There will be no impact on results of operations.

Inventories

The AcSB issued new CICA Handbook Section 3031, *Inventories*, which is effective for our company in the first quarter of 2008. The recommendations apply to our materials and supplies inventories and require major spare parts to be classified as future use fixed assets rather than inventory. We anticipate a significant transfer of book value from the materials and supplies category on the Balance Sheet to fixed assets. Additionally, the new handbook section will allow the reversal of prior period write-downs when the net realizable value of impaired inventory subsequently recovers.

DISCLOSURE CONTROLS AND INTERNAL CONTROLS OVER FINANCIAL REPORTING

As a reporting issuer we are required to comply with the Ontario Securities Commission's Multilateral Instrument 52-109 (Multilateral Instrument) concerning internal control and related certifications, often referred to as Bill 198. During 2005 and 2006, we documented all of our processes, risks and controls, and completed all testing necessary to make the required annual certifications. Commencing with our Consolidated Financial Statements for the year ended December 31, 2005, we certified that our disclosure controls and procedures provide reasonable assurance that all information considered necessary for appropriate disclosure has been accumulated and communicated to management on a timely basis. Commencing with our Consolidated Financial Statements for the year ended December 31, 2006, we also made certifications regarding the design of our internal controls over financial reporting.

Our focus for 2007 has been the ongoing sustainment of our control environment, including communication, evaluation and enhancements, as required to support the certifications of our President and Chief Executive Officer, and Chief Financial Officer (Certifying Officers). We have also carried out a comprehensive plan to test the operational effectiveness of our internal controls over financial reporting.

In compliance with the requirements of the Multilateral Instrument, our Certifying Officers have reviewed and certified the Consolidated Financial Statements for the year ended December 31, 2007, together with other financial information included in our annual securities filings. Our Certifying Officers have also certified that disclosure controls and procedures have been designed to provide reasonable assurance that material information relating to our company is made known within our company and that they operated effectively during the period. Further, our Certifying Officers have also certified that internal controls over financial reporting are designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with GAAP.

SELECTED ANNUAL INFORMATION

The following table sets forth audited annual information for each of the three years ended December 31, 2005, 2006 and 2007. This information has been derived from our audited annual Consolidated Financial Statements.

Consolidated Statement of Operations

Year ended December 31 (Canadian dollars in millions, except earnings per common share)	**2007**	**2006**	**2005**
Revenues[1]	4,655	4,545	4,416
Net income[1]	399	455	483
Basic and fully diluted earnings per common share *(Canadian dollars)*	3,809	4,366	4,652

Consolidated Balance Sheet

Year ended December 31 (Canadian dollars in millions, except cash dividends per share)	**2007**	**2006**	**2005**
Total assets[2]	12,790	12,210	11,798
Total long-term debt[3]	5,603	5,243	5,032
Cash dividends per common share *(Canadian dollars)*	3,070	3,320	2,730
Cash dividends per preferred share *(Canadian dollars)*	1.375	1.375	1.375

[1] As a result of the OEB's August 16, 2007 decision on Hydro One Networks' Transmission rate application that was effective January 1, 2007, revenues reflect a reduced revenue requirement based on the approved rate of return of 8.35%. Previously, the rate of return was 9.88%.
[2] Total assets for 2006 and 2005 reflect the reclassification of deferred debt costs in 2007, applied retroactively
[3] Unamortized net losses relating to settled swap agreements were reclassified to AOCI on January 1, 2007 without prior year reclassification.

OUTLOOK

To meet our challenge of being the best transmission and distribution company in North America, we will continue to concentrate on our strategic priorities relating to respect of the public trust, safety, our customers, system reliability, financial stewardship and our employees. Significant improvements have been made toward achieving our customer satisfaction and safety targets, while we maintain our financial profile and reliability performance. Our continued commitment to the people of Ontario has been recognized by the Edison Electric Institute (EEI) and by Corporate Knights magazine. Early in the year, EEI honoured us with the "Emergency Recovery Award" for outstanding storm restoration efforts in 2006. This was the first time a non-U.S. utility has won this prestigious award. Corporate Knights magazine recognized us as one of Canada's top 50 corporate citizens based on environmental, social and governance indicators. Our CDM program and leadership in the Smart Metering initiative were cited as key factors contributing to our ranking of third among utilities. This magazine also recognized us as Canada's most diverse utility and ranked us fifth overall in corporate Canada, based on the composition of our Board, senior executives and the company's practices and policies on diversity. In addition, Hydro One was selected as the recipient of the Utility Planning Network's 2007 Metering Award in the category of Automated Meter Reading Initiative – North American Municipal or Cooperative among numerous entries from around the globe.

Consistent with our continued commitment to the public interest and the Province's energy policies, we are planning significant investments in transmission infrastructure and the continued proactive maintenance of our assets to ensure the electricity system's reliability. Our transmission investment plan supports the achievement of the Province's renewable and nuclear objectives, facilitates the development and use of renewable energy resources, promotes system efficiency, sustains equipment performance, meets customers' service quality needs, and facilitates the integration of new supply.

In its transmission rate decision issued on August 16, 2007, the OEB approved our entire operation, maintenance and administration and capital work programs applied for in 2007 and 2008, expressing confidence in our ability and expertise to make an appropriate assessment of what is needed "to maintain a robust, safe, and reliable transmission system". However, the decision was not favourable in other areas such as the approved return on equity. We plan to file a transmission rate application for 2009 and 2010 rates. These rates, if approved, should provide the funding required to maintain and meet the infrastructure requirements of the transmission system in the public interest.

Our investment plan does not include spending for large scale investments, such as the east-west transmission grid or potential long-term transmission projects identified in the IPSP. For certain long-term projects addressing generation-enabling connection lines and reliability of local area supply, the IPSP recommends that project development work (preliminary engineering, cost estimating, options assessment, and Environmental Assessment and Section 92 approvals, as required) begin upon approval of the IPSP by the OEB. As such, we would be prepared to initiate project development work for these projects to enable expedited construction once a need date is confirmed by the OPA and once we have a reasonable expectation of cost recovery through rates. For some projects such as the transmission connection for generation in the Nipigon area, the IPSP recommends that development work commence in 2008. It is anticipated that the final decision to proceed with the longer term major projects, such as new high voltage transmission lines from north to south, will be made when the next IPSP is prepared in about three years.

The 2006 distribution rate decision has provided a base funding level to build upon. The 2008 Cost of Service application supports the implementation of our Smart Meter Program, and enhances sustainment programs to improve reliability and customer service. In 2007, an OEB decision clarified the recoverability of costs associated with the minimum level of smart meter functionality, thereby reducing the uncertainty of recovery of this program. Smart meter costs in excess of minimum functionality will be reviewed as part of the 2008 Cost of Service hearing. Given the magnitude and unique nature of the Smart Meter Program, recovery of costs will be a key focus. In addition, the distribution investment plan does not provide for the implementation of a Smart Network, which would leverage the smart meter technology to enable further internal productivity initiatives through wireless broadband.

We remain committed to a prudent and measured approach to distribution rationalization. In October 2006, the Government announced a two-year exemption of the electricity transfer tax. We will consider and respond to opportunities for acquisitions or divestitures, on a voluntary and commercial basis, where they are consistent with our strategy and direction from our shareholder. The investment plan does not include any funding for any LDC acquisitions or divestitures.

Key enablers of the successful implementation of the work program are our human and material resourcing strategies. Our human resource strategy is focused on hiring through partnering with universities, colleges and our unions, as well as skills development and retention. Significant retirement projections and increasing work volumes will result in an unprecedented number of new hires in the near-term. With regard to materials, we are seeing increasing lead times and costs as market shortages emerge globally. Consequently, sourcing strategies are being developed and implemented to ensure availability of materials to support the work programs.

Through the outlook period, we anticipate no changes to our role within the industry and that our financial returns will be sufficient to maintain our credit quality. In November 2007 the Agency Review Panel issued the second phase of its report on Ontario's provincially-owned electricity agencies. The report confirmed that, overall, Ontario's electricity sector and the provincial agencies within it are functioning reasonably well. We do not anticipate any structural changes to our company.

FORWARD LOOKING STATEMENTS AND INFORMATION

Our oral and written public communications, including this MD&A, often contain forward-looking statements that are based on current expectations, estimates, forecasts and projections about our business and the industry in which we operate and include beliefs and assumptions made by the management of our company. Such statements include, but are not limited to statements about our strategy; statements related to the IPSP and projects flowing therefrom; statements about smart meters including costs, cost recovery and deployment and/or implementation plans; expectations regarding the timing, content and impact of future applications and decisions related to our transmission and distribution businesses; the anticipated results on our business processes and productivity as a result of our business systems and processes project; the anticipated impact of CDM programs; statements regarding the reliability of our distribution and transmission systems; expectations regarding load growth and new generation; expectations regarding developments in the statutory and operating framework for electricity distribution and transmission in Ontario including changes to codes, licenses, rates, rate orders, cost recovery, rates of return, rate structures and revenue requirements in both our transmission and distribution businesses and the timing of decisions from the OEB; statements regarding future capital expenditures and our investment plans; expectations regarding the results of our on-going and planned projects; expectations regarding our strategy for acquisitions or divestitures of distribution assets; expectations regarding future pension contributions; expectations regarding workforce demographics; expectations regarding environmental expenditures and other environmental matters including the need for environmental approvals and assessments; expectations regarding borrowing requirements; expectations regarding anticipated expenditures associated with transferring assets located on Indian lands; statements regarding provincial ownership of our transmission corridors; the estimated impact of changes in the forecast long-term Government of Canada bond yield (used in determining our regulated rate of return) on our results of operations; the estimated impact of changes in interest rates on our results of operations; statements about employee future benefit costs; statements about emerging accounting pronouncements; statements about the outlook period including our expectations regarding our role within the industry, our financial returns, and structural changes to our company. Words such as "expect," "anticipate," "intend," "attempt," "may," "plan," "will", "believe," "seek," "estimate," and variations of such words and similar expressions are intended to identify such forward-looking statements. These statements are not guarantees of future performance and involve assumptions and risks and uncertainties that are difficult to predict. Therefore, actual outcomes and results may differ materially from what is expressed, implied or forecasted in such forward-looking statements. We do not intend, and we disclaim any obligation to update any forward-looking statements, except as required by law.

These forward-looking statements are based on a variety of factors and assumptions including, but not limited to the following: no unforeseen changes in the legislative and operating framework for Ontario's electricity market; no unfavourable decisions from the OEB and other regulatory bodies concerning outstanding rate and other applications; no unforeseen changes in rate orders or rate structures for our distribution and transmission businesses; a stable regulatory environment; and no significant event occurring outside the ordinary course of business. These assumptions are based on information currently available to us, including information obtained from third party industry analysts. Actual results may differ materially from those predicted by such forward-looking statements. While we do not know what impact any of these differences may have, our business, results of operations, financial condition and our credit stability may be materially adversely affected. Factors that could cause actual results or outcomes to differ materially from the results expressed or implied by forward-looking statements include, among other things:

- the content of the final IPSP, as approved by the OEB;
- delays or denials of the requisite approvals and accommodations for our planned projects;
- the risks associated with being controlled by the Province including potential conflicts of interest that may arise between us, the Province and related parties;
- the risks related to our work force demographic and our potential inability to attract and retain qualified personnel;
- the risks associated with being subject to extensive regulation including risks associated with OEB action or inaction;

- regulatory decisions regarding our revenue requirements, cost recovery and rates;
- the potential impact of CDM programs on our load and our revenues;
- the potential impact of not being able to recover all of our project costs associated with the installation of smart meters;
- unanticipated changes in electricity demand or in our costs;
- the risks associated with the execution of our capital and operation, maintenance and administration programs necessary to maintain the performance of our aging asset base;
- the risk to our facilities posed by severe weather conditions, natural disasters or catastrophic events and our limited insurance coverage for losses resulting from these events;
- the risk that we may incur significant costs associated with transferring assets located on Indian lands;
- the inability to negotiate collective agreements consistent with our rate orders or in a timely fashion and the potential for labour disputes;
- the potential for substantial and currently undetermined environmental costs and liabilities;
- the risks associated with maintaining a complex information technology systems infrastructure and transitioning most of our financial and business processes to an integrated business and financial reporting system;
- the potential that we may incur significant expenses to replace some or all of the functions currently outsourced if our agreement with Inergi LP is terminated;
- the impact of the ownership by the Province of lands underlying our transmission system;
- the potential impact of not being able to recover our pension costs;
- the risk that we are not able to arrange sufficient cost effective financing to repay maturing debt and to fund capital expenditures and other obligations;
- the risks of counter-party default on our outstanding derivative contracts;
- the risks associated with changes in interest rates; and
- the risks associated with changes in the forecast long-term Government of Canada bond yield.

We caution the reader that the above list of factors is not exhaustive. Some of these and other factors are discussed in more detail under “Risk Management and Risk Factors” in this MD&A. You should review the section entitled “Risk Management and Risk Factors” in detail.

This MD&A is dated as at February 13, 2008. Additional information about our company, including our Annual Information Form, is available on SEDAR at www.sedar.com.

HYDRO ONE INC.
MANAGEMENT'S REPORT

The Consolidated Financial Statements, Management's Discussion and Analysis ("MD&A") and related financial information presented in this Annual Report have been prepared by the management of Hydro One Inc. ("Hydro One" or the "Company"). Management is responsible for the integrity, consistency and reliability of all such information presented. The Consolidated Financial Statements have been prepared in accordance with accounting principles generally accepted in Canada and applicable securities legislation. The MD&A has been prepared in accordance with National Instrument 51-102, Part 5.

The preparation of the Consolidated Financial Statements and information in the MD&A involves the use of estimates and assumptions based on management's judgement, particularly when transactions affecting the current accounting period cannot be finalized with certainty until future periods. Estimates and assumptions are based on historical experience, current conditions and various other assumptions believed to be reasonable in the circumstances, with critical analysis of the significant accounting policies followed by the Company as described in Note 2 to the Consolidated Financial Statements. The preparation of the Consolidated Financial Statements and the MD&A includes information regarding the estimated impact of future events and transactions. The MD&A also includes information regarding sources of liquidity and capital resources, operating trends, risks and uncertainties. Actual results in the future may differ materially from the present assessment of this information because future events and circumstances may not occur as expected. The Consolidated Financial Statements and MD&A have been properly prepared within reasonable limits of materiality and in light of information up to February 13, 2008.

In meeting its responsibility for the reliability of financial information, management maintains and relies on a comprehensive system of internal control and internal audit. The system of internal control includes a written corporate conduct policy; implementation of a risk management framework; effective segregation of duties and delegation of authorities; and sound and conservative accounting policies that are regularly reviewed. This structure is designed to provide reasonable assurance that assets are safeguarded and that reliable information is available on a timely basis. In addition internal and disclosure controls have been documented, evaluated, tested and identified consistent with Multilateral Instrument 52-109 (Bill 198). An internal audit function independently evaluates the effectiveness of these internal controls on an ongoing basis and reports its findings to management and the Audit and Finance Committee of the Hydro One Board of Directors.

The Consolidated Financial Statements have been examined by Ernst & Young LLP, independent external auditors appointed by the Hydro One Board of Directors. The external auditors' responsibility is to express their opinion on whether the Consolidated Financial Statements are fairly presented in accordance with accounting principles generally accepted in Canada. The Auditors' Report, which appears on page 28, outlines the scope of their examination and their opinion.

The Hydro One Board of Directors, through its Audit and Finance Committee, is responsible for ensuring that management fulfills its responsibilities for financial reporting and internal controls. The Audit and Finance Committee of Hydro One met periodically with management, the internal auditors, and the external auditors to satisfy itself that each group had properly discharged its respective responsibility and to review the Consolidated Financial Statements before recommending approval by the Board of Directors. The external auditors had direct and full access to the Audit and Finance Committee, with and without the presence of management, to discuss their audit and their findings as to the integrity of the financial reporting and the effectiveness of the system of internal controls.

The Company's President and Chief Executive Officer, and Chief Financial Officer have certified Hydro One's annual Consolidated Financial Statements and annual MD&A filed under provincial securities legislation, related disclosure controls and procedures, and the design of related internal controls over financial reporting pursuant to Multilateral Instrument 52-109.

On behalf of Hydro One Inc.'s management:

Laura Formusa
President and Chief Executive Officer

Beth Summers
Chief Financial Officer

HYDRO ONE INC.
AUDITORS' REPORT

To the Shareholder of Hydro One Inc.

We have audited the Consolidated Balance Sheets of Hydro One Inc. (the Company) as at December 31, 2007 and December 31, 2006, and the Consolidated Statements of Operations, Retained Earnings and Cash Flows of the Company for each of the years in the two-year period ended December 31, 2007. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these Consolidated Financial Statements present fairly, in all material respects, the financial position of the Company as at December 31, 2007 and December 31, 2006 and the results of its operations and its cash flows for each of the years in the two-year period ended December 31, 2007 in accordance with Canadian generally accepted accounting principles.

Ernst & Young LLP

Ernst & Young LLP
Chartered Accountants
Licensed Public Accountants
Toronto, Canada

February 13, 2008

HYDRO ONE INC.
CONSOLIDATED STATEMENTS OF OPERATIONS

Year ended December 31 (Canadian dollars in millions)	**2007**	**2006**
Revenues		
Transmission *(Notes 7 and 13)*	1,242	1,245
Distribution *(Note 13)*	3,382	3,273
Other	31	27
	4,655	4,545
Costs		
Purchased power *(Note 13)*	2,240	2,221
Operation, maintenance and administration *(Note 13)*	995	880
Depreciation and amortization *(Note 3)*	521	515
	3,756	3,616
Income before financing charges and provision for payments in lieu of corporate income taxes	899	929
Financing charges *(Note 4)*	295	295
Income before provision for payments in lieu of corporate income taxes	604	634
Provision for payments in lieu of corporate income taxes *(Notes 5 and 13)*	205	179
Net income	399	455
Other comprehensive income	3	-
Comprehensive income	402	455
Basic and fully diluted earnings per common share *(Canadian dollars) (Note 12)*	3,809	4,366

CONSOLIDATED STATEMENTS OF RETAINED EARNINGS

Year ended December 31 (Canadian dollars in millions)	**2007**	**2006**
Retained earnings, January 1	1,184	1,079
Net income	399	455
Dividends *(Note 12)*	(325)	(350)
Retained earnings, December 31	1,258	1,184

See accompanying notes to Consolidated Financial Statements.

HYDRO ONE INC.
CONSOLIDATED BALANCE SHEETS

December 31 (Canadian dollars in millions)	**2007**	**2006**
Assets		
Current assets:		
Accounts receivable (net of allowance for doubtful accounts - $21 million; 2006 - $19 million) *(Note 13)*	759	777
Regulatory assets *(Note 7)*	103	121
Materials and supplies	67	56
Other	17	13
	946	967
Fixed assets *(Note 6)*:		
Fixed assets in service	16,812	16,238
Less: accumulated depreciation	6,220	6,180
	10,592	10,058
Construction in progress	622	468
	11,214	10,526
Other long-term assets:		
Deferred pension asset *(Note 10)*	380	382
Regulatory assets *(Note 7)*	110	190
Goodwill	133	133
Other assets	7	12
	630	717
Total assets	12,790	12,210

See accompanying notes to Consolidated Financial Statements.

HYDRO ONE INC.
CONSOLIDATED BALANCE SHEETS (continued)

December 31 (Canadian dollars in millions)	**2007**	**2006**
Liabilities		
Current liabilities:		
Bank indebtedness	12	29
Accounts payable and accrued charges *(Notes 11 and 13)*	731	661
Regulatory liabilities *(Note 7)*	114	-
Accrued interest	55	49
Short-term notes payable *(Note 8)*	-	60
Long-term debt payable within one year *(Note 8)*	540	395
	1,452	1,194
Long-term debt *(Note 8)*	5,063	4,848
Other long-term liabilities:		
Employee future benefits other than pension *(Note 10)*	855	803
Regulatory liabilities *(Note 7)*	469	473
Environmental liabilities *(Note 11)*	52	55
Long-term accounts payable and accrued charges	13	16
	1,389	1,347
Total liabilities	7,904	7,389
Contingencies and commitments *(Notes 9, 15 and 16)*		
Shareholder's equity *(Note 12)*		
Preferred shares (authorized: unlimited; issued: 12,920,000)	323	323
Common shares (authorized: unlimited; issued: 100,000)	3,314	3,314
Retained earnings	1,258	1,184
Accumulated other comprehensive income	(9)	-
Total shareholder's equity	4,886	4,821
Total liabilities and shareholder's equity	12,790	12,210

See accompanying notes to Consolidated Financial Statements.

On behalf of the Board of Directors:

Rita Burak
Chair

Walter Murray
Chair, Audit and Finance Committee

HYDRO ONE INC.
CONSOLIDATED STATEMENTS OF CASH FLOWS

Year ended December 31 (Canadian dollars in millions)	**2007**	**2006**
Operating activities		
Net income	399	455
Adjustments for non-cash items:		
Depreciation and amortization (net of removal costs)	482	474
Revenue difference deferral account	73	-
Retail settlement variance accounts	46	7
Other regulatory asset and liability accounts	1	19
Transmission earnings sharing mechanism	-	33
Amortization of debt discount	5	27
	1,006	1,015
Changes in non-cash balances related to operations *(Note 14)*	135	(106)
Net cash from operating activities	1,141	909
Financing activities		
Long-term debt issued	700	775
Long-term debt retired	(355)	(589)
Short-term notes payable	(60)	60
Dividends paid	(325)	(350)
Other	(1)	(4)
Net cash used in financing activities	(41)	(108)
Investing activities		
Capital expenditures	(1,091)	(823)
Other assets	8	2
Net cash used in investing activities	(1,083)	(821)
Net change in cash and cash equivalents	17	(20)
Cash and cash equivalents, January 1	(29)	(9)
Cash and cash equivalents, December 31 *(Note 14)*	(12)	(29)

See accompanying notes to Consolidated Financial Statements.

1. DESCRIPTION OF THE BUSINESS

Hydro One Inc. (Hydro One or the Company) was incorporated on December 1, 1998, under the *Business Corporations Act* (Ontario) and is wholly owned by the Province of Ontario (the Province). The principal businesses of Hydro One are the transmission and distribution of electricity to customers within Ontario. These businesses are regulated by the Ontario Energy Board (OEB).

2. SIGNIFICANT ACCOUNTING POLICIES

Basis of Consolidation

The Consolidated Financial Statements include the accounts of the Company and its wholly-owned subsidiaries: Hydro One Networks Inc. (Hydro One Networks), Hydro One Remote Communities Inc., Hydro One Brampton Inc., Hydro One Brampton Networks Inc. (Hydro One Brampton), Hydro One Telecom Inc., Hydro One Delivery Services Company Inc. and Hydro One Network Services Inc.

Hydro One Brampton Inc. was dissolved on January 30, 2007. Hydro One Network Services Inc. was dissolved on December 14, 2006. Hydro One Delivery Services Inc. will be dissolved pursuant to the *Business Corporations Act* (Ontario).

Basis of Accounting

The Consolidated Financial Statements are prepared in accordance with accounting principles generally accepted in Canada (Canadian GAAP).

Rate-setting

The rates of the Company's electricity transmission and distribution businesses are subject to regulation by the OEB. In October 2005, the OEB initiated a proceeding to review Hydro One Network's transmission rates and to approve revenue requirements for 2006, 2007 and 2008 based on cost of service regulation. On February 21, 2006, the OEB announced a decision to apply an earnings sharing mechanism (ESM) to equally share, between Hydro One's shareholder and its customers, any transmission earnings in excess of the approved rate of return of 9.88% for the period January 1, 2006 until new transmission rates were set.

In September 2006, Hydro One Networks filed a transmission rate application. On March 30, 2007, prior to their decision on our transmission rate application, the OEB issued a decision ordering that the transmission ESM cease effective December 31, 2006. The decision also approved the concept of establishing a new revenue difference deferral account (RDDA) to record the revenue differential between existing transmission rates and the new rates that were anticipated to be approved later in the year, for the period commencing January 1, 2007.

On August 16, 2007, the OEB issued its decision in respect of Hydro One Networks' 2007 and 2008 transmission rate application. The decision, which was effective January 1, 2007, approved all operating and capital expenditures for 2007 and 2008. However, the decision resulted in a reduction in the approved return on equity from 9.88% to 8.35%. The OEB also approved final amounts and disposition treatments for certain regulatory liabilities including: the RDDA, the ESM and export and wheeling fees, as well as the transmission market ready regulatory asset.

The Company's distribution rates are also based on a revenue requirement that includes a rate of return. On April 12, 2006, the OEB announced its decision regarding the Company's rate applications in respect of the distribution businesses of Hydro One Networks and Hydro One Brampton. On the basis of the written evidence submitted, the OEB approved the requested increase in the revenue requirement based on a reduction in the approved rate of return, from a targeted 9.88% to 9.00%, effective May 1, 2006.

In 2006, the OEB commenced a process of establishing an Incentive Regulation Mechanism (IRM) for the years 2007 to 2010. The process includes a formulaic approach to establishing 2007 rates with a rate rebasing approach to be staggered across all Ontario distributors between 2008 and 2010. Hydro One Networks and Hydro One Brampton applied for marginal distribution rate adjustments in February 2007, based on an OEB-approved formula that considers inflation, efficiency targets and significant events outside the control of management. In April 2007, the OEB approved the Company's submissions on the basis of its cost of capital and second generation IRM policies, and the revised rates were implemented effective May 1, 2007.

Hydro One Networks submitted the revenue requirement portion of its 2008 cost of service application in accordance with the OEB's multi-year distribution rate-setting plan on August 15, 2007. This application seeks the approval of a revenue requirement of $1,067 million based on a return of 8.64% for 2008. On December 18, 2007, Hydro One Networks filed the details of its cost allocation and rate design proposals, which include a plan to reduce the number of rate classes for its customers and consolidate or harmonize the rates for its existing rate classes to the new proposed rate classes. Based on the OEB's processing guidelines, a decision is anticipated in the Fall of 2008. On November 1, 2007, Hydro One Brampton filed an application for 2008 rates on the basis of the OEB's cost of capital and second generation IRM policies.

The OEB has the general power to include or exclude costs, revenues, losses or gains in the rates of a specific period, resulting in a change in the timing of accounting recognition from that which would have applied in an unregulated company. Such change in timing involves the application of rate regulated accounting, giving rise to the recognition of regulatory assets and liabilities. The Company's regulatory assets represent certain amounts receivable from future customers and costs that have been deferred for accounting purposes because it is probable that they will be recovered in future rates. In addition, the Company has recorded regulatory liabilities which represent amounts for expenses incurred in different periods than would be the case had the Company been unregulated. The Company continually assesses the likelihood of recovery of each of its regulatory assets and continues to believe that it is probable that the OEB will factor its regulatory assets and liabilities into the setting of future rates. If, at some future date, the Company judges that it is no longer probable that the OEB will include a regulatory asset or liability in future rates, the appropriate carrying amount will be reflected in results of operations in the period that the assessment is made. Specific regulatory assets and liabilities are disclosed in Note 7.

Revenue Recognition and Allocation

Transmission revenues are collected through OEB-approved rates, which are based on an approved revenue requirement that includes a rate of return. Such revenue is recognized as power is transmitted and delivered to customers.

Distribution revenues attributable to the delivery of electricity are based on OEB-approved distribution rates and are recognized as electricity is delivered to customers. The Company estimates the monthly revenue for the period based on wholesale power purchases because customer meters are not generally read at the end of each month. Unbilled revenue included within accounts receivable as at December 31, 2007 amounted to $413 million (2006 - $386 million).

Distribution revenue also includes an amount relating to rate protection for rural residential and remote customers, which is received from the Independent Electricity System Operator (IESO) based on a standardized customer rate that is approved by the OEB. The current legislation provides rate protection for prescribed classes of rural residential and remote consumers by reducing the electricity rates that would otherwise apply.

Segment revenues for transmission, distribution and other also include revenue related to sales of other services and equipment. Such revenue is recognized as services are rendered or as equipment is delivered.

Corporate Income and Capital Taxes

Under the *Electricity Act, 1998*, Hydro One is required to make payments in lieu of corporate taxes to the Ontario Electricity Financial Corporation (OEFC). These payments are calculated in accordance with the rules for computing income and taxable capital and other relevant amounts contained in the *Income Tax Act* (Canada) and the *Corporations Tax Act* (Ontario) as modified by the *Electricity Act*, *1998*, and related regulations.

The Company provides for payments in lieu of corporate income taxes relating to its regulated businesses using the taxes payable method as directed by the OEB. Under the taxes payable method, no provisions are made for future income taxes as a result of temporary differences between the tax basis of assets and liabilities and their carrying amounts for accounting purposes. When unrecorded future income taxes become payable, it is expected that they will be included in the rates approved by the OEB and recovered from the customers of Hydro One at that time. The Company provides for payments in lieu of corporate income taxes relating to its unregulated businesses using the liability method.

Materials and Supplies

Materials and supplies represent spare parts and construction material held for internal construction and maintenance of fixed assets. These assets are carried at lower of average cost or net realizable value.

Fixed Assets

Fixed assets are capitalized at cost which comprises materials, labour, engineering costs, overheads, depreciation on service equipment and the OEB-approved allowance for funds used during construction applicable to capital construction activities within regulated businesses, or interest applicable to capital construction activities within unregulated businesses.

Fixed assets in service consist of transmission, distribution, communication, administration and service assets and easements. Fixed assets also include future use assets such as land and capitalized development costs associated with deferred capital projects.

Some of the Company's transmission and distribution assets, particularly those located on unowned easements and rights-of-way, may have asset retirement obligations, conditional or otherwise. The majority of the Company's easements and rights-of-way are either of perpetual duration or are automatically renewed annually. Land rights with finite terms are generally subject to extension or renewal. As the Company expects to use the majority of its installed assets for an indefinite period, no removal date can be determined and consequently a reasonable estimate of the fair value of most asset retirement obligations cannot be made at this time. If, at some future date, it becomes possible to estimate the fair value cost of disposing of assets that the Company is legally required to remove, a related asset retirement obligation will be recognized at that time.

Transmission

Transmission assets include assets used for the transmission of high-voltage electricity, such as transmission lines, support structures, foundations, insulators, connecting hardware and grounding systems, and assets used to step up the voltage of electricity from generating stations for transmission and to step down voltages for distribution, such as transformers, circuit breakers and switches.

Distribution

Distribution assets comprise assets related to the distribution of low-voltage electricity, including lines, poles, switches, transformers, protective devices and metering systems.

Communication

Communication assets include the fibre-optic and microwave radio system, optical ground wire, towers, telephone equipment and associated buildings.

Administration and Service

Administration and service assets include administrative buildings, major computer systems, personal computers, transport and work equipment, tools, vehicles and minor fixed assets.

Easements

Easements include statutory rights of use to transmission corridors and abutting lands granted under the *Reliable Energy and Consumer Protection Act, 2002*, as well as other amounts related to access rights.

Construction in Progress

Overhead costs, including corporate functions and services costs, are capitalized on a fully allocated basis, consistent with an OEB-approved methodology. Financing costs are capitalized on fixed assets under construction based on the OEB's approved allowance for funds used during construction (2007 – 5.20%; 2006 – 6.39%).

Depreciation

The capital costs of fixed assets are depreciated on a straight-line basis, except for transport and work equipment, which are depreciated on a declining balance basis.

Effective January 1, 2007, the Company prospectively revised its fixed asset depreciation rates resulting from a periodic external review required by the OEB. The estimated impact of the change in rates is a reduction in depreciation expense of approximately $7 million per annum. A summary of the new rates for the various classes of assets is included below:

	Depreciation rates (%)	
	Range	Average
Transmission	1% - 4%	2%
Distribution	1% - 13%	2%
Communication	1% - 13%	5%
Administration and service	1% - 20%	8%

Depreciation rates for easements are based on their contract life. The majority of easements are held in perpetuity and are not depreciated.

In accordance with group depreciation practices, the original cost of normal fixed asset retirements is charged to accumulated depreciation, with no gain or loss reflected in results of operations. Gains and losses on sales of fixed assets and losses on premature retirements are charged to results of operations as adjustments to depreciation expense. Depreciation expense also includes the costs incurred to remove fixed assets.

The estimated service lives of fixed assets are subject to periodic review. Any changes arising from such a review are implemented on a remaining service life basis consistent with their inclusion in rates.

Goodwill

Goodwill represents the cost of acquired local distribution companies in excess of fair value of the net identifiable assets purchased and is evaluated for impairment on an annual basis, or more frequently if circumstances require. Goodwill impairment is assessed based on a comparison of the fair value of the reporting unit to the underlying carrying value of the reporting unit's net assets, including goodwill, with any write-down of the carrying value of goodwill being charged against the results of operations.

The Company has determined that goodwill is not impaired. All of the goodwill is attributable to the distribution business segment.

Discounts and Premiums on Debt

Discounts and premiums are amortized over the period of the related debt using the effective interest method.

Financial Instruments

Effective January 1, 2007, the Company adopted four new accounting standards comprising the following sections of the Handbook of the Canadian Institute of Chartered Accountants (CICA): 1530, *Comprehensive Income*; 3855, *Financial Instruments – Recognition and Measurement*; 3861, *Financial Instruments – Disclosure and Presentation;* and 3865, *Hedges*. The adoption of these new standards required changes in the accounting for financial instruments and hedges, and the recognition of certain transition adjustments that were recorded in opening accumulated other comprehensive income (AOCI) as described below, consistent with the CICA Handbook sections. The comparative annual Consolidated Financial Statements have not been restated. The principal changes in the accounting for financial instruments and hedges due to the adoption of these accounting standards are described below.

Comprehensive Income

Comprehensive income is composed of the Company's net income and other comprehensive income (OCI). OCI includes the amortization of net unamortized hedging losses on discontinued cash flow hedges, and the change in fair value on existing cash flow hedges. The impact of the amortization of net hedging losses that were discontinued prior to the transition date was immaterial to the Statement of Operations.

Financial Assets and Liabilities

Under the new standards, all financial instruments are classified into one of the following five categories: held-to-maturity investments, loans and receivables, held-for-trading, other liabilities or available-for-sale. All financial instruments, including derivatives, are carried at fair value on the Consolidated Balance Sheet except for loans and receivables, held-to-maturity investments and other financial liabilities, which are measured at amortized cost. Held-for-trading financial instruments are measured at fair value and all gains and losses are included in financing charges in the period in which they arise. Available-for-sale financial instruments are measured at fair value with revaluation gains and losses included in OCI until the instrument is derecognized or impaired. The Company has classified its financial instruments as follows:

Short-term investments	Held-to-maturity
Long-term accounts receivable	Loans and receivables
Bank indebtedness	Other liabilities
Short-term notes payable	Other liabilities
Long-term debt (excluding MTN Series 8 Note)	Other liabilities
MTN Series 8 Note	Designated as held-for-trading

The MTN Series 8 Note is a step-up coupon note with extendable maturity dates up to 2011. (See Notes 8 and 9)

Where there is an economic hedge, as in the case of the MTN Series 8 note and associated interest rate swap, the Company has applied the fair value option without hedge accounting. The impact was not material.

All financial instrument transactions are recorded at trade date.

Derivatives and Hedge Accounting

All derivative instruments, including embedded derivatives, are carried at fair value on the Consolidated Balance Sheet unless exempted from derivative treatment as a normal purchase and sale. All changes in fair value are recorded in financing charges unless cash flow hedge accounting is used, in which case changes in fair value are recorded in OCI to the extent that the hedge is effective. The impact of the change in the accounting policy related to embedded derivatives was not material.

The Company does not engage in derivative trading or speculative activities.

The Company periodically develops hedging strategies for execution taking into account risk management objectives. At the inception of a hedging relationship, the Company documents the relationship between the hedging instrument and the hedged item. This would include linking all derivatives to specific assets and liabilities on the Consolidated Balance Sheet or to specific firm commitments or forecasted transactions. The Company would also assess, both at the inception of the hedge and on an ongoing basis, whether the derivatives that are used are effective in offsetting changes in fair values or cash flows of hedged items.

Upon adoption of the new standards, the Company reclassified unamortized hedging losses on cash flow hedges that had been discontinued prior to the transition date to AOCI. The hedging losses are amortized to financing charges using the effective interest method over the term of the hedged debt.

Transaction Costs

Transaction costs for financial assets and liabilities that are other than held-for-trading, are added to the carrying value of the asset or liability and then amortized over the expected life of the instrument using the effective interest method. The impact of the change in amortization basis from an annuity method to the effective interest method was not material.

Employee Future Benefits

Employee future benefits provided by Hydro One include pension, group life insurance, health care and long-term disability.

In accordance with the OEB’s rate orders, pension costs are recorded when employer contributions are paid to the pension fund in accordance with the *Pension Benefits Act* (Ontario). Actuarial valuations are conducted at least every three years. Pension costs are also calculated on an accrual basis. Pension costs are actuarially determined using the projected benefit method prorated on service and based on assumptions that reflect management’s best estimate of the effect of future events, including future compensation increases, on the actuarial present value of accrued pension benefits. Pension plan assets, consisting primarily of listed equity securities as well as corporate and government debt securities, are valued using fair values. Past service costs from plan amendments and all actuarial gains or losses are amortized on a straight-line basis over the expected average remaining service life of the employees covered.

Employee future benefits other than pension are recorded on an accrual basis. Costs are determined by independent actuaries using the projected benefit method prorated on service and based on assumptions that reflect management’s best estimates. Past service costs from plan amendments and actuarial gains or losses are amortized on a straight-line basis over the expected average remaining service life of the employees covered.

Employee future benefit costs are attributed to labour and charged to operations or capitalized as part of the cost of fixed assets.

Environmental Costs

Hydro One recognizes a liability for estimated future expenditures associated with the assessment and remediation of contaminated lands and for the phase-out and destruction of polychlorinated biphenyl (PCB) contaminated mineral oil from electrical equipment, based on the net present value of these estimated future expenditures. As the Company anticipates that the related expenditures will continue to be recoverable in future rates, a regulatory asset has been recognized to reflect the future recovery of these costs from customers. Hydro One reviews its estimates of future environmental expenditures on an ongoing basis.

Use of Estimates

The preparation of financial statements in conformity with Canadian GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities at the date of the financial statements, and the reported amounts of revenues and expenses for the year. Actual results could differ from estimates, including changes as a result of future decisions made by the OEB or the Province.

3. DEPRECIATION AND AMORTIZATION

Year ended December 31 (Canadian dollars in millions)	**2007**	**2006**
Depreciation of fixed assets in service	384	379
Fixed asset removal costs	39	41
Amortization of regulatory and other assets	98	95
	521	515

4. FINANCING CHARGES

Year ended December 31 (Canadian dollars in millions)	**2007**	**2006**
Interest on short-term notes payable	4	2
Interest on long-term debt payable	308	296
Amortization of debt discount	5	27
Other	7	9
Less: Interest capitalized on construction in progress	(24)	(28)
Interest accreted on regulatory accounts	-	(7)
Interest earned on investments	(5)	(4)
	295	295

5. PROVISION FOR PAYMENTS IN LIEU OF CORPORATE INCOME TAXES

The provision for payments in lieu of corporate income taxes (PILs) differs from the amount that would have been recorded using the combined Canadian Federal and Ontario statutory income tax rate. A reconciliation between the statutory and effective tax rates is provided as follows:

Year ended December 31 (Canadian dollars in millions)	**2007**	**2006**
Income before provision for PILs	604	634
Federal and Ontario statutory income tax rate	36.12%	36.12%
Provision for PILs at statutory rate	218	229
Increase (decrease) resulting from:		
Net temporary differences:		
Transmission amounts received but not recognized for accounting purposes	25	12
Retail settlement variance accounts	17	2
Pension contributions in excess of pension expense	(13)	(16)
Overheads capitalized for accounting but deducted for tax purposes	(12)	(11)
Interest capitalized for accounting purposes but deducted for tax purposes	(9)	(13)
Capital cost allowance in excess of depreciation and amortization	(9)	(3)
Employee future benefits other than pension expense in excess of cash payments	7	14
Environmental expenditures	(4)	(6)
Recovery of PILs related to prior years	-	(30)
Other	(5)	2
Net temporary differences	(3)	(49)
Net permanent differences	(10)	(1)
Provision for PILs	205	179
Effective income tax rate	33.94%	28.23%

In 2006, Hydro One recognized a tax benefit of approximately $30 million in respect of a recovery of PILs from prior years following a successful appeal allowing a deduction for certain overhead costs that had been previously capitalized.

Future income taxes relating to the regulated businesses have not been recorded in the accounts as they are expected to be recovered through future revenues. As at December 31, 2007, future income tax liabilities of $253 million (2006 - $281 million), based on substantively enacted income tax rates, have not been recorded. In the absence of rate regulated accounting, the Company's provision for PILs would have been recognized using the liability method rather than the taxes payable method. As a result, the provision for PILs would have been lower by approximately $28 million (2006 – higher by $16 million), including the impact of a change in substantively enacted tax rates.

Future income taxes relating to the non-regulated businesses have also not been recorded in the accounts as they have not met the criterion of "more likely than not" to be realized. As at December 31, 2007, future income tax assets of $4 million (2006 - $4 million), based on substantively enacted income tax rates, have not been recorded.

6. FIXED ASSETS

December 31 (Canadian dollars in millions)	Fixed Assets in Service	Accumulated Depreciation	Construction in Progress	Total
2007				
Transmission	8,708	3,152	370	5,926
Distribution	5,902	2,133	115	3,884
Communication	739	305	58	492
Administration and service	978	556	79	501
Easements	485	74	-	411
	16,812	6,220	622	11,214
2006				
Transmission	8,293	3,024	359	5,628
Distribution	5,651	2,129	86	3,608
Communication	822	383	18	457
Administration and service	989	583	5	411
Easements	483	61	-	422
	16,238	6,180	468	10,526

Financing costs are capitalized on fixed assets under construction, including allowance for funds used during construction on regulated assets and interest on unregulated assets, and were $24 million in 2007 (2006 - $28 million).

7. REGULATORY ASSETS AND LIABILITIES

Regulatory assets and liabilities arise as a result of the rate-making process. Hydro One has recorded the following regulatory assets and liabilities:

December 31 (Canadian dollars in millions)	**2007**	**2006**
Regulatory assets:		
Regulatory asset recovery account II	66	87
Environmental	65	70
Employee future benefits other than pension	42	84
Regulatory asset recovery account I	19	58
Market ready	13	-
Smart meters	4	10
Other	4	2
Total regulatory assets	213	311
Less: current portion	103	121
	110	190
Regulatory liabilities:		
Deferred pension	380	382
Revenue difference deferral account	73	-
Retail settlement variance accounts	50	2
Export and wheeling fees	38	49
Transmission earnings sharing mechanism	28	34
Other	14	6
Total regulatory liabilities	583	473
Less: current portion	114	-
	469	473

Regulatory assets

Regulatory asset recovery account II (RARA II)

On April 12, 2006, the OEB announced its decision regarding the Company's rate application in respect of the distribution business of Hydro One Networks. As part of this decision, the OEB also approved the distribution-related deferral account balances sought by Hydro One. The OEB ordered that the approved balances be recovered on a straight-line basis over a four year period from May 1, 2006 to April 30, 2010. The RARA II includes retail settlement and cost variance amounts and distribution low-voltage service amounts, plus accrued interest. In the absence of rate regulated accounting, amortization expense in 2007 would have been lower by $23 million (2006 - $16 million). In addition, related financing charges would have been higher by $3 million (2006 - $5 million).

Environmental

Hydro One records a liability for the estimated future expenditures required to remediate past environmental contamination. Because such expenditures are expected to be recoverable in future rates, the Company has recognized an equivalent amount as a regulatory asset. This regulatory asset is expected to be amortized to results of operations on a basis consistent with the pattern of actual expenditures expected to be incurred up to the year 2030. The OEB has the discretion to examine and assess the prudence and the timing of recovery of all of Hydro One's future regulatory expenditures. In the absence of rate regulated accounting, amortization expense in 2007 would have been lower by $12 million (2006 - $17 million).

Employee future benefits other than pension

Employee future benefits other than pension are recorded using the accrual method as required by Canadian GAAP. The OEB has allowed for the recovery of past service costs, which arose on the adoption of the accrual method, in the revenue requirement on a straight-line basis over a 10-year period. As a result, in 1999 Hydro One recorded a regulatory asset, with an original balance of $419 million, to reflect this regulatory treatment. This regulatory asset has a remaining recovery period of 1 year (2006 - 2 years) and does not earn a return. In the absence of rate regulated accounting, amortization expense in 2007 would have been lower by $42 million (2006 - $42 million).

Regulatory asset recovery account I (RARA I)

On December 9, 2004, the OEB issued a decision on the prudence of the distribution related deferral account balances for which recovery was sought by Hydro One in its May 31, 2004 application. Amounts for which recovery was approved represented balances incurred prior to December 31, 2003, plus associated interest. The OEB ordered that the approved amounts be aggregated into a single regulatory account to be recovered on a straight-line basis over the period ending April 30, 2008. Hydro One Networks has requested an extension of the period for the RARA I recovery until such time as new rates are implemented. The RARA I includes distribution business low-voltage services amounts, deferred environmental expenditures incurred in 2001 and 2002, deferred market ready expenditures, retail settlement variance amounts, and other amounts primarily consisting of accrued interest. Any over or under recovery of the RARA I due to continuance of the rate rider will be tracked for disposition at a future date. In the absence of rate regulated accounting, amortization expense in 2007 would have been lower by $20 million (2006 - $20 million). In addition, related financing charges would have been higher by $1 million (2006 - $3 million).

Market ready

In September 2006, as part of its transmission rate application, Hydro One Networks applied for the recovery of various regulatory deferral accounts including the transmission market ready costs incurred in connection with market opening. The transmission related transition-costs were incurred to meet IESO requirement associated with registration and authorization activities. On August 16, 2007, as a result of the oral and written evidence the OEB approved the recovery of substantially all of these costs. Consequently, the market ready regulatory asset was established and recovery is being factored into rates over the four-year period ending December 31, 2010. In the absence of rate regulated accounting, operation, maintenance and administration expense would have been higher by $16 million (2006 - $nil) and revenue would have been higher by $4 million (2006 - $nil).

Smart meters

On March 21, 2006, the OEB approved the establishment of regulatory deferral accounts for smart meter-related expenditures and a monthly customer charge of 27 cents and 28 cents per metered customer for Hydro One Networks and Hydro One Brampton, respectively, was reflected in Hydro One's revenue requirement. Consistent with the OEB's direction and pending further guidance, the Company recognized a regulatory asset consisting of the net balance of capital and operating expenditures for smart meters less recoveries received from customers. In April 2007, as part of its decision regarding the Company's 2007 distribution rate applications, the OEB increased the monthly customer charge effective May 1, 2007 to 93 cents and 67 cents per metered customer for Hydro One Networks and Hydro One Brampton, respectively.

On August 8, 2007, the OEB issued a decision on its combined proceeding to determine recoverability of expenditures incurred by distributors. Expenditures associated with the minimum functionality for advanced metering infrastructure incurred by Hydro One Networks and Hydro One Brampton were approved for recovery. As a result of this decision, smart meter expenditures are no longer deferred as regulatory assets. Such expenditures are now classified as capital or are charged to results of operations consistent with the Company's standard accounting practices. Expenditures determined to be above the minimum functionality have been brought forward for review in Hydro One Networks cost of service rate application filed in 2007.

The OEB decision also required that related revenues be based upon a calculated revenue requirement specific to smart meters. As a result, the carrying value of the smart meter regulatory asset account represents the difference between revenue recorded on this basis and actual recoveries received under existing rate adders. In the absence of rate regulated accounting, year-to-date operation, maintenance and administration expense would have been lower by $3 million (2006 – higher by $4 million) and revenues would have been lower by $2 million (2006 – higher by $2 million).

Regulatory liabilities

Deferred pension

In accordance with the OEB's 1999 transitional rate order, pension costs are recorded in results of operations when employer contributions are paid into the pension plan. The Company's deferred pension asset represents the cumulative difference between employer contributions and pension costs and the deferred pension regulatory liability results from the Company's recognition, as the result of OEB direction, of revenues and expenses in different periods than would be the case for an unregulated enterprise. In the absence of rate regulated accounting, operating, maintenance and administration expense would have been higher by $1 million (2006 - $50 million).

Revenue difference deferral account (RDDA)

On March 30, 2007, the OEB issued a decision approving the establishment of the RDDA to record the revenue differential between existing transmission rates and the new rates that were anticipated to be approved later in the year. The new deferral account was to represent the revenue differential between existing and future rates for the period commencing January 1, 2007. On August 16, 2007, in its decision on Hydro One Networks' 2007 and 2008 transmission rates, the OEB approved final amounts and disposition treatments for the RDDA liability, which will be returned to customers over the fourteen-month period ending December 31, 2008.

Retail settlement variance accounts (RSVA)

Hydro One has deferred certain retail settlement variance amounts under the provisions of Article 490 of the OEB's *Accounting Procedures Handbook*. The OEB's December 9, 2004 decision allowed for recovery of retail settlement variance amounts accumulated prior to December 31, 2003, inclusive of interest, within the RARA I. The OEB's April 12, 2006 decision allowed for recovery of retail settlement variance amounts accumulated since January 1, 2004 and forecasted through to April 30, 2006, inclusive of interest, within the RARA II. The Company has accumulated a net liability in its RSVA since May 1, 2006 which was taken into consideration in the revenue requirement of Hydro One Networks as part of the 2008 distribution rate application filed with the OEB in December 2007.

Export and wheeling fees

Consistent with the IESO's Market Rules, an export and wheeling fee is collected by the IESO and remitted to Hydro One at the rate of $1 per MWh on electricity exported outside of Ontario. The amounts collected in respect of these export and wheeling fees, plus interest, were taken into consideration in the revenue requirement of Hydro One's transmission business as part of the Company's transmission rate application filed with the OEB in September 2006. On August 16, 2007, the OEB issued its decision in respect of the Company's transmission rate application and approved final amounts and disposition treatments for the export wheeling fees. The export wheeling fees will be factored into rates over a four-year period ending December 31, 2010.

Transmission earnings sharing mechanism (ESM)

On February 21, 2006, the OEB issued a decision that established an ESM to equally share, between the Company's shareholder and ratepayers, any transmission earnings in excess of the approved rate of return of 9.88%, for the period January 1, 2006 until new transmission rates were set. Consequently, 50% of the Company's excess earnings were deferred as a regulatory liability. On March 30, 2007, the OEB issued a decision ordering that the transmission ESM cease effective December 31, 2006. The ESM was taken into consideration in setting the revenue requirement of Hydro One Networks for 2007 and 2008. On August 16, 2007, in its decision on Hydro One Networks 2007 and 2008 transmission rates, the OEB approved final amounts and disposition treatments for the ESM which will be returned to customers over a fourteen-month period ending December 31, 2008.

8. DEBT

December 31 (Canadian dollars in millions)	**2007**	**2006**
Short-term notes payable	-	60
Long-term debt:		
4.45% notes due 2007	-	282
4.55% notes due 2007	-	73
4.70% (2006 – 4.10%) notes due 2008[1]	40	40
4.00% notes due 2008	500	500
3.95% notes due 2009	400	400
7.15% debentures due 2010	400	400
6.40% notes due 2011	250	250
5.77% notes due 2012	600	600
4.64% notes due 2016	450	450
5.18% notes due 2017	300	-
7.35% debentures due 2030	400	400
6.93% notes due 2032	500	500
6.35% notes due 2034	385	385
5.36% notes due 2036	600	600
4.89% notes due 2037	400	-
6.59% notes due 2043	315	315
5.00% notes due 2046	75	75
	5,615	5,270
Less: Long-term debt payable within one year	(540)	(395)
Net unamortized premiums	13	9
Unamortized hedging losses[2]	-	(12)
Unamortized debt issuance costs	(25)	(24)
Long-term debt	5,063	4,848

[1] Step-up coupon from 4.10% to 6.40%, extendable to 2011.

[2] Unamortized net losses relating to settled swap agreements were reclassified to AOCI on January 1, 2007 without prior year reclassification.

Short-term debt represents promissory notes issued pursuant to the Company's Commercial Paper Program. The notes are denominated in Canadian dollars with varying maturities not exceeding 365 days. In 2007, the notes had a weighted-average interest rate of 5.7%.

Hydro One has a $750 million committed and unused revolving standby credit facility with a syndicate of banks maturing in August 2010. If used, interest on the facility would apply based on Canadian benchmark rates. This credit facility supports the Company's Commercial Paper Program.

The Company issues notes for long-term financing under the Medium-Term Note Program. The maximum authorized principal amount of medium-term notes issuable under this program is $2,500 million of which $2,200 million is remaining and is currently available until July 2009.

The long-term debt is subject to covenants that, among other things, limit permissible debt as a percentage of total capitalization, limit ability to sell assets and impose a negative pledge provision, subject to customary exceptions. At December 31, 2007, the Company was in compliance with these covenants.

The long-term debt is unsecured and denominated in Canadian dollars. Such debt is summarized by the number of years to maturity in the following table:

Years to Maturity	Principal Outstanding on Notes and Debentures *(Canadian dollars in millions)*	Weighted Average Interest Rate *(Percent)*
1 year	540	4.1
2 years	400	4.0
3 years	400	7.2
4 years	250	6.4
5 years	600	5.8
	2,190	5.3
6 – 10 years	750	4.9
Over 10 years	2,675	6.2
	5,615	5.7

9. FAIR VALUE OF FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

The carrying amounts of all financial instruments, except long-term debt, approximate fair value. The fair value of derivative financial instruments reflects the estimated amount that the Company, if required to settle an outstanding contract, would have been required to pay or would be entitled to receive at year end. The fair value of long-term debt, based on year end quoted market prices for the same or similar debt of the same remaining maturities, is provided in the following table:

December 31 (Canadian dollars in millions)	**2007**		**2006**	
	Carrying Value	Fair Value	Carrying Value	Fair Value
Long-term debt[1]	5,615	6,005	5,270	5,831

[1] The carrying value of long-term debt represents the par value of the notes and debentures, other than the step-up note, which is marked to market.

Hydro One may enter into derivative agreements, such as forward starting pay fixed interest rate swap agreements, to hedge against the effect of future interest rate movements on long-term fixed rate borrowing requirements. These transactions are accounted for as cash flow hedges of anticipated transactions. In October 2007, upon issuance of debt under the Company's medium term note program, Hydro One terminated two forward interest rate swap agreements having a total notional principal amount of $200 million, resulting in a net gain of $0.4 million. The net gain was recorded as other comprehensive income and is being amortized to financing charges over the term of the related debt. In late 2007, Hydro One entered into two new forward starting pay fixed interest rate swap agreements with a notional amount of $140 million.

As at December 31, 2007, the Company had a pay floating interest rate swap agreement related to a step-up coupon note issuance with an initial maturity date in 2007, and with extended maturity dates up to 2011. In 2006, the interest rate swap was accounted for as a fair value hedge. In 2007, the interest rate swap was accounted for using the fair value option without hedge accounting. This agreement has a notional principal amount of $40 million and a fair value of $nil (2006 - $nil).

The Company has no significant counter-party credit risk exposure as the fair value of the interest rate swap contracts was not significant in 2007 or in 2006.

Financial assets create a risk that a counter-party will fail to discharge an obligation, causing a financial loss. As at December 31, 2007, there were no significant concentrations of credit risk with respect to any class of financial assets. The Company's revenue is earned from a broad base of customers. As a result, Hydro One did not earn a significant amount of revenue from any single customer. As at December 31, 2007, there were no significant balances of accounts receivable due from any single customer.

The Company will continue to use derivative instruments to manage interest rate risk. Derivative financial instruments result in exposure to credit risk, since there is a risk of counter-party default. Hydro One monitors and minimizes credit risk through various techniques including dealing with highly rated counter-parties, limiting total exposure levels with individual counter-parties and entering into master agreements which enable net settlement.

10. EMPLOYEE FUTURE BENEFITS

Hydro One has a contributory defined benefit pension plan covering all regular employees of Hydro One and its subsidiaries, except Hydro One Brampton. Employees of Hydro One Brampton participate in the Ontario Municipal Employees Retirement System (OMERS), a multi-employer public sector pension fund. Current contributions by Hydro One Brampton are approximately $1 million annually.

Plan Asset Mix

Hydro One's pension plan asset mix at December 31, 2007 and 2006 was as follows:

	% of Plan Assets	
December 31	**2007**	**2006**
Equity securities	62.5	64.6
Debt securities	34.1	32.0
Other	3.4	3.4
	100.0	100.0

Supplementary Information

The Hydro One pension plan does not hold any direct securities of the Company, but did hold debt securities of the Province of $90 million and $92 million at December 31, 2007 and 2006 respectively.

The Company's pension plan provides benefits based on highest three-year average pensionable earnings. For new management employees who commenced employment on or after January 1, 2004, and for new Society of Energy Professionals hired after November 17, 2005, benefits are based on highest five-year average pensionable earnings. After retirement, pensions are indexed to inflation. The measurement date used to determine plan assets and the accrued benefit obligation is December 31. Based on the actuarial valuation filed with the Financial Services Commission of Ontario on September 20, 2007, effective for December 31, 2006, the Company contributed $95 million to its pension plan in respect of 2007 (2006 - $86 million), all of which is required to satisfy minimum funding requirements. Contributions are payable one month in arrears. All of the contributions are expected to be in the form of cash. Contributions after 2009 will be based on an actuarial valuation effective December 31, 2009 and will depend on future investment returns, and changes in benefits or actuarial assumptions.

Total cash payments for employee future benefits made in 2007, consisting of cash contributed by the Company to its funded pension plan and cash payments directly to beneficiaries for its unfunded other benefit plans was $137 million in 2007 (2006 - $122 million).

Year ended December 31 (Canadian dollars in millions)	Pension **2007**	Pension **2006**	Employee Future Benefits other than Pension **2007**	Employee Future Benefits other than Pension **2006**
Change in accrued benefit obligation				
Accrued benefit obligation, January 1	5,411	5,355	1,100	1,143
Current service cost	105	106	23	33
Interest cost	282	267	57	58
Benefits paid	(264)	(253)	(42)	(36)
Plan amendments	-	6	-	22
Net actuarial gain	(457)	(70)	(44)	(120)
Accrued benefit obligation, December 31	5,077	5,411	1,094	1,100
Change in plan assets				
Fair value of plan assets, January 1	5,123	4,713	-	-
Actual return on plan assets	142	571	-	-
Benefits paid	(264)	(253)	-	-
Employer's contributions[1]	95	86	-	-
Employees' contributions	17	17	-	-
Administrative expenses	(13)	(11)	-	-
Fair value of plan assets, December 31	5,100	5,123	-	-
Funded status				
Funded excess (Unfunded benefit obligation)	23	(288)	(1,094)	(1,100)
Unamortized net actuarial losses	336	645	178	236
Unamortized past service costs	21	25	21	25
Deferred pension asset (accrued benefit liability)	380	382	(895)	(839)
Less: current portion	-	-	40	36
Deferred pension asset (long-term liability)	380	382	(855)	(803)

[1] In January, 2008, the Company made a contribution of $8 million in respect of 2007 (2007 - $8 million in respect of 2006).

Year ended December 31 (Canadian dollars in millions)	Pension **2007**	**2006**	Employee Future Benefits other than Pension **2007**	**2006**
Components of net periodic benefit cost				
Current service cost, net of employee contributions	88	89	23	33
Interest cost	282	267	57	58
Actual return on plan asset net of expenses	(129)	(560)	-	-
Actuarial gain	(457)	(70)	(44)	(120)
Plan amendments	-	6	-	22
Other	-	(1)	-	(1)
Costs arising in the period	(216)	(269)	36	(8)
Differences between costs arising in the period and costs recognized in the period in respect of:				
Return on plan assets	(212)	248	-	-
Actuarial loss (gain)	522	177	59	149
Plan amendments	3	(3)	4	(19)
Net periodic benefit cost[2]	97	153	99	122
Charged to results of operations[2]	58	42	60	75
Effect of 1% increase in health care cost trends on:				
Accrued benefit obligation, December 31	-	-	167	156
Service cost and interest cost	-	-	12	13
Effect of 1% decrease in health care cost trends on:				
Accrued benefit obligation, December 31	-	-	(132)	(124)
Service cost and interest cost	-	-	(9)	(10)
Significant assumptions				
For net periodic benefit cost:				
Expected rate of return on plan assets	6.75%	6.75%	-	-
Weighted-average discount rate	5.25%	5.00%	5.24%	4.98%
Rate of compensation scale escalation (without merit)	3.25%	3.25%	3.25%	3.25%
Rate of cost of living increase	2.50%	2.50%	2.50%	2.50%
Average remaining service life of employees *(years)*	10	10	9	10
Rate of increase in health care cost trend[3]	-	-	4.40%	4.40%
For accrued benefit obligation, December 31:				
Weighted-average discount rate	5.50%	5.25%	5.50%	5.24%
Rate of compensation scale escalation (without merit)	3.00%	3.25%	3.00%	3.25%
Rate of cost of living increase	2.25%	2.50%	2.25%	2.50%
Rate of increase in health care cost trend[4]	-	-	4.40%	4.40%

[2] The Company follows the cash basis of accounting. During 2007, pension costs of $95 million (2006 - $86 million) were attributed to labour, of which $58 million (2006 - $42 million) was charged to operations, $37 million (2006 - $34 million) was capitalized as part of the cost of fixed assets, and $nil (2006- $10 million) was attributed to a regulatory asset.

[3] 8.69% in 2007 grading down to 4.40% per annum in and after 2018 (2006 – 7.87% in 2006 grading down to 4.40% per annum in and after 2014).

[4] 8.33% in 2008 grading down to 4.40% per annum in and after 2018 (2006 – 8.69% in 2007 grading down to 4.40% per annum in and after 2014).

11. ENVIRONMENTAL LIABILITIES

December 31 (Canadian dollars in millions)	**2007**	**2006**
Environmental liabilities, January 1	70	79
Interest accretion	4	5
Expenditures	(12)	(17)
Revaluation adjustment	3	3
Environmental liabilities, December 31	65	70
Less: current portion	(13)	(15)
	52	55

Estimated future environmental expenditures for each of the five years subsequent to December 31, 2007 and in total thereafter are as follows: 2008 - $13 million; 2009 - $12 million; 2010 - $10 million; 2011 - $8 million; 2012 - $6 million and thereafter - $35 million.

There are uncertainties in estimating future environmental costs due to potential external events such as changing regulations and advances in remediation technologies. Hydro One continuously reviews factors affecting its cost estimates as well as the environmental condition of the various properties. The actual cost of investigation or remediation may differ from current estimates.

12. SHARE CAPITAL

Common and Preferred Shares

On March 31, 2000, the Company issued to the Province 12,920,000 5.5% cumulative preferred shares with a redemption value of $25.00 per share, and 99,990 common shares, bringing the total number of outstanding common shares to 100,000. The Company is authorized to issue an unlimited number of preferred and common shares.

The preferred shares are entitled to an annual cumulative dividend of $18 million, which is payable on a quarterly basis. The preferred shares are redeemable at the option of the Province at a price of $25 per share, representing the stated value, plus any accrued and unpaid dividends if the Province sells a number of the common shares which it owns to the public such that the Province’s holdings are reduced to less than 50% of the common shares of the Company. Hydro One may elect, without condition, to pay all or part of this redemption price by issuing additional common shares to the Province. If the Province does not exercise its redemption right, the Company would have the ability to adjust the dividend on the preferred shares to produce a yield that is 0.50% less than the then-current dividend market yield for similarly rated preferred shares. The preferred shares do not carry voting rights, except in limited circumstances, and would rank in priority over the common shares upon liquidation.

Dividends

Common dividends are declared at the sole discretion of the Hydro One Board of Directors, and are recommended by management based on results of operations, financial condition, cash requirements and other relevant factors such as industry practice and shareholder expectations.

In 2007, preferred dividends in the amount of $18 million (2006 - $18 million) and common dividends in the amount of $307 million (2006 - $332 million) were declared.

Earnings per Share

Earnings per share is calculated as net income during the year, after cumulative preferred dividends, divided by the weighted-average number of common shares outstanding during the year.

13. RELATED PARTY TRANSACTIONS

The Province, OEFC, IESO, OPA and Ontario Power Generation Inc. (OPG) are related parties of Hydro One. In addition the OEB is related to the Company by virtue of its status as a Provincial Crown Corporation. Transactions between these parties and Hydro One were as follows:

Hydro One received revenue for transmission services from IESO, based on uniform transmission rates approved by the OEB. Transmission revenue for 2007 includes $1,203 million (2006 - $1,206 million) related to these services.

Hydro One receives amounts for rural rate protection from the IESO. Distribution revenue for 2007 includes $127 million (2006 - $127 million) related to this program. Hydro One also received revenue related to the supply of electricity to remote northern communities from the IESO. Distribution revenue for 2007 includes $21 million (2006 - $21 million) related to these services.

In 2007, Hydro One purchased power in the amount of $2,213 million (2006 - $2,183 million) from the IESO administered electricity market and $27 million (2006 - $38 million) from OPG.

Under the *Ontario Energy Board Act, 1998,* the OEB is required to recover all of its annual operating costs from gas and electricity distributors and electricity transmitters. In 2007, Hydro One incurred $10 million (2006 - $9 million) in OEB fees.

Hydro One has service level agreements with the other successor corporations. These services include field, engineering, logistics and telecommunications services. Revenues related to the provision of construction and equipment maintenance services to the other successor corporations were $12 million (2006 - $15 million), primarily for the transmission business. Operation, maintenance and administration costs related to the purchase of services from the other successor corporations were less than $1 million in each of 2007 and 2006.

Consistent with the OPA mandate, the OPA is responsible for some of our CDM programs. The funding includes program costs, incentives and management fees and bonuses. In 2007, Hydro One received $3 million (2006 – $nil) from the OPA in respect of the CDM programs and had a net accounts receivable of $3 million (2006 – $nil).

The provision for payments in lieu of corporate income taxes was paid or payable to the OEFC and dividends were paid or payable to the Province.

The amounts due to and from related parties as a result of the transactions referred to above are as follows:

December 31 (Canadian dollars in millions)	**2007**	**2006**
Accounts receivable	97	114
Accounts payable and accrued charges	(234)	(230)

Included in accounts payable and accrued charges are amounts owing to the IESO in respect of power purchases of $202 million (2006 - $195 million).

14. CONSOLIDATED STATEMENTS OF CASH FLOWS

For the purposes of the Consolidated Statements of Cash Flows, “cash and cash equivalents” refers to the Balance Sheet item “bank indebtedness.”

The changes in non-cash balances related to operations consist of the following:

Year ended December 31 (Canadian dollars in millions)	**2007**	**2006**
Accounts receivable decrease (increase)	18	(149)
Materials and supplies increase	(11)	-
Accounts payable and accrued charges increase (decrease)	70	(39)
Accrued interest increase	6	6
Long-term accounts payable and accrued charges decrease	(3)	(7)
Employee future benefits other than pension increase	52	87
Other	3	(4)
	135	(106)

Supplementary information:		
Interest paid	306	302
Payments in lieu of corporate income taxes	230	252

15. CONTINGENCIES

Legal Proceedings

Hydro One is involved in various lawsuits, claims and regulatory proceedings in the normal course of business. In the opinion of management, the outcome of such matters, except as noted below, will not have a materially adverse effect on the Company's consolidated financial position, results of operations or cash flows.

On March 29, 1999, the Whitesand First Nation Band commenced an action in the Ontario Court (General Division), now the Superior Court Justice, naming as defendants the Province, the Attorney General of Canada, Ontario Hydro, OEFC, OPG and the Company. On May 24, 2001, the Whitesand First Nation Band issued an almost identical claim against the same parties. The reason for the second claim is the procedural defence of the Province that proper notice of the first claim was not given under the *Proceedings Against the Crown Act* (Ontario). These actions seek declaratory relief, injunctive relief and damages in an unspecified amount. The Whitesand Band alleges that since at least the first half of the twentieth century, Ontario Hydro has erected dams, generating stations and other facilities within or affecting the band's traditional lands and that those facilities have caused damage to band members and the lands, including substantial flooding and erosion. The Whitesand Band also claims treaty rights to a share of the profits arising from the activities of these Ontario Hydro facilities, an entitlement to increases in annuity payments established by treaty and for breach of an alleged contract to reimburse the band for negotiation costs with Ontario Hydro. The Whitesand Band asserts multiple causes of action, including trespass, breach of fiduciary duty, nuisance and negligence. The May 24, 2001 case was consolidated in 2004 with a similar claim by Red Rock First Nation Band which commenced on September 7, 2001 as all procedural issues in both matters were the same. There is now one action in which the claims of both Whitesand and Red Rock are set out. The claims relating to activities of Ontario Hydro (i.e., flooding) are the matters for which OPG would have responsibility pursuant to Transfer Orders under the *Electricity Act, 1998*. In the consolidated claim, Whitesand and Red Rock seek to tie Hydro One into the flooding allegations on the alleged basis of the integrated nature of the transmission system with the entire electricity system, which includes the method of generating power. To date, Hydro One has not filed a defence. Hydro One believes that it is unlikely that the outcome of this litigation will have a material adverse effect on its consolidated financial position, results of operations or cash flows.

Transfer of Assets

The transfer orders by which Hydro One acquired certain of Ontario Hydro's businesses as of April 1, 1999 did not transfer title to some assets located on lands held for bands or bodies of Indians under the *Indian Act* (Canada). Currently, the OEFC holds these assets. Under the terms of the transfer orders, Hydro One is required to manage these assets until it has obtained all consents necessary to complete the transfer of title of these assets to itself. The Company cannot predict the aggregate amount that it may have to pay, either on an annual or one-time basis, to obtain the required consents. However, it anticipates having to pay more than the approximately $900,000 per year than it currently is paying to these Indian bands and bodies. If the Company cannot obtain consents from the Indian bands and bodies, OEFC will continue to hold these assets for an indefinite period of time. If the Company cannot reach a satisfactory settlement, it may have to relocate these assets from the Indian lands to other locations at a cost that could be substantial or, in a limited number of cases, to abandon a line and replace it with diesel generation facilities. The costs relating to these assets could have a material adverse effect on the Company's results of operations if it is not able to recover them in future rate orders.

Draft PCB regulations

Future changes in environmental regulations may result in material changes to the Company's estimated liability related to the management of PCBs. On November 4, 2006, Environment Canada published new draft regulations governing the management of PCBs. These draft regulations may be finalized in 2008. The Company has estimated its operating expenditures for complying with these draft regulations to be between $250 million and $375 million in excess of amounts already recorded as environmental liabilities on its Balance Sheet. If required, most of these additional expenditures are expected to be incurred between 2013 and 2025. No obligation has been recorded in the financial statements for these increased expenditures due to continued uncertainty regarding the timing and content of the final regulations. In the event that an obligation related to new regulations is recorded, the Company expects to simultaneously record a regulatory asset of equivalent value.

16. COMMITMENTS

Agreement with Inergi

Effective March 1, 2002, Cap Gemini Canada Inc. began providing services to Hydro One through Inergi. As a result of this initiative, Hydro One receives from Inergi a range of services including information technology, customer care, supply chain and certain human resources and finance services for a ten-year period. The initial service level price ranged between $90 million and $130 million per year, subject to external benchmarking every three years to ensure Hydro One is receiving a defined competitive and continuously improved price. In connection with this agreement, on March 1, 2002 the Company transferred approximately 900 employees to Inergi, including about 130 non-regular employees.

The annual commitments under the agreement in each of the five years subsequent to December 31, 2007, and in total thereafter are as follows: 2008 - $100 million, 2009 - $97 million; 2010 - $93 million; 2011 - $90 million; 2012 - $16 million and thereafter - $nil.

Prudential Support

Purchasers of electricity in Ontario, through the IESO, are required to provide security to mitigate the risk of their default based on their expected activity in the market. The IESO could draw on these guarantees if Hydro One Networks or Hydro One Brampton fails to make a payment required by a default notice issued by the IESO. The maximum potential payment is the face value of any bank letters of credit plus the nominal amount of the parental guarantee. As at December 31, 2007, the Company provided prudential support using only parental guarantees, reflecting a change from 2006. If Hydro One's highest long term credit rating deteriorated to below the "Aa" category, the Company would be required to resume providing letters of credit as prudential support. Prudential support at December 31, 2007 was provided using bank letters of credit of $nil million (2006 - $22 million) and parental guarantees of $325 million (2006 - $275 million).

Retirement Compensation Arrangements

Bank letters of credit have been issued to provide security for the Company's liability under the terms of a trust fund established pursuant to the supplementary pension plan for the employees of Hydro One and its subsidiaries. The trustee is required to draw upon the letters of credit if Hydro One is in default of its obligations under the terms of this plan. Such obligations include the requirement to provide the trustee with an annual actuarial report as well as letters of credit sufficient to secure the Company's liability under the plan, to pay benefits payable under the plan and to pay the letter of credit fee. The maximum potential payment is the face value of the bank letters of credit. As at December 31, 2007, Hydro One had bank letters of credit of $95 million (2006 - $93 million) outstanding relating to retirement compensation arrangements.

Operating Leases

The future minimum lease payments under operating leases for each of the five years subsequent to December 31, 2007 and in total thereafter are as follows: 2008 - $6 million; 2009 - $5 million; 2010 - $2 million; 2011 - $1 million; 2012 - $1 million and thereafter - $1 million.

17. SEGMENT REPORTING

Hydro One has three reportable segments:

- The transmission business, which comprises the core business of providing transportation and connection services, is responsible for transmitting electricity throughout the Ontario electricity grid;
- The distribution business, which comprises the core business of delivering and selling electricity to customers; and
- The "other" segment, which primarily consists of the telecommunications business.

The designation of segments is based on a combination of regulatory status and the nature of the products and services provided. The accounting policies followed by the segments are the same as those described in the summary of significant accounting policies (see Note 2). Segment information on the above basis is as follows:

Year ended December 31 (Canadian dollars in millions)	**Transmission**	**Distribution**	**Other**	**Consolidated**
2007				
Segment profit				
Revenues	1,242	3,382	31	4,655
Purchased power	-	2,240	-	2,240
Operation, maintenance and administration	415	549	31	995
Depreciation and amortization	242	273	6	521
Income (loss) before financing charges and provision for payments in lieu of corporate income taxes	585	320	(6)	899
Financing charges				295
Income before provision for payments in lieu of corporate income taxes				604
Capital expenditures	560	511	20	1,091
2006				
Segment profit				
Revenues	1,245	3,273	27	4,545
Purchased power	-	2,221	-	2,221
Operation, maintenance and administration	390	460	30	880
Depreciation and amortization	241	269	5	515
Income (loss) before financing charges and provision for payments in lieu of corporate income taxes	614	323	(8)	929
Financing charges				295
Income before provision for payments in lieu of corporate income taxes				634
Capital expenditures	402	417	4	823

December 31 (Canadian dollars in millions)	**2007**	**2006**
Total assets		
Transmission	7,273	6,950
Distribution	5,411	5,161
Other	106	99
	12,790	12,210

All revenues, costs and assets, as the case may be, are earned, incurred or held in Canada.

18. SUBSEQUENT EVENTS

On January 21, 2008, the Company entered into a forward starting pay fixed interest rate swap agreement to hedge against the effect of future interest rate movements on long-term fixed rate borrowing requirements. This transaction had a notional amount of $60 million and is used to lock in the interest rate of a forecasted debt issuance planned for later in 2008. This transaction is being accounted for as a cash flow hedge of a forecasted transaction.

On January 28, 2008 the Company increased its committed revolving credit facility, which supports its commercial paper program, by $250 million to $1,000 million. The maturity date remains unchanged at August 10, 2010.

19. COMPARATIVE FIGURES

The comparative Consolidated Financial Statements have been reclassified from statements previously presented to conform to the presentation of the December 31, 2007 Consolidated Financial Statements.

HYDRO ONE INC.
FIVE-YEAR SUMMARY OF FINANCIAL AND OPERATING STATISTICS

Year ended December 31 (Canadian dollars in millions)	**2007**	**2006**	**2005**	**2004**	**2003**
Statement of operations data					
Revenues					
Transmission	1,242	1,245	1,310	1,262	1,298
Distribution	3,382	3,273	3,085	2,874	2,734
Other	31	27	21	17	26
	4,655	4,545	4,416	4,153	4,058
Costs					
Purchased power	2,240	2,221	2,131	1,987	1,872
Operation, maintenance and administration	995	880	792	771	795
Depreciation and amortization	521	515	487	480	454
	3,756	3,616	3,410	3,238	3,121
Regulatory recovery[1]	-	-	-	91	-
Income before financing charges and provision for payments in lieu of corporate income taxes	899	929	1,006	1,006	937
Financing charges	295	295	325	331	348
Income before provision for payments in lieu of corporate income taxes	604	634	681	675	589
Provision for payments in lieu of corporate income taxes	205	179	198	177	193
Net income	399	455	483	498	396
Basic and fully diluted earnings per common share *(Canadian dollars)*	3,809	4,366	4,652	4,798	3,779

December 31 (Canadian dollars in millions)					
Balance sheet data					
Assets					
Transmission	7,273	6,950	6,813	6,771	6,576
Distribution	5,411	5,161	4,893	4,836	4,614
Other	106	99	92	95	94
Total assets	12,790	12,210	11,798	11,702	11,284
Liabilities					
Current liabilities (including current portion of long-term debt)	1,452	1,194	1,341	1,262	1,192
Long-term debt	5,063	4,848	4,443	4,590	4,517
Other long-term liabilities	1,389	1,347	1,298	1,326	1,284
Shareholder's equity					
Share capital	3,637	3,637	3,637	3,637	3,637
Retained earnings	1,258	1,184	1,079	887	654
Accumulated Other Comprehensive Income	(9)	-	-	-	-
Total liabilities and shareholder's equity	12,790	12,210	11,798	11,702	11,284

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HYDRO ONE INC.
FIVE-YEAR SUMMARY OF FINANCIAL AND OPERATING STATISTICS (continued)

Year ended December 31 (Canadian dollars in millions)	2007	2006	2005	2004	2003
Other financial data					
Capital expenditures					
Transmission	560	402	349	432	289
Distribution	511	417	338	288	292
Other	20	4	4	7	16
Total capital expenditures	1,091	823	691	727	597
Ratios					
Net asset coverage on long-term debt[2]	1.87	1.92	1.93	1.88	1.86
Earnings coverage ratio[3]	2.67	2.67	2.69	2.70	2.43
Operating statistics					
Transmission					
Units transmitted *(TWh)*[4]	152.2	151.1	157.0	153.4	151.7
Ontario 20-minute system peak demand *(MW)*[4]	25,809	27,056	26,219	25,204	24,849
Ontario 60-minute system peak demand *(MW)*[4]	25,737	27,005	26,160	24,979	24,753
Total transmission lines *(circuit-kilometres)*	28,915	28,600	28,547	28,643	28,621
Distribution					
Units distributed to Hydro One customers *(TWh)*[4]	30.2	29.0	29.7	28.5	27.9
Units distributed through Hydro One lines *(TWh)*[4,5]	45.7	44.7	45.6	44.8	44.7
Total distribution lines *(circuit-kilometres)*	122,933	122,460	122,118	121,736	121,285
Customers	1,311,714	1,293,396	1,273,768	1,258,925	1,238,748
Total regular employees	4,602	4,295	4,189	4,118	3,967

[1]As a result of the oral and written evidence submitted by Hydro One, on December 9, 2004 the OEB issued a ruling, citing prudence, and approving recovery of amounts previously delayed by the *Electricity Pricing, Conservation and Supply Act, 2002,* relating to regulatory deferral account balances sought by Hydro One in its May 31, 2004 submission. Consequently, a one-time regulatory recovery of $91 million was recorded.

[2] The net asset coverage on long-term debt ratio is calculated as total assets minus total liabilities excluding long-term debt (including current portion) divided by long-term debt (including current portion).

[3] The earnings coverage ratio has been calculated as the sum of net income, financing charges and provision for payments in lieu of corporate income taxes divided by the sum of financing charges, capitalized interest and cumulative preferred dividends.

[4] System related statistics include preliminary figures for December.

[5] Units distributed through Hydro One lines represent total distribution system requirements and include electricity distributed to consumers who purchased power directly from the IESO.

HYDRO ONE INC.
MANAGEMENT'S DISCUSSION AND ANALYSIS

RESULTS OF OPERATIONS

As used in this section, references to increases and decreases, whether in terms of amounts or percentages, are made by comparison of the three months ended March 31, 2008 to the three months ended March 31, 2007.

Revenues

Three months ended March 31 (Canadian dollars in millions)	**2008**	**2007**	**$ Change**	**% Change**
Transmission	304	327	(23)	(7)
Distribution	908	944	(36)	(4)
Other	10	7	3	43
	1,222	1,278	(56)	(4)
Average Ontario 60-minute peak demand *(MW)* [1]	22,275	23,480	(1,205)	(5)
Distribution - units distributed to customers *(TWh)* [1]	8.5	8.6	(0.1)	(1)

[1]System-related statistics are preliminary

The demand for electricity generally follows normal weather-related variations, and, therefore, our energy-related revenues, all other things being equal, will tend to be higher in the first and third quarters than in the second and fourth quarters.

Transmission

Transmission revenues predominantly consist of our transmission tariff, which is based on the monthly peak demand for electricity across our high-voltage network. The tariff is designed to recover revenues necessary to support a transmission system with sufficient capacity to accommodate the maximum expected demand, which is primarily influenced by weather and economic conditions. Transmission revenues also include minor amounts of ancillary revenues which are primarily attributable to maintenance services provided to generators and secondary use of our land rights-of-way.

Our transmission revenues were lower by $23 million, or 7%, in the first quarter of 2008, compared to the same period last year. Lower average peak demands compared to the same period last year resulted in lower tariff revenues of about $16 million and we also experienced lower other transmission revenues of approximately $1 million.

In addition, as a result of the Ontario Energy Board’s (OEB’s) August 16, 2007 decision on our transmission rate application, our tariff revenues were lower than the comparable period by approximately $6 million. In its decision, the OEB approved all of our work program expenditure requirements, but reduced our rate of return on equity from 9.88% to 8.35%. The impact of the OEB’s decision, which was effective January 1, 2007, was recognized at the decision date. A new regulatory liability, the Revenue Difference Deferral Account (RDDA), was recorded to reflect excess amounts recovered from customers. This account, together with the OEB’s transmission Earnings Sharing Mechanism (ESM) that was put in place to equally share 2006 excess transmission earnings between the customers and our shareholder, will be repaid to customers over the period November 1, 2007 to December 31. 2008. In the first quarter of 2008, compared to the first three months of 2007, we experienced a $39 million reduction to our transmission revenues as a result of the OEB’s decision to reduce our rate of return. This impact was partially offset by adjustments to our earned revenue of $33 million reflecting the fact that rates include a refund of amounts that were previously recorded as revenue reductions in the ESM in 2006 and RDDA in 2007.

Distribution

Distribution revenues include our distribution tariff, which is based on OEB-approved rates, as well as amounts to recover the cost of purchased power used by our customers. Accordingly, distribution revenues are primarily influenced by our distribution rates, the amount of electricity we distribute, and the cost of purchased power. Distribution revenues also include a minor amount of ancillary distribution services revenues, such as fees related to the use of our poles by the telecommunications and cable television industries, and miscellaneous charges such as those for late payments.

Distribution revenues were lower by $36 million, or 4%, in the first quarter relative to the comparative period. This reduction primarily reflects lower purchased power cost recoveries of $45 million as described below under “Purchased

Power." This reduction in revenues was partially offset by revenue increases following two OEB decisions. The OEB's August 8, 2007 decision on its combined smart meter proceeding allowed us to begin recording revenue related to our installed smart meters. The decision resulted in an increase of $6 million reflecting recovery of our investments under this program. Effective May 1, 2007, the OEB approved increases in distribution tariff rates for our subsidiaries, Hydro One Networks Inc. and Hydro One Brampton Inc., under an OEB incentive rate-setting mechanism. These increases, which support the maintenance and investment requirements of our distribution systems and which enable continued safe and reliable delivery of electricity to our customers throughout Ontario, resulted in higher distribution revenues of $1 million during the quarter. We also experienced higher ancillary revenues of $2 million.

We estimate that a 1% decrease in the forecast long-term Government of Canada bond yield used in the current OEB formula for determining our rate of return would reduce our Transmission Business' results of operations by approximately $20 million and our Distribution Business' results of operations by approximately $13 million.

Purchased Power

Purchased power costs incurred by our Distribution Business represent the cost of electricity delivered to customers within our distribution service territory and consist of the wholesale commodity cost of energy, the Independent Electricity System Operator's (IESO's) wholesale market service charges, and transmission charges levied by the IESO. The commodity cost of energy for certain low-volume and designated customers is based on the OEB's Regulated Price Plan (RPP), which consists of a two-tiered pricing structure with threshold amounts adjusted twice annually. Customers who are not eligible for the RPP pay the market price for electricity, adjusted for the difference between market prices and the prices paid to generators under the *Electricity Restructuring Act, 2004*. A summary of the RPP impacting the reporting period is provided below.

	Tier Threshold (kWh/month)		Tier Rates (cents/kWh)	
Effective Date	**Residential**	**Non-Residential**	**First Tier**	**Second Tier**
November 1, 2006	1,000	750	5.5	6.4
May 1, 2007	600	750	5.3	6.2
November 1, 2007	1,000	750	5.0	5.9

Purchased power costs decreased by $45 million, or 7%, to $596 million in the first quarter compared to the same period last year. Our decreased purchased power costs were primarily due to lower costs of $28 million associated with the OEB's RPP for residential and other eligible customers, the impact of lower charges levied by the IESO of $15 million, including transmission charges due to the OEB's August 16, 2007 transmission rate decision and wholesale market service charges, and lower demand for electricity of $9 million. These decreases were partially offset by higher wholesale commodity prices of $7 million for customers who are not eligible for the RPP.

Operation, Maintenance and Administration

Our operation, maintenance and administration costs are comprised primarily of labour, material, equipment and purchased services in support of the operation and maintenance of the transmission and distribution systems. These costs also include property taxes and payments in lieu thereof on our transmission and distribution lines, stations and buildings.

Operation, maintenance and administration costs for each of our three business segments were as follows:

Three months ended March 31 (Canadian dollars in millions)	**2008**	**2007**	**$ Change**	**% Change**
Transmission	97	99	(2)	(2)
Distribution	115	128	(13)	(10)
Other	9	7	2	29
	221	234	(13)	(6)

Transmission

Operation, maintenance and administration expenditures incurred to sustain our high-voltage transmission stations, lines and rights-of-way decreased by $2 million, or 2%, in the first quarter compared to the same period last year. This change was attributable to a $12 million reduction in our support costs, primarily as the result of a one-time settlement credit associated with our transfer of pension assets to the Inergi LP (Inergi) pension plan following approval from the Financial Services

Commission of Ontario. This settlement related to the transfer of approximately 770 regular employees to Inergi effective March 1, 2002. The impact of this reduction was partially offset by an increase in our work program expenditures of $10 million required to maintain our safe and reliable operation of the transmission system. We carried out increased planned line maintenance, station-related corrective maintenance and forestry work consistent with making an earlier start to this year's program given favourable weather conditions.

Distribution

Operation, maintenance and administration expenditures necessary to maintain our low-voltage distribution system decreased by $13 million, or 10%, in the first three months of 2008 compared to the relative period last year. We experienced lower support expenditures of $11 million, primarily as a result of the Inergi pension asset transfer settlement. Our work program expenditures were also lower by $2 million, primarily as a result of lower conservation and demand management program expenditures following the completion of the OEB program requirements associated with the third phase Market Adjusted Rate of Return and reduced line clearing work. The impact of these work program reductions was partially offset by increased expenditures incurred to respond to winter storm damage.

Depreciation and Amortization

Depreciation and amortization expense for the first three months of the year increased by $5 million, or 4%, to $130 million relative to the comparative period. This increase was mainly attributable to increased depreciation expense related to the placement of new assets in service, consistent with our ongoing capital work program.

Financing Charges

Financing charges decreased by $4 million, or 5%, to $69 million in the quarter compared to the same period last year. This reduction in our net interest expense was primarily due to a $6 million interest credit related to the Inergi pension asset transfer settlement. The impact of this reduction was partially offset by a $2 million increase in interest expense reflecting a higher average level of debt, partially offset by a lower average effective interest rate.

Provision for Payments in Lieu of Corporate Income Taxes

The provision for payments in lieu of corporate income taxes decreased by $7 million, or 12%, to $49 million in the first quarter compared to the same period last year. This decrease was primarily due to a reduction in the statutory tax rate from 36.12% to 33.5%, combined with the impact of other minor temporary differences. Our income before the provision for payments in lieu of corporate income taxes included the effects of the Inergi pension asset transfer settlement.

Net Income

Net income of $157 million was higher by $8 million, or 5%, compared to 2007 first quarter results. This increase was mainly due to the impact of the Inergi pension asset transfer settlement following approval by the Financial Services Commission of Ontario. We also experienced an increase in our distribution tariff revenues reflecting increased smart meter revenues as a result of the August 8, 2007 OEB decision. The impact of these factors was partially offset by lower transmission revenues resulting from the August 16, 2007 transmission rate decision, lower average monthly peak demands and increased work program requirements.

QUARTERLY RESULTS OF OPERATIONS

The following table sets forth unaudited quarterly information for each of the eight quarters from June 30, 2006 through March 31, 2008. This information has been derived from our unaudited interim Consolidated Financial Statements which, in the opinion of our management, have been prepared on a basis consistent with the audited annual Consolidated Financial Statements and which include all adjustments, consisting only of normal recurring adjustments, necessary for fair presentation of our financial position and results of operations for those periods. These operating results are not necessarily indicative of results for any future period and should not be relied upon to predict our future performance.

(Canadian dollars in millions)	2008		2007				2006	
Three months ended	**Mar. 31**	**Dec. 31**	**Sep. 30**[2]	**Jun. 30**	**Mar. 31**	**Dec. 31**	**Sep. 30**	**Jun. 30**
Total revenues[1]	1,222	1,129	1,128	1,120	1,278	1,142	1,165	1,078
Net income[1]	157	90	67	93	149	101	103	99
Net income to common shareholder[1]	153	85	63	88	145	96	99	94

[1] The demand for electricity generally follows normal weather-related variations, and therefore our electricity-related revenues and profit, all other things being equal, would tend to be higher in the first and third quarters than in the second and fourth quarters.

[2] As a result of the OEB's August 16, 2007 decision on our transmission rate application that was effective January 1, 2007, revenues reflect a reduced revenue requirement based on the approved rate of return of 8.35%. Previously, the rate of return was 9.88%. Revenues in the third quarter of 2007 reflect a $38 million adjustment to revenues in respect of the period January 1, 2007 to August 16, 2007 and reflect the OEB's decision to reduce the rate of return and revise the capital structure of our Transmission Business.

LIQUIDITY AND CAPITAL RESOURCES

Our primary sources of liquidity and capital resources are funds generated from operations, debt capital market borrowings and bank financing. These resources will be used to satisfy our capital resource requirements, which continue to include capital expenditures, servicing and repayment of our debt, payments related to our outsourcing arrangements, investing activities, and dividends.

Summary of Sources and Uses of Cash

Three months ended March 31 (Canadian dollars in millions)	2008	2007
Operating activities	232	294
Financing activities		
Long-term debt issued	550	400
Short-term notes	-	(60)
Dividends paid	(41)	(107)
Investing activities		
Capital expenditures	(211)	(187)
Other financing and investing activities	8	4
Net change in cash and cash equivalents	538	344

Operating Activities

Net cash from operating activities decreased by $62 million, to $232 million, compared to the same period in 2007. This change was primarily due to changes in funding requirements relative to the comparative period, primarily in relation to accounts payable and accrued liabilities associated with our work programs and power purchases.

Financing Activities

Short-term liquidity is provided through funds from operations and our commercial paper program, under which we are authorized to issue up to $1 billion in short-term notes with a term to maturity of less than 365 days. At March 31, 2008, we had no short-term notes payable outstanding. Our commercial paper program is supported by a committed revolving credit facility with a syndicate of banks. On January 28, 2008, we increased the facility from $750 million to $1,000 million. The maturity date remains unchanged at August 10, 2010. The short-term liquidity under this program and anticipated levels of funds from operations should be sufficient to fund our normal operating requirements. At March 31, 2008, we had $6,165 million in long-term debt outstanding, including the current portion. Our notes and debentures mature between 2008 and 2046. Long-term financing is provided by our access to the debt markets, primarily through our Medium-Term Note Program. We currently plan to refinance maturing debt principally through this program. The maximum authorized principal amount of medium-term notes issuable under this program is $2,500 million, of which $1,650 million is remaining and is currently available until July 2009.

	Rating	
Rating Agency	**Short-term Debt**	**Long-term Debt**
DBRS Limited	R-1 (middle)	A (high)
Moody's Investors Service Inc.	Prime-1	Aa3
Standard & Poor's Rating Services Inc.	A-1	A

We have the customary covenants normally associated with long-term debt. Among other things, our long-term debt covenants limit our permissible debt as a percentage of our total capitalization, limit our ability to sell assets and impose a negative pledge provision, subject to customary exceptions. The credit agreement related to our $1,000 million credit facility has no material adverse change clauses that could trigger default. However, the credit agreement requires that we provide notice to the lenders of any material adverse change within three business days of the occurrence. The agreement also provides limitations that debt cannot exceed 75% of total capitalization and that debt issued by our subsidiaries cannot exceed 10% of the total book value of our assets. We are in compliance with all of these covenants and limitations as at March 31, 2008.

During the first quarter of 2008, we issued $550 million in long-term debt under our Medium-Term Note Program. There were no debt maturities in the first quarter. During the first quarter of 2007, we issued $400 million in debt under our Medium-Term Note Program and had no maturities. For the first quarter of 2008, we had no change in our short-term notes outstanding, compared to a reduction of $60 million in the same period in 2007.

In the first three months of 2008, we paid dividends to the Province of Ontario (the Province) in the amount of $41 million, consisting of $37 million in common dividends and $4 million in preferred dividends. In the comparative period last year, we paid common dividends of $103 million and preferred dividends of $4 million.

Common dividends are declared at the sole discretion of our Board of Directors, and are recommended by management based on results of operations, financial condition, cash requirements and other relevant factors such as industry practice and shareholder expectations. Common dividends pertaining to the quarterly financial results are generally declared and paid in the immediately following quarter.

Investing Activities

Cash used for investing activities primarily represents capital expenditures for each of our three business segments as follows:

Three months ended March 31 (Canadian dollars in millions)	**2008**	**2007**	**$ Change**	**% Change**
Transmission	107	95	12	13
Distribution	102	91	11	12
Other	2	1	1	100
	211	187	24	13

Transmission

Transmission capital expenditures increased by $12 million, to $107 million in the first quarter compared to the same period in 2007. Our expenditures to expand and reinforce the transmission system were relatively unchanged in the first three months of the year at $47 million, a decrease of $1 million compared to the first quarter of last year. This reduction was primarily attributable to last year’s substantial completion of work on our Whitby and London Talbot transformer stations and reduced expenditures on our Lambton Transformer Station, partially offset by load connection work at our Pleasant Transformer Station and increased work on our lines and stations development projects. These projects include our Essa

Transformer Station to Stayner Transformer Station connection, which will improve the adequacy and reliability of supply to the Southern Georgian Bay region in recognition of the growing needs of our customers. In addition, in the first quarter of 2008, we commenced work on our Bruce to Milton Transmission Reinforcement Project to connect redeveloped nuclear and wind generation sources in the Huron-Grey-Bruce area. We also continued work on our new interconnection with Québec, which will increase access to emission-free hydroelectric power. The impact of these increased expenditures was partially offset by last year's completion of our Downtown Toronto Cable Project and last year's expenditures on our Cambridge Preston Transformer Station and our Niagara Reinforcement Project, final completion of which continues to be delayed by the aboriginal land dispute in the Caledonia area. Discussions continue between the involved aboriginal peoples and the various government entities involved. We will complete this project when site access becomes available.

Expenditures to sustain our existing transmission system were $39 million in the quarter, representing a decrease of $2 million compared to the same period in 2007, as a result of lower expenditures on a number of small lines and stations improvement projects. The impact of this reduction was partially offset by increased expenditures related to the refurbishment and replacement of end-of-life equipment at our Claireville Transformer Station to improve current reliability and to meet growing demands. Our other transmission capital expenditures were $21 million in the quarter, $15 million higher than the comparable period last year. This increase resulted from higher information technology expenditures primarily related to an entity-wide system improvement project to replace soon to be retired assets and increase productivity, combined with information security enhancements to the Ontario Grid Control Centre.

Distribution

Distribution capital expenditures increased by $11 million, to $102 million in the first quarter of 2008, compared to the same period in the prior year. Our capital expenditures to expand and reinforce our distribution network were $41 million, $3 million higher than the same period last year. This increase primarily reflects ongoing investments in our Smart Meter Program. During the quarter, we installed approximately 98,000 meters, bringing our cumulative program total to about 386,000 deployed smart meters. The impact of this increase was partially offset by lower expenditures for new customer connections.

Expenditures to sustain our low-voltage distribution system were $45 million in the quarter, an increase of $4 million from the same period in 2007. This increase was primarily a result of higher winter storm-recovery expenditures and planned end-of-life wood pole replacements within our lines work program. These increases were partially offset by lower planned asset replacement work. Our other distribution capital expenditures were $16 million in the quarter, representing an increase of $4 million from last year. This increase is primarily attributable to higher information technology expenditures related to our entity-wide system improvement project.

Future Capital Expenditures

Our capital expenditures in 2008 are budgeted at approximately $1.4 billion. The 2008 capital budgets for our transmission and distribution businesses are about $800 million and $600 million respectively. Our capital expenditures are expected to exceed $1.5 billion in both 2009 and 2010, primarily reflecting increasing investments to expand, refurbish or replace transmission infrastructure. Our overall investment levels reflect transmission infrastructure requirements consistent with government policy, Ontario Power Authority planning information as set up in its Integrated Power System Plan, local area supply requirements and preventive and corrective maintenance requirements to manage aging assets. These investments will facilitate an adequate and reliable supply of electricity in the public interest. These investment levels also reflect the continued mass deployment of smart meters within our distribution businesses that began in 2007. An entity-wide system improvement project to replace soon to be retired assets and increase productivity is also underway. Capital expenditures of our other business segment are budgeted at about $11 million in 2008, about half of the 2007 level, as the implementation of a dedicated fibre optic network that was initiated in 2007 will be completed this year.

Summary of Contractual Obligations and Other Commercial Commitments

The following table presents a summary of our debt and other major contractual obligations as well as other major commercial commitments.

March 31, 2008 (Canadian dollars in millions)	**Total**	**2008**[1]	**2009/2010**	**2011/2012**	**After 2012**
Contractual Obligations *(due by year)*					
Long-term debt – principal repayments	6,165	540	800	1,100	3,725
Long-term debt – interest payments	5,357	287	606	524	3,940
Inergi LP outsourcing agreement[2]	369	75	189	105	-
Operating lease commitments	15	4	8	2	1
Total Contractual Obligations	11,906	906	1,603	1,731	7,666
Other Commercial Commitments *(by year of expiry)*					
Bank line[3]	1,000	-	1,000	-	-
Letters of credit[4]	99	99	-	-	-
Guarantees[4]	325	325	-	-	-
Pension[5]	173	71	102	-	-
Total Other Commercial Commitments	1,597	495	1,102	-	-

[1] The amounts disclosed represent the balances due over the period April 1, 2008 to December 31, 2008.

[2] On March 1, 2002, Inergi began providing a range of services to us for a 10-year period, including information technology, customer care, supply chain and certain human resources and finance services.

[3] As a backstop to our commercial paper program, we have a $1,000 million revolving standby credit facility with a syndicate of banks which matures in August 2010.

[4] We currently have bank letters of credit of $95 million outstanding relating to retirement compensation arrangements. We have also provided prudential support to the IESO on behalf of our subsidiaries, as required by the Market Rules, using parental guarantees of up to a maximum of $325 million. Although no letters of credit are required for prudential support, we would have to resume providing bank letters of credit if our credit rating deteriorated to below the "Aa" category.

[5] Contributions to the pension fund are made one month in arrears. Contributions for 2008 are based on an actuarial valuation filed in September 2007 and effective December 31, 2006. Our annual pension contributions for 2008 and 2009 will be about $94 million. Contributions beyond 2009 will be based on an actuarial valuation effective December 31, 2009 and will depend on future investment returns, changes in benefits or actuarial assumptions. Pension contributions beyond 2009 are not estimable at this time.

The amounts in the above table under long-term debt are not charged to our results of operations, but are reflected on our Balance Sheet and Statement of Cash Flows. Interest associated with this debt is recorded under financing charges on our Statement of Operations or in our capital programs, but these financing charges are not reflected in the above table. Payments in respect of operating leases and our outsourcing agreement with Inergi are recorded under operation, maintenance and administration costs on our Statement of Operations or in our capital programs.

RELATED PARTY TRANSACTIONS

Related party transactions primarily consist of our transmission revenues received from, and our power purchases payments made to, the IESO, which is a related party by virtue of its status as an agency of our shareholder, the Province. The year-over-year changes related to these amounts are described more fully in our discussion of our transmission revenues and purchased power costs. Other significant related party transactions include our dividends which are paid to the Province and our payments in lieu of corporate income taxes which are paid or payable to the Ontario Electricity Financial Corporation.

STATUS OF OUR TRANSITION TO INTERNATIONAL FINANCIAL REPORTING STANDARDS (IFRS)

On February 13, 2008, the Canadian Accounting Standards Board confirmed that publicly accountable enterprises will be required to adopt IFRS in place of Canadian Generally Accepted Accounting Principles (GAAP) for interim and annual reporting purposes for fiscal years beginning on or after January 1, 2011. At this time, the impact on our future financial position and results of operations is not reasonably determinable or estimable.

We commenced our IFRS conversion project in 2007 and we have established a formal project governance structure. This structure includes a steering committee consisting of senior levels of management from finance, information technology, treasury and our operations organizations, among others. Regular reporting will occur to senior executive management and to the Audit and Finance Committee of our Board of Directors. We have also engaged an external expert advisor.

Our project consists of four phases: diagnostic; design and planning; solution development; and implementation. We have completed the diagnostic phase which involved a high level review of the major differences between current Canadian GAAP and IFRS. Currently, we have determined that the areas of accounting difference with the highest potential to impact our company are rate regulated accounting, accounting for fixed assets, payments in lieu of corporate income taxes, employee future benefits, as well as initial adoption of IFRS under the provisions of IFRS 1, *First-Time Adoption of IFRS*.

We are now proceeding to the design and planning phase which will involve establishing issue-specific work teams to focus on generating options and making recommendations in the identified risk areas. Subsequent to carrying out this work at the consolidated level, we will also focus on the specific impacts on our various subsidiaries and regulated businesses that may affect their unconsolidated financial statements. During the design and planning phase, we will establish a staff communications plan, begin to develop our staff training programs, and evaluate the impacts of the IFRS transition on other business activities.

As part of our entity-wide system improvement project, many of our major financial systems will be replaced. To ensure that the future requirements of IFRS can be met, we have included links with this initiative within the governance structure of our IFRS project. We will also ensure there are strong communications between our IFRS project and staff accountable for disclosure controls and internal control over financial reporting. Control requirements will be reevaluated as our IFRS project progresses.

The OEB has also begun its own IFRS project to determine the nature of any changes that should be made in regulatory accounting requirements in response to IFRS. On May 8, 2008, the OEB announced the creation of an IFRS Consultation which will provide an opportunity for Board staff to work with industry participants to identify transition issues and suggest how those issues might be addressed. We plan on participating in this process. We intend to closely monitor any International Financial Reporting Interpretations Committee (IFRIC) initiatives with the potential to impact rate regulated accounting under IFRS and will participate in any related processes, as appropriate.

RECENT DEVELOPMENTS

Bruce to Milton Transmission Reinforcement Project

We announced our recommendations regarding the potential route refinements on our Bruce to Milton Transmission Reinforcement Project in mid-March 2008. The assessments we conducted included input we received from public consultation in the potentially affected areas. Based on our assessments, we have recommended moving the proposed line section in the Halton Hills area from the east to the west side of the existing transmission corridor. The route recommendations will be further examined in the environmental assessment study, which is subject to approval by the Ministry of the Environment as part of the environmental assessment process. The terms of reference for the environmental assessment were approved by the Minister of the Environment on April 4, 2008. The OEB's Section 92 Leave-to-Construct hearing commenced May 1, 2008.

2008 Distribution Rate Applications

In 2007, we filed a cost of service application with the OEB for our Distribution Business operated through our subsidiary Hydro One Networks Inc. The interrogatory process was completed on April 4, 2008, with an oral hearing scheduled to begin on June 23, 2008. Based on the OEB's guidelines, a decision is anticipated in the Fall of 2008. As a result, we requested that existing 2007 rates be declared interim effective May 1, 2008. We proposed the establishment of a variance account to track the difference between existing rates and the OEB-approved 2008 rates, once new rates are approved and until such time that new rates are actually implemented. On April 11, 2008, the OEB issued a decision approving the establishment of the variance account and declaring our existing 2007 rates interim effective May 1, 2008, with the exception of the component of our rates regarding transmission-related charges applied to our embedded distributors. No amounts will be recorded in the variance account until the OEB makes a decision on the rate application, including the effective date for final rates.

On March 19, 2008, the OEB released its decision regarding the 2008 rate application made by our subsidiary Hydro One Brampton Networks Inc. The OEB approved our submission on the basis of the OEB's cost of capital and second generation incentive regulation mechanism policies. The revised rates, including an amount of 67 cents per month per metered customer for smart meters, were approved with an implementation date of May 1, 2008.

Collective Agreements

We successfully reached new collective agreements with the Power Workers' Union, Canadian Auto Workers and International Brotherhood of Electrical Workers, with three-year terms effective April 1, 2008. The collective agreements have been ratified.

SELECTED FINANCAL HIGHLIGHTS AND RATIOS

Three months ended March 31 (Canadian dollars in millions) (except as otherwise noted)	**2008**	**2007**
Net income	157	149
Net cash from operating activities	232	294
Capital expenditures	211	187
Earnings per common share *(Canadian dollars)*	1,524	1,446
Earnings coverage ratio[1]	2.68	2.74
Net asset coverage on long-term debt[2]	1.81	1.86
Total debt to capitalization[3]	55%	54%

[1]The earnings coverage ratio has been presented for the twelve months ended March 31, 2008 and March 31, 2007, respectively and has been calculated as the sum of net income, provision for payments in lieu of corporate income taxes and financing charges divided by the sum of financing charges, capitalized interest and cumulative preferred dividends.

[2]The net asset coverage on long-term debt ratio has been presented as at March 31, 2008 and December 31, 2007 and has been calculated as total assets minus total liabilities excluding long-term debt (including current portion) divided by long-term debt (including current portion).

[3]Total debt to capitalization ratio has been presented as at March 31, 2008 and December 31, 2007 and has been calculated as total debt divided by total debt plus total shareholder's equity.

FORWARD-LOOKING STATEMENTS AND INFORMATION

Our oral and written public communications, including this document, often contain forward-looking statements that are based on current expectations, estimates, forecasts and projections about our business and the industry in which we operate and include beliefs and assumptions made by the management of our company. Such statements include, but are not limited to: expectations regarding developments in the statutory and operating framework for electricity distribution and transmission in Ontario including changes to codes, licenses, rates, rate orders, cost recovery, rates of return, rate structures and revenue requirements in both our transmission and distribution businesses and the timing of decisions from the OEB; expectations regarding our financing activities; statements regarding the pension asset transfer; statements regarding future capital expenditures and our investment plans; expectations regarding the results of our projects; statements regarding future pension contributions; the estimated impact of changes in the forecast long-term Government of Canada bond yield (used in determining our regulated rate of return) on our results of operations; and statements about IFRS. Words such as "expect," "anticipate," "intend," "attempt," "may," "plan," "will", "believe," "seek," "estimate," and variations of such words and similar expressions are intended to identify such forward-looking statements. These statements are not guarantees of future performance and involve assumptions and risks and uncertainties that are difficult to predict. Therefore, actual outcomes and results may differ materially from what is expressed, implied or forecasted in such forward-looking statements. We do not intend, and we disclaim any obligation to update any forward-looking statements, except as required by law.

These forward-looking statements are based on a variety of factors and assumptions including, but not limited to the following: no unforeseen changes in the legislative and operating framework for Ontario's electricity market; no unfavourable decisions from the OEB and other regulatory bodies concerning outstanding rate and other applications; no unforeseen changes in rate orders or rate structures for our distribution and transmission businesses; a stable regulatory environment; and no significant event occurring outside the ordinary course of business. These assumptions are based on information currently available to us, including information obtained from third party industry analysts. Actual results may differ materially from those predicted by such forward-looking statements. While we do not know what impact any of these differences may have, our business, results of operations, financial condition and our credit stability may be materially adversely affected. Factors that could cause actual results or outcomes to differ materially from the results expressed or implied by forward-looking statements include, among other things:

- the content of the final Integrated Power System Plan, as approved by the OEB;
- delays or denials of the requisite approvals and accommodations for our planned projects;
- regulatory decisions regarding our revenue requirements, cost recovery and rates;
- the risk that we are not able to arrange sufficient financing to repay maturing debt and to fund capital expenditures and other obligations;
- the risks associated with changes in the forecast long-term Government of Canada bond yield; and
- future interest rates, inflation , changes in benefits and changes in actuarial assumptions.

We caution the reader that the above list of factors is not exhaustive. Some of these and other factors are discussed in more detail under "Risk Management and Risk Factors" in the 2007 annual Management's Discussion and Analysis (MD&A). You should review the section entitled "Risk Management and Risk Factors" in detail.

This MD&A is dated as at May 14, 2008. Additional information about our company, including our Annual Information Form, is available on SEDAR at www.sedar.com.

HYDRO ONE INC.
CONSOLIDATED STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME (unaudited)

Three months ended March 31 (Canadian dollars in millions)	**2008**	**2007**
Revenues		
Transmission	304	327
Distribution	908	944
Other	10	7
	1,222	1,278
Costs		
Purchased power	596	641
Operation, maintenance and administration *(Note 3)*	221	234
Depreciation and amortization	130	125
	947	1,000
Income before financing charges and provision for payments in lieu of corporate income taxes	275	278
Financing charges *(Note 3)*	69	73
Income before provision for payments in lieu of corporate income taxes	206	205
Provision for payments in lieu of corporate income taxes	49	56
Net income	157	149
Other comprehensive income	(1)	-
Comprehensive income	156	149
Basic and fully diluted earnings per common share *(Canadian dollars)*	1,524	1,446

CONSOLIDATED STATEMENTS OF RETAINED EARNINGS (unaudited)

Three months ended March 31 (Canadian dollars in millions)	**2008**	**2007**
Retained earnings, beginning of period	1,258	1,184
Net income	157	149
Dividends *(Note 4)*	(41)	(107)
Retained earnings, end of period	1,374	1,226

CONSOLIDATED STATEMENTS OF ACCUMULATED OTHER COMPREHENSIVE INCOME (unaudited)

Three months ended March 31 (Canadian dollars in millions)	**2008**	**2007**
Accumulated other comprehensive income, beginning of period	(9)	(12)
Other comprehensive income	(1)	-
Accumulated other comprehensive income, end of period	(10)	(12)

See accompanying notes to Consolidated Financial Statements.

HYDRO ONE INC.
CONSOLIDATED BALANCE SHEETS (unaudited)

(Canadian dollars in millions)	**March 31, 2008**	**December 31, 2007**
Assets		
Current assets		
Short-term investments	538	-
Accounts receivable (net of allowance for doubtful accounts) *(Note 2)*	828	759
Regulatory assets	82	103
Materials and supplies *(Note 2)*	26	27
Other	9	17
	1,483	906
Fixed assets		
Fixed assets in service	16,826	16,743
Less: accumulated depreciation	6,317	6,220
	10,509	10,523
Construction in progress	742	622
Future use land, components and spares *(Note 2)*	111	109
	11,362	11,254
Long-term assets		
Deferred pension asset	395	380
Regulatory assets	103	110
Goodwill	133	133
Long-term accounts receivable and other assets	7	7
	638	630
Total assets	13,483	12,790
Liabilities		
Current liabilities		
Bank indebtedness	12	12
Accounts payable and accrued charges	676	731
Regulatory liabilities	88	114
Accrued interest	101	55
Long-term debt payable within one year	940	540
	1,817	1,452
Long-term debt *(Note 5)*	5,219	5,063
Other long-term liabilities		
Regulatory liabilities	512	469
Employee future benefits other than pension	870	855
Environmental liabilities	50	52
Long-term accounts payable and other liabilities	14	13
	1,446	1,389
Total liabilities	8,482	7,904
Shareholder's equity		
Preferred shares (authorized: unlimited; issued: 12,920,000)	323	323
Common shares (authorized: unlimited; issued: 100,000)	3,314	3,314
Total share capital	3,637	3,637
Retained earnings	1,374	1,258
Accumulated other comprehensive income	(10)	(9)
Total retained earnings and accumulated other comprehensive income	1,364	1,249
Total shareholder's equity	5,001	4,886
Total liabilities and shareholder's equity	13,483	12,790

See accompanying notes to Consolidated Financial Statements.

HYDRO ONE INC.
CONSOLIDATED STATEMENTS OF CASH FLOWS (unaudited)

Three months ended March 31 (Canadian dollars in millions)	**2008**	**2007**
Operating activities		
Net income	157	149
Adjustments for non-cash items:		
Depreciation and amortization (excluding removal costs)	123	115
Revenue difference deferral account	(20)	-
Retail settlement variance accounts	28	16
Other regulatory asset and liability accounts	(4)	11
Amortization of discount	-	3
	284	294
Changes in non-cash balances related to operations	(52)	-
Net cash from operating activities	232	294
Financing activities		
Long-term debt issued	550	400
Short-term notes payable	-	(60)
Dividends paid	(41)	(107)
Other	6	(1)
Net cash from financing activities	515	232
Investing activities		
Capital expenditures	(211)	(187)
Other assets	2	5
Net cash used in investing activities	(209)	(182)
Net change in cash and cash equivalents	538	344
Cash and cash equivalents, beginning of period	(12)	(29)
Cash and cash equivalents, end of period	526	315

See accompanying notes to Consolidated Financial Statements.

1. BASIS OF PRESENTATION

These interim Consolidated Financial Statements do not conform in all respects to the disclosure requirements of Canadian generally accepted accounting principles for annual financial statements and should, therefore, be read in conjunction with the annual Consolidated Financial Statements of Hydro One Inc. (Hydro One or the Company) for the year ending December 31, 2007 which include information necessary or useful to understanding the Company's business and financial statement presentation. In particular, the Company's significant accounting policies and practices are presented as Note 2 to the annual Consolidated Financial Statements, and have been consistently applied in the preparation of these interim Consolidated Financial Statements, except as described below in Note 2 to the interim Consolidated Financial Statements.

The demand for electricity generally follows normal weather-related variations, and therefore the Company's energy-related revenues, all other things being equal, will tend to be higher in the first and third quarters than in the second and fourth quarters.

2. ACCOUNTING CHANGES

Change in Accounting Policy – Inventory

Effective January 1, 2008, the Company retrospectively adopted Canadian Institute of Chartered Accountants' (CICA) Handbook Section 3031, *Inventories,* with reclassification of comparative prior period amounts. This new section requires that certain major spare parts and standby equipment be reclassified from inventory to fixed assets. The new Handbook section also allows that previously recorded impairment losses taken on inventory to be reversed if there is evidence that the net realizable value has subsequently recovered.

The Company already includes certain major standby equipment as in-service fixed assets and depreciates these assets over their useful lives. To meet the requirements of the new section, the Company has reclassified approximately $42 million (2007 - $40 million) in asset components and equipment previously classified as materials and supplies inventory.

Concurrent with the above reclassification, the Company also reclassified future use land with a carrying value of approximately $69 million (2007 - $69 million) from "fixed assets in service" to "future use land, components and spares."

Future use land, components and spares are not depreciated until they are transferred to active capital projects and those projects are placed in-service.

Change in Capital Disclosures and Financial Instrument Disclosures and Presentation

Effective January 1, 2008, the Company adopted three new accounting standards comprising the CICA Handbook Sections 1535, *Capital Disclosures*; 3862, *Financial Instruments Disclosures*; and 3863, *Financial Instruments Presentation*. The adoption of these new standards required the disclosure of qualitative and quantitative information about the Company's capital and how it is managed, and an increased emphasis on disclosure about the risks associated with recognized and unrecognized financial instruments. The adoption of the new standard on presentation carried forward unchanged the presentation requirements from Section 3861, *Financial Instruments Disclosure and Presentation,* and therefore adoption of this new standard did not have any impact on the interim Consolidated Financial Statements.

Capital Disclosures

The Company's objectives with respect to its capital structure are to maintain effective access to capital on a long-term basis at reasonable rates, and to deliver appropriate financial returns. In order to ensure ongoing effective access to capital, the Company targets to maintain an "A" category long-term credit rating.

The Company considers the capital structure to consist of shareholder's equity, short-term and long-term debt, and cash and cash equivalents. The Company's capital structure as at March 31, 2008 and December 31, 2007 was as follows:

(Canadian dollars in millions)	**March 31, 2008**	**December 31, 2007**
Long-term debt payable within one year	940	540
Less (plus): Cash and cash equivalents	526	(12)
	414	552
Long-term debt	5,219	5,063
Preferred Shares	323	323
Common Shares	3,314	3,314
Retained Earnings	1,374	1,258
	5,011	4,895
Total Capital	10,644	10,510

For the purposes of this table and the Consolidated Statements of Cash Flows, "cash and cash equivalents" refers to the Consolidated Balance Sheet items "short-term investments" and "bank indebtedness."

The Company has customary covenants typically associated with long-term debt. Among other things, Hydro One's long-term debt and credit facility covenants limit the permissible debt to 75% of the Company's total capitalization, limit the ability to sell assets and impose a negative pledge provision, subject to customary exceptions. Hydro One is in compliance with all of these covenants and limitations.

Financial Instrument Disclosures

Exposure to market risk, credit risk and liquidity risk arises in the normal course of the Company's business.

Market Risk

Market risk refers primarily to risk of loss that results from changes in commodity prices, foreign exchange rates and interest rates. The Company does not have commodity risk and its foreign exchange risk is currently insignificant, although the Company could in future decide to issue foreign currency denominated debt. Hydro One is exposed to fluctuations in interest rates as the regulated rate of return for the Company's distribution and transmission businesses is derived using a formulaic approach which is in part based on the forecast for long-term Government of Canada bond yields. The Company estimates that a 1% decrease in the forecast long-term Government of Canada bond yield used in the current OEB formula for determining the Company's rate of return would reduce its Transmission Business' results of operations by approximately $20 million and its Distribution Business' results of operations by approximately $13 million.

Credit Risk

Financial assets create credit risk that a counter-party will fail to discharge an obligation, causing a financial loss. The Company's revenue is earned on a broad base of customers. As a result, Hydro One did not earn a significant amount of revenue from any individual customer. As at March 31, 2008, there were no significant balances of accounts receivable due from any single customer.

In the quarter, the Company's provision for bad debts increased by $1 million to $22 million as a result of write-offs and adjustments determined on the basis of a review of overdue accounts, taking into consideration historical experience. As at March 31, 2008, approximately 5% of the Company's accounts receivable were aged more than 60 days, while approximately 86% was classified as current.

Hydro One manages its counter-party credit risk through various techniques including, entering into transactions with highly rated counter-parties, limiting total exposure levels with individual counterparties consistent with the Company's Board-approved Credit Risk Policy, entering into master agreements which enable net settlement and the contractual right of offset, and monitoring the financial condition of counterparties. Short-term investments held as at March 31, 2008, were consistent with the credit exposure limits specified under the Company's Credit Risk Policy. The Company's credit risk for short-term investments and accounts receivable is limited to the carrying amount on the Consolidated Balance Sheet.

The Company uses derivative financial instruments to manage interest rate risk. Derivative financial instruments result in exposure to credit risk since there is a risk of counter-party default. As at March 31, 2008, the only derivative instrument held by Hydro One was a floating interest rate swap agreement related to a $40 million step-up coupon note. The exposure to credit risk from this derivative instrument as at March 31, 2008 was insignificant.

Liquidity Risk

Liquidity risk refers to the Company's ability to meet its financial obligations as they come due. Short-term liquidity is provided through cash and cash equivalents on hand, funds from operations, and the Company's Commercial Paper Program, under which Hydro One is authorized to issue up to $1 billion in short-term notes with a term to maturity of less than 365 days. The Commercial Paper Program is supported by a $1 billion committed revolving credit facility with a syndicate of banks maturing in August 2010. The short-term liquidity under this program should be sufficient to fund normal operating requirements.

Emerging Accounting Changes – Rate Regulated Operations

In August 2007, the Canadian Accounting Standards Board (AcSB) issued a decision, effective January 1, 2009, to withdraw the temporary exemption in CICA Handbook Section 1100, *Generally Accepted Accounting Principles*, which permits the recognition and measurement of assets and liabilities arising from rate regulation. Further, CICA Handbook Section 3465, *Income Taxes* was amended to require the recognition of future income tax liabilities and assets for regulated enterprises that were previously not subject these provisions. Consequently, the Company will be required to reflect on its Consolidated Balance Sheet, the effect of applying the liability method when accounting for payments in lieu of corporate income taxes and a corresponding regulatory asset. The Company is currently assessing the impact of the AcSB's decision on its Balance Sheet.

3. PENSION ASSET TRANSFER

Effective March 1, 2002, Hydro One began receiving a range of services from Inergi LP, including information technology, customer care, supply chain and certain human resources and financial services. In connection with this agreement, the Company transferred approximately 770 regular employees to Inergi LP. On March 10, 2008, the Company was granted consent from the Financial Services Commission of Ontario to transfer pension assets and related pension liabilities for affected employees from the Hydro One Pension Plan to the Inergi LP Pension Plan. The pension asset transfer will occur in the second quarter. Under the agreement, the Company recognized a settlement of $21 million in its results of operations, inclusive of a related interest credit of $6 million.

4. DIVIDENDS

During the three months ended March 31, 2008, preferred dividends in the amount of $4 million (2007 - $4 million) and common dividends in the amount of $37 million (2007 - $103 million) were declared.

5. LONG-TERM DEBT

In January 2008, the Company entered into a forward starting interest rate swap agreement to hedge against the effect of future interest rate movements on long-term fixed rate borrowing requirements. This transaction had a notional amount of $60 million and was used to lock in the interest rate of a forecasted debt issuance which took place on March 3, 2008. The transaction was accounted for as a cash flow hedge of a forecasted transaction.

On March 3, 2008, Hydro One issued additional notes under the Company's medium term note program. The new issue was comprised of medium term notes with a principal amount of $250 million having a 3 year term with a coupon rate of 4.08%. The notes are due March 3, 2011. At the same time the Company made an additional offering of 5.18% medium-term notes that originally settled October 18, 2007. The issue is comprised of medium term notes with a principal amount of $300 million having a 9.6 year term with a coupon rate of 5.18%. The notes are due October 18, 2017. In relation to this debt issuance, on March 3, 2008, the Company terminated the three forward starting interest rate swaps having a total notional principal amount of $200 million entered into in the last quarter of 2007 and the first quarter of 2008. The transactions had been accounted for as cash flow hedges of a forecasted debt issue for the purpose of fixing the interest rate for the debt issuance. The net loss realized on terminating the swaps was $1.2 million which has been recorded in Other Comprehensive Income and will be amortized to financing charges over the term of the related debt.

6. EMPLOYEE FUTURE BENEFITS

Total benefit costs are as follows:

Three months ended March 31 (Canadian dollars in millions)	**2008**	**2007**
Pension		
Net periodic benefit cost	10	25
Pension fund contribution	25	25
Less: Portion attributable to labour and capitalized as part of the cost of fixed assets	10	10
Charged to results of operations	15	15
Employee Future Benefits Other than Pension		
Net periodic benefit cost	23	27
Less: Portion attributable to labour and capitalized as part of the cost of fixed assets	9	10
Charged to results of operations	14	17

7. SEGMENTED REPORTING

Hydro One has three reportable segments:

- The Transmission Business, which comprises the core business of providing transportation and connection services, is responsible for transmitting electricity throughout the Ontario electricity grid;
- The Distribution Business, which comprises the core business of delivering and selling electricity to customers; and
- An "other" segment primarily consisting of a telecommunications business.

The designation of segments has been based on a combination of regulatory status and the nature of the products and services provided. Segment information on the above basis is as follows:

Three months ended March 31 (Canadian dollars in millions)	**Transmission**	**Distribution**	**Other**	**Consolidated**
2008				
Segment profit				
Revenues	304	908	10	1,222
Purchased power	-	596	-	596
Operation, maintenance and administration	97	115	9	221
Depreciation and amortization	59	70	1	130
Income before financing charges and provision for payments in lieu of corporate income taxes	148	127	-	275
Financing charges				69
Income before provision for payments in lieu of corporate income taxes				206
Capital expenditures	107	102	2	211

Three months ended March 31 (Canadian dollars in millions)	**Transmission**	**Distribution**	**Other**	**Consolidated**
2007				
Segment profit				
Revenues	327	944	7	1,278
Purchased power	-	641	-	641
Operation, maintenance and administration	99	128	7	234
Depreciation and amortization	60	64	1	125
Income (loss) before financing charges and provision for payments in lieu of corporate income taxes	168	111	(1)	278
Financing charges				73
Income before provision for payments in lieu of corporate income taxes				205
Capital expenditures	95	91	1	187

(Canadian dollars in millions)	**March 31, 2008**	**December 31, 2007**
Total assets		
Transmission	7,310	7,273
Distribution	5,529	5,411
Other	644	106
	13,483	12,790

All revenues, costs and assets, as the case may be, are earned, incurred or held in Canada.

8. SUBSEQUENT EVENTS

On April 11, 2008, the OEB ordered that existing 2007 distribution rates be declared interim as of May 1, 2008. The OEB also noted that it will allow Hydro One to track in a variance account the difference between revenue based on current rates and the distribution 2008 revenue requirement to be approved later this year for the period from May 1, 2008 until such time as final rates are implemented. No amounts will be recorded in the variance account until the OEB makes a decision on the Company’s current distribution rate application, including the effective date for final rates.

On April 11, 2008, Hydro One gave notice that it will not extend the maturity date of its $40 million extendible step-up note beyond its current maturity date of May 15, 2008. The notes will be redeemed at that time at a redemption price equal to the principal amount plus any accrued and unpaid interest.

9. COMPARATIVE FIGURES

The comparative unaudited interim Consolidated Financial Statements have been reclassified from statements previously presented to conform to the presentation of the March 31, 2008 unaudited interim Consolidated Financial Statements.

Hydro One Networks Inc.
Distribution
Reconciliation of Regulatory Financial Results with Audited Financial Statements
For year ending December 31, 2006

	Total per Exhibit A-9-1, Attachment 3	Adjustments	Utility Income
	(a)	(b)	(c)
Revenue			
Energy Sales	2,740		2,740
Rural Rate Protection	125		125
Other	41		41
	2,906	-	2,906
Costs			
Purchased Power	1,954		1,954
Operations, maintenance and administration (Note 1)	416	(12)	404
Depreciation and amortization	249		249
Capital Taxes (Note 1)		12	12
	2,619	0	2,619
Income before financing charges and provision for payments in lieu of corporate income taxes	287	(0)	287
Financing Charges	115		115
Income before provision for payments in lieu of corporate income taxes	172	(0)	172
Provision for Payments in lieu of corporate income taxes (Note 2)	46	18	64
Net Income	126	(18)	108

Note 1: Capital taxes are included in DX audited OM&A total, whereas in the rate evidence are shown as a separate line item

Note 2: Difference relates to prior year adjustments, such as the 1999-2002 income tax refund for capitalized overhead relating to corporate functions and services reversal ($14 million), provisions to return, etc.

HYDRO ONE NETWORKS INC.
2006 Distribution Financial Statements reconciled to USofA Trial balance

BALANCE SHEET (December 31, 2006)

	Financial Statement item	USofA Account/s	$millions
	ASSETS		
	Current assets		
1	Inter-company demand facility	2240	0
2	Accounts receivable	1005, 1100, 1105, 1110, 1130, 1180	585
3	Materials and supplies	1330	23
4	Current - Other	1460, 1525, 1180	4
5	Current Assets		612
	Fixed assets in service		
6	Generation Plant	1615, 1620, 1665, 1675, 1680	1
7	Distribution Plant	1565, 1805, 1806, 1808, 1815, 1820, 1830, 1835, 1840, 1845, 1850, 1860, 1875	5,241
8	General Plant	1905, 1908, 1910, 1915, 1920, 1925, 1930 1935, 1940, 1945, 1950, 1955, 1960, 1980, 1985, 1990	624
9	Fixed Assets in Service		5,867
10	Less: accumulated depreciation	2105	2,329
11			3,538
12	Construction in progress	2055	87
13			3,625
	Other long-term assets		
14	Regulatory assets	1460, 1465, 1470, 1508, 1518, 1525, 1548, 1550, 1555, 1556, 1570, 1580, 1582, 1584, 1586, 1588, 1590, 1592	245
15	Goodwill	2060	73
16	Deferred debt costs	1425	9
17	Long-term Accounts Receivable & Other Assets	2040	1
18	Other Long-term Assets		328
19	**TOTAL ASSETS**		**4,565**
	LIABILITIES		
	Current liabilities		
20	Inter-company demand facility	2240	68
21	Accounts payable and accrued charges	2205, 2210, 2215, 2220, 2290, 2292, 2294, 2296	394
22	Accrued interest	2268	21
23	Long-term debt payable within one year	2260	105
24	Current Liabilities		588
25	Long-term debt	2530	**1,990**
	Other long-term liabilities		
26	Employee future benefits other than pension	2306	444
27	Environmental liabilities	2320	37
28	Regulatory liabilities-retail settlement variance accounts	1550, 1580, 1582, 1584, 1586, 1588, 1584, 1586, 1592	5
29	Long-term accounts payable & accrued charges	2425	5
30	Other Long Term Liabilities		491
31	**TOTAL LIABILITIES**		**3,069**
32	Contingencies and commitments		**0**
33	Excess of assets over liabilities		**1,496**
34	**TOTAL LIABILITIES and EXCESS OF ASSETS OVER LIABILITIES**		**4,565**

HYDRO ONE NETWORKS INC.
2006 Distribution Financial Statements reconciled to USofA Trial balance

STATEMENT OF OPERATIONS (Year ended December 31, 2006)

	Financial Statement item	USofA Account/s	$ millions
	REVENUES		
34	Energy sales	4006, 4020, 4025, 4035, 4050, 4062, 4066, 4068, 4750, 4080	$ 2,740
35	Rural rate protection	4245	125
36	Other Revenue	4082, 4084, 4210, 4225, 4235, 4390, 4398, 4000	41
37	TOTAL REVENUE		2,906
	COSTS		
38	Purchased power	4705, 4710, 4730	1,954
	Operation, maintenance & administration		
39	Operation	4510 4845, 5005, 5010, 5012, 5014, 5015, 5016, 5017, 5020, 5025, 5030, 5035, 5040, 5045, 5050, 5055, 5060, 5065, 5070, 5075, 5085, 5090, 5095	41
40	Maintenance	5105, 5110, 5112, 5114, 5120, 5125, 5130, 5145, 5150, 5160 ,5165, 5170, 5172, 5175, 5178, 5185, 5186, 5190, 5192, 5195	196
41	Billing and Collecting	5310, 5315, 5320, 5330, 5335, 5340	104
42	Community Relations	5410, 5420, 5425	1
43	Administrative and General Expenses	4330, 6105, 6225, 6505, 5610, 5615, 5620 5625, 5630 5640, 5645, 5655, 5665, 5670, 5675, 5680	73
44			
45	Depreciation and amortization	5705, 5715, 5740, 4355	249
46	TOTAL COSTS		2,619
47	**Income before financing charges & provision for payments in lieu of corporate income taxes**		287
48	Financing charges	6005, 6010, 6035, 6040	115
49	**Income before provision for payments in lieu of corporate income taxes**		172
50	Provision for payments in lieu of corporate Income taxes	6110	46
51	**NET INCOME**		**$ 126**

RATING AGENCY REPORTS

Included in this Exhibit are copies of the most recent rating agency reports performed by Dominion Bond Rating Service, Moody's Investor Service and Standard & Poor's.

Attachment 1: Dominion Bond Rating Service, Report Dated: June 30, 2006
Attachment 2: Moody's Investor Service, Credit Opinion Dated: August 28, 2006
Attachment 3: Standard & Poor's, Report Dated: September 15, 2006
Attachment 4: Standard & Poor's, Research Update Dated: March 26, 2007
Attachment 5: Dominion Bond Rating Service, Report Dated: November 15, 2007
Attachment 6: Standard & Poor's, Report Dated: November 23, 2007
Attachment 7: Moody's Investor Service, Credit Opinion Dated: December 7, 2007

Credit Rating Report

Hydro One Inc.

Report Date: June 30, 2006
Press Released: June 23, 2006
Previous Report: February 4, 2005

Matthew Kolodzie, CFA/Nick Dinkha, CFA
416-593-5577 x2296/x2314
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Rating

Rating	Trend	Rating Action	Debt Rated
R-1 (middle)	Stable	Upgraded	Commercial Paper
A (high)	Stable	Upgraded	Senior Unsecured Debentures

(All figures in Canadian dollars, unless otherwise noted.)

Rating History

	Current	2005	2004	2003	2002	2001	2000
Commercial Paper	R-1 (middle)	R-1 (low)	R-1 (low)	R-1 (low)	R-1 (low)	R-1 (low)	R-1 (low)
Senior Unsecured Debentures	A (high)	A	A	A	A	A	A

Rating Update

On June 23, 2006, Dominion Bond Rating Service ("DBRS") upgraded the rating on the Senior Unsecured Debentures of Hydro One Inc. ("Hydro One" or the "Company") to A (high) with a Stable trend from "A" with a Positive trend, and upgraded the rating on Hydro One's Commercial Paper to R-1 (middle) from R-1 (low), also with a Stable trend. Key factors supporting the upgrade include: (1) improvements to the regulatory framework in Ontario in recent years; (2) the supportive political environment for the electricity industry; and (3) the expectation that Hydro One's financial profile, which has seen material improvement since 2002, will remain strong over the medium to longer term.

The regulatory framework in Ontario has stabilized over the past two years, and recent decisions by the Ontario Energy Board ("OEB") have been supportive of Hydro One's regulated operations. For example, in its latest decision on Hydro One's transmission operations (February 21, 2006), the OEB stated that it is mindful of the fact that heavy handed regulation is not good for investor confidence. This is an important consideration at a time when Hydro One will experience increased capital investment requirements to address transmission system constraints that have been identified by the Independent Electricity System Operator ("IESO"). In addition, for the first time since 1999, Hydro One's distribution rate base has been adjusted to reflect investments made over the past five years. While there is a level of uncertainty regarding the rate setting process beyond 2006, DBRS is of the view that the OEB will continue to be supportive and allow for full cost of service recovery and the ability to earn a fair market-based rate of return. DBRS is of the view that the current government is unlikely to interfere with the ratemaking process for regulated transmission and distribution operators as it has made a strong commitment to ensuring that ratepayers pay the full cost of electricity production and supply.

The key challenge for Hydro One will be managing potentially over $2.0 billion in transmission upgrades and conservation and demand management initiatives (i.e., smart meters) over the next five years. Cash flow from operations is expected to remain near $900 million annually over the next few years, but will be insufficient to fully fund capital expenditures and dividends. The annual shortfall will be funded with debt. Despite the cash flow shortfall, total adjusted debt-to-capital is expected to remain around 55% over the medium term as Hydro One's equity will experience modest growth through retained earnings. (Continued on page 2.)

Rating Considerations

Strengths:
- Involved primarily in regulated activities
- Attractive Ontario-based business franchise
- Strong and supportive shareholder – Province of Ontario

Challenges:
- Regulatory risk/risk of political intervention
- Low regulatory returns
- Lack of access to equity markets

Financial Information

	12 mos.	For the year ended December 30				
	Mar. 31, 2006	2005	2004	2003	2002	2001
Fixed-charges coverage (times)	3.07	3.05	2.92	2.75	2.33	2.44
Adjusted total debt-to-capital	54.0%	52.4%	54.1%	54.9%	56.4%	56.1%
Cash flow-to-adjusted total debt	17.7%	18.4%	17.5%	16.6%	13.8%	14.1%
Cash flow/capital expenditures (times)	1.34	1.37	1.27	1.43	1.27	1.25
Net income ($ millions) (adj. for non-recurring, after pfd.)	486	465	412	378	341	356
Cash flow from operations ($ millions)	962	946	920	855	725	708
Approved ROE	9.88%	9.88%	9.88%	9.88%	9.88%	9.88%
Deemed common equity in capital structure	36.0%	36.0%	36.0%	36.0%	36.0%	36.0%

The Company

Hydro One Inc., one of the successor companies of the former Ontario Hydro, holds and operates electricity transmission and distribution assets, as well as a fibre-optic network across most of Ontario. Hydro One is the largest transmission operator in Ontario (servicing 95% of the province's transmission throughput), is the second largest electricity distributor in Ontario based on distribution throughput, and is the largest based on the number of customers. The Company is wholly owned by the Province of Ontario (the "Province"), although the Province does not guarantee debt issued by Hydro One.

Authorized Commercial Paper Amount

Program limit is Cdn$750 million (authorized limit remains Cdn$1 billion).

RATING UPDATE CONTINUED

Fixed charges coverage is expected to remain in the 2.75 times to 3.00 times range and cash flow-to-adjusted total debt is expected to be in the 16% to 18% range. As such, Hydro One's financial profile is expected to remain adequate to support an A (high) rating over the medium to longer term, given the Company's stable regulated transmission and distribution (T&D) operations in Ontario and barring any unforeseen negative changes to the regulatory framework, or political agendas. DBRS notes that a recent draft proposal by OEB staff to reduce the allowed ROE on distribution operations to below 9.0% would erode Hydro One's expected financial profile should this recommendation be ultimately adopted in future OEB decisions. However, impact on Hydro One's credit metrics cannot be assessed until the OEB's consultation process is complete and a final decision is made.

REGULATION

Hydro One's electricity distribution and transmission subsidiary (Hydro One Networks) is regulated by the OEB under the *Electricity Act*, 1998 (the "Electricity Act"), with the following noteworthy amendments:

- The *Electricity Pricing, Conservation and Supply Act*, 2002 ("Bill 210") – December 9, 2002.
- The *Ontario Energy Board Amendment Act* (Electricity Pricing), 2003 ("Bill 4") – December 18, 2003.
- The *Electricity Restructuring Act*, 2004 ("Bill 100") – December 9, 2004.

Hydro One's deemed capital structure is 36% common equity, 4% preferred equity, and 60% debt. Revenues from distribution operations are based on a fixed service charge and a volumetric charge, whereas revenues from transmission operations are based on peak monthly demand. The following is a summary of the regulatory framework for Hydro One's transmission and distribution operations.

Transmission:

On February 21, 2006, the OEB released its latest decision on Hydro One's transmission operations. This rate decision did not address any change in transmission rates, in fact transmission rates are still based on Hydro One's 2000 revenue requirements for transmission. The purpose of this rate decision was to deal with what the OEB had viewed as over-earnings by Hydro One's transmission operations. This has been achieved through the establishment of an earnings sharing mechanism, which will remain in place until transmission rates are addressed with a full rate hearing, likely some time in 2007. Key highlights of this latest decision are:

- The allowed ROE of 9.88% for transmission operations will remain in place until a new rate is established, likely in 2007.
- Any excess earnings, above an ROE of 9.88%, will be shared 50/50 with customers.

Distribution:

On November 11, 2005, the OEB set the allowable ROE for all Ontario local distribution companies (LDCs) at 9.00% (down from 9.88% in 2005).

On April 12, 2006, the OEB issued its rate decision on Hydro One's 2006 distribution rate application, with new distribution rates becoming effective on May 1, 2006. Hydro One elected to use the 2006 test year in its 2006 distribution rate application. The following are highlights of this rate decision:

- An approved rate base for distribution operations of $3,711 million. This represents the first rate base increase since the Electricity Act was implemented, which was set based on Hydro One's 1999 distribution rate base of $2,637 million.
- An approved debt rate of 6.24% on long-term debt and 3.33% on short-term debt, equivalent to a blended debt rate of 5.93% (53.7% of Hydro One's deemed capital structure for distribution is comprised of long-term debt and 6.3% is comprised of unfunded short-term debt).
- A $0.30 per residential customer per month as a result of the OEB's generic decision on Smart Metering.
- The total approved revenue requirement for Hydro One's distribution operations is $965 million, an overall increase of $130 million from the previously approved revenue requirement.
- The OEB disallowed Hydro One's proposal to harmonize distribution rates amongst all its customers, including LDCs the Company acquired in 2001.

Generic Cost of Capital (Distribution):

- On April 27, 2006, the OEB indicated its intent to establish a multi-year electricity distribution rate-setting plan for all LDCs in Ontario, which will include:
  - A generic cost of capital to be used in adjusting annual revenue requirements for 2007 and beyond, and
  - A mechanistic incentive rate adjustment for the period.
- The initial term of the multi-year plan will be three years, beginning with the 2007 rate adjustment.
- On June 19, 2006, the OEB posted on its website a draft report of Board staff containing staff's initial proposals for both the cost of capital and the second generation incentive regulation mechanism. The OEB intends to issue a second draft on July 20, 2006.
- DBRS notes that Hydro One's recent ratings upgrade is premised on the Company's reduced business risk profile associated with improvements to the regulatory framework and the supportive political environment that has materialized in recent years, together with improved credit metrics. In its draft report, Board staff has recommended an allowed ROE range of well below 9.0% for distribution operations (in the range of 7.52% to 8.36%), which would have a material negative impact on cash flow-to-debt and interest coverage ratios for Hydro One, especially if the same ROE range subsequently gets adopted for transmission operations.

However, it is too early to determine the impact on credit metrics until the consultation and review process is completed and a final decision is made. Furthermore, DBRS notes that due to past government intervention in the regulatory process, Hydro One's distribution operations earned well below the previous 9.88% ROE.

RATING CONSIDERATIONS

Strengths: (1) Almost all of Hydro One's assets and earnings are in regulated electricity T&D operations. Despite political interference in the Ontario electricity sector in the past, the current regulatory framework is supportive of Hydro One's T&D operations and is expected to remain supportive over the near to medium term. As such, T&D operations are expected to continue to provide a high degree of stability to Hydro One's earnings and financial profile. DBRS highlights a statement in Hydro One's most recent transmission decision, whereby the OEB indicated that in formulating its rate decision it was mindful not to diminish investor confidence in the utility by heavy handed regulatory actions. This is an important consideration, given the investment that Hydro One will have to make in upgrading the Ontario transmission grid over the coming years.

(2) Hydro One's transmission franchise area is one of the strongest in Canada, given that it covers virtually all of Ontario. While the Company's distribution franchise is less attractive, as it includes a large geographic area (most of rural Ontario outside major urban centres) with a low population density/high cost of service, the acquisition of 88 municipal electric utilities in 2001 has reduced unit costs and the regulatory framework provides full cost of service recovery with a market-based rate of return.

(3) While Hydro One faced a high degree of political interference during the previous government's mandate, the Province of Ontario (currently rated AA with a Stable trend by DBRS) continues to be a strong and supportive shareholder to the Company. The Province's support has been demonstrated in the past by various actions, including the provision of a line of a credit in 2002 when Hydro One was unable to access the capital markets. DBRS notes, however, that the rating on Hydro One is a stand-alone rating and is not guaranteed by the Province.

Challenges: (1) The key challenge facing Hydro One is regulatory risk and the risk of political intervention. Regulatory risk is an inherent challenge for any regulated utility given that the regulatory framework essentially dictates the maximum profitability that can be achieved and the degree of protection to bondholders. While some uncertainty exists regarding the regulatory framework beyond 2006, DBRS expects the OEB to remain supportive by continuing to allow full cost of service recovery with a market-based rate of return on regulated T&D operations. The key risk with respect to political intervention would be the imposition of a rate freeze, as was seen in 2002, which was at a time of high electricity prices and near a provincial election. However, DBRS believes the risk of political intervention in the rate-setting process is relatively low under the current provincial government's tenure, as this government has made a strong commitment to passing along the full cost of power to electricity ratepayers.

(2) The ROE of 9.0% for Ontario electricity distribution and 9.88% for electricity transmission is low in comparison with similar regulated utilities in the U.S., which are typically in the 10% to 12% range. As such, cash flow and coverage ratios for regulated utilities in Ontario will typically be lower than for similarly regulated utilities in the United Staes. However, the regulated rates of return for Ontario utilities are currently in line with the lower rates of return typically granted to regulated utilities in Canada. DBRS notes, however, that the Board staff recommendation of an ROE in the range of 7.52% to 8.36% will be lower than any other jurisdiction in Canada, placing additional pressure on credit metrics. Furthermore, there is a risk that lower ROEs for regulated utilities in Canada may make access to capital more challenging in the future, given that foreign content limits for investors have been eliminated by the Canadian government.

(3) Hydro One does not have access to the equity capital markets, as it is 100%-owned by the Province of Ontario. This limits the Company's financial flexibility, especially given its significant capital development commitments with respect to improving the reliability of the transmission grid. However, given the support of the provincial government, DBRS would expect Hydro One to reduce its dividends to the Province in order to support its equity base.

EARNINGS AND OUTLOOK

Income Statement	12 mos. ended	For the year ended December 31 (1)				
($ millions)	March 30, 2006	2005	2004	2003	2002	2001
Net revenues	2,271	2,285	2,189	2,186	2,173	2,199
EBITDA	1,473	1,493	1,418	1,391	1,366	1,375
EBIT	990	1,006	938	937	955	991
Gross interest expense	296	303	294	315	381	378
Net income (adjusted for non-recurring items, before prefs.)	504	483	430	396	359	374
Net income (after preferred dividends)	486	465	480	378	326	356
Return on average common equity (before non-recurring)	11.1%	10.8%	11.8%	9.7%	8.7%	9.7%

Segmented Information		12 mos. ended	For the year ended December 3				
($ millions)	%	March 30, 2006	2005	2004	2003	2002	2001
Net revenues:							
Transmission	56%	1,280	1,310	1,262	1,298	1,317	1,259
Distribution	43%	969	954	910	862	824	893
Other	1%	22	21	17	26	32	47
Total net revenues		2,271	2,285	2,189	2,186	2,173	2,199
Earnings before interest and taxes:							
Transmission		680	711	665	688	741	686
Distribution		319	305	284	252	263	339
Other		(9)	(10)	(11)	(3)	(49)	(34)
Total EBIT		990	1,006	938	937	955	991
Transmission throughputs (TWh)		n/a	157.0	153.4	151.7	153.2	146.9
Distribution throughputs (TWh)		29.3	29.7	28.5	27.9	27.1	21.3

n/a = not applicable.

Summary:

- The increase in EBIT in 2005 was largely a result of: Higher transmission revenues due to higher monthly peak demand in 2005 resulting from an abnormally hot summer, and
  - Earnings from distribution operations that were also positively impacted by weather as well as the collection of various regulatory deferrals.
- In general, EBIT has remained relatively stable over the past five years, in the $935 million to $1 billion range, which is reflective of the company's regulated operations.
- Interest expense has remained largely unchanged over the past three years, reflective of the Company's relatively stable debt levels.

Outlook:

- EBIT is expected to drop to near the $900 million range for 2006, under a more normal weather scenario (versus the more extreme weather experienced in 2005), and grow at a modest pace along with growth in rate base.
  - Also contributing to the lower EBIT is higher OM&A, resulting from an increase in pension contributions and increased spending on reliability-related maintenance.
- Furthermore, the earnings sharing mechanism for transmission operations will have a modestly negative impact on earnings in comparison to previous years.
- Earnings from one year to the next will continue to be sensitive to changes in monthly peak demand for electricity given the current regulatory framework for transmission.
- While there is a level of uncertainty regarding the rate setting process beyond 2006, DBRS is of the view that the OEB will continue to be supportive and allow for full cost of service recovery and the ability to earn a fair market-based rate of return.

FINANCIAL PROFILE

Statement of Cash Flow	12 mos. ended	For the year ended December 31				
($ millions)	March 31, 2006	2005	2004	2003	2002	2001
Net income adjusted for non-recurring items, after pfd.	486	465	412	378	341	356
Depreciation & amortization	446	446	446	417	384	352
Amortization of debt re-couponing	55	59	62	60	-	-
Other recurring non-cash items	(25)	(24)	-	-	-	-
Cash Flow From Operations	962	946	920	855	725	708
Capital expenditures	(719)	(691)	(727)	(597)	(570)	(566)
Common dividends	(343)	(273)	(247)	(226)	(174)	(240)
Free Cash Flow Before Working Capital Changes	(100)	(18)	(54)	32	(19)	(98)
Change in working capital	88	194	(33)	138	(199)	188
Net Free Cash Flow	(12)	176	(87)	170	(218)	90
Other investments/acquisitions/disposition	9	9	19	3	27	(447)
Other non-recurring adjust., incl. retail settlement variance	2	2	6	21	(52)	-
Net debt financing	121	(188)	83	(184)	232	357
Net equity/other financing	1	1	7	(12)	-	-
Net change in cash	121	0	28	(2)	(11)	0
Fixed charges coverage (times)	3.07	3.05	2.92	2.75	2.33	2.44
Adjusted debt-to-capital*	54.0%	52.4%	54.1%	54.9%	56.4%	56.1%
Cash flow/adjusted total debt (times)*	17.7%	18.4%	17.5%	16.6%	13.8%	14.1%
Cash flow/capital expenditures (times)	1.34	1.37	1.27	1.43	1.27	1.25

*Adjusted for equity treatment of preferred shares.

Summary:

- •• Cash flow from operations improved modestly in 2005 and for the 12-months ended March 31, 2006, but remained insufficient to fully fund capital expenditure requirements and dividends.
- •• However, a significant positive change in working capital funded the shortfall in 2006, as well as $188 million in net debt repayment.
- •• Cash flow-to-debt and interest coverage ratios have continued to improve over the past few years, and are well within the range of an A (high) T&D utility with a supportive regulatory framework.

Outlook:

- •• Cash flow from operations is expected to remain near $900 million annually over the next few years, but will remain insufficient to fully fund capital expenditures and dividends. The shortfall is expected to be funded with debt.
  - •• Annual capital expenditures (maintenance and upgrades) are expected to be in the $750 million to $800 million range as Hydro One continues to focus on transmission upgrades to mitigate critical system constraints, and
  - •• Dividends will likely be in the $250 million to $275 million range.
- •• Despite the cash flow shortfall, total adjusted debt-to-capital is expected to remain around 55% over the medium term as Hydro One's equity will experience modest growth through retained earnings.
- •• Fixed charges coverage is expected to remain in the 2.75 times to 3.00 times range and cash flow-to-adjusted total debt is expected to remain in the 16% to 18% range.
- •• As such, Hydro One's financial profile is expected to remain adequate to continue to support the A (high) rating over the medium term, given the Company's stable regulated T&D operations in Ontario.

LONG-TERM DEBT MATURITIES AND BANK LINES

As of June 30, 2006

	2006	2007	2008	2009	2010	2011-2015	2016 & thereafter	Total
$ (millions)	141	395	500	400	400	850	2,500	5,185
Avg. coupon	4.2%	4.4%	4.0%	4.0%	7.2%	6.0%	6.6%	5.6%

Long-Term Debt:

- •• Hydro One currently has available $1.95 billion on its $2.5 billion MTN Shelf, which was established in June 2005. The majority of funds received from the issuance of MTNs under its Shelf have been used to refinance maturing debt.
- •• Hydro One faces a manageable level of term debt maturities over the next five years. Maturities will likely be refinanced with debt issued under the above-noted Shelf.

Bank Lines and Commercial Paper:

- In August 2004, Hydro One reduced its syndicated committed bank lines to $750 million from $1 billion and, consequently, reduced the limit on its commercial paper program to $750 million.
  - However, the authorized Board limit on its commercial paper program remains $1 billion.
  - Hydro One has a $750 million committed 364-day revolving credit facility, maturing in August 2006. DBRS expects this to be extended.
- As at March 31, 2006, Hydro One had $40 million of commercial paper outstanding.

Hydro One Inc.

Balance Sheet
($ millions)

Assets	Mar. 31, 2006	As at December 31 2005	2004	**Liabilities & Equity**	Mar. 31, 2006	As at December 31 2005	2004
Cash + short-term investments	119	-	-	Short-term debt	10	9	49
Accounts receivable	724	622	707	L.t. debt due one year	589	589	539
Material and supplies	62	56	47	A/P + accr'ds	691	743	674
Current Assets	905	678	754	**Current Liabilities**	1,290	1,341	1,262
Net fixed assets	10,197	10,116	9,813	Long-term debt	4,778	4,466	4,613
Post-employment benefits	433	449	534	Post-employ. benefits	739	716	654
Def'd debt costs + long-term rec.	35	43	48	L.t. pay. + other liab.	613	610	672
Regulatory asset	426	430	443	Preferred shares	323	323	323
Goodwill	133	133	133	Shareholders' equity	4,386	4,393	4,201
Total	12,129	11,849	11,725	**Total**	12,129	11,849	11,725

Ratio Analysis	12 mos.	For the year ended December 31						
Liquidity Ratios	Mar. 31, 2006	2005	2004	2003	2002	2001	2000	1999
Current ratio	0.70	0.51	0.60	0.55	0.37	0.37	0.55	0.58
Acc. depreciation/gross fixed assets	36.7%	36.5%	35.8%	35.3%	34.5%	33.6%	32.5%	31.5%
Cash flow/total debt (1)	17.9%	18.7%	17.7%	16.9%	13.9%	14.3%	14.9%	15.1%
Cash flow/adj. total debt (1)	17.7%	18.4%	17.5%	16.6%	13.8%	14.1%	14.7%	15.1%
Adj. total debt/EBITDA	3.69	3.44	3.71	3.69	3.86	3.65	3.65	3.62
Cash flow/capital expenditures	1.34	1.37	1.27	1.43	1.27	1.25	1.54	1.39
Cash flow-dividends/capital expenditures	0.86	0.97	0.93	1.05	0.97	0.83	0.71	1.39
Total debt-to-capital (1)	53.3%	51.8%	53.5%	54.2%	55.7%	55.4%	53.5%	54.6%
Total adjusted debt-to-capital (1)	54.0%	52.4%	54.1%	54.9%	56.4%	56.1%	54.2%	54.6%
Average coupon on long-term debt	5.62%	5.61%	5.60%	5.50%	7.60%	8.05%	8.13%	7.70%
Hybrids/common equity	7.4%	7.4%	7.7%	8.1%	8.5%	8.8%	8.8%	0.0%
Deemed common equity	36.0%	36.0%	36.0%	36.0%	36.0%	36.0%	36.0%	36.0%
Common dividend payout (before extras.)	70.6%	58.7%	60.0%	59.8%	51.0%	67.4%	58.7%	38.6%
Coverage Ratios (2)								
EBIT interest coverage	3.36	3.34	3.20	3.00	2.51	2.63	2.50	2.45
EBITDA interest coverage	4.99	4.94	4.83	4.44	3.59	3.65	3.42	3.29
Fixed-charges coverage	3.07	3.05	2.92	2.75	2.33	2.44	2.30	2.32
Earnings Quality/Operating Efficiencies & Statistics								
Operating margin	43.6%	44.0%	42.9%	42.9%	43.9%	45.1%	43.5%	45.6%
Net margin (before extras., after pfd.)	21.4%	20.4%	18.8%	17.3%	15.7%	16.2%	17.0%	18.7%
Return on avg. common equity (before extras.)	11.1%	10.8%	10.1%	9.7%	9.1%	9.7%	9.4%	12.7%
Approved ROE	9.88%	9.88%	9.88%	9.88%	9.88%	9.88%	9.88%	9.35%
Rate base - transmission ($ millions)	5,718	5,718	5,718	5,718	5,718	5,718	5,718	5,638
Rate base - distribution ($ millions)	2,637	2,637	2,637	2,637	2,637	2,637	2,445	2,467
Distribution lines (km)	n/a	122,118	121,736	121,285	120,767	120,448	113,880	113,400
Transmission lines (km)	n/a	28,547	28,643	28,621	28,492	28,387	28,490	28,889
Transmission throughputs (TWh)	n/a	157.0	153.4	151.7	153.2	146.9	146.9	144.1
Distribution throughputs (TWh)	29.3	29.7	28.5	27.9	27.1	21.3	17.6	18.1

(1) Adjusted for equity treatment of preferred shares.
(2) EBIT includes interest income; interest expense is gross interest expense.

n/a = not applicable.

Credit Opinion: Hydro One Inc.

Hydro One Inc.

Toronto, Ontario, Canada

Ratings

Category	Moody's Rating
Outlook	Stable
Senior Unsecured -Dom Curr	Aa3
Commercial Paper	P-1

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Key Indicators

Hydro One Inc.

	[1]LTM	2005	2004	2003	2002
(CFO Pre-W/C + Interest) / Interest Expense [2]	3.4x	3.3x	3.3x	3.2x	2.6x
(CFO Pre-W/C) / Debt	15.4%	16.2%	15.4%	16.0%	11.2%
(CFO Pre-W/C - Dividends) / Debt	9.9%	11.7%	11.4%	12.1%	8.4%
(CFO Pre-W/C - Dividends) / Capex	90.8%	107.9%	102.2%	121.5%	88.5%
Debt / Book Capitalization	63.5%	62.8%	64.2%	63.6%	67.0%
EBITA Margin %	25.0%	26.4%	25.3%	27.0%	24.3%

[1] Last 12 months to June 30, 2006 [2] CFO pre-W/C, which is also referred to as FFO in the Global Regulated Electric Utilities Rating Methodology, is equal to net cash flow from operations less net changes in working capital items

Note: For definitions of Moody's most common ratio terms please see the accompanying User's Guide.

Opinion

Company Profile

Hydro One Inc. (HOI) is wholly owned by the Province of Ontario. Its revenues and cash flows are almost completely derived from its transmission and distribution businesses, both of which are regulated by the Ontario Energy Board (OEB). HOI owns and operates virtually all of Ontario's electricity transmission system, and is responsible for a substantial portion of regulated electricity distribution in the province.

Recent Developments

HOI's Aa3 senior unsecured rating reflects the application of Moody's July 2006 rating methodology update for government-related issuers (GRIs), which describes the publication of baseline credit assessments (BCAs) on a 1-21 scale. Please refer to Moody's Rating Methodology entitled "The Application of Joint Default Analysis to Government-Related Issuers", published in April 2005, and its accompanying press release, for further background, as well as Moody's July 2005 Special Comment entitled "Rating Government-Related Issuers in Americas Corporate Finance" for a detailed discussion of the application of joint default analysis to GRI's in the Americas.

Rating Rationale

In accordance with Moody's GRI rating methodology, the Aa3 ratings of HOI reflect the combination of the following inputs:

- BCA in the range of 5 to 7 (on a scale of 1 to 21, where 1 represents the equivalent risk of a Aaa, 2 a Aa1, 3 a Aa2 and so forth)

- Aa2 local currency rating of the province of Ontario

- High dependence

- High support

The BCA range of 5 to 7 reflects HOI's stable and predictable cash flows and the low business risk of its regulated wires businesses. The BCA also reflects HOI's limited ability to raise equity and the potential that HOI can be utilized as an instrument of public policy. As demonstrated by the rate cap provisions of Bill 210 introduced in 2002, public policy goals are not always completely aligned with the interests of debtholders. HOI's financial metrics are consistent with those of other regulated utilities with a BCA of 5 to 7 in the low business risk category.

Going forward, HOI faces potentially significant credit challenges in terms of the evolution of the regulatory environment, capital spending pressures and an aging labour force. While a measure of relative regulatory and political stability has emerged over the last few years, the company is currently in the midst of two regulatory processes, the outcomes of which could have significant impact on the company's financial condition. Firstly, as part of the OEB's multi-year electricity distribution rate setting plan, OEB staff have tabled a discussion paper setting forth staff's proposal for establishing the cost of capital for rate-making purposes and establishing a 2nd generation incentive regulation mechanism (2nd Generation IRM) applicable to Ontario's electricity distributors (LDCs). Moody's notes that staff's cost of capital proposal is subject to change following stakeholder consultation and ultimately review by the OEB panel. However, if staff's cost of capital proposal, and in particular its allowed ROE formula, is adopted without change, Moody's believes it would likely result in a weakening of HOI's cash flow credit metrics which could place downward pressure on the company's BCA. Staff's proposal contemplates a capital structure common to all LDCs which would be comprised of 40% common equity and 60% debt. However, any actual preferred equity outstanding up to 4% of rate base would be captured within the 40% common equity component. Assuming that over time HOI's preferred equity will represent a diminishing portion of the capital structure, staff's proposal would allow HOI to increase its common equity thickness relative to the 36% common equity component currently used in determining HOI's distribution rates. However, Moody's believes that any benefit of thicker equity would be more than offset by an ROE that could be 50 to 100 bps below those of other regulated utilities in Canada. The staff proposal also outlines an annual adjustment to the cost of capital calculation which would be one component of the price cap mechanism for annually adjusting distribution rates under the 2nd generation IRM. In Moody's view, the benefits of transparent mechanisms for the adjustment of ROE, cost of capital and distribution rates would be more than offset by the reduced cash flows that staff's cost of capital proposal implies.

The second major regulatory process is HOI's 2007-2008 transmission rate application which is expected to be filed in the third quarter of 2006. While the outcome of that hearing cannot be determined at this time, it would seem likely that OEB staff would propose an allowed ROE/cost of capital mechanism for HOI's transmission business that is similar to that which it proposes for Ontario's electricity distributors. Given that HOI's transmission business represents approximately 65% of the company's assets and operating profit, Moody's would be concerned about the potential for material weakening of HOI's cash flows.

HOI expects to have large capital expenditure needs for a number of years. In addition to ongoing maintenance capital expenditures, the company expects to incur significant capex in support of the Ontario Power Authority's (OPA) pending Integrated Power System Plan (IPSP) and the provincial government's smart meter initiative. The OPA's IPSP, which is scheduled to be published in March 2007, is expected to call for significant expansion/reinforcement of Ontario's transmission grid in support of the government's objectives concerning generation supply mix, increased renewables generation and increased grid efficiency/congestion reduction. In addition, HOI anticipates that it will be required to spend between $600 million and $1.2 billion between 2007 and 2010 to fulfill its role in achieving the government's objective of installing smart meters in all Ontario homes and businesses by 2010. During 2007 and 2008 the company forecasts capital expenditures in excess of approximately $1.2 billion per year. Moody's estimates that approximately $1.4 billion will be required for transmission capital expenditures in 2007 and 2008. The balance of roughly $1 billion will be spent on the distribution side with approximately 40% being spent on smart metering. HOI's smart meter expenditures are currently being recorded in a regulatory deferral account. While Moody's expects that HOI will be afforded the opportunity to fully recover its smart meter costs, the timing of cost recovery is uncertain, as the period over which these cost are recovered has yet to be determined. Moody's notes that to some degree both the quantum and the timing of IPSP and smart meter expenditures are outside of HOI's control. HOI anticipates that it will fund a portion of the forecast capital expenditures with internally generated cash flows and the balance with debt. Given the province's ownership of HOI, the company has limited access to additional equity. Moody's estimates that, in the absence of a significant reduction in its dividend payout, HOI's FFO interest coverage and FFO/Debt ratios could come under pressure as a result of the company's capital expenditure needs.

The extent of HOI's capital expenditures over the next few years highlights another challenge that HOI and many other utilities face: that of an aging workforce. According to the company, approximately 25% of its workforce is eligible for retirement by 2008. The availability and cost of skilled labour necessary to successfully complete the work required under the forthcoming IPSP and the province's smart meter plan as well as HOI's ongoing system operation and maintenance could prove to be a challenge.

High dependence reflects the importance of the issuer to the provincial economy and its operating and financial proximity to the government.

High support reflects the strategic importance of the issuer to the province, the government's history of providing support through dividend deferrals in its capacity as a shareholder of the company and the government's history of intervening in the electricity sector.

Rating Outlook

The stable outlook is based on the predictable cash flow generated by HOI's regulated transmission and distribution businesses.

What Could Change the Rating - Up

- While considered unlikely at this time, a sustainable improvement in cash flow metrics (FFO interest coverage exceeding 4.5x and FFO/Debt exceeding 20%) related to increases in the deemed equity component and allowed ROE could result in a positive rating action

What Could Change the Rating - Down

- Reduced support level

- Downward revisions in ROE, undue reliance on debt to finance capital expenditures or other factors which lead to a sustained weakening of cash flow metrics (FFO interest coverage below 3.0x and FFO/Debt below the mid-teens)

- Actions on the part of the shareholder that impede the company's ability to act in a commercial manner

- Material changes in the ownership, governance or management structures

- Further restructuring of the electricity sector that increases HOI's business or financial risk profiles

Rating Factors

Hydro One Inc.

Select Key Ratios for Global Regulated Electric Utilities

Rating	Aa	Aa	A	A	Baa	Baa	Ba	Ba
Level of Business Risk	**Medium**	**Low**	**Medium**	**Low**	**Medium**	**Low**	**Medium**	**Low**
CFO pre-W/C + Interest to Interest (x) [1]	>6	>5	3.5-6.0	3.0-5.7	2.7-5.0	2-4.0	<2.5	<2
CFO pre-W/C to Debt (%) [1]	>30	>22	22-30	12-22	13-25	5-13	<13	<5
CFO pre-W/C - Dividends to Debt (%) [1]	>25	>20	13-25	9-20	8-20	3-10	<10	<3
Total Debt to Book Capitalization (%)	<40	<50	40-60	50-70	50-70	60-75	>60	>70

[1] CFO pre-W/C, which is also referred to as FFO in the Global Regulated Electric Utilities Rating Methodology, is equal to net cash flow from operations less net changes in working capital items

STANDARD & POOR'S

Corporate Ratings

Hydro One Inc.

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RatingsDirect
Publication Date
Sept. 15, 2006

Corporate Credit Rating

A/Stable/A-1

Financial risk profile:

Moderate

Debt maturities:*

2006 C$589 mil.
2007 C$395 mil.
2008 C$500 mil.
2009 C$400 mil.
2010 C$400 mil.
2011 C$250 mil.
2012 C$600 mil.
2030 and beyond C$1,950 mil.
*Maturities as of Dec. 31, 2005

Major Rating Factors

Strengths:

- Low-risk electricity transmission and distribution network businesses
- Monopoly position
- Regulated cash flows
- Supportive shareholder

Weaknesses:

- Moderate financial profile
- Large capital expenditure program

- Transmission and distribution revenues subject to some volumetric risk

Rationale

The ratings on Hydro One Inc. reflect the company's monopoly electricity transmission and distribution networks, relatively stable and secure cash flows, improved financial profile, and the support of its owner, the Province of Ontario (AA/Stable/A-1+). These strengths are offset by regulatory uncertainty, and the financial and operational risks associated with the company's large capital expenditure program.

Toronto-based Hydro One is the incumbent electricity transmission business and largest distributor of electricity in Ontario. The company owns and operates more than 97% of the province's transmission network as measured by revenue, and its distribution network service territory covers about 75% of the province. Hydro One's monopoly position and regulatory restrictions limit the risk of network bypass.

Hydro One's debt-servicing capacity is supported by the regulated returns it receives from its network businesses. The company's relatively secure and predictable earnings, which provide 99% of cash flows, reflect its low-risk assets. The regulated cash flows are determined on a cost-of-service and rate-of-return methodology such that the company recovers all prudent costs and a return on its capital investment.

Hydro One's funds from operations (FFO) interest and debt coverages are not expected to show improvement and could weaken in the next few years. In the four-year period from 2005-2008, the company will recover C$144 million in regulatory costs. FFO cash interest coverage is expected to remain substantially the same, at about 4.3x. FFO interest coverage could decline in the next few years from its three-year average and 2005 levels of 3.7x to 3.4x, respectively, assuming financially unfavorable outcomes of upcoming regulatory decisions and the eventual approval and execution of increased capital spending. The tempering effect of the refinancing of higher cost debt maturing in 2006 and 2007, and at today's lower interest rates, is factored into these projections. In the next two to three years, FFO-to-average total debt is also expected to decrease to about 15% from its 2005 level of 19%; incremental debt will be required to partially fund upcoming capital expenditures, some of which will not immediately contribute to cash flow. The company is expected to debt finance 20% or more of forecast capital expenditure in the next several years. Hydro One's leverage, as measured by total debt-to-total capital, is likely to creep back up to its historical level of 55%, as compared with 52% in 2005. The fall to 52% in 2005 was due in part to the redemption in late 2005 of C$109 million of notes due in January 2006.

The province's ownership of Hydro One enhances the utility's credit quality. Although the province does not formally guarantee Hydro One's debt obligations, the strategic nature of the company within the provincial economy and the government's demonstrated willingness to financially assist the business under extraordinary circumstances in the past bode well for future support.

Hydro One's operational and financial performance is subject to regulatory risk. The transparency, predictability, and stability of the regulatory regime governing the company's electricity transmission and distribution operations continue to improve. Nevertheless, political interference in the regulatory process in recent years and the transitioning nature of the regulatory environment pose ongoing risks for the company's cash flows. The outcome of the Ontario Energy Board's (OEB) ongoing generic cost-of-capital review will be used to determine rates for 2007 and beyond, and could affect the cash flow strength of Hydro One's distribution segment. Both the allowed returns and the regulatory capital structure are being examined by the regulator; a decision is expected before year-end.

Hydro One's underlying annual capital expenditure program carries financial and operational risk. Although predominantly funded from internal sources, expected capital expenditure (including smart meter investment) in the C$800 million-C$1.2 billion range per year in the next few years will be a drain on the company's cash flow and reduce its financial flexibility. Total capital expenditure of C$691 million in 2005 was below budget but is expected to rebound in 2006 and increase further in 2007 to the higher end of the forecast range. Capital spending estimates include the cost of installing smart meters for all distribution customers by 2010 as well as expected upgrades and expansion of the transmission system to accommodate growth in domestic demand, new generation facilities, and to facilitate increased imports and exports. A decision by the OEB earlier this year clarified that, like its other infrastructure investments, Hydro One's estimated C$600 million-C$1.2 billion investment in smart meters in the next four years will also be added to its revenue-generating regulated asset base.

Short-term credit factors

The short-term rating on Hydro One is 'A-1'. The company has adequate liquidity to meet debt maturities, capital expenditure requirements, and dividend commitments in 2006. Unused and committed bank lines, together with expected strong cash flows, ready access to the debt capital markets, and discretionary spending on capital expenditure, provide Hydro One with sufficient liquidity and the financial flexibility to meet its annual capital expenditure estimate of C$800 million-C$1.2 billion, annual dividend payments of C$250 million-C$300 million, and C$141 million of debt maturing in the remainder of 2006. As of June 30, 2006, the company had C$130 million short-term notes outstanding through its board-approved C$1 billion short-term note program.

In support of Hydro One's liquidity, the company can draw on:

- Committed and largely available bank lines estimated at about C$620 million as of June 30, 2006;
- Expected annual regulated cash flows in 2006, as represented by FFO, of about C$900 million;
- Its well-supported MTN shelf program, which had C$1.95 billion of available credit as of June 30, 2006; and
- Discretionary capital expenditure for 2006 estimated at about 15% of forecast.

Hydro One's bank lines consist of a C$750 million committed demand line of credit, with a syndicate of banks, maturing in August 2007. The committed demand facility also has a two-year term-out option. The bank line is used for general corporate purposes and to support its C$1 billion Canadian CP program.

The company is well within its banking covenant of total debt-to-total capital of 75% and has no material adverse change clauses that could trigger a default. A potential call on liquidity would happen in the event the credit rating on Hydro One fell to the 'BBB' category. This would trigger a tripling of Hydro One's prudential support to the independent market operator by way of bank LOCs, which can vary throughout the year from C$10 million-C$25 million.

Outlook

The stable outlook reflects the low-risk nature of the company's business and greater transparency and predictability of outcomes within the Ontario regulatory environment. Regulatory autonomy also has improved, although the potential for political intervention to override regulatory decisions remains. There are currently no forecast or expected scenarios within the current environment that would result in either a ratings downgrade or upgrade. Significant deterioration in the company's financial and operational performance could put pressure on the ratings, but such a scenario is relatively unlikely. Given the supportive and stable shareholder relationship, modest lowering of allowed returns in future regulatory determinations on the company's cash flow strength and the pressures of upcoming increased capital spending are not expected to lead to a negative outlook. A positive outlook or rating upgrade, although currently not forecast given upcoming capital spending plans, could result from a prolonged period of no political intervention in the regulatory environment governing the company's operations.

Business Description

Hydro One's operations primarily center on its low-risk electricity transmission and distribution operations that account for 99% of its consolidated assets and generate virtually all of its FFO. As part of its distribution operations, the company also undertakes regulated delivery of electricity to 1.3 million customers. In addition, the company markets surplus fiber optic capacity. Hydro One's 28,500-kilometer (km) high voltage provincial transmission grid accounts for about 55% of consolidated assets and is the second largest in Canada and is interconnected to neighboring Canadian provinces and northern states of the U.S. The company's 122,100-km distribution operation is also one of the country's largest. The distribution system covers approximately 75% of Ontario and delivers about 15% of the province's demand load.

The company is wholly owned by the Province of Ontario, which holds all the common and preferred shares outstanding. Hydro One's board of directors is appointed by the province and although the company's business plan and dividend policy are set by the board, they are reviewed by the government before implementation. The company's close relationship with its owner has been demonstrated through the provision of financial support in the past and, although no financial support can be assured in the future, the strategic importance of Hydro One to the economy of Ontario would suggest it is appropriate to factor into the ratings an element of implied support from Hydro One's higher rated owner.

Business Risk Profile

A stable regulatory regime supports credit quality

The OEB undertakes regulatory oversight of Hydro One's monopoly distribution and transmission operations. Hydro One's regulated cash flows are determined on a cost-of-service and rate-of-return methodology and although the relatively low allowed returns limit upside in cash flows and are subject to regulatory lag, nevertheless, they provide relative predictability and security of cash flow. The company's allowed economic return is based on a deemed (for regulatory purposes) equity component in its capital structure of 36%, on which an ROE (currently 9.0% for distribution and 9.88% for transmission in 2006, as compared with 9.88% for both in 2005) is allowed. Indications are that the ROE allowed for in Hydro One's rates for 2007 and beyond could drop further if OEB staff recommendations are adopted by the OEB in its upcoming generic cost-of-capital decision. Hydro One is also permitted to hold 4.0% of its capital in preferred equity on which a dividend rate of 5.5% is earned.

There is a long history of regulated entities in both Ontario and Canada being allowed to recoup unforeseen previously incurred costs (or regulatory assets) after the fact through rate riders. The cash recovery of these costs is subject to a prudency review and regulatory approval. For Hydro One, the current recovery of regulatory assets means additional annual cash flows in the period 2005-2007 of about C$35 million.

The regulatory regime in Ontario has shown signs of improved stability and predictability in recent times but remains subject to the risk of political intervention. The existing regime continues to provide for ministerial intervention, with the Minister of Energy retaining the ability to override decisions of the OEB, which is what occurred under the previous government. The political risk associated with the tariff-setting process weakens the supportive nature of the price regulation and continues to present a risk to the cash flows of electricity network operators such as Hydro One.

Hydro One's regulated retail services, undertaken as part of its distribution operations, are protected from commodity price and volume risk by OEB-regulated prices. The establishment of the government-sponsored Ontario Power Authority in 2004 to manage, among other functions, variance accounts for the regulated retail function of local distribution companies (LDCs) further removes a risk to Hydro One's cash flows and reduces demands on working capital. Customers not eligible for the regulated energy price pay the wholesale commodity price. Any regulatory or government action to remove the direct pass-through mechanism, or to require Hydro One to take on an obligation to ensure adequate supplies of energy to end-use customers, would have a negative influence on the ratings on Hydro One.

Ontario is Hydro One's primary market

Hydro One's primary market is the growing province of Ontario, which accounts for close to 40% of Canada's GDP. Although Hydro One's transmission operations service the entire province, the company's distribution business, apart from its Brampton network on the outskirts of Toronto, is largely rural based. Ontario's economy posted moderate growth of 2.8% in 2005 following 2.6% real GDP growth in 2004. The province is forecasting economic growth to remain in low gear, with real GDP expected to slow to 2.3% in 2006 and 2.5% in 2007, reflecting the impact of the sharp appreciation of the Canadian dollar, high oil prices, and deceleration of growth in the U.S. economy. GDP growth in Ontario, which has generally performed better than the national average, has also been reflected in higher throughput and growth in customer connections for Hydro One. Growth in distribution throughput was 4.0% in 2005 to 29,677 GWh, up from 2.0% growth experienced in 2004, while the company's distribution customer base of almost 1.3 million increased at a more modest rate of 1.2%, down slightly from 1.6% in 2004 and 2003.

The diversity of Hydro One's customer base supports the stability of its revenues and limits its exposure to any particular customer or customer class. A breakdown of contributors to the company's total revenue highlights the diversity of its customer base, with its province-wide transmission business contributing about 30% of revenues, residential customers of the distribution business contributing about 37%, commercial customers about 23%, and large industrials and embedded distributors about 3% and 6%, respectively. The company's top-10 customers are predominately LDCs and, although they account for a disproportionate percentage of energy delivered, their percentage of gross revenue is only about 2%. Furthermore, the vast majority of the larger LDCs supplied are investment-grade credits.

Operations are dominated by low-risk transmission and distribution

Hydro One's low-risk transmission and distribution businesses dominate its operations. The transmission business represents about 55% of fixed assets, and contributes about 60% of cash flow, while its distribution business largely comprises the remaining assets and cash flows. The company's regulated retail services, as part of its distribution operations, represent a small portion of assets and, despite contributing a significant amount of revenue, provide minimal cash flow benefits because of the direct pass-through of all energy costs to consumers. The company has a small telecommunications business that leases surplus fiber optic capacity. The telecommunications business represents only a minor part of Hydro One's operations, providing less than 1% of gross revenues and a similar portion of the company's fixed assets.

The operational performance of the company's transmission assets is quite good; however, the performance of its distribution assets is adversely affected by operational challenges not generally faced by more urban-based utilities in the Canadian industry and generally underperform relative to comparable utilities in the industry, as measured by the Canadian Electricity Association composite index (see table 1). A mitigating factor for the cash flows of the distribution business is the absence of penalties for underperformance.

Table 1

Hydro One Inc. Operational Performance—Reliability Measures

	2005	2004	2003*	2002	2001	2000
Distribution network						
CAIDI (minutes)	223.2	129.0	258.0	228.0	174.0	156.0
CEA composite index (minutes)	N.A.	120.0	130.0	102.0	90.0	84.0
SAIDI (minutes)	867.6	414.0	906.0	750.0	522.0	450.0
CEA composite index (minutes)	N.A.	237.0	307.0	246.0	222.0	192.0
SAIFI (interruptions)	3.9	3.2	3.5	3.2	3.0	2.9
CEA composite index (interruptions)	N.A.	2.0	2.4	2.3	2.4	2.3
Distribution energy losses (%)	6.8	6.9	6.8	7.2	7.5	N.A.
Transmission network						
SAIDI (minutes)	57.7	42.3	53.1	70.9	59.1	38.6
SAIFI (interruptions)¶	1.3	1.3	1.6	1.5	1.4	1.4
CEA composite index (interruptions)¶	N.A.	1.5	2.1	2.0	2.0	N.A.
System unavailability (%)	1.6	1.7	2.0	N.A.	N.A.	N.A.
Unsupplied energy (minutes)	13.7	12.9	18.2	N.A.	N.A.	N.A.
Transmission energy losses (%)	2.6	2.5	2.5	2.8	2.9	N.A.

*Hydro One's distribution network's reliability measures exclude Aug. 14, 2003, blackout. CEA's reliability measures exclude significant events, i.e., Aug. 14, 2003, blackout and Hurricane Juan. CAIDI—Customer average interruption duration index. ¶Figures reflect momentary and sustained interruptions. CEA—Canadian Electricity Association. SAIDI—System average interruption duration index. SAIFI—System average interruption frequency index. N.A.—Not available.

Hydro One's capital expenditure could increase about 1.5x in the next several years, from about C$800 million in 2006 to in excess of C$1.2 billion in 2007 and 2008, with about 55% being spent on its transmission assets. The focus of the capital expenditure is on developing, upgrading, and reinforcing the transmission and distribution systems, and on ensuring safety and reliability. Although the timing of these projects remains uncertain and the spending is significant, the company is not expected to undertake major projects without previous regulatory approval.

With a transmission network tariff levied on the basis of peak load, and its distribution tariff levied on per unit of energy delivered, a risk to Hydro One's cash flows is fluctuations in volumes of energy delivered. This risk has been highlighted in recent years with weather-induced reductions in volume contributing to falls in expected revenues. Although the variability in gross revenues is not overly significant relative to the company's total cash flows, the government's push for greater demand-side management has the potential to lower peak demand and slow down growth in electricity distributed, leading to marginally lower returns for the business.

A medium- to long-term risk to Hydro One's business and financial profiles is the impact of potential rationalization within the Ontario LDC sector in the coming years. Although not viewed as an immediate issue for the rating, Hydro One's expected active participation in such a scenario could present future financing, execution, and integration risks.

Asset-intensive nature of Hydro One's monopoly business reduces competitive risk

Although some competitive pressures exist, Hydro One's natural monopoly transmission system is largely shielded from direct competition. The company does not hold a legal monopoly over its service territory and there is no restriction on other transmission businesses building and operating transmission networks in Ontario; however, the company's cost-reflective pricing and the capital cost involved in large-scale duplication of the network reduce the risk of bypass. Furthermore, the OEB-approved uniform transmission pricing across Ontario mitigates the risk of bypass from competing transmitters and should a bypass occur, tariffs would be rebalanced across remaining customers with minimal financial impact on the company. Of greater concern is the company's exposure to the risk of lost revenue from embedded generation arising from high wholesale electricity prices.

Noncontiguous service territories of LDCs expose Hydro One to competition for new services in nondesignated areas adjacent to its distribution service territories. The issue presents a competitive challenge for the company, but a decision by the OEB in mid-2004 would appear to limit the risk to greenfield development at the border of existing service territories and not put at risk cash flows secured by Hydro One's existing network.

Profitability largely dictated by regulatory directives

Given the cost-plus nature of its regulatory framework, Hydro One's profitability is largely dictated by regulatory directives that currently provide the company with the ability to earn an ROE on a stable capital structure. The equity returns allowed for in the determination of rates are already low by international benchmarks and, subject to an OEB hearing in the fall of 2006, could decrease further and pressure the company's cash flow interest and debt coverages. Unlike its distribution network business, which has typically not earned its allowed ROE, the company's transmission assets have historically achieved more than the allowed ROE. An earnings sharing mechanism for the transmission business only was introduced by the regulator in 2006 with the utility to split, on a 50-50 basis, excess earnings above its allowed rate of ROA.

Financial Risk Profile

Accounting—it's business as usual

Hydro One's consolidated financial statements are prepared in accordance with Canadian GAAP. No material changes to Canadian GAAP or the accounting policies adopted by Hydro One are expected in the foreseeable future that would materially alter the financial statements as presented by Hydro One. Standard & Poor's Ratings Services treats Hydro One's C$323 million 5.5% cumulative preferred shares as equity. The shares are held by the province, and are entitled to an annual cumulative dividend of C$18 million. The shares rank in priority above the common shares upon liquidation. The adjusted interest coverage ratios (as presented in tables 2 and 3) reflect an interest expense that includes C$58 million in amortization of a refinancing discount, representing about 18% of total interest expense. In its analysis, Standard & Poor's removes the amortization expense from the interest expense to capture the cash cost of the interest paid.

Table 2

Hydro One Inc.—Peer Comparison*

Industry Sector: Electric Utilities—Canada

	—Average of past three fiscal years—				
	Sector Median¶	**Hydro One Inc.**	**Toronto Hydro Corp.**	**Hamilton Utilities Corp.**	**Hydro Ottawa Holding Inc.**
Rating		A/Stable/A-1	A-/Stable/—	A/Stable/—	A-/Stable/—
(Mil. C$)					
Sales	901.6	4,209.0	2,445.7	452.2	639.4
Net income from cont. oper.	85.8	459.0	96.0	10.5	13.6
Funds from oper. (FFO)	215.0	938.0	233.6	29.1	44.3
Capital expenditures	124.7	671.7	141.9	22.1	73.1
Total debt	1,213.0	5,131.0	1,217.2	105.2	230.3
Preferred shares	7.3	323.0	N/A	N/A	N/A
Total capital	2,398.3	9,641.3	2,023.8	280.6	450.0
Ratios					
EBIT interest coverage (x)	2.6	2.7	3.0	3.3	2.1
FFO interest coverage (x)	3.3	3.5	3.8	4.8	3.8
Return on common equity	10.0	10.7	12.4	6.5	6.3
NCF/capital expenditures (%)	83.6	100.3	135.6	89.2	60.3
FFO/total debt (%)	18.7	18.3	19.3	27.7	18.9
Total debt/capital (%)	52.9	53.2	60.1	37.5	51.2

*Adjusted by capital operating leases. ¶For the fiscal years ended 2001-2004. N/A—Not applicable. NCF—Net cash flow.

Table 3

Hydro One Inc.—Financial Statistics*

Industry Sector: Electric Utilities—Canada

	—Average of past three fiscal years—	2005	2004	2003	2002	2001
Rating		A/Stable/A-1	A/Stable/A-2	A-/Negative/A-2	A/Watch Neg/A-1	AA-/Stable/A-1+
(Mil. C$)						
Sales	4,209.0	4,416.0	4,153.0	4,058.0	4,044.0	3,466.0
Net income from cont. oper.	459.0	483.0	498.0	396.0	344.0	374.0
Funds from oper. (FFO)	938.0	976.0	944.0	894.0	691.0	726.0
Capital expenditures	671.7	691.0	727.0	597.0	570.0	566.0
Total debt	5,131.0	5,078.7	5,218.9	5,095.4	5,214.3	5,010.5
Preferred shares	323.0	323.0	323.0	323.0	323.0	323.0
Total capital	9,641.3	9,794.7	9,742.9	9,386.4	9,353.3	9,004.5
Ratios						
EBIT interest coverage (x)	2.7	2.9	2.8	2.5	2.4	2.6
FFO interest coverage (x)	3.5	3.7	3.6	3.3	2.9	3.0
Return on common equity	10.7	10.8	11.6	9.7	8.5	9.6
NCF/capital expenditures (%)	100.3	99.6	94.0	108.6	93.1	84.6
FFO/total debt (%)	18.3	19.0	18.4	17.5	13.7	15.3
Total debt/capital (%)	53.2	51.9	53.6	54.3	55.7	55.6

*Adjusted by capital operating leases. NCF—Net cash flow.

Cash flow adequacy

Hydro One's annual FFO of close to C$900 million is sufficient to meet its expected dividend payments of close to C$300 million and the bulk of the company's capital expenditure program in 2006. The company's annual capital expenditure, however, is expected to increase from about C$800 million to C$1.3 billion in the next few years and will require partial debt funding. The company's net cash flow-to-capital expenditure is expected to range between 70%-80%.

Capital structure and financial flexibility

Hydro One's move to address structural deficiencies in its debt portfolio in recent times has reduced the level of financing risk the company faces. As of Dec. 31, 2005, 62% (C$3.1 billion) of Hydro One's debt still had a maturity date of up to seven years, with the remaining 38% maturing in 24 years or more. Maturing debt in any one year, however, does not represent more than 15% of the company's total long-term debt outstanding of C$5.2 billion as of June 30, 2006. The company's liability management strategy is to target an average term for its debt portfolio of 10 to 15 years. In the past few years, the company has increased its previously short, average term for its debt of about four years to the current weighted-average term of 14 years.

Further reducing financial risk for the company is its policy of hedging interest rate and foreign exchange exposure. The company generally maintains less than 20% of debt (including debt maturing within the year) at floating rates and carries no material foreign exchange exposure, with all debt in Canadian dollars. The weighted-average coupon rate of Hydro One's debt at year-end 2005 was 5.6%.

The lack of diversity of Hydro One's funding sources is not a ratings concern. The company relies heavily on the Canadian debt capital markets as its main funding source and although such reliance poses a concentration risk, the company's well-supported position in the market mitigates this somewhat. The debt capital markets provide the vast majority of Hydro One's financing, with the company relying on bank facilities largely for general corporate purposes and as a backup to its CP program. Maturing debt is to be financed through the company's C$2.5 billion MTN shelf program. As of June 30, 2006, C$1.95 billion remained available until July 2007.

As it has done since 1999, Hydro One's leverage, as measured by total debt-to-total capital, is expected to remain stable in the next few years at about 54%. Debt could increase annually by as much as C$300 million-C$700 million in the period 2007-2008, as it will be used to partially fund capital expenditure. All debt is unsecured and supported by a negative pledge. As of mid-2006, the company's capital structure comprised C$5.3 billion in debt, C$4.4 billion in common shares and retained earnings, and C$323 million in preferred shares.

Ease of access to the debt capital markets and bank debt, an ability to defer a portion of capital expenditure, and the company's close relationship with its owner support Hydro One's financing flexibility. The company has good access to the debt funding through its C$1 billion CP program, its committed but unused bank lines, and the remaining availability on its MTN shelf program. In addition to its ability to tap debt markets, Hydro One can defer about C$100 million of forecast capital expenditure per year, close to one-third of its annual interest expense. The government, as shareholder, is a further potential source of financing and provider of backup liquidity for the company. Hydro One is unlikely to have ready access to new equity in the form of cash injections; however, the flexibility afforded to it to defer annual common dividend payments of as much as C$300 million mitigates this financing constraint somewhat. The deferral of the dividend and discretionary capital expenditure is more than sufficient to meet forecast annual cash interest costs of about C$300 million-C$330 million.

Ratings List

Hydro One Inc.	
Sr unsecd debt	
Local currency	A
CP	
Local currency	A-1
Ontario (Province of)	
Corporate Credit Rating	AA/Stable/A-1+
Sr unsecd debt	AA
Ontario Electricity Financial Corp.	
Ontario Power Generation Inc.	
Corporate Credit Rating	BBB+/Positive/—
CP	
Local currency	A-2

Corporate Credit Rating History

Feb. 22, 2002	A+/A-1
Apr. 1, 2002	A/A-1
Feb. 21, 2003	A-/A-2
Apr. 22, 2004	A/A-2
July 15, 2005	A/A-1

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Exhibit A-11-1
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STANDARD & POOR'S RatingsDirect

RESEARCH

Research Update:

Hydro One Inc. Outlook Revised To Positive; 'A' Ratings Affirmed

Publication date: 26-Mar-2007
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Rationale

On March 26, 2007, Standard & Poor's Ratings Services revised its outlook on utility holding company, Hydro One Inc., to positive from stable. At the same time, Standard & Poor's affirmed its 'A' long-term corporate credit rating and senior unsecured debt ratings on Hydro One. The revised outlook primarily reflects clearer evidence of regulatory stability and no expectation of disruptive market restructuring that would affect its local distribution company (LDC) credit quality. An outlook is not necessarily a precursor of a rating change. (For more details on the credit positive trends affecting the sector please refer to our commentary "Shining A Light On The Positive Outlook For Ontario Electricity Distributors" to be published following this research update, on RatingsDirect, the real-time Web-based source for Standard & Poor's credit ratings, research, and risk analysis.)

The ratings reflect the company's low-risk monopoly electricity transmission and distribution networks, secure and relatively predictable regulated cash flows, and the support of its owner, the Province of Ontario (AA/Stable/A-1+). These strengths are offset by an intermediate financial profile that will be further challenged by the company's large capital expenditure program in the next several years. Hydro One had C$5.2 billion in long-term debt outstanding as of Dec. 31, 2006.

Hydro One's monopoly position, the asset intensive nature of its businesses, and regulatory oversight limit competitive risk. Toronto-based Hydro One is the incumbent electricity transmission business and largest distributor of electricity in Ontario. The company owns and operates more than 97% of the province's transmission network as measured by revenue, and its distribution network service territory covers about 75% of the province.

Hydro One's debt-servicing capacity is supported by the regulated returns it receives from its electricity delivery businesses. Secure and relatively predictable regulated cash flows are supported by cost-of-service and rate-of-return regulation. The company can expect to recover all prudent costs incurred and earn a modest return on its capital investment. Furthermore, the company faces limited risk related to commodity price and volume variability. Although Hydro One's distribution business bills customers for the cost of the commodity consumed, the company has no obligation to ensure adequate electricity supply.

The province's ownership of Hydro One enhances the utility's credit quality. Although Ontario does not formally guarantee Hydro One's debt obligations, the strategic nature of the company within the provincial economy and the government's demonstrated willingness to financially assist the business under extraordinary circumstances in the past bode well for future support.

Hydro One has an intermediate financial profile and cash flow interest and debt coverages could weaken in the next few years. Pension-adjusted funds from operations (FFO) interest coverage of 4.7x in 2006 was up from 4.4x in 2005 largely as a result of distribution rate increases in 2005 and 2006. AFFO interest coverage could drift downward in the next several years but is not

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expected to fall below 4.0x. Cash flow strength in coming years will depend on: the outcome of an upcoming transmission rate hearing, regulatory approvals of budgeted capital expenditures, and the impact of weather variability on revenue. FFO-to-total debt is expected to remain with the 15%-20% range as compared with its 2006 level of 20%. The company is expected to debt finance 20% or more of forecast capital expenditure during the upcoming period of significant expansion. Hydro One's leverage, as measured by pension-adjusted total debt-to-total capital, is also likely to creep back up to the historical level of about 65%, compared with 60% in 2006.

Although predominantly funded from internal sources, capital spending during the next few years will be a drain on the company's cash flow and reduce its financial flexibility. Capital expenditure of C$1.2 billion is budgeted for 2007, a 40% increase compared with the C$863 million spent in 2006, and higher-than-historical average. This period of increased capital spending is a result of planned upgrades and expansion of the transmission system to accommodate: growth in domestic demand, new generation facilities, and facilitate increased imports and exports. The 2007 capital program also includes a portion of the estimated C$600 million-C$1.2 billion investment that Hydro One will make in smart meters for all distribution customers by 2010 in the next four years. Subject to a prudency review and like its other infrastructure investments, Hydro One's investment in smart meters will also be added to its revenue-generating regulated asset base.

Short-term credit factors

The short-term rating on Hydro One is 'A-1'. Unused and committed bank lines, together with strong cash flow from operations and ready access to the debt capital markets, provide Hydro One with sufficient liquidity and the financial flexibility to meet its forecast capital expenditure estimate of C$1.25 billion, annual dividend payments of C$250 million to C$350 million, and C$395 million of debt maturing in 2007. As of Dec. 31, 2006, C$60 million had been drawn from the company's C$1 billion short-term note program. The company remains well within its banking covenant of total debt-to-total capital of 75% and has no material adverse change clauses that could trigger a default.

In support of Hydro One's liquidity, the company can draw on:

- A committed C$750 million bank line of which C$690 million was available as of Dec. 31, 2006. The bank line is used for general corporate purposes and to support its C$1 billion Canadian CP program. The line matures in August 2007 and has a two-year term-out option;
- Its expected annual regulated cash flows in 2007, as represented by unadjusted FFO, of about C$860 million;
- An MTN shelf program, maturing in July 2007, which had C$1.725 billion of available credit as of Dec. 31, 2006; and
- Discretionary capital expenditure estimated in the range of C$150 million- C$200 million in 2007.

Outlook

The positive outlook reflects a steady improvement in Hydro One's business risk profile. The improvement is largely a result of steadily increasing clarity and stability with regards to regulatory methodology and timetables that influence both the transmission and distribution business, and the continued absence of disruptive market restructuring and political involvement in the regulatory process. Should this trend continue it could result in a positive rating action, but more than a single-notch improvement is highly unlikely. Given the supportive and stable shareholder relationship, the expected temporary downward pressure on the company's cash flow strength due to the pressures of upcoming increased capital spending should not lead to a revised outlook. A negative rating action could result from a material change in the company's financial or business risk profile, possibly from an adverse regulatory ruling, market restructuring, or its shareholder relationship.

Ratings List

Filed: August 15, 2007
EB-2007-0681

Hydro One Inc.

Outlook Revised To Positive	To	From
Corporate credit rating	A/Positive/A-1	A/Stable/A-1
Ratings Affirmed		
Senior unsecured	A	
Commercial paper		
Global scale	A-1	
Canadian scale	A-1(Mid)	

Complete ratings information is available to subscribers of RatingsDirect, the real-time Web-based source for Standard & Poor's credit ratings, research, and risk analysis, at www.ratingsdirect.com. All ratings affected by this rating action can be found on Standard & Poor's public Web site at www.standardandpoors.com; under Credit Ratings in the left navigation bar, select Find a Rating, then Credit Ratings Search.

Rating Report

Report Date:
November 15, 2007

Previous Report:
June 30, 2006

Hydro One Inc.

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The Company
Hydro One Inc., through its wholly owned subsidiaries, owns and operates electric transmission and distribution assets, as well as a fibre-optic network across most of Ontario. Hydro One is the largest transmission and distribution operator in Ontario (servicing over 95% of the Province's transmission throughput). The Company is wholly owned by the Province of Ontario (rated AA).

Commercial Paper: Authorized Limit of $1 Billion

Recent Actions
June 23, 2006
Upgraded

January 31, 2005
Confirmed & Trend Change

Rating

Debt Rated	Rating	Rating Action	Trend
Commercial Paper	R-1 (middle)	Confirmed	Stable
Senior Unsecured Debentures	A (high)	Confirmed	Stable

Rating Rationale

DBRS has confirmed the rating of Hydro One Inc.'s (Hydro One or the Company) Commercial Paper at R-1 (middle) and its Senior Unsecured Debentures at A (high), both with Stable trends. The rating confirmations reflect Hydro One's low level of business risk stemming from its regulated electric transmission and distribution operations, accompanied by a solid financial profile underpinned by its robust balance sheet and strong credit metrics. The rating confirmations also consider the aggressive capital expenditure program being implemented throughout Hydro One's system, combined with the negative impact from the recent transmission rate decision in which the Ontario Energy Board (OEB) reduced the regulatory-approved return on equity (ROE) by 153 basis points to 8.35% from 9.88% in 2006, for both F2007 and F2008. However, Hydro One's rate base was increased by 11% to $6,344 million ($5,718 million in 2006), and its equity thickness was increased by 4% to 40%. Overall, DBRS expects transmission rate charges to be reduced by approximately $80 million to $100 million, which is approximately a 7% reduction from F2006 net revenues. This will place temporary pressure on interest coverage ratios, with a 35 to 45 basis point reduction in EBIT/interest anticipated from the rate order, but a measurable change in the Company's financial profile is not expected. DBRS anticipates a number of Hydro One's regulatory-approved capital projects to be completed and in service by the 2009/2010 rate years, thereby increasing the rate base and, subsequently, its earnings profile. (Continued on page 2.)

Rating Considerations

Strengths

(1) Low-risk, regulated electric transmission and distribution businesses
(2) Solid balance sheet and credit metrics
(3) Strong and extensive transmission and distribution franchise area
(4) Top quartile for transmission reliability

Challenges

(1) Substantial capital expenditure program
(2) Significant external financing required
(3) Approved ROE sensitive to interest rates
(4) Earnings sensitive to monthly peak demand for electricity and, to a lesser extent, to the volume of electricity sold
(5) Managing construction execution risk with large capital projects
(6) Lack of access to equity capital markets

Financial Information

(CAD millions)	12 mos ended Sept. 2007 *	For the year ended December 30 2006	2005	2004	2003
Cash flow from operations **	903	930	945	920	855
EBIT gross interest coverage (1)	2.77	2.77	2.78	2.63	2.49
Fixed charge coverage (1)	2.57	2.57	2.59	2.44	2.34
Total adjusted debt-to-capital (%) (1)	53.7%	53.3%	52.6%	54.3%	55.0%
Cash flow-to-total adjusted debt (%) (1)	16.2%	17.1%	18.3%	17.4%	16.6%
Cash flow/capital expenditures (times)	0.91	1.13	1.37	1.27	1.43
Gross free cash flow ***	(390)	(225)	(19)	(54)	32
Return on average equity (before non-recurring items) (%)	9.3%	9.8%	10.8%	10.1%	9.7%
Approved ROE - Distribution	9.00%	9.00%	9.88%	9.88%	9.88%
Approved ROE - Transmission	8.35%	9.88%	9.88%	9.88%	9.88%

(1) DBRS-adjusted for operating lease debt and interest expense equivalents. DBRS-adjusted for preferred shares (20% debt/ 80% equity).
* DBRS adjusted Transmission earnings for non-cash items to normalize impact from OEB rate decision.
** CFO before working capital.*** Gross free cash flow = CFO - capital expenditures - dividends.

Rating Rationale (Continued from page 1.)

Despite the impact to earnings, the decision remains in line and reasonably consistent with previous decisions rendered for electric distribution companies (LDCs), with respect to regulatory treatment of equity thickness and ROE methodology. The regulatory-approved ROE methodology highlights the formulaic sensitivity to long-term interest rate volatility, which could continue to challenge ROE levels and subsequently earnings and cash flows going forward if rates move downward.

Furthermore, on the regulatory front, DBRS expects Hydro One's distribution operations to file a rate application for a mid-year rate adjustment in 2008, outlining its capital plan while addressing the additional capital investment currently not included in its rate base. The regulatory framework for LDCs under the 2nd Generation Incentive Regulation Mechanism (IRM) and Cost of Capital is viewed by DBRS as reasonable, providing sufficient earnings and cash flow stability.

Hydro One is entering a significant capital investment cycle, driven primarily by the increasing reliability needs, replacement of aging assets and changing supply-mix initiatives in Ontario. As a result, DBRS expects capital expenditures to remain elevated over the medium term, averaging between $1.1 billion to $1.5 billion, which, combined with dividends, is expected to exceed operating cash flows by approximately $500 million to $800 million per year. These free cash flow deficits are expected to be entirely debt financed, which will put temporary pressure on the Company's balance sheet and coverage ratios, as the invested capital is not included in the rate base until the completion of the projects. Also, given that a material portion of Hydro One's capital expenditures are for large transmission projects that involve lengthy construction times and there is potential for delays caused by the intervenor process, timely project completion within budget is important to maintain the Company's financial health.

DBRS views the expected pressure on the Company's earnings and balance sheet as temporary, and expects Hydro One's financial metrics to remain within a range supportive of the assigned ratings, given its low level of business risk, solid financial profile, strong balance sheet and experienced management team.

Rating Considerations Details

Strengths

(1) Hydro One is a regulated electric transmission and distribution utility. As such, the Company's business risk profile is low, due to the following factors: (1) Hydro One can recover all prudently incurred operating costs and approved capital project costs within a reasonable time frame as revenue requirements are predetermined based on forward-looking cost of service; (2) the Company will not undertake large capital expenditures without a reasonable expectation of recovering them in its rates; and (3) the regulatory environment continues to become more transparent with respect to the regulatory treatment of equity thickness and ROE methodology. DBRS believes that the OEB will be supportive in the recovery of capital costs as well as operating expenses that are necessary for a safe and reliable electric system.

(2) Hydro One's credit metrics remain solid for an A (high) regulated utility: Debt-to-capital ratio is 53.7%, EBIT/interest coverage is 2.77 times and cash flow-to-debt is 16.2%. Although DBRS expects coverage ratios to experience some downward pressure given the lower approved revenue requirements for its transmission business coupled with higher overall capital expenditures driving sizable free cash flow deficits, the Company's financial metrics are expected to remain within a range that is consistent with its business risk level and the assigned ratings.

(3) Hydro One owns and operates substantially all of Ontario's electric transmission system and is linked to five adjoining jurisdictions, accommodating imports of about 4,000 MW and exports of approximately 5,800 MW of electricity. The Company's distribution system is the largest in Ontario and spans roughly 75% of the province, serving approximately 1.3 million rural and urban customers and 48 large industrial customers. The large geographic area and low population density translates into a higher rate of service for its distribution business relative to other electricity distribution companies.

(4) Hydro One's transmission business continues to achieve top quartile reliability measures, which should facilitate a healthy relationship with the regulator going forward.

Challenges

(1) Hydro One is entering an aggressive build-out program over the next several years, in which DBRS expects a measurable increase in capital investment from present levels to a range of $1.1 billion to $1.5 billion per year through 2009. This, combined with dividends, is expected to cause a cash flow deficit of an estimated $500 million to $800 million per annum. These sizable free cash flow deficits, combined with lengthy construction times, will put temporary pressure on the balance sheet and coverage ratios during the build-out. DBRS notes that capital projects are spread out over time, which helps to minimize liquidity issues that accompany such large projects.

(2) Hydro One will have to go to the debt market in significant size to fund its considerable free cash flow deficits and refinance a heavy-but-manageable debt repayment schedule over the medium term. Maintaining adequate access to the public debt market and adequate availability under its credit facility ($750 million) is important during this build-out period.

(3) Regulatory-approved ROE levels are low and could continue to trend lower if long-term interest rates decline. Approved ROE for the transmission operation declined to 8.35% for both F2007 and F2008, from 9.88% in 2006, while the distribution segment remained at 9.00% in 2007, down 88 basis points from 9.88% in 2005.

(4) Earnings and cash flows for the transmission segment, and to a lesser extent distribution operations, are sensitive to monthly peak demand and volume of electricity sold, given that rates typically include a variable rate component. Seasonality, economic cyclicality, weather patterns and Conservation Demand Management (CDM) programs directly impact the volume of electricity sold or peak monthly electrical demand, and hence, revenue earned from electricity sales.

(5) The size and magnitude of Hydro One's upcoming designated projects (e.g., the Bruce Project, estimated at $613 million), combined with the continued increases in material and labour costs and the significant number of intervenors involved, could potentially expose Hydro One to rising project costs beyond the amount forecasted in its regulatory applications. There is no assurance that cost overruns beyond the regulatory-approved amounts will be recovered if deemed imprudent by the OEB. However, DBRS notes that Hydro One is experienced in managing projects and is focused on mitigating the risk of cost overruns.

(6) Due to provincial ownership, Hydro One is unable to access the equity capital markets. This limits the Company's financial flexibility, as free cash flow deficits will likely be financed through its $750 million Commercial Paper (CP) program (fully backstopped by a credit facility) or debt issuance under its remaining $2.2 billion medium-term notes (MTNs) program. Also, the Company has historically paid out a high level of dividends (a five-year average of 64% of net income). Given the increasing liquidity requirements, DBRS anticipates some dividend management may be required going forward as Hydro One is committed to investing heavily in its electricity system.

Regulation

Hydro One's electricity distribution operations are regulated by the OEB under the *Ontario Energy Board Act*, 1998 (the OEB Act), as modified by the following noteworthy amendments:
• The *Electricity Pricing, Conservation and Supply Act*, 2002 (Bill 210) – December 9, 2002.
• The *Ontario Energy Board Amendment Act* (Electricity Pricing), 2003 (Bill 4) – December 18, 2003.
• The *Electricity Restructuring Act*, 2004 (Bill 100) – December 9, 2004.

Currently, the capital structure and ROE methodology used by the OEB to establish transmission and distribution rates is based on a deemed debt-to-equity structure of 60-40 and the long Canada bond forecast rate.

Transmission
In August 2007, the OEB reduced Hydro One's base transmission rates, retroactive for the period January 1, 2007 to December 31, 2008, resulting in approximately a 7% reduction in base revenue requirements relative to F2006 net revenues. The methodology used by the OEB to establish the transmission rates was based on a rate base of $6,344 million ($5,718 million from 2000 to 2006), a deemed debt-to-equity structure of 60-40, an approved weighted-average debt rate of 5.80% and an allowed ROE of 8.35%. Also, the OEB approved Hydro One's operations, administration and capital expenditure budgets, along with the expensing and recovery of the carrying costs of the Niagara Reinforcement Project, until the project is completed and placed into service; however, the OEB did not approve the request for allowing certain capital expenditures into rate base before project completion. New transmission rates are retroactive to January 1, 2007, and were implemented on November 1, 2007 (with $85 million in over recovery from Jan. 1, 2007 to Oct. 31, 2007, allocated back on a monthly basis).

Distribution
Hydro One's distribution business operates under a performance-based incentive mechanism with a deemed ROE of 9.0% based on a forward-looking cost of service for the mid-year rate decision.

On December 20, 2006, the OEB issued a 2007 rate adjustment model (2nd Generation IRM and Cost of Capital) and corresponding instructions to distributors for the purpose of adjusting distributor rates effective May 1, 2007. As a result, base distributions rates, exclusive of rate riders, were adjusted formulaically to reflect an allowance for inflation of 1.9%, a fixed productivity offset of 1.0% and removal of the federal large corporation tax. As such, no major financial impact for distributors is expected due to the inflation factor generally being slightly higher than the productivity factor. In each of three subsequent years, one-third of the electricity distributors will have their distribution rates reviewed and reset by the OEB through a cost-of-service type of rate proceeding. LDCs re-based in 2008 will be subject to an IRM applied in succeeding years up to the 2010 rate year. By 2010, all electricity distributors in Ontario will have undergone a re-basing of rates.

The net effect of the OEB decision in 2007 was to provide for approximately a 0.5% increase in base distribution rates to all customer classes for the May 1, 2007 to April 30, 2008 period. DBRS notes that, as of May 1, 2007, the OEB approved an amount of $0.93 per month from metered customers as part of the delivery charge on their bill, related to the implementation of the province's Smart Meter Program. The delivery charge effectively pre-funds the Company's OM&A cost, while defraying a portion of its financing costs, until meters are installed and included in its rate base.

Earnings and Outlook

Segmented Information		12 mos. ended	For the year ended December 31			
(CAD millions)		Sept. 07 *	2006	2005	2004	2003
Net revenues						
Transmission	52.1%	1,273	1,245	1,310	1,262	1,298
Distribution	46.6%	1,137	1,052	954	910	862
Other	1.3%	32	27	21	17	26
Total net revenues		**2,442**	**2,324**	**2,285**	**2,189**	**2,186**
EBIT by segment						
Transmission	67.6%	634	614	711	665	688
Distribution	33.4%	313	323	305	284	252
Other	-1.0%	(9)	(8)	(10)	(11)	(3)
Total EBIT		**938**	**929**	**1,006**	**938**	**937**

Income Statement	12 mos. ended	For the year ended December 31			
(CAD millions)	Sept. 07 *	2006	2005	2004	2003
Net revenues	2,442	2,324	2,285	2,189	2,186
OM&A expense	984	880	792	771	795
EBITDA	1,458	1,444	1,493	1,418	1,391
EBIT	938	929	1,006	938	937
Interest expense (1)	310	307	303	294	315
Core net income (before non-recurring items and prefs)	434	455	483	430	396
Reported net income (after prefs)	416	461	465	480	378
Operating margin	38%	40%	44%	43%	43%
Return on average equity (before non-recurring items)	9.3%	9.8%	10.8%	10.1%	9.7%

(1) Interest expense on short-term and long-term debt balances, excludes deferred financing charges.

* DBRS adjusted Transmission earnings for non-cash items to normalize the impact from the recent OEB rate decision.

Summary

Despite higher year-over-year net revenues, EBITDA and EBIT remained relatively flat as modest earnings growth from Hydro One's distribution operations offset the negative impact from increasing overall maintenance-related expenditures and lower 2006 transmission earnings on the earnings sharing mechanism implemented by the OEB.

- Operating costs continue to trend higher, having increased approximately 10% per year since 2005, which highlights the increased work programs needed to maintain the current capability of the system as well as higher information technology requirements. DBRS expects operating costs to continue to trend higher over the medium term.
- During F2006, the OEB applied an earnings sharing mechanism (ESM) to any transmission earnings in excess of the approved rate of return of 9.88%. This had a negative impact on transmission EBIT, leading to a notable decline from the F2005 level. The ESM was discontinued for 2007.

Interest expense has incrementally trended upward, largely tracking higher debt levels.

Overall, earnings remain robust and relatively stable as Hydro One continues to earn its allowed ROE, underscoring continued focus on productivity and cost-effectiveness.

Outlook

Earnings are expected to be pressured over the near to medium term, stemming from the recent OEB rate decision, which is anticipated to impact transmission revenues by approximately $80 million to $100 million over each of the next two years. However, earnings should improve beyond 2008 from the reduced levels, reflecting the following factors:

- A number of regulatory-approved transmission projects are expected to be completed and in service by the 2009 rate year, thereby increasing the rate base and, subsequently, its earnings profile.
- Also, Hydro One will have its distribution rates reviewed and reset through a forward-looking cost-of-service type rate proceeding in 2008, with an IRM applied in succeeding years up to 2010. The rate base should reflect the additional capital expenditures over the next couple of years.

The paradigm of lower ROE levels and the subsequent impact on earnings should be largely offset by higher respective rate bases and increased equity thickness, going forward.

Financial Profile

Statement of Cash Flow	12 mos. ended	For the year ended December 31			
(CAD millions)	Sept. 07	2006	2005	2004	2003
Core net income, (before non-recurring, after pfd.)	416	437	465	412	378
Depreciation & amortization	477	474	446	446	417
Amortization of debt re-couponing	10	27	58	62	60
Other recurring non-cash items	0	(8)	(24)	0	0
Cash Flow from Operations	**903**	**930**	**945**	**920**	**855**
Capital expenditures	(995)	(823)	(691)	(727)	(597)
Common dividends	(298)	(332)	(273)	(247)	(226)
Free Cash Flow before Working Capital Changes	**(390)**	**(225)**	**(19)**	**(54)**	**32**
Change in working capital	65	(92)	194	(33)	138
Net Free Cash Flow	**(325)**	**(317)**	**175**	**(87)**	**170**
Other investments/acquisitions/disposition	21	15	9	19	3
Other non-recurring, incl. retail settlement variance	63	40	2	6	21
Cash flow before financing	**(241)**	**(262)**	**186**	**(62)**	**194**
Net debt financing	139	246	(188)	83	(183)
Equity financing	0	0	0	0	0
Other financing	(1)	(4)	2	7	(13)
Net change in cash	(103)	(20)	0	28	(2)
Total adjusted debt (CAD millions) (1)	5,574	5,427	5,156	5,293	5,165
Cash flow gross interest coverage (1)	3.90	4.01	4.10	4.11	3.70
Fixed charges coverage (times) (1)	2.57	2.57	2.59	2.44	2.34
Total adjusted debt-to-capital (%) (1)	53.7%	53.3%	52.6%	54.3%	55.0%
Cash flow/total adjusted debt (times) (1)	16.2%	17.1%	18.3%	17.4%	16.6%
Cash flow/capital expenditures (times)	0.91	1.13	1.37	1.27	1.43
Dividend payout ratio	68.7%	69.3%	56.5%	49.6%	57.1%

(1) DBRS-adjusted for operating lease debt and interest expense equivalents. DBRS-adjusted for preferred shares (20% debt/ 80% equity).

Summary

Operating cash flow has remained reasonably stable, with the recent modest decline largely tracking net income. However, the continued growth in sustaining and development capital spending, combined with dividends, has resulted in increasing gross free cash flow deficits over the last two years.

To date, the Company has effectively managed the size of its capital expenditure programs. However, the recent upward trend in capital investment is indicative of the growing reliability needs in Ontario as a number of Hydro One's assets are coming to the end of their useful life. This is further accentuated by the increasing cost of manufactured products for utility infrastructure, coupled with expenditures on higher required generation-related and load customer connection expenditures.

Working capital requirements continue to fluctuate with the timing of the Company receiving or paying a customer rebate (pass-through of the commodity cost of electricity) from the Independent Electricity System Operator (IESO).

Despite the increasing free cash flow deficits, key credit metrics remain relatively stable, as higher debt levels have been largely offset with a growing equity base. The credit metrics remain solidly within the current rating category for a low-risk regulated utility with debt-to-capital at 53.7%, fixed charge coverage at 2.57 times and cash flow-to-debt at 16.2%.

Outlook

Hydro One's financial profile is expected to deteriorate over the medium term, given the measurable growth in its capital expenditure budget, driving higher free cash flow deficits.

Cash flow from operations is expected to decrease modestly, as lower net income is partially offset by higher depreciation, trending in line with higher capital expenditures.

With Hydro One entering a significant capital build-out program, DBRS expects the following to occur:

- Annual capital expenditures are expected to average approximately $1.1 billion to $1.5 billion from 2007 to 2009, with the majority related to transmission development projects, smart meter deployment and replacement of aging assets. However, there continues to be some uncertainty around the timing and scope of these capital expenditures within this time horizon. DBRS notes that capital will not be committed unless Hydro One obtains regulatory approval for cost recovery.
- With the significant ongoing replacement of aging assets, the increases in future sustaining capital expenditures are expected to abate beyond 2008.
- Common dividends are declared at the sole discretion of the Hydro One board of directors and are recommended by management based on financial conditions and liquidity requirements, which should provide some flexibility for dividend management, as the Company is committed to investing heavily in its electricity system.
- As such, the Company's leverage is expected to increase over the medium term, as the substantial capital expenditure program and dividend policy will result in sizable free cash flow deficits. These deficits and the subsequent higher leverage in the capital structure – in a longer-term range of 55% to 58% – will temporarily pressure cash flow-to-debt and interest coverage ratios, from present levels. DBRS does not expect the Company's financial profile to change significantly, with credit metrics remaining adequate for the assigned ratings.

Capital Expenditures: Designated Projects

Source: OEB Transmission Rate Decision EB-2005-0501, Exhibit D1, Schedule 4, Tab 1

Designated Projects	Historic	Test	Total	
(CAD millions)	2004-2006	2007-2008	(including future years)	%
Bruce Project	0	57	613	69%
Quebec Intertie	1	113	115	13%
Static Var Compensators	0	10	54	6%
Niagara Reinforcement	97	2	101	11%
Total	**98**	**182**	**883**	**100%**

Niagara Reinforcement project reinforces the transmission system in the Niagara region and provides access to new sources of generation. The project was substantively completed in F2006, with final completion delayed by the aboriginal land dispute in the Caledonia area. The OEB has allowed Hydro One to recover its carrying cost of the project until the asset is in-service and included in the Company's rate base. DBRS expects this to occur in the 2009 rate application.

Québec Interconnection project, in which Hydro One is collaborating with Hydro-Québec, will allow the transfer of 1,250 MW between the two provinces when it is completed in 2010. The Hydro One and Hydro-Québec grids are not synchronous, so for power to be exchanged it must be converted to the requirements of the receiving grid. The total estimated project cost is $808 million, of which $115 million is earmarked for Hydro One's capital budget.

Bruce to Milton project is in the preliminary stages of seeking the necessary provincial permits to have the estimated $613 million, 500 kV, 180 km line connection from the Bruce Power nuclear plants on Lake Huron to the Milton switching station west of Toronto. The proposed project could serve to deliver up to an additional 3,000 MW of generation capacity.

Long-Term Debt Maturities and Bank Lines

Long-term principal repayments as at September 30, 2007		
Year	%	(CAD millions)
2007	0.8%	40
2008	9.4%	500
2009	7.5%	400
2010	7.5%	400
2011	4.7%	250
Thereafter	70.1%	3,725
Total		5,315

(CAD millions) As at September 30, 2007	Committed	Outstanding	Available	Maturity
Commercial Paper backup facility*	750	161	589	8/10/2010

* Multi year revolving standby credit facility with a syndicate of banks.

Long-Term Debt

Hydro One finances its operations and capital programs with long-term debt (Senior Unsecured, $5.315 billion as at September 30, 2007) and a $750 million CP program (fully backed up by a credit facility).

- The debt repayment schedule is heavy but manageable over the next five years as Hydro One will have to refinance approximately 30% of its outstanding debt. Refinancing the debt should be well within Hydro One's financing capacity given its solid financial profile and good access to the public debt markets.
- DBRS anticipates that Hydro One will target a weighted-average long-term debt life between 12 and 18 years, with evenly spread out maturities, thus providing more flexibility while limiting refinancing risk.
- In June 2007, Hydro One filed a $2.5 billion MTNs program under the Preliminary Short-Form Base Shelf Prospectus. As at October 25, 2007, $2.2 billion was available.
- The Trust Indenture pertaining to all senior unsecured issuance includes the following covenants, subject to customary exceptions:
  - Any additional indebtedness is subject to a 75% capitalization ratio test.
  - Negative pledge clause.
  - Limitations on ability to sell principle properties.

Liquidity

Liquidity requirements will increase over the medium term to accommodate higher capital expenditures and regulatory working capital needs. DBRS notes that Hydro One has sufficient flexibility to accommodate the increasing liquidity needs, with its authorized CP program and availability under its MTNs program. However, the Company recently issued $300 million under its MTNs program to redeem the outstanding CP with the remainder for general corporate purposes. As of September 30, 2007, the Company currently has $589 million in unused capacity under the credit facility.

- As of August 1, 2007, Hydro One was able to meet prudential support obligations for power purchases through the IESO using only parental guarantees, which will further boost liquidity by releasing current $10 million letters of credit.
- Hydro One's board has authorized a CP limit of $1 billion; however, the Company has set the limit of its CP program at $750 million, matching the limit of the revolving credit facility.
- The credit facility is a multi-year facility that matures in 2010. The Company has the ability to increase the facility to $1 billion upon the mutual agreement with its lenders.

Hydro One Inc.

Balance Sheet
(CAD millions)

Assets	As at Sept. 30/07	As at December 31 2006	2005	Liabilities & Equity	As at Sept. 30/07	As at December 31 2006	2005
Cash + short-term investments	-	-	-	Short-term debt	175	89	9
Accounts receivable	748	777	628	L.t. debt due one year	540	395	589
Material, supplies & other	76	69	68	A/P + accr'ds	862	710	743
Current Assets	824	846	696	**Current Liabilities**	1,577	1,194	1,341
Net fixed assets	11,001	10,526	10,110	Long-term debt	4,764	4,848	4,466
Post-employment benefits	382	382	449	Post-employ. benefits	848	803	716
Def'd debt costs + long-term rec.	7	12	33	L.t. pay. + other liab.	530	544	582
Regulatory asset	238	311	400	Preferred shares	323	323	323
Goodwill	133	133	133	Shareholders' equity	4,543	4,498	4,393
Total	12,585	12,210	11,821	**Total**	12,585	12,210	11,821

Ratio Analysis	12 mos. ended	For the year ended December 31			
Liquidity Ratios	Sept. 30/07 *	2006	2005	2004	2003
Current ratio	0.52	0.71	0.52	0.60	0.55
Cash flow/total debt (1)	16.2%	17.1%	18.3%	17.4%	16.6%
Total adjusted debt-to-capital (1)	53.7%	53.3%	52.6%	54.3%	55.0%
Cash flow/capital expenditures	0.91	1.13	1.37	1.27	1.43
Cash flow-dividends/capital expenditures	0.61	0.73	0.97	0.93	1.05
Adj. total debt/EBITDA (1)	3.82	3.76	3.45	3.73	3.71
Hybrids in capital structure	3.1%	3.2%	3.3%	3.3%	3.4%
Deemed common equity	40.0%	36.0%	36.0%	36.0%	36.0%
Common dividend payout (before extras.)	71.6%	76.0%	58.7%	60.0%	59.8%
Coverage Ratios					
EBIT gross interest coverage (1)	2.77	2.77	2.78	2.63	2.49
EBIT net interest coverage (1)	3.14	3.14	3.09	2.83	2.69
EBITDA gross interest coverage (1)	4.31	4.31	4.12	3.97	3.70
EBITDA net interest coverage (1)	4.87	4.87	4.58	4.27	3.98
Fixed-charges coverage (1)	2.57	2.57	2.59	2.44	2.34
Earnings Quality/Operating Efficiencies & Statistics					
Operating margin	38.4%	40.0%	44.0%	42.9%	42.9%
Net margin (before non-recurring, after pfd.)	17.0%	18.8%	20.4%	18.8%	17.3%
Return on avg. equity (before non-recurring items)	9.3%	9.8%	10.8%	10.1%	9.7%
Approved ROE (Distribution)	9.0%	9.0%	9.88%	9.88%	9.88%
Approved ROE (Transmission)	8.35%	9.88%	9.88%	9.88%	9.88%
Rate base - distribution ($ millions)	3,711	3,711	2,637	2,637	2,637
Rate base - transmission ($ millions)	6,344	5,718	5,718	5,718	5,718
Transmission throughputs (TWh)	na	151.1	157.0	153.4	151.7
Distribution throughputs (TWh)	29.9	29.0	29.7	28.5	27.9
Average annual 60-minute peak demand (MWh)	27,435	27,005	26,160	24,979	24,753

(1) DBRS-adjusted for operating lease debt and interest expense equivalents. DBRS-adjusted for preferred shares (20% debt/ 80% equity).
* DBRS adjusted Transmission earnings for non-cash items to normalize the impact from the recent OEB rate decision.

Unit Costs and Revenues for Electricity Throughputs	12 mos. ended	For year ended December 31			
Distribution operations (cents/kWh)	Sept. 2007	2006	2005	2004	2003
Net revenues	3.80	3.63	3.21	3.19	3.09
OM&A	2.76	2.51	2.19	2.20	2.19
EBIT	1.05	1.11	1.03	1.00	0.90
Transmission operations (cents/kWh)					
Net revenues	na	0.82	0.83	0.82	0.86
OM&A	na	0.42	0.38	0.39	0.40
EBIT	na	0.41	0.45	0.43	0.45

Hydro One Inc.

Report Date:
November 15, 2007

Rating

Debt Rated	Rating	Rating Action	Trend
Commercial Paper	R-1 (middle)	Confirmed	Stable
Senior Unsecured Debentures	A (high)	Confirmed	Stable

Rating History

	Current	2006	2005	2004	2003	2002
Commercial Paper	R-1 (middle)	R-1 (middle)	R-1 (low)	R-1 (low)	R-1 (low)	R-1 (low)
Senior Unsecured Debentures	A (high)	A (high)	A	A	A	A

Related Research

- •October 16, 2007, Press Release: Rates Issue of $300 Million, 5.18% Medium-Term Notes at A (high)
- •March 9, 2007, Press Release: Rates Issue of $400 Million, 4.89% Medium-Term Notes at A (high)
- •October 19, 2006, Press Release: Rates Issue of $75 Million, 5.00% Medium-Term Notes at A (high)
- •August 22, 2006, Press Release: New Issue
- •June 30, 2006, Rating Report: Hydro One Inc.

Note:
All figures are in Canadian dollars unless otherwise noted.

STANDARD & POOR'S

COMMENTARY REPORT

Hydro One Inc.

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Publication Date
Nov. 23, 2007

Rationale

The ratings on Ontario-based Hydro One Inc. reflect the company's low-risk monopoly electricity transmission and distribution networks, secure and relatively predictable regulated cash flows, and the support of its owner, the Province of Ontario (AA/Stable/A-1+). Offsetting these strengths is an intermediate financial risk profile that will face the challenges of a lower rate of return on its transmission rate base and the company's large capital expenditure program in the next several years. Hydro One had C$5.2 billion in long-term debt outstanding as of Dec. 31, 2006.

Hydro One's monopoly position, the asset intensive nature of its businesses, and regulatory oversight limit competitive risk. It is the key electricity transmission provider and largest distributor of electricity in the province. The company owns and operates more than 97% of Ontario's transmission network as measured by revenue, and its predominantly rural distribution service territory incorporates about 75% of the province as measured by surface area.

Hydro One's debt-servicing capacity relies on secure and relatively predictable regulated cash flows supported by cost-of-service plus rate-of-return regulation. The company can expect to recover all prudent costs incurred and earn a modest return on its capital investment. Furthermore, the company faces limited risk related to commodity price and volume variability. Although Hydro One's distribution business bills customers for the cost of the commodity consumed, the company has no obligation to ensure adequate electricity supply.

Provincial ownership enhances the utility's credit quality. Although Ontario does not formally guarantee Hydro One's debt obligations, the company's strategic nature within the provincial economy and the government's demonstrated willingness to financially assist the business under extraordinary circumstances in the past bode well for future support.

Hydro One has an intermediate financial risk profile. We expect weaker cash flow interest and debt coverage in the next few years due to a recent transmission revenue decision that lowered the allowed ROE on transmission assets to 8.35% from 9.88%, further exacerbated by the upcoming period of higher-than-normal capital expenditures. Adjusted funds from operations (AFFO) interest coverage of 4.6x in 2006 was up from 4.4x in 2005 largely as a result of distribution rate increases in 2005 and 2006 and regulatory asset recovery. AFFO interest coverage will drift downward in the next several years, and could fall below 3.5x. AFFO-to-total debt could also weaken to the 14%-17% range, compared with its 2006 level of 20%. The extent of the deterioration will depend on the timing of regulatory approvals and execution of budgeted capital expenditures, and the impact of weather variability on revenue. The company expects to debt finance 20% or more of forecast capital expenditure during the upcoming period of significant expansion. During this period, Hydro One's leverage, as measured by adjusted total debt-to-total capital, could creep back up closer to the historical level of about 64%, compared with 60% in 2006.

Although predominantly funded from internal sources, capital spending during the next few years will be a drain on the company's cash flow and reduce its financial flexibility. Hydro One has budgeted C$1.4 billion in capital expenditure for 2008, a 70% increase compared with the C$823 million spent in 2006, and higher-than-historical average. This period of increased capital spending is a result of planned upgrades and expansion of the transmission system to accommodate: growth in domestic electricity demand, the connection of new generation facilities, and facilitate increased imports and exports. The 2008 capital program also includes a portion of the estimated C$700 million investment that Hydro One will make in smart meters for all distribution customers by 2010 in the next four years. Like its other infrastructure investments, Hydro One's investment in smart meters will also be added to its revenue-generating regulated asset base.

Short term credit factors

The short-term rating on Hydro One is 'A-1'. Unused and committed bank lines, together with strong cash flow from operations and ready access to the debt capital markets, provide the utility with sufficient liquidity and the financial flexibility to meet its forecast capital expenditure estimate of C$1.2 billion, annual dividend payments of C$250 million to C$350 million, and C$355 million of debt maturing in 2007. As of Sept. 30, 2007, C$161 million had been drawn from the company's C$1 billion short-term note program. The company remains well within its banking covenant of total debt-to-total capital of 75% and has no material adverse change clauses that could trigger a default.

In support of Hydro One's liquidity, the company can draw on:

- A committed C$750 million bank line of which C$589 million was available as of Sept. 30, 2007. The bank line is used for general corporate purposes and to support its C$1 billion Canadian CP program. The line matures in August 2010;
- Its expected annual regulated cash flows as represented by unadjusted FFO of about C$860 million in 2007;
- C$2.2 billion remaining capacity on a C$2.5 billion MTN shelf program, maturing in July 2009; and
- Discretionary capital expenditure estimated at C$150 million- C$200 million.

Outlook

The positive outlook reflects a steady improvement in Hydro One's business risk profile. The improvement is largely a result of steadily increasing clarity and stability with regards to regulatory methodology and timetables that influence both the transmission and distribution business, and the continued absence of disruptive market restructuring and political involvement in the regulatory process. Should this trend continue it could result in a positive rating action, but more than a single-notch improvement is highly unlikely. Given the supportive and stable shareholder relationship, the temporary downward pressure on the company's cash flow strength due to the pressures of upcoming increased capital spending should not lead to a revised outlook. A negative rating action could result from a material change in the company's financial or business risk profile or its shareholder relationship, an adverse regulatory ruling, or unfavorable market restructuring.

Credit Opinion: Hydro One Inc.

Hydro One Inc.

Toronto, Ontario, Canada

Ratings

Category	Moody's Rating
Outlook	Stable
Senior Unsecured -Dom Curr	Aa3
Commercial Paper	P-1

Contacts

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Key Indicators

Hydro One Inc.

	LTM 9/07	2006	2005	2004	2003
(CFO Pre-W/C + Interest) / Interest Expense [1]	**3.8x**	**3.9x**	**3.4x**	**3.4x**	**3.3x**
(CFO Pre-W/C) / Debt [1]	**16.2%**	**17.8%**	**16.7%**	**15.9%**	**16.6%**
(CFO Pre-W/C - Dividends) / Debt [1]	**11.1%**	**11.9%**	**12.0%**	**11.7%**	**12.4%**
(CFO Pre-W/C - Dividends) / Capex [1]	**70.1%**	**89.7%**	**107.8%**	**102.2%**	**121.5%**
Debt / Book Capitalization	**58.7%**	**58.4%**	**61.1%**	**62.6%**	**61.8%**
EBITA Margin %	**18.8%**	**21.6%**	**24.9%**	**25.3%**	**27.0%**

[1] CFO pre-W/C, which is also referred to as FFO in the Global Regulated Electric Utilities Rating Methodology, is equal to net cash flow from operations less net changes in working capital items

Note: For definitions of Moody's most common ratio terms please see the accompanying User's Guide.

Opinion

Company Profile

Hydro One Inc. (HOI) is wholly owned by the Province of Ontario. Its revenues and cash flows are almost completely derived from its transmission and distribution businesses, both of which are regulated by the Ontario Energy Board (OEB or the Board). HOI owns and operates virtually all of Ontario's electricity transmission system, and is responsible for a substantial portion of regulated electricity distribution in the province.

Recent Developments

On August 16, 2007 the OEB rendered its decision with respect to HOI's transmission rates for 2007 and 2008. The decision resulted in a reduction in the transmission business' allowed ROE to 8.35% from the existing 9.88% and the 10.5% level sought in HOI's September 12, 2006 application. The decision was retroactive to January 1, 2007 with rate decreases taking effect November 1, 2007. Over-collections from January 1, 2007 to October 31, 2008 are to be returned to customers through rates by December 31, 2008. Moody's believes that this decision will have a significant negative impact on HOI's key credit metrics and could create downward pressure on HOI's Baseline Credit Assessment (BCA).

On August 15, 2007 HOI filed its cost-of-service distribution revenue requirement application for 2008 seeking a net distribution rate increase of approximately 4%. Moody's does not expect an OEB decision in this proceeding before the second quarter of 2008

In its 2007 Integrated Power System Plan (IPSP), the Ontario Power Authority (OPA) forecasts that approximately $4 billion in transmission capital expenditures will need to be made between 2010 and 2025 to facilitate the connection of renewable generation projects and promote system reliability. Although the OPA believes that in the near-term, transmission proponents will need to undertake development work in connection with the transmission projects recommended in the IPSP, it does not foresee significant expenditures in respect of these project until 2010 or later. While the OPA does not assign responsibility for future transmission projects, Moody's believes that HOI is ideally positioned for and will actively pursue the right to undertake a significant portion of these expenditures. Accordingly, Moody's expects that HOI's capital expenditures and financing requirements, which will be elevated in the near-term, are likely to remain at elevated levels through the medium-term.

On November 23, 2007, HOI's board of directors announced that Laura Formusa, Acting President and Chief Executive Officer since December 8, 2006, had been appointed President and Chief Executive Officer of HOI. In May 2007, the Agency Review Panel (ARP) published its report and recommendations on executive compensation at Ontario's government owned/created electricity sector institutions. In June 2007, the Ontario Government announced its acceptance of the ARP's recommendations including those that, over time, are expected to result in 25-30% reductions in senior management compensation at Ontario electricity sector institutions including HOI. Moody's believes that the appointment of Ms. Formusa and the Ontario Government's adoption of the ARP's recommendations are not likely to have a material impact on HOI's credit profile.

Rating Rationale

In accordance with Moody's Government Related Issuer (GRI) rating methodology, the Aa3 ratings of HOI reflect the combination of the following inputs:

- Baseline Credit Assessment (BCA) in the range of 5 to 7 (on a scale of 1 to 21, where 1 represents the equivalent risk of a Aaa, 2 a Aa1, 3 a Aa2 and so forth)

- Aa1 local currency rating of the province of Ontario

- High default dependence

- High probability of extraordinary support

The BCA range of 5 to 7 reflects the following key ratings drivers.

SIGNIFICANT BUSINESS POSITION IN A RELATIVELY STABLE LEGISLATIVE BUT EVOLVING REGULATORY ENVIRONMENT

Moody's considers HOI's regulatory and business positions to be in the A category, reflecting its stable and predictable cash flows and the low business risk of its regulated wires businesses. Virtually all of HOI's activities are regulated with the exception of its telecommunications business, which represents less than 1% of total assets. HOI is the largest transmission operator in Ontario, owning and operating roughly 96% of the province's transmission capacity. HOI is also the largest electricity distributor in Ontario with a geographically dispersed and largely rural service territory; however, the BCA also recognizes the potential that HOI, which is 100% owned by the Province of Ontario, can be utilized as an instrument of public policy. Moody's notes that public policy goals are not always completely aligned with the interests of debt holders.

HOI deals with a single provincial regulator, the OEB, which regulates both the transmission and distribution segments of its business. The legislative environment in Ontario has been relatively stable since 2005 but the regulatory framework continues to evolve and suffers from significant regulatory lag. HOI completed it first cost-of-service proceeding for the Transmission segment in 2007. The OEB's August 16th decision came almost a year after the company's application was filed. The decision is expected to have a materially negative impact on HOI's 2008 financial metrics due to its retroactive nature which goes back to January 1, 2007. With rate adjustments going into effect on November 1, 2007, Moody's expects HOI's 2008 metrics to be impacted not only by rising capital expenditures and the lower transmission rates applicable to 2008 but also by the refund in 2008 of over-collections related to 2007. As noted below, Moody's expects that HOI's future CFO pre-WC/Interest could be in the range of 3.5x while CFO pre-WC/Debt could fall to roughly 13%. Any deterioration of CFO pre-WC/Interest below 3.5x and/or CFO pre-WC/Debt below 13% would likely result in a decrease in HOI's BCA Rates in HOI's distribution segment will be established pursuant to a cost-of-service proceeding in 2008 following which rates are expected to be adjusted in accordance with the OEB's yet-to-be finalized 3rd Generation Incentive Regulation Mechanism (IRM). While the regulatory environment in Ontario continues to evolve, Moody's anticipates that there will be increased transparency and predictability of rate decisions for HOI after 2008 as we expect that the distribution rates will be established pursuant to a formula driven mechanism under the OEB's 3rd Generation IRM. Moody's also expects that the adoption of formula driven IRM should reduce or eliminate regulatory lag post-2008.

FLEXIBILITY TO RECOVER COSTS AND EARN RETURNS

Moody's considers HOI's flexibility to recover costs and earn returns to be in the A category. Within HOI's distribution segment (approximately 42% of total assets) commodity costs are a full pass-through to customers.

HOI filed a distribution rate application for its 2008 revenue requirement with the Board, on August 15, 2007. Moody's does not expect a decision in this proceeding until the second quarter of 2008. As previously noted, rates subsequent to 2008 are expected to be set in accordance with the OEB's 3rd Generation IRM subject to periodic rebasing.

DIVERSIFIED OPERATIONS WITHIN ONTARIO

Moody's considers HOI's diversification to be in the Baa category. While all of the company's operations are located in the Province of Ontario and are subject to regulation by a single regulator, HOI's transmission and distribution assets are substantial and geographically dispersed across Ontario. HOI's $7.2 billion transmission segment is comprised of a network of approximately 28,600 circuit-kilometres representing approximately 96% of Ontario's transmission capacity and servicing virtually every region of the province. It includes significant interties with adjacent jurisdictions such as Quebec, Manitoba, New York and Michigan. The $5.3 billion distribution segment is comprised of approximately 124,700 circuit-kilometres servicing approximately 1.3 million customers, predominantly in rural areas of the province.

VIRTUALLY NO UNREGULATED BUSINESS

Moody's considers HOI's unregulated business characteristics to be in the Aa category, reflecting the fact that virtually all of HOI's activities are regulated by the OEB. HOI's only unregulated operations consist of a small telecommunications operation representing less than 1% of total assets.

FINANCIAL METRICS EXPECTED TO WEAKEN WITH LOWER ROEs; LIQUIDITY CHALLENGED BY LARGE CAPEX PROGRAM

As a result of declining ROEs in both the distribution and transmission segments as well as undertaking increased capital expenditures, HOI's financial metrics are expected to weaken during 2008 and 2009. Moody's expects that CFO pre-WC/Interest could be in the range of 3.5x while CFO pre-WC/Debt could fall to roughly 13%. At these levels, Moody's would consider HOI's financial metrics to be in the low Baa/high Ba range and weak relative to HOI's current BCA which is in the range of 5 to 7. Any deterioration of CFO pre-WC/Interest below 3.5x and/or CFO pre-WC/Debt below 13% would likely result in a decrease in HOI's BCA.

HOI expects to have large capital expenditure needs for a number of years. Maintenance capital expenditures, particularly in the transmission segment, are expected to rise significantly in coming years reflecting the age of HOI's system and an increased proportion of end-of-life assets as well as rising materials and labour costs. HOI also expects to make significant growth capital expenditures in support of provincial policy objectives such as smart metering and increased renewable generation. Elevated levels of capital expenditures are expected to add to the stress on HOI's credit metrics caused by declining ROEs. Major projects require the investment of debt and equity capital in the near-term while it could be several years before they begin generating cash flow to service the invested capital. Given the province's ownership of HOI, the company has limited ability to raise equity. Moody's estimates that, in the absence of a significant reduction in its dividend payout, HOI's cash flow metrics will come under further pressure as a result of the company's capital expenditure plans.

In evaluating a company's liquidity, Moody's typically assumes that the company loses access to the capital markets (both short and long term) for a period of 12 months. In this context, we then evaluate the company's various sources and uses of cash including the flexibility to defer or reduce uses of cash such as capital expenditures and dividends. HOI's commercial paper (CP) program is rated Prime-1 (Aa) based on the stable cash flow generated by its regulated transmission and distribution operations. We anticipate that the company will generate funds from operations of approximately $1.8 billion in aggregate during 2008 and 2009. After dividends of about $500 million and capital expenditures and working capital changes of approximately $3 billion, Moody's expects the company to be free cash flow negative by approximately $1.7 billion over the 2008 to 2009 period. HOI intends to fund its free cash flow shortfalls and approximately $540 million of scheduled debt maturities in the next twelve months primarily with issuances under its $2.5 billion MTN shelf filed June 21, 2007. Following HOI's $300 million MTN issuance on October 18, 2007, $2.2 billion remained available under the shelf. Given scheduled debt matruities of $500 million in June 2009, Moody's expects that HOI will renew its MTN shelf prior to its July 2009 expiry.

In addition to the MTN shelf, HOI has a $1 billion CP program. In support of its CP program, the company maintains a syndicated committed $750 million 3-year bank facility which currently matures in August 2010. The facility contains a maximum debt to total capitalization ratio covenant of 75%. At September 30, 2007, availability under the company's bank facility was approximately $480 million, given approximately $160 million of outstanding CP, $15 million of drawn bank debt, and $93 million of LCs outstanding. While it is somewhat unusual that HOI's CP back-up facility is smaller than its CP program size, Moody's notes that HOI has stated that it will not issue more than $750 million under its CP program without increasing the size of the CP back-up line to ensure that it has 100% coverage of the CP outstandings.

Based on the company's forecasted capital expenditures Moody's estimates that HOI's borrowing requirements over the next twelve months could, without a significant reduction in the company's dividend payout or timely issuances of additional MTN debt, exceed the amount available under the company's committed credit facilities. In the normal course, Moody's expects that the company will proactively access the term debt markets and/or pursue other measures to ensure that it has sufficient short-term liquidity to support its Prime - 1 (Aa) short-term rating.

Moody's recognizes that HOI has some degree of flexibility in the timing of roughly $500 million of its planned operating and capital expenditures. These expenditures could be deferred for a period of time in the event that access to additional capital became constrained. However, Moody's notes that these OEB-approved expenditures can only be deferred for a finite period and that any such deferral would likely have adverse consequences for future system reliability and operating costs. Moody's also recognizes that some of the forecasted capital expenditures in future years have yet to be approved by either HOI's board or the OEB and, as such, might not materialize. Notwithstanding, Moody's believes most of the forecasted capital spending will be approved and will ultimately take place with the result that HOI's capital expenditures will remain elevated through the medium-term. Accordingly, Moody's believes that HOI's liquidity requirements have increased in a semi-permanent basis. Similarly, Moody's considers the company to be significantly more dependent upon continued access to the public debt markets than it has been in recent years.

CHALLENGES ASSOCIATED WITH AN AGING WORKFORCE

The extent of HOI's capital expenditures over the next few years highlights another challenge that HOI and many other utilities face: that of an aging workforce. At HOI's December 31, 2006 year-end, the company estimated that, approximately 25% of its workforce would become eligible for retirement by the end of 2008. The availability and cost of skilled labour necessary to successfully complete the work required under HOI's substantial capital expenditure plans as well its ongoing system operation and maintenance could prove to be a challenge.

DEFAULT DEPENDENCE HIGH

High default dependence reflects the importance of the issuer to the provincial economy and its operating and financial proximity to the government.

EXTRAORDINARY SUPPORT

Moody's expectation of high probability of extraordinary support reflects the strategic importance of the issuer to the province, the government's history of providing support through dividend deferrals in its capacity as the shareholder of the company and the government's history of intervening in the electricity sector.

Rating Outlook

The stable outlook reflects the fact that HOI's weak credit metrics are largely balanced by its low business risk profile and dominant business position in the Ontario electricity market. It also reflects Moody's expectation that HOI will significantly improve its liquidity resources in the context of its forecasted significant and growing capital expenditure profile.

What Could Change the Rating - Up

- While considered unlikely at this time, a sustainable improvement in cash flow metrics (CFO pre-WC/Interest exceeding 6.0x, CFO pre-WC/Debt exceeding 30% and (CFO pre-WC less Dividends)/Debt exceeding 25%) could result in an increase in both HOI's BCA and published rating.

What Could Change the Rating - Down

One or more of the following could result in a reduction of either HOI's BCA or its published rating:

- A material reduction in the perceived probability of extraordinary support

- A sustained weakening of cash flow metrics such as CFO pre-WC/Interest coverage below 3.5x, CFO pre-WC/Debt below 13% and/or CFO pre-WC/Debt below 9%

- Failure of the company to ensure sufficient sources of liquidity in support of its growing capital expenditure program

- Actions on the part of the shareholder that impede the company's ability to act in a commercial manner

- Material changes in the ownership, governance or management structures

- Further restructuring of the electricity sector that increases HOI's business or financial risk profiles

Rating Factors

Hydro One Inc.

Select Key Ratios for Global Regulated Electric Utilities

Rating	Aa	Aa	A	A	Baa	Baa	Ba	Ba
Level of Business Risk	**Medium**	**Low**	**Medium**	**Low**	**Medium**	**Low**	**Medium**	**Low**
CFO pre-W/C to Interest (x) [1]	>6	>5	3.5-6.0	3.0-5.7	2.7-5.0	2-4.0	<2.5	<2
CFO pre-W/C to Debt (%) [1]	>30	>22	22-30	12-22	13-25	5-13	<13	<5
CFO pre-W/C - Dividends to Debt (%) [1]	>25	>20	13-25	9-20	8-20	3-10	<10	<3
Total Debt to Book Capitalization (%)	<40	<50	40-60	50-70	50-70	60-75	>60	>70

[1] CFO pre-W/C, which is also referred to as FFO in the Global Regulated Electric Utilities Rating Methodology, is equal to net cash flow from operations less net changes in working capital items

PROSPECTUS FOR
MOST RECENT FINANCING

Included in this Exhibit is a copy of the $2.5 billion Medium Term Note Short Form Base Shelf Prospectus dated June 21, 2007.

No securities regulatory authority has expressed an opinion about these securities and it is an offence to claim otherwise.

This short form prospectus has been filed under legislation in each of the provinces of Canada that permits certain information about these securities to be determined after this prospectus has become final and that permits the omission from this prospectus of that information. The legislation requires the delivery to purchasers of a prospectus supplement containing the omitted information within a specified period of time after agreeing to purchase any of these securities. All shelf information omitted from this shelf prospectus will be contained in one or more shelf prospectus supplements that will be delivered to purchasers together with the base shelf prospectus.

This short form prospectus constitutes a public offering of these securities only in those jurisdictions where they may be lawfully offered for sale and therein only by persons permitted to sell such securities. The securities to be issued hereunder have not been and will not be registered under the United States Securities Act of 1933, as amended, or any state securities laws and may not be offered, sold or delivered within the United States of America and its territories and possessions except in certain transactions exempt from the registration requirements of such Act. See "Plan of Distribution".

***Information has been incorporated by reference in this short form prospectus from documents filed with securities commissions or similar authorities in Canada**. Each shelf prospectus supplement will be incorporated by reference into this shelf prospectus for the purposes of securities legislation as of the date of the shelf prospectus supplement and only for the purposes of the distribution of the securities to which the shelf prospectus supplement pertains. Copies of the documents incorporated herein by reference may be obtained on request without charge from the Secretary of Hydro One Inc., 483 Bay Street, North Tower, 15th Floor, Toronto, Ontario, M5G 2P5, (416) 345-6044 and are also available electronically at www.sedar.com. For the purpose of the Province of Québec, this simplified prospectus contains information to be completed by consulting the permanent information record. A copy of the permanent information record may be obtained without charge from the Secretary of Hydro One Inc. at the above-mentioned address and telephone number and is also available electronically at www.sedar.com.*

SHORT FORM BASE SHELF PROSPECTUS

New Issue June 21, 2007

HYDRO ONE INC.
$2,500,000,000
Medium Term Notes
(unsecured)

Hydro One Inc. may offer and issue from time to time medium term notes (the "Notes") in an aggregate principal amount of up to $2.5 billion in Canadian currency (or the equivalent thereof in other currencies or currency units at the time of issue) during the twenty-five months from the date of issuance of the receipt for this short form shelf prospectus.

The Notes will have a term to maturity of not less than one year and will be issuable in Canadian currency (or in other currencies or currency units at the time of issue) in fully registered definitive or global form, in which case the Notes will be exchangeable only under certain conditions for definitive Notes.

Notes issued hereunder will be direct unsecured obligations of our company, will be issued under a trust indenture in any number of series or separate issues thereof, and will at their respective dates of issue rank *pari passu* with all other unsecured and unsubordinated Indebtedness (as defined below) of our company then outstanding, except as to any sinking fund which pertains exclusively to any particular Indebtedness of our company.

The specific variable terms of an offering of Notes (including the aggregate principal amount of the Notes being offered, the currency or currencies, the issue and delivery date, the form, the maturity date, the interest rate (either fixed or floating and, if floating, the manner of calculation thereof), the issue price, the interest payment date(s), any redemption or repayment provisions, any provisions entitling our company to extend the maturity date of the Notes, whether the Notes are exchangeable or convertible into other securities issued by our company or, subject to appropriate regulatory approval, by another corporation, partnership, unincorporated syndicate or organization, trust or other entity, the name(s) of the dealer(s) offering the Notes, the commission payable to such dealer(s), the method of distribution and the net proceeds to our company) will be set forth in a prospectus supplement or pricing supplement which will accompany this short form shelf prospectus. Unless otherwise indicated in a prospectus supplement or pricing supplement, the Notes will not be listed on any securities exchange.

This short form shelf prospectus does not qualify the issuance of Notes: (i) entitling the holder to exchange or convert the Notes into securities issued by another entity (other than our company); or (ii) in respect of which the payment of principal and/or interest may be determined, in whole or in part, by reference to one or more underlying interests including, for example, an equity or debt security, a statistical measure of economic or financial performance including, but not limited to, any currency, consumer price or mortgage index, or the price or value of one or more commodities, indices or other items, or any other item or formula, or any combination or basket of the foregoing items. For greater certainty, however, this short form shelf prospectus does qualify for issuance Notes in respect of which the payment of principal and/or interest may be determined, in whole or in part, by reference to published rates of a central banking authority or one or more financial institutions, such as a prime rate or a bankers' acceptance rate, or to recognized market benchmark interest rates, such as CDOR, LIBOR or EURIBOR.

There is no market through which these securities may be sold and purchasers may not be able to resell securities purchased under this short form shelf prospectus. This may affect the pricing of the securities in the secondary market, the transparency and availability of trading prices, the liquidity of the securities, and the extent of issuer regulation. See "Risk Factors".

RATES ON APPLICATION

The Notes may be offered severally by one or more of BMO Nesbitt Burns Inc., Casgrain & Company Limited, CIBC World Markets Inc., HSBC Securities (Canada) Inc., Laurentian Bank Securities Inc., National Bank Financial Inc., RBC Dominion Securities Inc., Scotia Capital Inc. and TD Securities Inc. pursuant to the dealer agreement referred to under the heading "Plan of Distribution" or such other dealers as may be selected from time to time by our company (the "Dealers"), in each case acting as agent of our company or as principal. Where the Notes are offered by the Dealer(s) as agent, the commissions payable in connection with sales of such Notes shall be agreed from time to time between our company and any such Dealers. Where the Notes are purchased by the Dealer(s) as principal, the Notes shall be purchased at such prices and with such commissions as may be agreed from time to time between our company and any such Dealer(s) for resale to the public at prices to be negotiated with each purchaser. Such resale prices may vary during the distribution period and as between purchasers. In each case, the commissions payable, if any, will be set forth in a prospectus supplement or pricing supplement that will accompany and be incorporated by reference in this short form shelf prospectus. Each Dealer's compensation will increase or decrease by the amount by which the aggregate price paid for Notes by purchasers exceeds or is less than the price paid by the Dealer, acting as principal, to our company. We may also offer the Notes directly to potential purchasers pursuant to applicable statutory exemptions at prices and upon terms negotiated between the purchaser and our company.

BMO Nesbitt Burns Inc., CIBC World Markets Inc., HSBC Securities (Canada) Inc., Laurentian Bank Securities Inc., National Bank Financial Inc., RBC Dominion Securities Inc., Scotia Capital Inc. and TD Securities Inc. are subsidiaries or affiliates of lenders (the "Banks") that have made a credit facility available to our company. As of June 21, 2007, there is no outstanding indebtedness under this credit facility, however, if and when there is outstanding indebtedness to the Banks under the credit facility or any future credit facility with the Banks, our company may be considered a connected issuer of such dealers for purposes of securities laws in certain Canadian provinces. See "Plan of Distribution".

The offering of Notes is subject to the approval of certain legal matters on behalf of our company by Osler, Hoskin & Harcourt LLP and on behalf of the Dealers by Blake, Cassels & Graydon LLP.

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Unless the context otherwise requires, all references herein to currency are references to Canadian dollars.

DOCUMENTS INCORPORATED BY REFERENCE

The following documents, which have been filed with the securities commission or similar authority in each of the provinces of Canada, are specifically incorporated by reference in this short form shelf prospectus:

(a) the renewal annual information form of our company dated February 16, 2007;

(b) the comparative audited consolidated financial statements of our company, and the notes thereto, as at and for the fiscal years ended December 31, 2006 and 2005, together with the report of the auditors thereon;

(c) management's discussion and analysis of financial results ("MD&A") for the year ended December 31, 2006; and

(d) the comparative unaudited consolidated financial statements of our company, and the notes thereto, as at March 31, 2007 and for the three month periods ended March 31, 2007 and March 31, 2006 together with MD&A for those periods.

Updated earnings coverage ratios, as required, will be filed quarterly with the appropriate securities regulatory authorities either as prospectus supplements or as part of our company's unaudited interim and audited annual consolidated financial statements and will be deemed to be incorporated by reference into this short form shelf prospectus for the purposes of the offering of Notes hereunder.

Any documents of the types referred to in paragraphs (a) through (d) above, and any material change reports (except confidential material change reports) and business acquisition reports filed by our company with the securities regulatory authorities in Canada since the end of the financial year in respect of which our then current AIF is filed, shall be deemed to be incorporated by reference into this short form shelf prospectus. Upon a new annual information form and new annual financial statements and related MD&A being filed by our company with, and where required, accepted by, the applicable securities regulatory authorities during the currency of this short form shelf prospectus, the previous annual information form, the previous annual financial statements and related MD&A, and all previous interim financial statements and related MD&A filed prior to the commencement of our company's financial year in which the new annual information form, new annual financial statements and related MD&A are filed shall be deemed no longer to be incorporated into this short form shelf prospectus for purposes of future offers and sales of Notes hereunder.

A pricing supplement or prospectus supplement containing the specific variable terms for an issue of Notes will be delivered to purchasers of such Notes together with this short form shelf prospectus and will be deemed to be incorporated by reference into this short form shelf prospectus as of the date of the pricing supplement or prospectus supplement, solely for the purposes of the Notes issued under that pricing supplement or prospectus supplement .

Any statement contained in this short form shelf prospectus or in a document incorporated or deemed to be incorporated by reference herein shall be deemed to be modified or superseded and not incorporated by reference, for purposes of this short form shelf prospectus, to the extent that a statement contained herein or in any other subsequently filed document which also is or is deemed to be incorporated by reference herein modifies or supersedes such prior statement. The modifying or superseding statement need not state that it has modified or superseded a prior statement or include any other information set forth in the document that it modifies or supersedes. The making of a modifying or superseding statement shall not be deemed an admission for any purposes that the modified or superseded statement, when made, constituted a misrepresentation, an untrue statement of a material fact or an omission to state a material fact that is required to be stated or that is necessary to make a statement not misleading in light of the circumstances in which it was made. Any statement so modified or superseded shall not constitute a part of this short form shelf prospectus, except as so modified or superseded.

FORWARD-LOOKING INFORMATION

This short form shelf prospectus, including the documents incorporated by reference herein, contains forward-looking statements that are based on current expectations, estimates, forecasts and projections about the business of our company and the industry in which it operates and includes beliefs and assumptions made by the management of our company. Such statements include, but are not limited to, statements about the general development of our business; recent regulatory developments including the installation of smart meters; our strategy as it relates to safety, reliability, productivity and cost efficiency; expectations regarding key capital expenditures; expectations regarding developments in the legislative and operating framework for electricity distribution and transmission in Ontario including changes to codes, licences, rate orders and rate structures in both our transmission and distribution businesses; the nature of our relationship with our shareholder, the Province of Ontario; environmental matters; and legal proceedings in which we are currently involved. Words such as “expect”, “anticipate”, “intend”, “attempt”, “may”, “plan”, “will”, “believe”, “seek”, “estimate”, and variations of such words and similar expressions are intended to identify such forward-looking statements. These statements are not guarantees of future performance and involve assumptions and risks and uncertainties that are difficult to predict. Therefore, actual outcomes and results may differ materially from what is expressed, implied or forecasted in such forward-looking statements. While we do not know what impact any of these differences may have, our business, results of operations, financial condition and credit stability may be materially adversely affected. We do not intend, and we disclaim any obligation to update any forward-looking statements, whether written or oral, or whether as a result of new information, future events or otherwise.

These forward looking statements are based on a variety of factors and assumptions including, but not limited to: no unforeseen changes in the legislative and operating framework for Ontario’s electricity market; favourable decisions from the Ontario Energy Board concerning outstanding rate and other applications; no unforeseen changes in rate orders or rate structures for our distribution and transmission businesses; a stable competitive environment; and no significant event occurring outside the ordinary course of business such as a natural disaster or other calamity. These assumptions are based on information currently available to our company including information obtained by our company from third-party industry analysts. Factors that could cause actual results or outcomes to differ materially from the results expressed or implied by forward-looking statements include, among other things:

- the risks associated with being controlled by the Province of Ontario including potential conflicts of interest that may arise between us, the Province of Ontario and related parties;
- the risks associated with being subject to extensive regulation including risks associated with Ontario Energy Board action or inaction;
- the potential for service disruptions and increased costs if we fail to maintain and improve our aging asset base;

- the risks to our facilities posed by severe weather, other natural disasters or catastrophic events, and our limited insurance coverage for losses resulting from these events;

- the potential failure to achieve anticipated reductions in operating costs from our outsourcing arrangement with Inergi LP;

- the inability to further improve our labour productivity and the risks associated with labour disputes;

- the risks related to the high number of retirements anticipated over the next few years and our potential inability to hire and recruit replacement staff;

- the potential for substantial and currently undetermined environmental costs and liabilities;

- the risk that we are not able to arrange sufficient cost effective financing to repay maturing debt and to fund capital expenditures, dividends and other obligations;

- the risk that we may be required to make substantial contributions to our pension plan;

- the risk that we may be subject to significant costs to complete the transfer of transmission, distribution and other assets located on Indian lands; and

- the impact of the acquisition by the Province of Ontario of owned lands underlying our transmission system.

We caution you that the above list of factors is not exclusive. Some of these and other factors (including factors you should consider concerning an investment in the Notes) are discussed in more detail under "Risk Factors" in this short form shelf prospectus and in the section entitled "Risk Factors" in our annual information form and the section entitled "Risk Management and Risk Factors" in our MD&A. You should review these sections in detail.

CREDIT RATINGS

The Notes have been rated A by Standard & Poor's Ratings Services ("S&P"), A (high) by DBRS Limited ("DBRS") and Aa3 by Moody's Investors Services, Inc. ("Moody's"). The following information relating to credit ratings is based on information made available to the public by the rating agencies.

Credit ratings are intended to provide investors with an independent measure of the credit quality of an issue of securities. The rating agencies rate long-term debt instruments by rating categories ranging from a high of AAA to a low of D (C in the case of Moody's). Long-term debt instruments which are rated in the A category by S&P mean the obligor has a strong capacity to meet its financial commitments but are considered somewhat more susceptible to the adverse effects of changes in circumstances and economic conditions than obligations in higher rated categories. However, the obligor's capacity to meet its financial commitments and obligations is still strong. S&P utilizes a plus or a minus modifier to indicate the relative standing within the rating category. Long-term debt instruments which are rated in the A category by DBRS are considered to be of a satisfactory credit quality, with substantial protection of interest and principal. Entities in the A category, however, are considered to be more susceptible to adverse economic conditions and have greater cyclical tendencies than higher-rated securities. The "high" modifier indicates relative standing within this rating category by DBRS. Long-term debt instruments which are rated in the Aa category by Moody's are judged to be of high quality and are subject to very low credit risk. Moody's applies numerical modifiers to each generic rating classification from Aa to Caa. The modifier 3 indicates a ranking in the lower end of that generic rating category.

The ratings mentioned above are not a recommendation to purchase, sell or hold our company's debt securities including the Notes and do not comment as to market price or suitability for a particular investor. There can be no assurance that the ratings will remain in effect for any given period of time or that the ratings will not be revised or withdrawn entirely by any or all of S&P, DBRS and Moody's at any time in the future if in their judgment circumstances so warrant.

ELIGIBILITY FOR INVESTMENT

In the opinion of Osler, Hoskin & Harcourt LLP, counsel to our company, and Blake, Cassels & Graydon LLP, counsel to the Dealers, unless otherwise specified in the applicable prospectus supplement or pricing supplement, the Notes, if issued on the date hereof, would be qualified investments under the *Income Tax Act* (Canada) (the "Tax Act") and the regulations thereunder for a trust governed by a registered retirement savings plan, registered retirement income fund, registered education savings plan or deferred profit sharing plan (other than a trust governed by a deferred profit sharing plan for which any employer is our company or an employer who does not deal with our company at arm's length).

OUR COMPANY

We are the leading electricity transmission and distribution company in Ontario. We own and operate substantially all of Ontario's electricity transmission system, accounting for approximately 96% of Ontario's transmission capacity as measured by revenues for the year ended December 31, 2006. Our transmission system is one of the largest in North America based on assets as at December 31, 2006. Our distribution system is the largest in Ontario based on assets as at December 31, 2006 and spans approximately 75% of Ontario, serving approximately 1.3 million customers. We have three reportable segments: (1) our transmission business; (2) our distribution business; and (3) our other business.

Our transmission business, which represented approximately $6.97 billion of our total assets of $12.23 billion as at December 31, 2006, transmits electricity through an approximately 28,600 circuit-kilometre high-voltage network. We transmit electricity from generators to our own distribution network, 51 local distribution companies and 64 large industrial customers directly connected to our transmission system. We also own and operate 26 facilities that interconnect our transmission system with systems in neighbouring provinces and states.

Our distribution business, which represented approximately $5.17 billion of our total assets of $12.23 billion as at December 31, 2006, distributes electricity through our approximately 124,700 circuit-kilometre low-voltage distribution system, including phase multipliers to municipalities and in rural areas. Customers of our distribution business include 34 local distribution companies that are not directly connected to our transmission system, 48 large industrial customers and approximately 1.3 million rural and urban customers. Hydro One Brampton Networks Inc. is our urban distribution company, serving approximately 120,000 customers in the Greater Toronto Area with approximately 4,845 circuit-kilometres of lines with phase multiplier. We also operate through our subsidiary, Hydro One Remote Communities Inc., 18 small, regulated generation and distribution systems in 20 remote communities across Northern Ontario that are not connected to Ontario's electricity grid.

Our other business segment is primarily represented by the operations of Hydro One Telecom Inc. This subsidiary markets dark and lit fibre-optic capacity to telecommunications carriers and commercial customers with broadband network requirements. The assets of this segment constituted $99 million of our total assets of $12.23 billion as at December 31, 2006.

The Ontario Energy Board regulates our transmission and distribution businesses and issues rate orders to establish the revenue requirements required to cover the approved cost of these businesses plus a specified rate of return.

The address of the head and registered office and principal place of business of our company is 483 Bay Street, North Tower, 15th Floor, Toronto, Ontario, M5G 2P5.

EARNINGS COVERAGE RATIOS

For the twelve months ended December 31, 2006 and the twelve months ended March 31, 2007, our company's consolidated income before provision for payment in lieu of corporate income taxes and interest expensed was $929 million and $948 million, respectively. Interest expense for these periods was $295 million and $295 million, respectively. Preferred share dividends declared for these periods were $18.0 million and $18.0 million, respectively.

The following table sets forth the earnings coverage ratio for our company for the twelve month period ended December 31, 2006, based on audited information, and for the twelve month period ended March 31, 2007, based on unaudited information, in each case without giving effect to any Notes to be issued under this short form shelf prospectus:

	December 31, 2006	March 31, 2007
Earnings coverage on long-term debt obligations(1)(2)	2.65	2.72

(1) The earnings coverage ratio has been calculated as the sum of net income, interest expense (which is net of capitalized interest) and provision for payments in lieu of corporate income taxes divided by the sum of interest plus preferred dividends declared.

(2) The earnings coverage ratio has been adjusted to give effect to the issuance on March 13, 2007 of $400 million of 4.89% medium term notes due March 13, 2037, as if such notes had been issued at the beginning of each respective twelve month period noted above. For purposes of calculating the earnings coverage ratio for periods noted above, it has also been assumed that the proceeds of such notes were used to repay medium term notes maturing in May 2007.

DESCRIPTION OF THE NOTES

The following is a summary of the material attributes and characteristics of the Notes, and does not purport to be complete and is qualified in its entirety by reference to the Notes and the Trust Indenture (as defined below).

The terms and conditions set forth in this section "Description of the Notes" will apply to each Note unless otherwise specified in the applicable prospectus supplement or pricing supplement. We reserve the right to set forth in a prospectus supplement or pricing supplement specific variable terms of or amendments to the Notes which are not within the options and parameters set forth in this short form shelf prospectus. References in this section "Description of the Notes" refer to all medium term notes of our company which have previously been or are to be issued under the Trust Indenture.

This short form shelf prospectus qualifies the distribution of $2.5 billion aggregate principal amount of Notes in Canadian currency (or the equivalent thereof in other currencies or currency units at the time of issue) which have been authorized for issue under the Trust Indenture. This amount is subject to amendment from time to time as determined by our company. Our company has previously issued $1.175 billion aggregate principal amount of medium term notes under our short form shelf prospectus dated June 24, 2005. Upon the issuance of a final receipt for this short form shelf prospectus, we will not qualify for distribution any additional Notes under the June 24, 2005 prospectus.

Notes issued hereunder will have a term to maturity of not less than one year and will be issuable in Canadian currency (or in other currencies or currency units at the time of issue) in fully registered definitive or global form, in which case the Notes will be exchangeable only under certain conditions for definitive Notes (as described under the subheading "Global Notes" below). Each interest-bearing Note will bear interest at either a fixed rate (a "Fixed Rate Note") or a floating rate (a "Floating Rate Note"). Notes will be issued from time to time at such rates of interest and at par, at a premium or at a discount, may be subject to redemption or repayment prior to maturity, and may include terms entitling the holder to exchange or convert the Notes into other securities issued by our company, or to extend the maturity dates of the Notes, which terms shall be determined by our company based on a number of factors, including advice from the Dealers. The Notes will be unsecured and will at their respective dates of issue rank *pari passu* with all other unsecured and unsubordinated Indebtedness and obligations of our company then outstanding, except as to any sinking fund which pertains exclusively to any particular Indebtedness of our company.

Neither the aggregate principal amount of Notes which will be issued and sold nor the issue price to the public of the Notes has been established as the Notes will be issued at such times, in such amounts and at such prices as our company determines from time to time. Notes issued hereunder will be offered and sold during the twenty-five months from the date of issuance of the receipt for this short form shelf prospectus at prices negotiated with the purchasers, and the prices at which the Notes will be offered and sold may vary as between purchasers and during the distribution period. The Notes will be issued from time to time at the discretion of our company in an aggregate principal amount not to exceed $2.5 billion in Canadian currency, or the equivalent thereof calculated at the applicable rates of exchange prevailing at the time of issue of Notes issued in currencies other than Canadian currency.

The specific variable terms of any offering of Notes, including, in the case of Floating Rate Notes, the information necessary for the calculation of interest thereon, will be set forth in a prospectus supplement or pricing supplement to this short form shelf prospectus. Where Notes are offered and sold in currencies other than Canadian dollars, the Canadian dollar equivalent of the offering price and the rate of exchange at the last feasible date will be included in the applicable prospectus supplement or pricing supplement.

Trust Indenture

The Notes will be issued under a trust indenture dated as of June 4, 2001, as supplemented or modified from time to time (the "Trust Indenture") between our company and Computershare Trust Company of Canada, as trustee (the "Trustee", which term shall include, unless the context requires, its successors and assigns). The following is a brief summary of the material attributes and characteristics of the Trust Indenture. This summary does not purport to be complete and reference should be made to the Trust Indenture for more detailed information.

The Trust Indenture permits the issuance from time to time of additional unsecured medium term notes without limitation as to aggregate principal amount, subject to compliance with the covenants contained therein.

The Notes will be direct obligations of our company and will rank *pari passu* with all other medium term notes from time to time issued and outstanding under the Trust Indenture and with other present and future unsubordinated and unsecured Indebtedness of our company, except as to any sinking fund which pertains exclusively to any particular Indebtedness of our company. The Notes will not be secured by any mortgage, pledge or charge, except in the circumstances referred to under the heading "Negative Pledge".

Negative Pledge

The Trust Indenture contains provisions to the effect that our company will not, nor will it permit any Designated Subsidiary (as defined below) to, create, assume or suffer to exist any Security Interest (as defined below) on any of our or the Designated Subsidiary's assets to secure any Obligation (as defined below) unless at the same time it shall secure all the Notes then outstanding on an equal basis. This covenant is, however, subject to the following exceptions:

- any Security Interest that secures the Obligations of a Designated Subsidiary which exists prior to the date on which it becomes a Designated Subsidiary and which (a) was not incurred in contemplation of that person becoming a Designated Subsidiary and (b) was not applicable to our company or any other Designated Subsidiary or the properties or assets of our company or any other Designated Subsidiary;

- any Security Interest granted by our company or a Designated Subsidiary to secure the Notes;

- any Purchase Money Mortgage (as defined below) or Capital Lease Obligation (as defined below) of our company or any Designated Subsidiary;

- any Security Interest on a property or asset acquired by our company or a Designated Subsidiary that secures the Obligations of a person, whether or not that Obligation is assumed by the acquiring person, which Security Interest exists at the time that property or asset is acquired and which (a) was not incurred in contemplation of that property or asset being acquired and (b) was not applicable to our company or any other Designated Subsidiary or the properties or assets of our company or any other Designated Subsidiary;

- any Security Interest given in the ordinary course of business by our company or a Designated Subsidiary to any bank or banks or other lenders to secure any Indebtedness payable on demand or maturing within 18 months of the date that Indebtedness is incurred or of the date of any renewal or extension of that Indebtedness;

- any Security Interest granted by any Designated Subsidiary in favour of our company or any Wholly-Owned Designated Subsidiary (as defined below);

- any Security Interest on or against cash or marketable debt securities pledged to secure any non-speculative Financial Instrument Obligation (as defined below) which hedges Indebtedness of our company or of a Designated Subsidiary;

- any Security Interest for taxes, assessments, government charges or claims that are being contested in good faith and in respect of which appropriate provision is made in our consolidated financial statements in accordance with Canadian generally accepted accounting principles ("Canadian GAAP");

- Security Interests securing appeal bonds or other similar Security Interests arising in connection with contracts, bids, tenders or court proceedings, including, without limitation, surety bonds, security for costs of litigation where required by law and letters of credit, or any other instruments serving a similar purpose;

- a Security Interest in cash or marketable debt securities in a sinking fund account established by our company in support of a series of Notes;

- a lien or deposit under workers' compensation, social security or similar legislation or good faith deposits in connection with bids, tenders, leases, contracts or expropriation proceedings, or deposits to secure public or statutory obligations or deposits of cash or obligations to secure surety and appeal bonds;

- any lien or privilege imposed by law, such as builders', carriers', warehousemen's, landlords', mechanics' and material men's liens and privileges, and any lien or privilege arising out of judgments or awards with respect to which our company or a Designated Subsidiary at the time is prosecuting an appeal or proceedings for review and with respect to which it has secured a stay of execution pending that appeal or proceedings for review; or any liens for taxes, assessments or governmental charges or levies not at the time due and delinquent or the validity of which is being contested at the time by our company or a Designated Subsidiary in good faith; or undetermined or inchoate lien privileges and charges incidental to current operations which have not at such time been filed pursuant to law against our company or a Designated Subsidiary or which relate to obligations not due or delinquent; or the deposit of cash or securities in connection with any lien or privilege referred to in this clause;

- any minor encumbrance, such as easements, rights-of-way, servitudes or other similar rights in land granted to or reserved by other persons, rights-of-way for sewers, electric lines, telegraph and telephone lines, oil and natural gas pipelines and other similar purposes, or zoning or other restrictions as to our company's use of real property, which do not in the aggregate materially detract from the value of that property or materially impair its use in the operation of the business of our company or a Designated Subsidiary;

- any right reserved to or vested in, whether by statutory provision or otherwise, any municipality or governmental or other public authority to terminate, purchase assets used in connection with or require annual or other periodic payments as a condition to the continuance of, any lease, license, franchise, grant or permit acquired by our company or a Designated Subsidiary;

- any lien or right of distress reserved in or exercisable under any lease for rent and for compliance with the terms of that lease;

- any Security Interest granted by our company or a Designated Subsidiary to a public utility or any municipality or governmental or other public authority when required by that utility, municipality or other authority in connection with the operations of our company or a Designated Subsidiary;

- any reservation, limitation, proviso or condition, if any, expressed in any original grants to our company or a Designated Subsidiary from the Crown; and

- any extension, renewal, alteration, substitution or replacement, in whole or in part, of any Security Interest referred to in the foregoing clauses, provided that the Security Interest is limited to all or part of the same property that secured the Security Interest, the principal amount of the secured Obligations is not increased by that action, the term of the secured Indebtedness is not shortened and the terms and conditions are no more restrictive in any material respect than the Security Interest so extended.

In addition to the Security Interests permitted above, our company or any Designated Subsidiary may create, assume or suffer to exist any Security Interest on any of its assets if, after giving effect to that Security Interest, the aggregate amount of Indebtedness secured by the Security Interests permitted only by this paragraph does not at that time exceed 5% of the Consolidated Net Worth (as defined below) of our company.

Limitation on Funded Obligations

So long as any of the Notes issued under the Trust Indenture remain outstanding, neither our company nor any of its Designated Subsidiaries will, directly or indirectly, guarantee, incur, issue or become liable for or in respect of any Funded Obligations (as defined below) unless after giving pro forma effect to that guarantee, incurrence, issuance or liability, including the application or use of the resulting net proceeds, the aggregate principal amount of Consolidated Funded Obligations (as defined below) does not exceed 75% of the Total Consolidated Capitalization (as defined below). This covenant, however, will not prevent the incurrence of Capital Lease Obligations, Purchase Money Obligations and non-speculative Financial Instrument Obligations.

Ceasing to be a Designated Subsidiary

The Board of Directors of our company may elect that any Designated Subsidiary cease to be a Designated Subsidiary, except that an election may not be made in respect of any Designated Subsidiary:

- if the Designated Subsidiary owns any Funded Obligations of our company or any shares, voting interests or Funded Obligations of any other Designated Subsidiary;

- if the Designated Subsidiary owns or has any ownership interest in any Principal Property (as defined below); or

- if, after giving effect to the election, our company would not be entitled to issue Funded Obligations in the principal amount of at least $1.00.

Mergers, Consolidations and Sales of Assets

Our company will not enter into any transaction in which all or substantially all of our property and assets would become the property of any other person, whether by way of reorganization, consolidation, amalgamation, arrangement, merger, transfer, sale or otherwise, unless:

- our company shall be the surviving person, or the person, if other than our company, formed by the amalgamation, consolidation or into which our company is merged or that acquires by disposition all or substantially all of the property or assets of our company shall be a company organized and validly existing under the federal laws of Canada or any of its provinces or territories and shall expressly assume, by a supplemental indenture executed and delivered to the trustee in form satisfactory to the Trustee, all of our company’s obligations under the Trust Indenture;

- immediately before and after giving effect to the transaction, no Event of Default or event that with the passing of time or the giving of notice, or both, would constitute an Event of Default shall have occurred and be continuing; and

- neither our company nor any successor, either at the time of or immediately after the consummation of any such transaction, will be insolvent or generally fail to meet, or admit in writing its inability or unwillingness to meet, its obligations as they generally become due.

Events of Default

The following are Events of Default under the Trust Indenture with respect to Notes of any series:

(1) failure to pay any principal or premium, if any, on any Notes when due, at maturity, upon redemption or otherwise and the continuance of such default for a period of five days;

(2) failure to pay any interest on any Notes when due and the continuance of that default for a period of 45 days;

(3) the sale, transfer or other disposition of all or substantially all of our undertaking or assets other than in accordance with the covenant described above under "Mergers, Consolidations and Sales of Assets";

(4) default in the performance or breach of any other covenant or agreement of our company under the Trust Indenture, any supplemental indenture or the Notes and the continuance of that default for a period of 60 days after written notice to our company by the Trustee or by holders of at least 25% of all Notes issued under the Trust Indenture;

(5) default by our company or any Material Subsidiary (as defined below), whether as primary obligor, guarantor or surety, on any payment of principal, premium, if any, or interest on any Indebtedness, the outstanding principal amount of which Indebtedness exceeds $100 million in the aggregate, beyond any applicable grace period or failure to perform or observe any other agreement, term or condition contained in any agreement under which that Indebtedness is created, or if any default, failure or other event under that agreement shall occur and be continuing, and the effect of that default, failure or other event is to cause $100 million or more of that Indebtedness to become due or to be required to be repurchased prior to any stated maturity;

(6) the rendering of a judgment or judgments, not subject to appeal, against our company or any Material Subsidiary in an aggregate amount in excess of $100 million by a court or courts of competent jurisdiction, which judgment or judgments remain undischarged and unstayed for a period of 60 days; and

(7) specified events of bankruptcy, insolvency or reorganization affecting our company or any Material Subsidiary.

If an Event of Default applicable only to the issued and outstanding Notes of a series occurs and is continuing, either the Trustee or the holders of not less than 25% in principal amount of Notes of that series then outstanding may declare the principal of, and interest and premium, if any, on all Notes of that series to be due and payable immediately.

If, however, an Event of Default applicable to all Notes issued and outstanding under the Trust Indenture, or an Event of Default described in clause (5), (6), or (7) above occurs and is continuing, either the Trustee or the holders of not less than 25% in principal amount of all issued and outstanding Notes, treated as one class, may declare the principal amount of all the Notes then outstanding to be due and payable immediately.

Subject to the provisions of the Trust Indenture relating to the duties of the Trustee, in case an Event of Default applicable to any Notes shall occur and be continuing, the Trustee will be under no obligation to exercise any of its rights or powers under the Trust Indenture at the request or direction of any of the holders of those Notes, unless those holders shall have offered to the Trustee reasonable indemnity. Subject to such provisions for the indemnification of the Trustee, the holders of a majority in principal amount of Notes of all series affected by an Event of Default will have the right to direct the time, method and place of conducting any proceedings for any remedy available to the Trustee or exercising any trust or power conferred on the Trustee in respect of the Notes of all series affected by that Event of Default.

Defeasance

The Trust Indenture requires the Trustee to release our company from its obligations under the Trust Indenture relating to a particular series of Notes if specified conditions are satisfied. Among other things, our company must deposit money or securities for the payment of all principal of and interest and any other amounts on that series of Notes as well as for the payment of the expenses of the Trustee. The deposited money or securities must be denominated in the currency in which principal of these Notes is payable and, in the case of deposited securities, must constitute direct obligations of Canada or specified provinces of Canada or an agency or instrumentality of Canada.

Amendments and Waivers

The Trust Indenture provides that our company and the Trustee may enter into supplemental indentures ("Supplemental Indentures") without the consent of the holders of the Notes of any or all series to:

- add limitations or restrictions to be observed upon the amount or issue of Notes, provided that such limitations or restrictions shall not be materially adverse to the interests of the holders of the Notes;
- add covenants for the protection of the holders of the Notes of any series;
- provide for any additional Events of Default;
- make such provisions not inconsistent with the Trust Indenture as may be necessary or desirable with respect to matters or questions arising thereunder, including the making of any modifications in the form of the Notes which do not affect the substance thereof and which it may be expedient to make, provided that such provisions and modifications will not adversely affect the holders of Notes;
- provide for the issue of Notes of any one or more series and establish the form and terms of any series of Notes;
- evidence the succession, or successive successions, of successors to our company and the covenants and obligations assumed by any such successor, in accordance with the provisions of the Trust Indenture; and
- giving effect to any extraordinary resolution or ordinary resolution of the holders of Notes in accordance with the Trust Indenture.

Other amendments and modifications of the Trust Indenture, Supplemental Indentures and Notes may be made by our company and the Trustee with the consent of the holders of not less than 66⅔% (and in certain circumstances, a majority) in principal amount of Notes of all series voting on such amendment or modification and, if the rights of holders of Notes of a particular series of Notes would be affected differently than rights of holders of Notes of other series, not less than 66⅔% (and, in certain circumstances, a majority) in principal amount of Notes of the series so affected by that modification or amendment voting on such amendment or modification, in each case, voting as one class. However, no modification or amendment may, without the consent of the holder of each outstanding Note of the affected series,

- reduce the principal amount at maturity of, extend the fixed maturity of, or alter the redemption provisions of, those Notes;
- change the currency in which those Notes or any premium or accrued interest is payable;
- reduce the percentage in principal amount at maturity outstanding of those Notes that must consent to an amendment, supplement or waiver or consent to take any action under the Trust Indenture, Supplemental Indenture or those Notes;

- impair the right to institute suit for the enforcement of any payment on or with respect to those Notes;
- waive a default in payment with respect to those Notes;
- reduce the rate or extend the time for payment of interest on those Notes;
- affect the ranking of those Notes in a manner adverse to the holders; or
- make any changes to the Trust Indenture, Supplemental Indentures or those Notes that would result in our company being required to make any withholding or deduction from payments made under or with respect to those Notes.

The holders of 66⅔% in principal amount of the Notes of all series with respect to which an Event of Default shall have occurred and be continuing, voting as one class, may waive any Event of Default, except in the case of a default in payment of principal with respect to the Notes or except, further, in respect of a covenant or provision which cannot be modified or amended without the consent of the holder of each outstanding Note affected.

<u>Definitions</u>

In addition to the definitions set out above, the Trust Indenture contains definitions substantially to the following effect:

"Capital Lease Obligation" means any monetary obligation of our company or a Designated Subsidiary under any leasing or similar arrangement which, in accordance with Canadian GAAP, would be classified as a capital lease and for the purposes of the Trust Indenture, the amount of Capital Lease Obligations will be the capitalized amount thereof, determined in accordance with Canadian GAAP;

"Consolidated Funded Obligations" means the aggregate amount of all Funded Obligations of our company and its Designated Subsidiaries determined on a consolidated basis in accordance with Canadian GAAP;

"Consolidated Net Worth" means, as at any date, the consolidated shareholders' equity of our company and its Designated Subsidiaries as at that date determined in accordance with Canadian GAAP;

"Contingent Liability" means any agreement, undertaking or arrangement by which any person guarantees, endorses or otherwise becomes or is contingently liable upon (by direct or indirect agreement, contingent or otherwise, to provide funds for payment, to supply funds to, or otherwise to invest in, a debtor, or otherwise to assure a creditor against loss) the Obligation of any other person (other than by endorsements of instruments in the course of collection), or guarantees the payment of dividends or other distributions upon the shares of any other person. The amount of any person's obligation under any Contingent Liability will, subject to any limitation contained in that Contingent Liability, be deemed to be the outstanding principal amount (or maximum principal amount, if larger) of the debt, obligation or other liability guaranteed thereby;

"Designated Subsidiary" means any subsidiary which is designated as such by the directors of our company, provided that any such subsidiary may only be so designated if, after giving effect thereto, our company would be entitled under the Supplemental Indenture to issue Funded Obligations in the principal amount of at least $1.00 and further provided that a subsidiary cannot be so designated if any of its shares are owned by a subsidiary which is not itself a Designated Subsidiary;

"Financial Instrument Obligations" means, with respect to any person at any time, the obligations of that person under any transaction that is a rate swap, basis swap, forward rate transaction, commodity swap, commodity option, commodity future, equity or equity index swap or option, bond, note or bill option, interest rate option, forward foreign exchange transaction, cap, collar or floor transaction, currency swap, cross-currency rate swap, swaption, currency option or any other similar transaction, including any option to enter into any of the foregoing, or any combination of the foregoing to the extent of the net amount due to or accruing due by the person under that obligation, determined by marking that obligation to market at that time in accordance with its terms;

"Funded Obligations" means all Indebtedness created, assumed or guaranteed, which matures by its terms on, or is renewable at the option of the obligor to, a date more than 18 months after the date of the original creation, assumption or guarantee thereof;

"Indebtedness" means, without duplication, with respect to any person,

(1) all obligations of that person for borrowed money, including obligations with respect to bankers' acceptances and contingent reimbursement obligations, excluding Preferred Securities issued by that person;

(2) all obligations issued or assumed by that person in connection with its acquisition of property in respect of the deferred purchase price of that property;

(3) all Capital Lease Obligations and Purchase Money Obligations of that person; and

(4) all Contingent Liabilities of that person in respect of any of the foregoing;

"Material Subsidiary" means, as at any date, a Designated Subsidiary,

(1) the total assets of which represent more than 10% of the total assets of our company determined on a consolidated basis as shown in the most recently publicly released consolidated financial statements of our company; or

(2) the total revenues of which represent more than 10% of the total revenues of our company determined on a consolidated basis as shown in the most recently publicly released consolidated financial statements of our company;

"Obligations" means, without duplication, with respect to any person, all items which, in accordance with Canadian GAAP, would be included as liabilities on the liability side of the balance sheet of that person as of the date at which Obligations are to be determined, other than Preferred Securities issued by that person; and all Contingent Liabilities of that person in respect of any of the foregoing;

"Preferred Securities" means:

(1) securities which on the date of issue by a person (a) have a term to maturity of more than 30 years, (b) are unsecured and rank subordinate to the unsecured and unsubordinated Indebtedness of that person outstanding on that date, (c) entitle that person to satisfy the obligation to pay the principal or face amount by issuing common shares, (d) entitle that person to defer the payment of interest for more than four years without causing an event of default to occur, and (e) entitle that person to satisfy the obligation to make payments of interest by issuing common shares; and

(2) shares of any class in the capital of a corporation or securities representing ownership interests in any person other than a corporation which, in either case, are not common shares;

"Principal Property" means any of our company's and our subsidiaries' fixed assets used for the transmission, transformation and distribution of electricity in Ontario as of June 4, 2001 (the date of the Trust Indenture);

"Purchase Money Mortgage" means any security interest, mortgage, pledge, charge or other encumbrance created, issued or assumed by our company or a Designated Subsidiary to secure a Purchase Money Obligation; provided that the security interest, mortgage, pledge, charge or other encumbrance is limited to the property (including associated rights) acquired, constructed, installed or improved using the funds advanced to our company or a Designated Subsidiary in connection with that Purchase Money Obligation;

"Purchase Money Obligation" means Indebtedness of our company or a Designated Subsidiary incurred or assumed to finance the purchase price, in whole or in part, of any property (except any Indebtedness which constitutes a Funded Obligation and which was incurred or assumed to finance the purchase price, in whole or in

part, of any shares, bonds or other securities) or incurred to finance the cost, in whole or in part, of construction or installation of or improvements to any real property or fixtures provided that such Indebtedness is incurred or assumed within 24 months after the purchase of such real property or fixtures or the completion of such construction, installation or improvements, as the case may be, and includes any extension, renewal or refunding of any such Indebtedness, so long as the principal amount thereof outstanding on the date of such extension, renewal or refunding is not increased;

"Security Interest" means any assignment, mortgage, charge (whether fixed or floating), hypothec, pledge, lien, or other encumbrance on or interest in property or assets that secures payment of Indebtedness or Obligation;

"Total Consolidated Capitalization" means, at any time and from time to time, without duplication, the sum of (1) the principal amount of all Consolidated Funded Obligations at the time outstanding, and (2) the total share capital of our company at the time outstanding, based upon the stated capital on the books of our company, and (3) the principal amount of all outstanding Preferred Securities referred to in clause (1) of the definition of "Preferred Securities" plus the total amount of (or less the amount of any net deficits in) the contributed or capital surplus of our company and the retained earnings of our company and all Designated Subsidiaries in accordance with Canadian GAAP after adding back the amount shown on the consolidated balance sheet of our company and its Designated Subsidiaries for minority interests applicable to Designated Subsidiaries and eliminating all intercorporate items, plus the amount of any premium on capital of our company not included in its surplus, and less the amount, if any, by which the capital account of our company or the consolidated capital surplus account of our company and all Designated Subsidiaries (determined in the manner described above) has at any time been increased as a result of any write-up in the value of the shares of a subsidiary which is not a Designated Subsidiary to reflect the equity of our company in its retained earnings or otherwise, or as a result of a restatement of the amount at which any other assets of our company or any Designated Subsidiary are recorded on its books. The amount of Total Consolidated Capitalization of our company and all Designated Subsidiaries at any time shall be ascertained in Canadian dollars; and

"Wholly-Owned Designated Subsidiary" means a Designated Subsidiary, all of the outstanding shares in the capital of which are owned, directly or indirectly, by or for our company and/or by or for one or more other Wholly-Owned Designated Subsidiaries.

Global Notes

Notes denominated in Canadian or United States dollars may be issued in the form of fully registered global notes ("Global Notes") held by, or on behalf of, CDS Clearing and Depository Services Inc. or another corporation performing similar services that is acceptable to the Trustee (the "Depository") as custodian of the Global Notes and, in such event, Notes will be registered in the name of the Depository or its nominee (a "Nominee"). Purchasers of Notes represented by Global Notes will not receive Notes in definitive form ("Definitive Notes"). Instead, ownership of such Notes will be constituted through beneficial interests in the Global Notes, and will be represented through book-entry accounts of institutions (including the Dealers), as direct and indirect participants of the Depository ("participants"), acting on behalf of the beneficial owners of such Notes. Each purchaser of a Note represented by a Global Note will receive a customer confirmation of purchase from the Dealer from or through whom the Note is purchased in accordance with the practices and procedures of such Dealer. The Depository will be responsible for establishing and maintaining book-entry accounts for its participants having interests in Global Notes.

Currently, CDS Clearing and Depository Services Inc. only allows depository eligibility for securities denominated in Canadian or United States dollars. Any Notes denominated in a currency other than Canadian or United States dollars will be represented by Definitive Notes until such time as the Depository allows depository eligibility for issues of securities denominated in such currencies.

If Global Note(s) are issued and the Depository notifies our company that it is unwilling or unable to continue as depository in connection with the Global Notes, or if at any time the Depository ceases to be a clearing agency or otherwise ceases to be depository and our company and the Trustee are unable to locate a qualified replacement, or if our company elects to terminate the book-entry system, beneficial owners of Notes represented by Global Notes will receive Definitive Notes.

Fixed Rate Notes

Each Fixed Rate Note will bear interest from its original issue date at the rate per annum on the face thereof until the principal amount thereof is paid or made available for payment. Interest on a Fixed Rate Note will be calculated and payable monthly, quarterly, semi-annually or annually in arrears on the dates specified in such Fixed Rate Note, or other such dates as may be agreed to between the purchaser of the Note and our company (each, an "Interest Payment Date") and at maturity or upon earlier redemption or repayment. Interest Payment Dates will be set forth in the applicable prospectus supplement or pricing supplement for the Fixed Rate Note. Each payment of interest in respect of an Interest Payment Date will include interest accrued to but excluding such Interest Payment Date.

Floating Rate Notes

Each Floating Rate Note will bear interest from its original issue date at rates described in the Floating Rate Note and specified in the applicable prospectus supplement or pricing supplement.

The rate of interest on each Floating Rate Note will be reset monthly, quarterly, or as otherwise specified in the Floating Rate Note and applicable prospectus supplement or pricing supplement. Interest on each Floating Rate Note will be payable monthly, quarterly or as otherwise specified in the Floating Rate Note and applicable prospectus supplement or pricing supplement. Unless otherwise specified in the Floating Rate Note and applicable prospectus supplement or pricing supplement, our company will be the calculation agent with respect to the Floating Rate Notes. Upon request of the holder of any Floating Rate Note, our company will provide the interest rate then in effect.

Payment of Interest and Principal

Interest on each interest bearing Note will be payable on such periodic basis or at maturity and on such date or dates as may be agreed upon by our company and the purchaser of the Note. Payments of interest on each interest bearing Definitive Note will be made by cheque payable on the interest payment date and mailed to the address of, or if so directed by the holder, funds representing the interest payable will be forwarded by electronic funds transfer on the interest payment date to the account of, the holder appearing on the registers maintained by Computershare Trust Company of Canada, as registrar and transfer agent (the "Transfer Agent", which term shall include such other registrar or transfer agent as may from time to time be appointed by our company) at the close of business in the City of Toronto on the tenth business day (being a day other than Saturday, Sunday, or a day on which financial institutions at the place of payment are authorized or obligated by law or regulation to close) prior to the interest payment date or such other day specified to the Trustee by our company and reflected in a Supplemental Indenture for a particular series of Notes. Payment of principal will be made at any branch in Canada of the bank designated in a Definitive Note against surrender of the Note.

Payment of interest and principal on each Global Note will be made to the Depository or the Nominee, as the case may be, as the registered holder of the Global Note. Interest payments on Global Notes will be made by wire transfer on the date interest is payable and delivered to the Depository or the Nominee, as the case may be, two business days before the date interest is payable. Principal payments on Global Notes will be made by wire transfer on the maturity date delivered to the Depository or the Nominee, as the case may be, at maturity against receipt of the Global Note. As long as the Depository or the Nominee is the registered owner of a Global Note, the depository or the Nominee, as the case may be, will be considered the sole owner of the Global Note for the purposes of receiving payment on the Note and for all other purposes under the Trust Indenture and the Note.

Our company expects that the Depository or Nominee, upon receipt of any payment of principal or interest in respect of a Global Note, will credit participants' accounts, on the date principal or interest is payable, with payments in amounts proportionate to their respective beneficial interests in the principal amount of such Global Note as shown on the records of the Depository or the Nominee. Our company also expects that such payments of principal and interest by participants to the owners of beneficial interests in such Global Note held through such participants will be governed by standing instructions and customary practices, as is the case with securities held for the accounts of customers in bearer form or registered in "street name" and will be the responsibility of such participants. The responsibility and liability of our company and the Trustee in respect of Notes represented by

Global Notes is limited to making payment of any principal and interest due on such Global Notes to the Depository or the Nominee.

Payments of interest and principal will be made in the currency in which the Note is denominated unless otherwise specified in the applicable prospectus supplement or pricing supplement.

If the payment date for any amount of principal or interest on any Note is not, at the place of payment, a business day such payment will be made on the next business day and the holder of such Note shall not be entitled to any further interest or other payment in respect of such delay.

Transfers

The registered holder of a Definitive Note may transfer such Note upon payment of taxes incidental thereto, if any, by executing the form of transfer provided on the reverse side of the Note and surrendering the Note to the Transfer Agent at its principal office in the City of Toronto, upon which one or more new Definitive Notes will be issued in authorized denominations in the same aggregate principal amount as the Note so transferred, registered in the name or names of the transferee or transferees.

Transfers of beneficial ownership in Notes represented by Global Notes will be effected through records maintained by the Depository for such Global Notes or the Nominee (with respect to the interest of participants) and on the records of participants (with respect to the interest of beneficial owners other than participants). Beneficial owners of an interest in a Note represented by a Global Note who are not participants in the Depository's book-entry system, but who desire to purchase, sell or otherwise transfer ownership of or other interests in Global Notes, may do so only through participants in the Depository's book-entry system. A purchaser's interest in a Note represented by a Global Note will only be exchangeable for Definitive Notes in the limited circumstances set forth under the subheading "Global Notes" above and in accordance with the procedures established by the Depository or the Nominee.

The ability of a beneficial owner of an interest in a Note represented by a Global Note to pledge the Note or otherwise take action with respect to such owner's interest therein other than through a participant may be limited due to the lack of a physical certificate.

No transfer of a Note will be registered during the 10 business days immediately preceding any date fixed for payment of interest on such Note or payment of the principal amount thereof.

PLAN OF DISTRIBUTION

The Notes may be offered for sale severally and on a continuous basis by one or more of BMO Nesbitt Burns Inc., Casgrain & Company Limited, CIBC World Markets Inc., HSBC Securities (Canada) Inc., Laurentian Bank Securities Inc., National Bank Financial Inc., RBC Dominion Securities Inc., Scotia Capital Inc. and TD Securities Inc. pursuant to an agreement dated June 21, 2007 among such dealers and our company (the "Dealer Agreement") or such other dealers as may be selected from time to time by our company, in each case acting as agent of our company or as principal. Where the Notes are offered by the Dealer(s) as agent(s), the commission payable by our company shall be agreed from time to time between our company and any such Dealer(s). Where the Notes are purchased by the Dealer(s) as principal, the Notes shall be purchased at such prices and with such commissions as may be agreed from time to time between our company and any such Dealer(s) for resale to the public at prices to be negotiated with each purchaser. Such resale prices may vary during the distribution period as between purchasers. Each Dealer's compensation will increase or decrease by the amount by which the aggregate price paid for Notes by purchasers exceeds or is less than the price paid by the Dealer, acting as principal, to our company. The commission payable in connection with sales of Notes shall be no higher than 1.5% and shall be set forth in a prospectus supplement or pricing supplement that shall accompany this short form shelf prospectus. Our company has agreed to reimburse the Dealers for certain expenses and to indemnify each Dealer against certain liabilities.

Our company may also offer the Notes directly to potential purchasers pursuant to applicable statutory exemptions at prices and upon terms negotiated between the purchaser and our company.

Our company and, if applicable, the Dealers, reserve the right to reject any offer to purchase the Notes in whole or in part. Our company also reserves the right to withdraw, cancel or modify the offering of the Notes under this short form shelf prospectus without notice. In addition, the obligations of the Dealers to purchase any particular issue of Notes may be terminated at the discretion of the Dealers upon the occurrence of certain stated events as set out in detail in the Dealer Agreement. However, the Dealers are obligated to take up and pay for all Notes of a particular issue if any of the Notes of that issue are purchased under the Dealer Agreement.

In connection with any offering of Notes, the Dealers may, when acting as an agent or purchasing as principal, over-allot or effect transactions which stabilize or maintain the market price of the Notes offered at a level above that which might otherwise prevail in the open market. Such transactions, if commenced, may be discontinued at any time.

The Dealers may from time to time purchase and sell the Notes in the secondary market but are not obliged to do so. There is no market through which Notes may be resold and purchasers may not be able to resell Notes purchased under this short form shelf prospectus. The offering price and other selling terms for any sales in the secondary market may, from time to time, be varied by the Dealers.

The offering of Notes hereunder is directed only to residents of the provinces of Canada and in the United States in certain circumstances exempt from the provisions of the United States Securities Act of 1933, as amended (the "Securities Act"). The Notes have not been and will not be registered under the Securities Act and may not be offered or sold within the United States except in certain transactions exempt from the registration requirements of the Securities Act, including transactions under Rule 144A under the Securities Act. The Dealers have agreed not to buy or offer to buy, to sell or offer to sell, or solicit any offer to buy any Notes in the United States of America, its territories or possessions except to "qualified institutional buyers" pursuant to the exemption in Rule 144A under the Securities Act. In addition, until 40 days after the commencement of the offering of an issue of Notes, an offer or sale of that issue within the United States by any Dealer (whether or not participating in the offering) may violate the registration requirements of the Securities Act if such offer or sale is made otherwise than in accordance with an exemption under the Securities Act. Terms used in this paragraph have the meanings given to them by Regulation S under the Securities Act.

BMO Nesbitt Burns Inc., CIBC World Markets Inc., HSBC Securities (Canada) Inc., Laurentian Bank Securities Inc., National Bank Financial Inc., RBC Dominion Securities Inc., Scotia Capital Inc. and TD Securities Inc. are subsidiaries or affiliates of Canadian chartered banks (the "Banks") which are lenders to our company under an amended and restated credit facility dated August 13, 2004, of up to $1.0 billion (as amended and restated from time to time, the "Credit Facility") which is used to backstop the issuance of commercial paper. As of June 21, 2007, there was no outstanding Indebtedness under the Credit Facility. Proceeds from the sale of particular series or issues of Notes in which such Dealers are acting as principals or agents may be used to repay Indebtedness under the Credit Facility, on the basis of each Bank's rateable portion of the Credit Facility. Consequently, if and when there is outstanding Indebtedness to the Banks under the Credit Facility, our company may be considered to be a connected issuer of each such Dealer for purposes of the securities laws of certain Canadian provinces. Other than payment of their portion of the commissions, if applicable, or as set forth above in respect of the Credit Facility, none of the proceeds of such offerings of Notes will be applied, directly or indirectly, for the benefit of BMO Nesbitt Burns Inc., CIBC World Markets Inc., HSBC Securities (Canada) Inc., Laurentian Bank Securities Inc., National Bank Financial Inc., RBC Dominion Securities Inc., Scotia Capital Inc., TD Securities Inc. or their affiliates. See "Use of Proceeds".

USE OF PROCEEDS

The net proceeds from the sale of Notes will be added to the general funds of our company and, together with funding from other sources, including internally generated funds and other external financings, will be used to finance our company's working capital requirements, to repay outstanding bank loans which may include indebtedness under the Credit Facility, debentures, notes or other Indebtedness, to make advances to subsidiaries of our company, to finance our company's capital expenditure program, to make acquisitions and for other general corporate purposes. Where appropriate, a prospectus supplement or pricing supplement will contain more specific information about the use of proceeds from each sale of Notes. All expenses relating to an offering of Notes, including any compensation paid to the Dealers, will be paid out of our company's general funds. Our company may from time to time issue debt instruments and incur additional Indebtedness otherwise than through the issue of Notes pursuant to this short form shelf prospectus.

RISK FACTORS

In addition to the other information contained and incorporated by reference in this short form shelf prospectus, a purchaser should consult its own financial and legal advisors and should carefully consider the following risk factors before investing in the Notes. Notes will not be an appropriate investment for a purchaser if the purchaser does not understand the terms of the Notes or financial matters in general. A purchaser should not purchase Notes unless the purchaser understands, and can bear, all of the investment risks involving the Notes. For a discussion of the risks to which our business and industry are subject, please see the section entitled "Risk Factors" in our company's renewal annual information form and the section entitled "Risk Management and Risk Factors" in our annual MD&A. In addition to those risks, an investment in the Notes is subject to the following additional risks:

We Must Receive Dividends and Other Payments from Our Subsidiaries in Order to Make Payments to Holders of Notes

We are a holding company that has no significant assets or operations other than the debt and equity of our subsidiaries. Our most significant subsidiary is Hydro One Networks Inc., a regulated wholly-owned subsidiary which owns and operates our transmission and distribution assets. We are dependent on dividends, interest, loans and other payments from this and other subsidiaries to meet our debt service and other obligations.

Our subsidiaries are separate legal entities and have no obligation to pay any amounts due under the Notes and, except for their respective obligations under existing intercompany debt obligations owing to us, have no obligation to make funds available to us, whether by dividends, interest, loans or other payments. In addition, these subsidiaries have not guaranteed the Notes. In the event of bankruptcy, liquidation or reorganization of any of our subsidiaries, the creditors of these subsidiaries will generally be entitled to the payment of their claims before any assets are made available for distribution to us, except to the extent that we are recognized as a creditor of those subsidiaries.

Our subsidiaries currently are not restricted in terms of their ability to pay dividends or make other payments to us, other than by solvency provisions under generally applicable Ontario corporate law. However, they could become so restricted in the future by, among other things, other laws as well as agreements to which they may become parties in the future.

The Notes Have No Existing Trading Market and May Be Subject to Trading Price Fluctuations

The Notes are new issues of securities for which there is no existing trading market. We do not intend to list the Notes on any Canadian, U.S. or other securities exchange. We cannot predict whether any trading market will develop for the Notes.

Even if a trading market develops for the Notes, the Notes could trade at prices that may be higher or lower than their initial offering prices, depending on many factors, including prevailing interest rates, our results of operations and financial position, the ratings assigned to the Notes and our other debt securities, and the markets for similar debt securities.

Foreign Currency Risks

An investment in Notes that are denominated or payable in other than Canadian dollars entails significant risks that are not associated with a similar investment in a security denominated in Canadian dollars. Such risks include, without limitation, the possibility of significant changes in rates of exchange between the Canadian dollar and the applicable foreign currency unit, the possibility of the imposition or modification of foreign exchange controls by either the Canadian or foreign governments, and potential illiquidity in the secondary market. These risks will vary depending upon the currency or currencies involved and, where appropriate, will be more fully described in a prospectus supplement.

The Notes will be governed by and construed in accordance with the laws of the Province of Ontario and the laws of Canada applicable therein. A judgment by a Canadian court relating to any Note may be awarded only in Canadian currency and such judgment may be based on a rate of exchange in existence on a day other than the day of payment.

This short form shelf prospectus does not describe all the risks of an investment in the Notes denominated or payable other than in Canadian dollars, and prospective investors should consult their own financial and legal advisor as to the risks entailed with respect thereto. Notes denominated in other than Canadian dollars are not appropriate investments for investors who are unfamiliar with foreign currency transactions.

Interest Rate Risks

Prevailing interest rates will affect the market price or value of the Notes. Generally, the market price or value of the Notes will decline as prevailing interest rates for comparable debt instruments rise, and increase as prevailing interest rates for comparable debt instruments decline. Fluctuations in interest rates may also impact borrowing costs of our company which may adversely affect its creditworthiness.

Changes in Creditworthiness or Credit Ratings

The perceived creditworthiness of our company and changes in credit ratings of the Notes may affect the market price or value and the liquidity of the Notes. In addition, negative changes in our company's credit rating may affect the credit ratings of the Notes.

Risks Associated with Floating Rate Notes

Investments in Floating Rate Notes entail risks not associated with investments in Fixed Rate Notes. The resetting of the applicable rate on a Floating Rate Note may result in a lower interest rate as compared to a Fixed Rate Note issued at the same time. The applicable rate on a Floating Rate Note will fluctuate in accordance with fluctuations in the instrument or obligation or other measure on which the applicable rate is based, which in turn may fluctuate and be affected by a number of interrelated factors, including economic, financial and political events over which our company has no control.

LEGAL MATTERS

Certain legal matters in connection with any offering hereunder will be passed upon by Osler, Hoskin & Harcourt LLP for our company and by Blake, Cassels & Graydon LLP for the Dealers. The partners and associates of the foregoing law firms beneficially own, directly or indirectly, less than one percent of the securities of our company or any associate or affiliate of our company.

AUDITORS, REGISTRAR AND TRANSFER AGENT

The auditors of our company are Ernst & Young LLP, Ernst & Young Tower, P.O. Box 251, 222 Bay Street, Toronto-Dominion Centre, Toronto, Ontario M5K 1J7. Ernst & Young LLP is independent in Ontario in accordance with its rules of professional conduct.

Registers for the registration and transfer of the Notes issued in registered form are kept at the principal offices of the Transfer Agent in the City of Toronto.

PURCHASERS' STATUTORY RIGHTS

Securities legislation in certain of the provinces of Canada provides purchasers with the right to withdraw from an agreement to purchase securities. This right may be exercised within two business days after receipt or deemed receipt of a prospectus and any amendment. In several of the provinces, securities legislation further provides a purchaser with remedies for rescission or, in some jurisdictions, damages if the prospectus and any amendment contains a misrepresentation or is not delivered to the purchaser, provided that the remedies for rescission or damages are exercised by the purchaser within the time limit prescribed by the securities legislation of the purchaser's province. The purchaser should refer to any applicable provisions of the securities legislation of the purchaser's province for the particulars of these rights or consult with a legal adviser.

AUDITORS' CONSENT

We have read the short form base shelf prospectus of Hydro One Inc. (the "Corporation") dated June 21, 2007 relating to the issue of up to $2,500,000,000 aggregate principal amount of medium term notes (unsecured) of the Corporation. We have complied with Canadian generally accepted standards for an auditor's involvement with offering documents.

We consent to the use through incorporation by reference in the above-mentioned prospectus of our report dated February 14, 2007 to the shareholder of the Corporation on the consolidated balance sheets of the Corporation as at December 31, 2006 and 2005 and the consolidated statements of operations, retained earnings and cash flows of the Corporation for each of the years then ended.

Toronto, Ontario
June 21, 2007

Ernst & Young LLP (signed)
Chartered Accountants
Licensed Public Accountants

CERTIFICATE OF HYDRO ONE INC.

Dated: June 21, 2007

This short form prospectus, together with the documents incorporated in this prospectus by reference, will, as of the date of the last supplement to this prospectus relating to the securities offered by this prospectus and the supplement(s), constitute full, true and plain disclosure of all material facts relating to the securities offered by this prospectus and the supplement(s) as required by the securities legislation of all of the provinces of Canada. For the purpose of the Province of Québec, this simplified prospectus, together with documents incorporated herein by reference and as supplemented by the permanent information record, will contain no misrepresentation that is likely to affect the value or the market price of the securities to be distributed.

(Signed) Laura Formusa
President and
Chief Executive Officer (Acting)

(Signed) Beth Summers
Chief Financial Officer

On behalf of the Board of Directors:

(Signed) Rita Burak
Chairman of the Board of Directors

(Signed) Walter Murray
Director

CERTIFICATE OF DEALERS

Dated: June 21, 2007

To the best of our knowledge, information and belief, this short form prospectus, together with the documents incorporated in this prospectus by reference will, as of the date of the last supplement to this prospectus relating to the securities offered by this prospectus and the supplement(s), constitute full, true and plain disclosure of all material facts relating to the securities offered by this prospectus and the supplement(s) as required by the securities legislation of all the provinces of Canada. For the purpose of the Province of Québec, this simplified prospectus, together with documents incorporated herein by reference and as supplemented by the permanent information record, will contain no misrepresentation that is likely to affect the value or the market price of the securities to be distributed.

BMO NESBITT BURNS INC.	CASGRAIN & COMPANY LIMITED	CIBC WORLD MARKETS INC.
By: (Signed) Grant Williams	By: (Signed) Roger G. Casgrain	By: (Signed) Darrell J. Burt
HSBC SECURITIES (CANADA) INC.	LAURENTIAN BANK SECURITIES INC.	NATIONAL BANK FINANCIAL INC.
By: (Signed) Rod A. McIsaac	By: (Signed) Thomas Berky	By: (Signed) James Stewart
RBC DOMINION SECURITIES INC.	SCOTIA CAPITAL INC.	TD SECURITIES INC.
By: (Signed) Tushar Kittur	By: (Signed) D. Gregory Lawrence	By: (Signed) Harold Holloway

SUMMARY OF HYDRO ONE DISTRIBUTION POLICIES

1.0 INTRODUCTION

Hydro One Distribution has a number of policies that apply to distribution customers, assets and systems, and financial management. Policies are subject to periodic review and/or revision as a result of statutory or regulatory change, or as the business evolves. The objectives of these policies are to ensure:

- compliance with statutory and regulatory obligations;
- fair and consistent commercial relationships with customers;
- efficient management of assets;
- consistent criteria for decision making;
- compliance with generally-accepted accounting principles;
- consistency for transaction processing; and,
- accurate and timely recording and reporting of financial information.

2.0 CHANGES TO POLICIES

In keeping with good corporate governance, Hydro One has reviewed and revised the following policies and procedures since the Board's review of Distribution Rates for 2006 (RP-2005-0020/EB-2005/0378).

- Procurement Policy
- Procurement Procedure
- Corporate Policy on Consultants
- Corporate Procedure for Retention of Consultants
- Corporate Charge Card Procedure

- •• Policy on Employee Business Expenses
- •• Employee Business Expenses Procedure

The following represent significant changes to the company's key policies since the RP-2005-0020/EB-2005-0378 Board review.

2.1 Comprehensive Income, Financial Instruments and Hedging

Effective January 1, 2007, Networks adopted four new accounting standards comprising the Canadian Institute of Chartered Accountants' (CICA) Handbook Sections 1530, *Comprehensive Income*; 3855, *Financial Instruments – Recognition and Measurement*; 3861, *Financial Instruments – Disclosure and Presentation;* and 3865, *Hedges*. The adoption of these new standards required changes in the accounting for financial instruments and hedges, and the recognition of certain transition adjustments that are recorded in opening accumulated other comprehensive income (AOCI). Comprehensive income is composed of the Company's net income and other comprehensive income (OCI). OCI includes the amortization of unamortized hedging losses on cash flow hedges that had been discontinued prior to the transition date.

Under the new financial instruments standards, all financial instruments are classified into one of five categories: held-to-maturity investments, loans and receivables, held-for-trading, other liabilities or available-for-sale. Networks' classification of existing financial instruments is summarized in the notes to its 2007 first quarter financial statements.

All derivative instruments, including embedded derivatives, are carried at fair value on the balance sheet unless exempted from derivative treatment as a normal purchase and sale. All changes in fair value are recorded in financing charges unless cash flow hedge accounting is used, in which case changes in fair value are recorded in OCI to the extent that the hedge is effective. Where there is an economic hedge, Networks has selected to apply the fair value option without hedge accounting. All financial instrument transactions are recorded at trade date.

Upon adoption of the new standards, the Company reclassified unamortized hedging losses on cash flow hedges that had been discontinued prior to the transition date to AOCI. The hedging losses are amortized through OCI over the term of the hedged debt. Previously these unamortized gains and losses were disclosed net with long-term debt.

Transaction costs for financial assets and liabilities that are classified as other than held-for-trading, are added to the carrying value of the asset or liability and amortized over the expected life of the instrument. Previously such costs incurred as a result of the issuance of long-term debt were disclosed as a separate long-term asset on the Balance Sheet.

2.2 Accounting for Conditional Asset Retirement Obligations

Effective April 1, 2006, Networks adopted new accounting recommendations for Conditional Asset Retirement Obligations issued by the Emerging Issues Committee of the CICA. Most of these obligations are not currently estimable because final retirement and removal dates cannot be determined as the related assets are expected to be used on an ongoing basis. Networks did determine that is has an estimable but immaterial liability associated with the disposal of treated wood utility poles.

SUMMARY OF INITIATIVES BASED ON LEGISLATIVE CHANGES

1.0 INTRODUCTION

Hydro One Inc. is subject to direction from its shareholder (the Government of Ontario), Ontario Energy Board decisions and government legislation and regulations. Each one of these sources has the potential to be a driver for change affecting Hydro One policies, processes and work programs, with associated cost implications. Hydro One complies with all regulatory and legislative requirements and incurs costs to do so. When new legislation or regulations are passed, or when OEB decisions are released, Hydro One responds to the directive by developing appropriate programs or initiatives to implement the required changes in a cost-effective fashion. As the electricity industry in Ontario continues to evolve, Hydro One actively participates in the design of industry-related changes with the intent of ensuring that costs are reasonable and that the impacts on customers are manageable. The costs of implementing the outcomes of ongoing industry changes include communicating changes to customers and modifying the impacted business processes, information systems, policies and procedures and staff training programs. The remainder of this Exhibit provides a brief summary of the key pieces of legislation, regulatory requirements, standards and guidelines to which Hydro One's Distribution Business must respond.

2.0 THE DISTRIBUTION SYSTEM AND RETAIL SETTLEMENT CODES

Hydro One is bound by the terms of its Distribution licence to adhere to the requirements of the Distribution System Code (DSC) and the Retail Settlement Code (RSC), both of which are administered by the Ontario Energy Board.

The DSC provides the minimum conditions a distributor must meet in carrying out its obligation to operate, maintain, manage and expand distribution systems and requires Hydro One to operate and maintain its system in accordance with "good utility practice." The DSC sets out the obligations of electricity distributors with respect to their customers, including the rules governing the economic evaluation of distribution system connections and expansions and also the minimum standards for facilities connected to a distribution system. It also includes guidance on the form of the Connection Agreement for load customers, and includes a Connection Agreement template for generator customers, which covers the technical and commercial responsibilities for both Hydro One and the customer.

The RSC sets the minimum obligations that distributors and retailers must meet in determining the costs of electricity services. It sets the rules for Hydro One's customer billing process and its interactions with retailers. The main aspects of the RSC include rules for processing service transaction requests, calculating distribution losses on customer bills, meter reading and billing cycles, and defining and setting timelines for billing options (such as retailer consolidated bills).

Both codes have been periodically amended over time. Hydro One has incorporated, or is in the process of incorporating, these amendments into its work practices and procedures. Recent changes include updates in 2006 to facilitate distributed generation and net metering, and updates in 2007 to connections and expansions, smart metering, and the elimination of Long Term Load Transfers.

3.0 ENVIRONMENTAL MANAGEMENT

Hydro One Distribution is subject to a wide range of legislation. The following are the major acts that govern Hydro One Distribution's activities. Many others can apply in specific circumstances but the following are applicable to most distribution work.

3.1 Federal Legislation

- *Canadian Environmental Protection Act*, which regulates the management of hazardous substances such as Polychlorinated Biphenyls ("PCBs").
- *Fisheries Act*, which regulates fish habitat and pollution prevention in and around water bodies that support fish.

3.2 Provincial Legislation

- *Environmental Protection Act*, which regulates waste management/disposal, spills and Certificates of Approval.
- *Ontario Water Resources Act*, which regulates discharges, sewage works and water works.
- *Pesticides Act*, which regulates the storage, use and application of pesticides.
- *Environmental Assessment Act*, which regulates the planning and environmental approvals of projects, such as high voltage stations that step down to distribution voltages.

3.3 Municipal Legislation

Many municipal by-laws regulate noise, discharges to sewers, pesticide use and the upkeep/maintenance of properties. The application of these will vary depending on the municipality.

3.4 Environmental Management and Governance

In order to comply with all legislated requirements, Hydro One Distribution has developed a number of environmental management programs. In addition, governance activities such as management system maintenance, program monitoring and reporting are provided by staff in the Health, Safety & Environment function.

The following is a summary of the major programs:

3.4.1 Land Assessment and Remediation

- Land and groundwater contamination is a legacy issue from spills, leaks and historical use of persistent herbicides at distribution stations for vegetation control. Underground tanks for fuel storage and dispensing have also been a cause of land and water contamination. At the time that these herbicides were used by the former Ontario Hydro, they were commonly used by North American utilities, and were compliant with regulatory requirements in place at the time. There was no knowledge of their potential negative environmental impact.
- Program management and funding requirements are described in Exhibit C1, Tab 2, Schedule 2.

3.4.2 Management of hazardous materials and wastes

- Hazardous materials such as PCBs and wastes (oils, solvents, etc.) are managed in accordance with regulatory requirements and good management practices;
- PCBs are a contaminant in a small percentage of oil-filled electrical equipment. The amount of PCBs has declined due to a program of PCB phase-out and destruction, which began in the mid-1980s. The continued removal of equipment from service in the future will ensure that Hydro One Distribution becomes a PCB-free utility;
- Occasionally spills, leaks and fires occur as a result of equipment failure, adverse weather or other causes. Most spills involve mineral oil from electrical equipment such as transformers. The environmental impact of spills is mitigated by a well-developed spill reporting and response system. This involves the timely reporting of spills to all appropriate authorities and the clean-up and remediation of areas impacted by the spill.
- Management of these programs and funding requirements are described in Exhibit C1, Tab 2, Schedule 2.

3.4.3 Vegetation Management (Herbicide Use)

- Herbicide use is an integral part of the vegetation management program associated with maintenance of the distribution system, including rights-of-way and stations. Environmental impacts are minimized through the use of approved product types, and approved methods and procedures for application. Property owner approval is obtained prior to the application of any herbicide on private properties. Vegetation management programs and funding requirements are fully described in Exhibit C1, Tab 2, Schedule 2.

4.0 ELECTRICAL SAFETY AUTHORITY

The Electrical Distribution Safety Regulation 22/04 established objective-based electrical safety requirements for the design, construction and maintenance of electrical distribution systems owned by licensed distributors. It requires:

- Approval of equipment, designs and plans.
- Inspection and certification of construction before it is put into use.
- An assessment of plant based on the Ontario Electrical Safety Code prior to selling plant to non-distributors.
- Approval by the utility to place objects at a distance less than CSA clearance standards from distribution lines.
- Disconnection of unused lines.
- Reporting of serious electrical incidents.
- Annual compliance audits of processes.
- Safety due diligence inspections conducted by the ESA to ensure safety standards are met.

Electrical safety is a very high priority for Hydro One Distribution as indicated in the strategic goals in Exhibit A, Tab 3, Schedule 1. To address this priority Hydro One Distribution has implemented comprehensive training programs to ensure all Electrical Distribution Safety Regulations are adhered to across the corporation. The associated program management and costs are described in Exhibit C1, Tab 2, Schedule 2.

5.0 SMART METERS

The Government of Ontario, as part of achieving a conservation culture, is proceeding with time-of-use (TOU) electricity pricing and the installation of smart meters throughout

Ontario by 2010. The enactment of the *Energy Conservation Leadership Act*, and changes to the *Electricity Act* and the *Ontario Energy Board Act*, along with new regulations, have defined the Government's Smart Meter Initiative, prescribed the technical and functional requirements of the smart meter solutions (Advanced Metering Infrastructure – AMI), and set the path for mass deployment of the meters across Ontario.

Regulations passed in August, 2006 (O. Reg. 425/06, 426/06 and 427/06), designate the smart metering activities of Hydro One Networks Inc. (among those of other utilities) as authorized discretionary metering activities and prescribe:

- the criteria and requirements for all smart meters and related equipment, systems and technology,
- the principles for related procurement activities and
- the principles and process for cost recovery.

In line with the legislative and regulatory requirements, Hydro One has begun full implementation of its smart metering program, including smart meter deployment, communication network development, and updating the customer information system (CIS) and associated processes to enable it to support TOU and Regulated Price Plan (RPP) implementation. These activities will require on-going investments in 2008 and beyond, as identified in Exhibits C1, Tab 2, Schedule 2 and D1, Tab 3, Schedule 2.

Hydro One's smart metering costs for 2005 through 2007 are included in a deferral account that is being requested in Exhibit F1, Tab 1, Schedule 1.

6.0 CONSERVATION AND DEMAND MANAGEMENT

The CDM program which Hydro One developed to utilize its Market Adjusted Rate of Return (MARR) funding will be substantially complete by the deadline of September 30, 2007. However, on May 22, 2007, Hydro One obtained an extension through April 30, 2008 and will dedicate the additional time to the completion of its Low Income/Social Housing program and also to complete the work on its Distribution Loss Reduction program.

Hydro One has participated in all four of the OPA sponsored CDM initiatives: Summer Savings; Residential and Small Commercial Demand Response; Business Incentive Program; and the Great Refrigerator Roundup. Hydro One intends to continue participating in future OPA-administered CDM programs and will look for opportunities to expand those programs, as appropriate, including possibly extending relevant programs to Transmission customers. Hydro One is also actively involved in implementing in-house power cost monitoring devices and a "Double Returns" program, which was in place last Winter and will be adopted for Summer 2007. Initial feedback from these programs shows they were successful, and Hydro One will consider extending these programs into future year, as appropriate. Funding for these initiatives will be recovered through the OPA and is not included in revenue requirement requested in this Application.

7.0 BILL 198 – INTERNAL CONTROLS, DECEMBER 9, 2002

Bill 198 requires that the controls that oversee the processes and systems that impact how the company initiates, records, processes, and reports transactions in significant accounts must be documented and evaluated on an annual basis. The Ontario Securities Commission (OSC) responded to Bill 198 with new Multilateral Instruments (MI) that govern internal controls. These require the CEO and CFO of Hydro One Inc. (as a public debt issuer) to attest to the appropriateness and effectiveness of internal financial controls and financial disclosure processes for the Company's consolidated financial information.

By the end of 2006, Hydro One completed its project to ensure compliance with Bill 198 requirements. This entailed changes to processes and technologies to ensure appropriate documentation is in place for the first year of compliance (2007). In addition, a unit has been put in place to sustain the Bill 198 requirement on an on-going basis. The Company is currently completing its 2007 compliance process. Further details of Hydro One's work in this area are provided in Exhibit A, Tab 12, Schedule 1, with associated costs in Exhibit C1, Tab 2, Schedule 6.

8.0 DISTRIBUTION CONNECTED GENERATION

The Provincial Government's objective to achieve a cleaner supply mix, and OPA procurement programs in support of this, have and will substantially increase Hydro One Distribution work and investments related to new generation connecting to the distribution system. The Renewable Energy Standard Offer Program (RESOP), which was launched in November, 2006, has generated some 1,000 projects expressing interest in potential connection to Hydro One's system, and of these, the Company has had several hundred applications for full Connection Impact Assessments. The OPA has also recommended a Clean Energy Standard Offer Program (CESOP) for combined heat and power and other projects. This project will be launched in the Fall of 2007. Its impact on Hydro One Distribution is uncertain at this time.

Assessing the feasibility of connecting so many potential projects to the system, and particularly the cumulative impact of such projects, has proven to be a technical and administrative challenge. Further challenges are anticipated as projects move to the phase of requesting cost estimates and potentially signing agreements to connect. Hydro

One Distribution has undertaken a number of initiatives to deal with this as outlined in Exhibit D1, Tab 3, Schedule 3.

9.0 ACCESS TO INFORMATION (FIPPA) AND PERSONAL PRIVACY (PIPEDA)

On December 10th, 2003, Hydro One Inc. became subject to Ontario's Freedom of Information and Protection of Privacy (FIPPA) legislation. On January 1st, 2004, Hydro One Inc. also became subject to Canada's Protection of Individual Privacy and Electronic Documents Act (PIPEDA). And most recently, on November 1st, 2004, the Corporation also became subject to Ontario's Personal Health Information Protection Act.

These pieces of legislation require that the Corporation provide public access to business records, as well as appropriate access to (and protection of) personal information. The personal information of customers and, in specific circumstances, employees, is now subject to legislated standards of protection.

Funding for these on-going activities is included in Shared Services OM&A (see Exhibit C1, Tab 2, Schedule 6).

10.0 BILL 100 ELECTRICITY RESTRUCTURING ACT, 2004

Bill 100, the Electricity Restructuring Act, 2004, which was passed at the end of 2004, enabled changes to electricity market settlement and billing processes. These changes included the implementation of the Provincial Benefit for customers billed on spot market commodity price and the introduction of the RPP. Hydro One made changes to its billing and settlement systems in order to calculate, settle and bill the Provincial Benefit, and the RPP. This included adjusting the two-tiered pricing and consumption thresholds in May and November of each year, plus changes to settlements with the IESO due to differences between the spot price and the two-tiered regulated price. Costs for this initiative are included in the Customer Care OM&A expenditures for 2008 that are detailed in Exhibit C1, Tab 2, Schedule 5.

PLANNING PROCESS

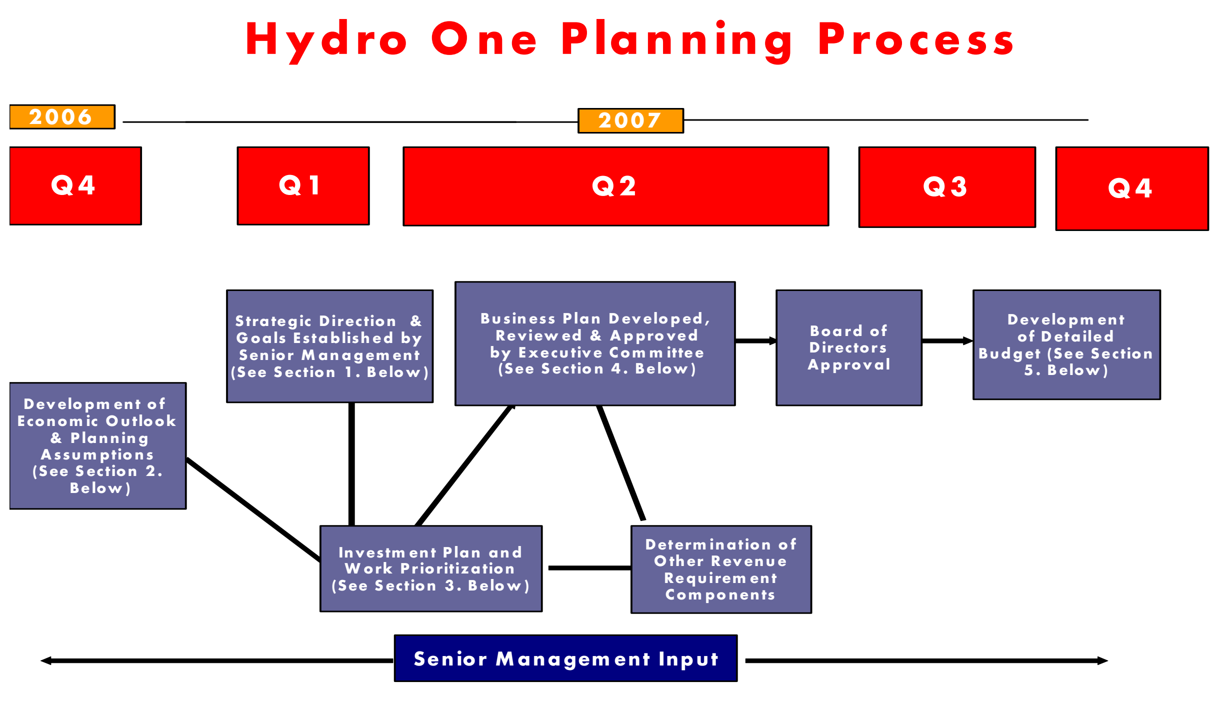
INTRODUCTION

Business planning is performed annually and focuses on the development of a five-year plan which comprises a detailed plan for the first three years in the planning cycle and a less detailed outlook for the remaining two year period. The planning cycle in 2007 pertained to the 2008-2012 period. The results as they apply to 2008 (the test year) form the basis for the rate submission.

The annual planning cycle consists of five phases:

1. Confirmation of corporate strategy;
2. Development of economic outlook and forecast assumptions;
3. Investment plan development;
4. Development of plans and work programs; and,
5. Refinement of plan into a detailed budget.

The following chart provides an overview of the planning process:



The key dates applicable to the 2008-2012 planning cycle include:

Date	Action
December 2006	Strategic goals confirmed
March 2007	Business plan instructions issued
May 2007	Investment Plan prioritized
June 2007	Lines of business submit business plans to Executive Committee
June 2007	Executive Committee holds business plan review meetings with lines of business vice presidents
August 2007	Hydro One Inc. Board approval of business plan
November 2007	Hydro One Inc. Board approval of detailed budget

1. Strategic Direction and Goals Established by Senior Management

Hydro One Distribution's strategic direction and goals are reviewed and confirmed by the CEO and other members of the senior management team. The strategic goals are included in the business planning instructions for reference by planners as the business plan is being developed. Please see Exhibit A, Tab 3, Schedule 1 for a description of the Company's strategic goals.

2. Development of Economic Outlook and Planning Assumptions

To facilitate the preparation of the business plan, an economic outlook and customer load forecast is developed and included with the planning instructions issued. This includes forecasts of key economic statistics, interest rates, labour escalation rates, income tax rates, cost allocation percentages, and cost rates for benefits. The assumptions used for the 2008 business plan are attached to this exhibit as Appendix A. A detailed discussion of the economic indicators is filed at Exhibit A, Tab 14, Schedule 2.

3. Investment Plan and Work Prioritization

As part of the investment planning phase, a work prioritization is completed to provide assurances as to the level of work accomplishments that should be undertaken to ensure an acceptable level of risk with respect to meeting the strategic goals. Customer needs (including anticipated load growth requiring new system capability), operational performance and asset conditions are examined to identify areas requiring investments. Investments are identified in advance and are included in a set of work or reference plans that are consistent with Hydro One Distribution's strategic goals and take into account customer, financial, operational, environmental, safety, regulatory and legal considerations. These result in an investment plan that is then submitted to Hydro One senior management for review and approval. The investment plan prepared during 2007 provides the basis for the 2008 forecast. Please see Exhibit A, Tab 14, Schedule 5 for a more detailed description of the work prioritization process.

4. Development of Plans and Work Programs

During the planning process, plans and work programs are further refined consistent with the economic and forecast assumptions. As part of this process, sufficient detail is provided to facilitate preparation of the 2008 Rate Application. At the end of this process, the Hydro One senior management team provides direction as necessary in order to balance the various factors under consideration including customer service levels, rate impacts and economic considerations.

The operations, maintenance and administration ("OM&A") budget and the capital budget that result from this planning process are discussed at Exhibit C1, Tab 2 and Exhibit D1, Tab 3 respectively. Refer to Exhibit A, Tab 14, Schedule 4 for an overview of the project and program approval process for Hydro One Distribution.

The financial plan is prepared, incorporating OM&A and capital work program levels consistent with the investment plan, as well as forecasts of revenue, cost of power, depreciation and amortization expense, financing charges, income tax, and working capital.

The resulting plan is reviewed by the Executive Committee of Hydro One Inc. As necessary, underlying assumptions are modified and the results finalized and presented for approval to the Hydro One Inc. Board of Directors.

5. Development of Detailed Budget

The final phase in the planning cycle is the budgeting phase, which focuses on fine-tuning of near-term, detailed information to facilitate plan implementation and monitoring of results for the year immediately following. During the budgeting phase, the cost impacts of any updated assumptions or work program requirements are examined and factored in as necessary.

APPENDIX A

2008 BUSINESS PLAN ASSUMPTIONS

1.0 ECONOMICS

	2008	2009	2010	2011	2012
CPI – Ontario (%)	1.9	2.2	2.2	2.0	2.0
Tx cost escalation for Construction (%)	1.0	1.0	1.3	2.0	2.8
Tx cost escalation for Operations & Maintenance (%)	1.5	0.6	0.4	1.2	1.6
Dx cost escalation for Construction (%)	1.9	1.4	1.5	2.2	2.4
Dx cost escalation for Operations & Maintenance (%)	0.9	-1.0	-0.6	1.1	1.6
Exchange Rate (CDN$/US$)	1.116	1.107	1.104	1.101	1.101

CPI-Ontario, and US cost escalators forecasts were based on the Global Insight November 2006 forecast. The exchange rate forecast was based upon the Global Insight October 2006 Long-Term Forecast and Analysis.

2.0 INTEREST RATES

	2008	2009	2010	2011	2012
HO1 5-Year Bond Rate (%)	4.77	5.17	5.27	5.27	5.37
HO1 10-Year Bond Rate (%)	5.01	5.41	5.51	5.51	5.61
HO1 30-Year Bond Rate (%)	5.37	5.77	5.87	5.87	5.97
90-Day Banker's Acceptance Rate (%)	4.49	4.60	4.62	4.62	4.62
Interest Capitalized Tx (%)	5.1	5.5	5.6	5.6	5.7
Interest Capitalized Dx (%)	5.1	5.5	5.6	5.6	5.7
Interest Capitalized Common (%)	5.1	5.5	5.6	5.6	5.7

H1 bond rates for 2008 were prepared based on the May 2007 Consensus Forecasts; the remaining years were based on the April 2007 Consensus Forecasts long term forecast. Hydro One credit spreads are based on an average of indicative new issue spreads for April 2007 from the dealers in Hydro One's medium term note syndicate.

The 90-Day Banker's Acceptance Rate for 2008 was prepared based on the Consensus Economics May 2007 forecast; the remaining years were based upon the Global Insight April 2007 Long-Term Forecast and Analysis.

Interest cap rates:
Forecast of Scotia Capital All-Corp Mid-Term Yield (from Treasury – May 31, 2007).

3.0 LABOUR ESCALATION

Specific details on annual labor escalation are provided below.

(a) Society Staff

1% performance (merit) pay in fiscal 2008. Assume +1% performance (merit) pay in each following year. Anticipate 3% economic increases effective April 1, 2008 and 3% each following year effective April 1st.

(b) PWU staff

Anticipate economic increases of 3% effective April 1, 2008. Assume 3% increases effective on April 1st of each subsequent year.

Step progressions - past experience (i.e. 2005) indicates that 9.9% of PWU receive progressions annually and that progressions result in a salary increase of 4.35% (note that trades progressions are higher than weekly salaried, and due to apprentice hiring over the past few years, the proportion of trades progressions has increased).

(c) MCP staff

4% annual increase per year in base pay for the entire period.

(d) Incentive Plan Payouts

All incentive plans have been discontinued, with the exception of the MCP Short Term Incentive Plan. Payout under that plan is assumed to be 20% in all years.

4.0 INCOME & CAPITAL TAX RATES

	2008	2009	2010	2011	2012
Federal Tax Rate	20.50%	20.00%	19.00%	19.00%	19.00%
Federal Surtax Rate	NIL	NIL	NIL	NIL	NIL
Provincial Rate	14.00%	14.00%	14.00%	14.00%	14.00%
Total Statutory Tax Rate	34.50%	34.00%	33.00%	33.00%	33.00%
Large Corporation Tax (LCT)	NIL	NIL	NIL	NIL	NIL
Capital Tax Rate	0.285%	0.225%	NIL	NIL	NIL

5.0 BENEFIT COSTS RATES (PAYROLL BURDEN)

Company	Category	2008	2009	2010	2011	2012
Networks	Non-Regular Staff % of total earnings*	5.6%	5.6%	5.6%	5.6%	5.7%
	Regular Staff % of total earnings* % of base pensionable earnings**	5.6% 37.2%	5.6% 37.0%	5.6% 36.8%	5.6% 36.7%	5.7% 36.5%
	Pension % of base pensionable earnings	29.8%	29.6%	29.4%	29.2%	29.0%

*CPP, Emp, Insurance, Emp. Health Tax, Workers' Compensation Schedule 1 Premiums
**Health, Dental, Life Insurance, Maternity, Retirement Bonus, Post-Retirement Health, dental, Life Insurance, OPRB (for Inergi where applicable)
Base Pensionable Earnings includes pensionable bonus.
Total Earnings includes base pay, bonus, overtime, taxable benefits and taxable allowances.

ECONOMIC INDICATORS

1.0 INTRODUCTION

Appendix A of Exhibit A, Tab 14, Schedule 1 provides the costing assumptions underlying the 2008 Business Plans. This exhibit provides additional background with respect to these assumptions.

2.0 ECONOMIC INDICATORS

2.1 Distribution Cost Escalation for Construction, Operations and Maintenance

The Distribution Cost Escalation for Construction, Operations & Maintenance provides a broad average measure of the industry-wide yearly price changes by tracking a representative basket of equipment and labour for these areas of business. This basket of goods is comprised of the following types of equipment and labour:

- Operation;
- Supervision and Engineering;
- Load Dispatching;
- Station Expenses;
- Lines;
- Meters;
- Customer Installations;
- Maintenance;
- Structures;
- Station Equipment;
- Overhead Lines;
- Underground Lines;

- Line Transformers; and
- Miscellaneous.

The data in Table 1 was provided by Global Insight, Power Planner, Third-Quarter 2006.

Table 1

	Historic			Bridge	Test
	2004	**2005**	**2006**	**2007**	**2008**
Distribution Cost Escalation for Construction (%)	5.8	8.0	7.9	3.7	1.9
Distribution Cost Escalation for Operations & Maintenance (%)	5.0	5.9	6.5	3.5	0.9

The Distribution Cost Escalation for Construction, Operations & Maintenance is used as a planning tool to predict expenditure level changes for distribution materials and services.

2.2 Consumer Price Index

The Consumer Price Index (CPI) provides a broad measure of the cost of living. Through the monthly CPI, Statistics Canada tracks the change in retail price of a representative shopping basket of about 600 goods and services from an average household's expenditure: food, housing, transportation, furniture, clothing, and recreation.

Hydro One Distribution operates wholly in the Province of Ontario, Canada. As a result, the CPI–Ontario exhibits the inflationary environment in which Hydro One Distribution operates. The CPI forecast is from Global Insight's November 2006 forecast and can be found in Table 2.

Table 2

	Historic			Bridge	Test
	2004	2005	2006	2007	2008
CPI – Ontario (%)	1.9	2.2	1.8	1.5	1.9

The CPI is used as a planning tool to forecast expenditure level changes for items such as fleet and sundry costs.

2.3 Exchange Rate (CDN$/US$)

Table 3 provides the 2004, 2005 and 2006 average exchange rates based on actual daily closing rates. The exchange rate forecast for 2007 and 2008 is based on the Global Insight October 2006 Long-Term Forecast and Analysis.

Table 3

	Historic			Bridge	Test
	2004	2005	2006	2007	2008
Exchange Rate (CDN$/US$)	1.301	1.212	1.134	1.135	1.116

While the exchange rate forecast is not directly used to forecast costs or other variables, it is an important variable affecting the performance of the Canadian and Ontario economies.

3.0 INTEREST RATES

Interest rate forecasts are used to determine the cost of capital for Hydro One Distribution as described in Exhibit B1, Tab 1, Schedule 1.

3.1 Long-Term Debt Rates

Table 4 contains Hydro One Inc.'s historical and forecast long-term interest rates. For 2004, 2005 and 2006 each rate is derived by adding the average actual daily closing Government of Canada bond yield for the applicable term (i.e. 5 year, 10 year or 30 year) to the corresponding Hydro One Inc. average actual credit spread.

Table 4

	Historic			Bridge	Test
	2004	**2005**	**2006**	**2007**	**2008**
5-Year					
Government of Canada %	3.81	3.58	4.10	4.13	4.43
Hydro One Credit Spread %	0.33	0.31	0.33	0.34	0.34
Hydro One Bond Interest Rate %	4.15	3.89	4.43	4.47	4.77
10-Year					
Government of Canada %	4.58	4.07	4.21	4.20	4.50
Hydro One Credit Spread %	0.54	0.50	0.51	0.51	0.51
Hydro One Bond Interest Rate %	5.12	4.57	4.72	4.71	5.01
30-Year					
Government of Canada %	5.13	4.43	4.27	4.25	4.55
Hydro One Credit Spread %	0.84	0.81	0.83	0.82	0.82
Hydro One Bond Interest Rate %	5.98	5.24	5.10	5.07	5.37

For 2007 and 2008, each rate is derived by adding the forecast Government of Canada bond yield to the corresponding Hydro One Inc. credit spread. The 10-year Government of Canada bond yield forecast for 2007 and 2008 is based on the May 2007 Consensus Forecasts. Other rates and spreads are determined as described below.

The 5 and 30-year Government of Canada bond yield forecasts are derived by adding the April 2007 average spreads (5-year to 10-year for the 5 year forecast and 30-year to 10-year for the 30-year forecast) to the 10-year Government of Canada bond yield forecast. This derivation is consistent with the Board's methodology in establishing the forecast for the 30-year Government of Canada yield, as employed in the formula based return on common equity approach for regulated utilities. Consistent with this methodology, Hydro One's credit spreads over the Government of Canada bonds are based on the average of indicative new issue spreads for April 2007 obtained from our Medium Term Note program dealer group for each planned issuance term.

3.2 Deemed Long-Term Debt Rate

The deemed long-term debt rate is calculated as the Long Canada Bond Forecast plus the average spread on "A/BBB" rated corporate bonds as per the *Report of the Board on Cost of Capital and 2nd Generation Incentive Regulation for Ontario's Electricity Distributors*, December 20, 2006 (Cost of Capital Report). The forecast for 2007 and 2008 is shown in Table 5 below. The 30-year Government of Canada forecast is obtained from Table 4 above and is added to the April 2007 average spread between 30-year Government of Canada bonds and the Long-Term Average Weighted Bond Yield (Scotia Capital Inc.) – All Corporates from the Bank of Canada.

Table 5

	Bridge 2007	**Test 2008**
30-year Government of Canada %	4.25	4.55
All Corporates Long-Term Bond Spread %	1.14	1.14
Deemed Long-Term Debt Rate %	5.39	5.69

3.3 Deemed Short-Term Debt Rate

The deemed short-term debt rate is the average of the 3-month bankers' acceptance (BA) rate plus a fixed spread of 25 basis points, as per the Cost of Capital Report.

The 3-month BA rates shown for 2004, 2005 and 2006 in Table 6 below are the average of the actual daily closing rates for each respective year. The forecast for 2007 and 2008 is based on the May 2007 Consensus Forecasts of the Government of Canada 3-month treasury bills, adjusted by the April 2007 average spread between 3-month BAs and 3-month treasury bills.

Table 6

	Historic			**Bridge**	**Test**
	2004	**2005**	**2006**	**2007**	**2008**
3-month BA Rate %	2.30	2.81	4.16	4.39	4.49

3.4 Allowance for Funds Used During Construction

For construction work in progress (CWIP), Hydro One Distribution capitalizes interest at the Scotia Capital Inc. All Corporate Mid-Term Average Weighted Bond Yield as per the methodology approved by the Board in its letter dated November 28, 2006 in proceeding EB-2006-0117.

For 2007 and 2008, this is calculated in Table 7 as the 10-year Government of Canada forecast from the above table plus the April 2007 average spread between the 10-year Government of Canada bond yield and the Scotia Capital Inc. Mid-Term Average Weighted Bond Yield (Scotia Capital Inc.) – All Corporates from the Bank of Canada.

Table 7

	Bridge	**Test**
	2007	**2008**
10-year Government of Canada %	4.20	4.50
All Corporates Mid-Term Bond Spread%	0.60	0.60
All Corporates Mid-Term Yield%	4.80	5.10

4.0 INCOME AND CAPITAL TAX RATES

The historical and forecast tax rates are presented in Table 8. Please refer to Exhibit C2, Tab 6, Schedule 1, for the calculation of Hydro One Distribution's income taxes and Exhibit C2, Tab 4, Schedule 1, for forecast year capital taxes.

Table 8

	Historic			**Bridge**	**Test**
	2004	**2005**	**2006**	**2007**	**2008**
Federal Tax Rate (%)	21.00	21.00	21.00	21.00	20.50
Federal Surtax Rate (%)	1.12	1.12	1.12	1.12	n/a
Provincial Rate (%)	14.00	14.00	14.00	14.00	14.00
Total Statutory Tax Rate (%)	**36.12**	**36.12**	**36.12**	**36.12**	**34.50**
Large Corporation Tax Rate (%)	0.200	0.175	n/a	n/a	n/a
Capital Tax Rate (%)	0.300	0.300	0.300	0.285	0.285

5.0 LABOUR ESCALATION RATES

Appendix A of Exhibit A, Tab 14, Schedule 1 provides the labour rate escalation assumptions for Hydro One Distribution's three compensation categories: the Society of Energy Professionals ("Society"), the Power Workers Union ("PWU") and Management Compensation Plan ("MCP") staff.

For Management Compensation employees, escalation factors were provided by Hydro One Distribution senior management. Details regarding management compensation are provided in Exhibit C1, Tab 3, Schedule 2.

Escalation factors for PWU and Society staff reflect the current collective agreements, which both were effective April 1, 2005. (There is a new Society Agreement in place which is consistent with the 2008 escalation factors presented in Exhibit A, Tab 14, Schedule 1, Appendix A.)

6.0 COST RATES FOR BENEFITS

Appendix A of Exhibit A, Tab 14, Schedule 1 provides the benefit cost rates or payroll burden assumptions incorporated in the 2008 Business Plan. These rates are applied to the forecast labour rates.

The "burden rate," expressed as a percentage, estimates employee current and future cost rates for benefits which are attributable to labour in the current period, and allocates such costs across Hydro One legal entities. The benefit costs include:

(a) Other post-retirement benefits (OPRB), such as future health and dental costs;
(b) Other post-employment benefits (OPEB), such as long-term disability;
(c) Supplementary pension plan (SPP);
(d) Pension (funding) contributions;
(e) Employee benefit costs during active employment; and
(f) Statutory benefit payments, such as CPP, EI, etc.

Cost items (a) through (d) are actuarially determined by Hydro One Inc.'s external actuaries, Mercer Consulting Inc., using assumptions recommended by the actuaries and accepted by Hydro One Inc.’s management. Assumptions are determined with reference to past experience and industry norms.

Cost item (e) is based on estimates from Mercer, and from Hydro One Inc.'s insurance provider Great West Life, as to anticipated escalation factors of health and dental costs. These estimates are compared to past experience.

Cost item (f) is based on government schedules of premium rates for CPP, EI, etc.

DISTRIBUTION BUSINESS LOAD FORECAST AND METHODOLOGY

1.0 INTRODUCTION

This exhibit discusses Hydro One Distribution's system load forecast and methodology. It provides information on a distribution total basis that assists Hydro One Distribution in forecasting the work programs that need to be undertaken by Hydro One Distribution to meet customers' growing electricity demands, and to accommodate new customer connections.

Hydro One Distribution uses a number of methods, such as econometric models, end-use models, and customer forecast surveys to produce the forecasts required for its distribution business. Similar methods are used by major utilities throughout North America.

All forecasts presented in this section are weather-normal, i.e. abnormal weather effects are removed from the base year for load forecasting purposes so that the forecast assumes typical weather conditions based on the average of the last 31 years. The weather correction methodology used by Hydro One Distribution is a proven technique that has performed well in past years. The same methodology was reviewed and approved by the Board in the Distribution Cost Allocation Review (EB-2005-0317) and for Hydro One's 2006 Distribution Rate case (RP-2005-0020/EB-2005-0378).

All forecasts produced are internally consistent. This means that the forecasts for all customer groups add up to the total for the entire customer base served by Hydro One Distribution distribution system. Also, the forecasts presented in this exhibit are consistent with the economic assumptions which are used in the business planning process and that are described in Exhibit A, Tab 14 Schedule 2.

Hydro One Distribution’s load forecast staff has significant experience in preparing provincial and local electricity demand forecasts and load profiles. The methodology described in this exhibit is similar to Hydro One’s 2006 Distribution Rate case (RP-2005-0020/EB-2005-0378). The performance of Hydro One Distribution’s system load forecast, since Hydro One Distribution’s separation from the former Ontario Hydro, has been fairly consistent as shown in Table 1 below.

Table 1

Comparison of Hydro One Distribution Forecast with Actual
(Variance of forecast expressed as percent of actual on weather corrected basis)

Forecast made for Plan Year	Variance for Plan Year	Variance for 2nd Year	Variance for 3rd Year
1997	0.12	-2.03	1.91
1998	-2.03	-3.39	-2.02
1999	-0.85	0.73	-0.15
2000	0.46	-0.03	0.76
2001	-1.80	-1.56	-2.44
2002	1.98	2.39	2.12
2003	-0.82	-1.37	-0.74
2004	0.14	0.62	0.76
2005	0.25	0.12	n/a
2006	-0.06	n/a	n/a
Mean (1997-2001)	-0.82	-1.26	-0.96
One standard deviation (+/-)	1.13	2.57	3.00
Mean (2002-2006)	0.30	0.04	0.09
One standard deviation (+/-)	1.04	2.38	2.74

Note: The forecast performance pertains to Hydro One Retail purchases, which account for about 96 percent of the revenue requirements in the Distribution Rate case. The remaining 4 percent pertains to revenue attributed to load distributed through the system for about 80 embedded Direct and embedded LDC customers.

Over the 2001-2002 period, Hydro One Distribution has acquired some 164,000 customers as part of its acquisition program of embedded LDCs. Therefore for the period leading up to 2002 the comparison of performance reflects a smaller customer base.

Between 1997-2001, the average variance of customers' energy purchase forecast compared to the weather corrected actual energy consumed is within one standard deviation of the forecast, despite large variances resulting from unusual events such as Ice Storm in 1998 and September 11 in 2001. One standard deviation means there is one in three chances that the actual will be outside the plus or minus range (alternatively, there is two in three chances that the actual will fall within the plus or minus range). The performance of the forecast in subsequent years, namely 2002 to 2006, shows that the forecast is tracking very well and certainly well within one standard deviation band for the corresponding energy purchases. The use of the one standard deviation as a measure of forecasting accuracy is an accepted standard in the utility industry.

Section 2 below provides more detailed discussion in respect of the various economic considerations that Hydro One Distribution staff take into consideration when applying the methodology for deriving the load forecasts.

Hydro One Distribution's forecasting methodology comprises a combination of elements that include consensus input, mechanical adjustments to models commonly used in the forecasting business to include changes in economic forecasts, energy prices, population and household trends, industrial development and production, residential and commercial building activities, and efficiency improvement standards. Economic inputs were based on analyses prepared by major economic establishments in the country such as Global Insight, Conference Board of Canada, Centre for Spatial Economics, University of Toronto, Canada Mortgage and Housing Corporation, Clayton Research; efficiency standard assumptions used in the end-use models were based on discussion with Ontario

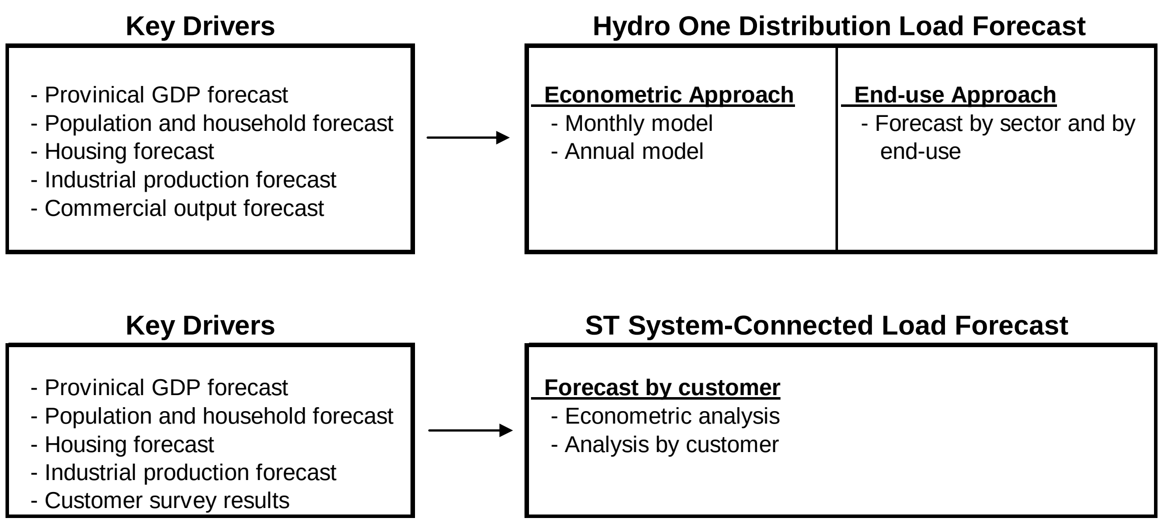
Ministry of Energy staff; specific customer development was based on forecast survey results from major customers. Information provided from these entities is consistent with the economic assumptions used in business planning as described in Exhibit A, Tab 14 Schedule 2. Also, inputs from these entities form the economic database (referred to henceforth as economic forecast) that is used to establish Hydro One Distribution load forecast. Section 3 below provides a detailed description of the methodology used by Hydro One to develop its load forecasts. Detailed modeling equations and definitions are presented in the Appendices.

When applying Hydro One Distribution's forecasting methodology to derive the 2008 requirements, Hydro One Distribution is expected to deliver 40,666 GWh of electricity to some 1,170,000 distribution customers. This represents an increase of 0.14 percent over the 2006 demand forecast and an increase of 1.7 percent over the 2006 customer count. Section 4 below provides more detailed discussion in respect of the comparison of the 2008 forecast in relation to the historic (2006) and bridge (2007) years. Hydro One Distribution's load forecast has incorporated the Board's latest decision for Hydro One Transmission Rate case (EB-2006-0501) to include 350 MW of natural conservation in the provincial CDM target of 1350 MW for 2007. The load forecast in 2008 also accounts for 251 MW of CDM program impacts assumed in the OPA's IPSP that was filed with the Board on August 29, 2007.

2.0 DISCUSSION OF THE ECONOMIC CONSIDERATIONS THAT INFLUENCE HYDRO ONE DISTRIBUTION'S LOAD FORECASTS

In this section we discuss some of the key economic considerations that must be taken into account in the process of developing load forecasts and in the application of forecasting methodologies. The elements of the forecasting process used by Hydro One Distribution are for the most part based on the knowledge of how the major economic drivers that affect the usage of electricity demand are likely to pan out over the forecast period, which in this case is for the year 2008. Consequently for the purpose of this application the focus is on the short term and the load forecast will reflect those impacts that are likely to have a major effect in this respect. The major economic drivers used in the analysis are summarized in Figure 1 below.

Figure 1
Hydro One Distribution Load Forecast Methodology



Key information used in the analysis includes the Ontario GDP, provincial demographic, industrial production and commercial output forecasts and regional analysis included in the economic forecast. Also taken into consideration are Hydro One Distribution CDM plans, which have a direct impact on distribution system energy demands.

The load forecast in support of this application was prepared and released in April 2007 using economic information and forecasts that were available in early 2007. The timing of the load forecast is driven by the needs of the business planning process which in turn are geared to match the timeline for this submission.

2.1 Provincial GDP Forecast

The provincial GDP forecast is a key driver for the load forecast. During the 1990s, the Ontario economy grew faster than the national economy. During the economic slowdown in 2003 and 2004, the Ontario GDP lagged behind the Canadian GDP because of the SARS outbreak and the Blackout in 2003 and rising Canadian dollars in both years for which the provincial manufacturing sector was the hardest hit. Industries that were negatively affected in recent years include the pulp and paper, chemical and auto-related industries. The provincial economy grew 2.8 percent in 2005 but slowed to 1.3 percent of output growth in 2006 due primarily to the high Canadian dollar and slow US economic growth. Based on the consensus forecast, the Ontario GDP is expected to grow 1.7 percent in 2007 and 2.9 percent in 2008. Because of the strong Canadian dollar, Ontario will continue to lag behind the national growth rates.

2.2 Provincial Population Forecast

Ontario population grew 1.7 percent in 2002, 1.1 percent in each of 2003, 2004 and 2005, and 1.0 percent in 2006. Population growth for the province is forecast to continue to outperform the nation in the forecast period. The economic forecast indicated that Ontario population is expected to grow at 1.2 percent in 2007 and 2008. Steady population growth contributes positively to the load forecast.

2.3 Provincial Housing Forecast

Helped by relatively low interest rates, demand for housing remained very strong in the last few years. Housing starts statistics showed growth of 84,000 houses in 2002, 86,000 houses in 2003, 84,000 houses in 2004, 78,000 in 2005, and 74,000 in 2006. Demand for housing is expected to slow in the next 2 years as interest rates continue rising. The consensus forecast indicated that housing starts will slow to about 67,000 units in 2007 and 68,000 units in 2008. This represents about 17 percent decline in housing starts relative to the 2002-2006 period.

2.4 Commercial Output Forecast

With the help of low interest rates, commercial activities remained strong in Ontario in the last five years, averaging about 3 percent a year. With rising Canadian dollar, commercial output growth is expected to soften from 3.3 percent growth achieved in 2006 to 2.3 percent in 2007 and 2.9 percent in 2008. Industries expected to enjoy above-average growth include wholesale and retail trade, financial services and health care services, while tourism-related industries such as accommodations and food services will continue to face some challenging times. Commercial output is important to the load forecast because commercial load comprises about 25 percent of the Hydro One Distribution System.

2.5 Industrial Production Forecast

After a decline of 1.5 percent in 2006, the manufacturing sector in Ontario is forecast to decline further by 0.4 percent in 2007 due primarily to the impact of higher Canadian dollar. Since early 2003, the Canadian dollar has appreciated by about 40 percent relative to the U.S. dollar. Industries that were hardest hit in the past few years include fabricated metals, paper and printing, chemicals, primary metals, machinery and wood. The economic forecast expects industrial production to grow by about 3.0 percent in 2008. The industrial production forecast is important to the load forecast because industrial activity comprised about 10 percent of total load and also because it is prone to economic cycles.

2.6 Conservation and Demand Management

Hydro One Distribution supports the Ontario Government's conservation and demand management (CDM) target to achieve a 1,350 MW of peak reduction by 2007 and a further reduction of 1,350 MW by 2010. Hydro One Distribution used the Board approved 3rd tranche funding of $39.5 million to cover its CDM programs for the 2004-2007 period. After the 3rd tranche funding, Hydro One will rely on the CDM funding from OPA to fund its CDM initiatives in 2008 and beyond.

Table 2 summarizes the cumulative CDM impact since 2004 assumed in Hydro One's distribution system load forecast for 2006, 2007 and 2008. The CDM impact includes programs undertaken by Hydro One Networks and programs implemented by other agencies such as federal and provincial governments, OPA and IESO. Hydro One Distribution's 2007 CDM impact is the same as the 2007 CDM impact approved by the Board for Hydro One's Transmission Rate case (EB-2006-0501) issued on August 16, 2007. A 350 MW reduction to the 2007 provincial CDM target of 1350 MW was made to account for the impact of natural conservation. The 2008 CDM impact is consistent with the OPA's IPSP filed with the Board on August 29, 2007.

Table 2

CDM Impact on Hydro One Distribution Load
(GWh)

Year	Hydro One Retail	Embedded Direct and LDC Customers	Total
2006	194	151	345
2007	311	242	554
2008	437	333	770

CDM programs that have been undertaken in the past two years or are in the process of being initiated include the following initiatives:

- improved building codes for new housing and more stringent efficiency standards for appliances;
- conservation programs to encourage more efficient use of lighting and appliances;
- demand response programs to reduce air conditioning and water heating load in the summer months;
- use of smart metering and TOU rates to encourage consumers to shift consumption patterns to off-peak period; and
- programs to increase supply or reduce demand such as fuel switching, using back-up generation or requesting large industrial customers to reduce consumption on a temporary basis.

The 2006 annual report filed by Hydro One Distribution on CDM (RP-2004-0203/EB-2005-0198) includes detailed program impacts on a bottom-up basis.

Hydro One Distribution does not currently have the data required to do a bottom-up analysis of the CDM impact on Hydro One's load forecast from the various CDM programs driven by various sources such as the Ontario Power Authority, Provincial Government and Federal Government.

2.7 Customer Forecast

In 2007 Hydro One Distribution is expected to serve about 1.17 million customers through its distribution system. Detailed customer information is retained in the Customer Settlement System (CSS) for billing and account management. Customer data are extracted from CSS regularly for tracking, analysis and reporting. Customer forecast was developed on an as-required basis to support the annual business planning process, system development plans and rate submissions to the Board. Active customer accounts and service points are used as the basis from which to prepare the customer forecast by rate class. The customer forecast takes into consideration the new customers requiring distribution services, existing customers moving out, provincial housing demand, population and household forecasts, vacancy rates and specific growth patterns of various customer groups.

Approximately nine to ten thousand customers are added to Hydro One Distribution's customer base on an annual basis. Customer growth in 2007 and 2008 is expected to be approximately 11,000 and 9,400 respectively (2007 customer growth includes an addition of 1,100 customers from Terrace Bay). This compares to an average of about 12,000 customers that were added per year in the period 2002-2006. The lower figure for 2008 is attributed to a reduction in housing starts.

3.0 LOAD FORECASTING METHODOLOGY

Hydro One Distribution system's load forecast is developed using both econometric and end-use approaches. The forecast base-year is corrected for abnormal weather conditions and the forecast growth rates are applied to the normalized base-year value. Thus the forecast is weather-normal in the sense that it predicts the future load under normal weather conditions.

3.1 Weather Correction Analysis

This section discusses the weather correction methodology used by Hydro One Distribution. Weather correction analysis removes the abnormal or extreme weather effects from the load data to yield average conditions that reflect the more normal or expected weather that is used in the forecast. It is essential that abnormal and extreme weather related impacts are removed before establishing the base-case load data, on which basis the load forecast will be developed. The volatility of abnormal or extreme weather conditions would likely adversely impact on the ability to provide a consistent and meaningful forecast for load growth. Hourly load data and hourly weather data of various weather stations across the province are used in the analysis.

Hydro One Distribution's weather correction methodology was developed jointly by forecasting and meteorology staff of the former Ontario Hydro. This weather correction method was used to forecast the total system load since 1988 and for forecasting local electric utility load since 1994. The weather correction methodology used by Hydro One Distribution is a proven technique that has performed well in the past years. The same methodology was reviewed and approved by the Board in the Distribution Cost Allocation Review (EB-2005-0378) and for Hydro One's 2006 Distribution Rate case (RP-2005-0020/EB-2005-0378).

Weather correction is a statistical process designed to remove the impact of abnormal or extreme weather conditions from historical load data. Normal weather data is defined to be data that is based on the average weather conditions experienced over the last 31 years. A weather-normal load forecast is a forecast of load assuming normal weather conditions with a weather-corrected base year. As shown in Table 3, using a fewer number of years for historic weather normalization has only a small impact on the total weather corrected energy consumption. This is an expected outcome since weather normalization has a more significant impact on peak than it does on energy due to the fact that energy consumption is less sensitive to short-term weather conditions.

Table 3

Comparison of Different Time Periods Used for Weather Normalization (in GWh)

Number of Years Used to Calculate Normal Weather	Actual Load for Hydro One Retail Customers in 2006	Weather Correction Required for Hydro One Retail Customers in 2006	Weather Corrected Load for Hydro One Retail Customers in 2006
Last 31 Years *	22485	437	22921
Last 20 Years	22485	367	22852
Last 10 Years	22485	308	22792
Last 5 Years	22485	404	22889

* Used by Hydro One Distribution to normalize the base year (2006) load.

Hydro One Distribution's weather correction methodology uses four years of daily load and weather data to establish a sound statistical relationship between weather and load at the applicable transformer station or delivery point used to supply customer demand. Weather variables used in the analysis include temperature, wind speed, cloud cover and humidity. The estimated weather effects are then aggregated up to the required time interval. Past experience shows that weather correction should best be done on a daily basis, rather than weekly, monthly or annual basis.

Daily weather-correction is preferred because the timing of extreme temperatures combined with wind speed and humidity can have a substantial impact on load that would otherwise not be captured by averages over longer period of time. In particular, when abnormal weather conditions continue for several days, the cumulative impact is much greater than would be the case if the same weather conditions prevailed over a much longer period of time.

The loads that are most impacted by changes in weather conditions are electric space heating and cooling in residential and commercial buildings. Across Ontario, the penetration rate of such loads varies widely, which means the weather sensitivity of load supplied from one transformer station or delivery point may differ quite significantly from that of load supplied from another transformer station or delivery point, even in the same climate zone. The climate in Ontario varies considerably from the Niagara Peninsula to Thunder Bay, so it is important to use data from the appropriate weather stations that are in close proximity to the transformer station or the customer delivery point when correcting for weather effects.

3.2 Hydro One Distribution Forecasting Methodology

Both econometric (top-down) and end-use (bottom-up) models are used to prepare load forecast for Hydro One Distribution. Both monthly and annual econometric models are used to forecast Hydro One Distribution's total distribution system load. End-use models using the results from the provincial end-use models are used to analyse the distribution system load by customer rate class (i.e. various residential and general service customers). Key information used in the analysis includes economic, demographic, industrial production and commercial output forecast provided in the economic forecast. The purpose of using both the econometric and end-use forecast models is to arrive at a balanced forecast that represents a consistent set when looked at from macro (econometric) and micro (end-use) perspectives.

Monthly Econometric Model

The monthly econometric model uses a multivariate time series approach to develop the monthly forecast for the Distribution system load. The model links monthly energy consumption to Ontario GDP and residential building permits. Appendix 1 provides the detailed regression equations and definitions.

Annual Econometric Model

The annual econometric model uses personal disposable income per household, relative energy price and cooling and heating degree-days to prepare the forecast. Appendix 2 provides the detailed regression equations and definitions.

End-Use Model

The end-use models cover the residential (year round and seasonal), commercial, industrial and agricultural sectors. Detailed equations of the end-use models are provided in Appendix 3.

The above models are used to prepare forecast for all existing and proposed rate classes:

Existing Rate Classes

Year Round Residential Customers

- Residential continuous use, high density (R1);
- Residential continuous use, normal density (R2);
- Residential continuous use, urban density (UR);
- Residential customer from acquired LDC's (Res);

Seasonal Residential Customers

- Residential seasonal use, high density (R3);
- Residential seasonal use, normal density (R4);

Agricultural Customers

- Farm customers
    - Farm service, continuous use, normal density, single phase (F1);
    - Farm service, continuous use, normal density, three phase (F3);
- General service and sub-transmission customers

General Service Industrial and Commercial Sectors

- General distribution supply, single phase (G1);
- General distribution supply, urban, (UG);
- General distribution supply, three phase (G3);
- General sub-transmission supply (T);
- General service customers from acquired LDC's (GS)
- Large general service customers from acquired LDC's (MLGS);
- Streetlight.

Proposed Rate Classes

- Urban residential
- Residential, high density
- Residential, normal density
- Seasonal
- General service, energy-billed
- General service, demand-billed
- Urban general service, energy-billed
- Urban general service, demand-billed
- Sub-transmission
- Street lighting
- Sentinel lighting
- Distributed generation

3.3 Methodology for Low Voltage System-Connected Customers

This section discusses the load forecasting methodology used for the analysis of Low Voltage (LV) system connected customers. These are the embedded customers who are directly connected to Hydro One's sub-transmission (ST) system or have a delivery point embedded in Hydro One's distribution service territory and include distribution utilities, industrial and commercial customers. Both econometric and customer analysis based on survey results from the customers, when available, are used in the forecast. This is supplemented by the economic data provided in the economic forecast.

In 2007, Hydro One Distribution conducted a customer load forecast survey with the embedded distribution utilities and embedded industrial customers with more than 5 MW of loads. In addition to questions relating to the total load of the customer, information at each of the delivery point was also collected. The customer survey results are used in preparing the customer forecast.

For embedded distribution utility customers, econometric analysis is used to prepare the load forecast as a group. For industrial customers, several information sources are used to prepare the forecast. These include:

- historical load profile of the customer,
- knowledge of the customer through industry monitoring,
- forecast provided by customer through the survey,
- company information through Hydro One Distribution account executives, industry and company forecasts from industry associations and government agencies, and
- production and industry forecasts provided in the economic forecast.

The econometric approach was used to forecast the load for embedded utilities and industrial analysis was used to forecast the load for the embedded industrial customers. In both cases, results from customer survey, when available, were taken into account in developing the forecast.

3.4 Methodology for Hourly Load Profiles

This section discusses the methodology for generating the hourly load profiles by customer class and for specific customer delivery points.

Hourly Load Shape by Customer Class

Hydro One Load Research team was the project lead undertaking joint load research work on behalf of the Ontario Load Data Research Group consisting of about 45 LDCs in the province. The load research methodology to collect new hourly load data for developing the generic load shapes by customer rate class was examined in detail by the Distribution Cost Allocation Working Group and was approved by the Board in RP-2003-0228 and EB-2005-0317.

The province-wide generic load shapes was prepared by the Hydro One Load Research team under the guidance of Professor Dean Mountain of McMaster University. Hydro One Load Research team subsequently used the generic load shapes to generate utility-specific load profiles for about 80 LDCs in Ontario, including Hydro One Distribution, for their cost allocation review filings under proceeding EB-2005-0317. Appendix 4 summarizes the methodology used by Hydro One Load Research team to weather-normalize the total utility load and for each rate class. Appendix 5 summarizes the methodology used to prepare the utility-specific load shapes using the generic load shapes. Hydro One Distribution used the above methodology to prepare hourly load shapes for all rate classes.

Hourly Load Shape by Customer Delivery Point

Electricity Power Research Institute (EPRI)'s Hourly Electric Load Model (HELM) is used to normalize the hourly load for each of the customer delivery points, taking out abnormal weather effects and load patterns. The customer forecast is used to drive the customer delivery point forecast. Key information used in the analysis includes hourly load and weather data.

The most updated customer totalization table is used to retrieve hourly electricity demand data for each of the customer delivery points connected to the ST system. The totalization table reflects the latest records from Hydro One Networks. For each customer delivery point, at least one full year of hourly data is retrieved and checked for data quality. Hourly weather data is also retrieved to prepare weather sensitivity analysis. Weather data analyzed include temperature, wind speed, cloud cover and humidity. Data for five weather stations across Ontario are used in the analysis. They include Toronto, Windsor, Ottawa, North Bay and Thunder Bay. Each delivery point is linked to the closest weather station.

In preparing the database for the load shape analysis, missing values are estimated by load on a similar day and hour during the same month. For weather-sensitive load, weather conditions are also taken into account in estimating the missing values. To perform the latter task, an hourly regression model (relating load to weather conditions) for each delivery point with missing values is developed.

EPRI's HELM is used to prepare the hourly weather response analysis by each delivery point. The model takes into account differences in load depending upon time of use (that is weekdays, weekends and holidays) and weather conditions. Load of industrial customers is assumed to be insensitive to weather and as such are forecast in relation to load on a similar day and hour during the historical period.

4.0 2008 LOAD FORECAST

Hydro One Distribution' distribution system is forecast to deliver in total 40, 666 GWh in 2008 on a weather-normal basis. Table 4 presents the load forecast before and after deducting the impact of CDM.

Before deducting the impact of CDM, Hydro One Distribution's load forecast is forecast to grow from 40, 955 GWh in 2006 to 41,046 GWh in 2007 and to 41,436 GWh in 2008 on a weather-normal basis. The forecast reflects slow economic growth in 2007 and particularly weak performance from the industrial customers and overall stronger economic growth in 2008.

In 2008, Hydro One Distribution is expected to serve about 1,170,000 customers. This reflects about 1.7 percent growth in the number of customers compared to 2006.

After removing the impact of CDM, Hydro One Distribution's load is forecast to decrease from 40, 609 GWh in 2006 to 40,493 GWh in 2007 and increase to 40,666 GWh in 2008 on a weather-normal basis.

Table 4

Hydro One Distribution Load Forecast Before and After CDM Impact (GWh)

Year	Retail Customers	Embedded Customers	Total
Load Forecast Before Deducting Impact of CDM			
2006	23,115	17,839	40,955
2007	23,256	17,790	41,046
2008	23,494	17,942	41,436
Annual Growth Rates			
2007	0.61	-0.27	0.22
2008	1.02	0.85	0.95
2006-2008	0.81	0.29	0.59
Load Impact of CDM			
2006	194	151	345
2007	311	242	554
2008	437	333	770
Load Forecast After Deducting Impact of CDM			
2006	22,921	17,688	40,609
2007	22,944	17,548	40,493
2008	23,057	17,609	40,666
Growth Rates			
2007	0.10	-0.79	-0.29
2008	0.49	0.35	0.43
2006-2008	0.30	-0.22	0.07

Note: All figures are weather normal and 2006 values after deduction of CDM a

Since the forecast is weather-normal; the actual load could be below or above the forecast depending on the weather conditions and/or a different economic growth pattern. Table 5 presents the upper and lower bands of one standard deviation for the Hydro One Distribution system load forecast. Based on historical data, there is a two in three chance that the actual in 2008 will fall within the upper and lower bands. The bands are derived using Monte Carlo simulation technique relating variations in load to variations in Ontario GDP and weather.

Table 5

One Standard Deviation Uncertainty Bands for Hydro One Distribution Load (GWh)

Year	Lower Band	Forecast	Upper Band
2007	39,789	40,493	41,175
2008	39,827	40,666	41,520

Appendix 1: Monthly Econometric Model

The monthly econometric model uses the State-Space approach in the regression equation, where the left-hand side of the equation represents the energy estimates, and the right-hand side contains the explanatory variables including the dummy variables that are used to capture special events that could affect the energy estimates because these events would likely cause variations in the load. The dummy variables are used to minimize the variability of the energy estimates around the forecast.

LRTLT = f (LGDPONT, LBPONT, D98Jan)

where:

LRTLT = logarithm of Distribution load,
LGDPONT = logarithm of Ontario GDP in constant 1997 dollars,
LBPONT = logarithm of Ontario residential building permits in constant dollar,
D98Jan = dummy variable to account for the load impact of 1998 Ice Storm, equals 1 in January 1998 and zero elsewhere,

The output parameters from the model are presented below. The State-Space (SS) estimated parameters are not associated with standard error and t-ratios (statistical relevance test).

Seasonal Factors	State-Space (SS) parameters:
A[1]	-0.134796
K[1]	-0.568914

Non-Seasonal Factors	SS parameters:
A[1]	0.531829
K[1]	-0.345868
GDPONT[-4]	0.0784784
BPONT[-9]	0.00440215
D98JAN	-0.0150467

R-squared = 0.989, R-squared corrected for mean = 0.989, Durbin-Watson Statistics = 2.31.

The goodness of fit, or the extent to which variability in the energy estimates is captured in the forecast, is measured in terms of R-squared (adjusted for mean), which in this case is close to 1. This result reflects statistical significance of the explanatory variables that are used to explain for the variations in load. In fact, the results show that in this case the fit is very good, and therefore there is confidence that the forecast will produce outcomes that are within the expected range of variability.

Using the forecast values for GDP, building permits and dummy variables, the above parameters are used in the monthly regression equation described on the previous page to generate the forecast for Hydro One Distribution load.

Appendix 2: Annual Econometric Model

Annual econometric model uses personal disposable income per household, relative energy price and cooling and heating degree-days to prepare the forecast. The annual model is expressed in the following regression equation:

LRTLT=C(1)+C(2)*LYPDPHH+C(3)*(LPELRES(-1)-LPGASRES(-1))
+C(4)*LCDD+C(5)*LHDD+C(6)*LRTLT(-1)-C(4)*C(6)*LCDD(-1)-C(5)
*C(6)*LHDD(-1)+C(7)*D99A+C(8)*TR+C(9)*TR2

where:

LRTLT = logarithm of Distribution load,
LYPDPHH = logarithm of Ontario personal disposable income per household in constant $,
LPELRES = logarithm of electricity price for Ontario residential sector,
LPGASRES = logarithm of natural gas price for Ontario residential sector,
LCDD = logarithm of cooling degree days for Pearson International Airport,
LHDD = logarithm of heating degree days for Pearson International Airport,
D99A = dummy variable to account for annexation of retail customers by municipal utilities equals 1 after 1999 and zero elsewhere,
TR = a dummy variable to account for a shift in growth pattern of Distribution load, increases by 1 per year prior to 1989 and no increase afterwards,
TR2 = TR to power 2,
C(1) – C(9) = variable coefficients.

The estimated coefficients and associated statistics are presented below.

	Estimated Coefficient	Standard Error	t-ratio
C(1)	5.548910	1.273869	4.355949
C(2)	0.303905	0.119354	2.546245
C(3)	-0.055342	0.025059	-2.208471
C(4)	0.004952	0.007168	0.690828
C(5)	0.195571	0.043265	4.520272
C(6)	0.286776	0.103890	2.760383
C(7)	-0.020994	0.007506	-2.796974
C(8)	-0.100598	0.023221	-4.332256
C(9)	0.002619	0.000546	4.795182

R-squared = 0.995, Adjusted R-squared = 0,993, Durbin-Watson Statistic = 1.90.

Similar to the regression analysis in the case of the Monthly Econometric model above, the goodness of fit, measured by (Adjusted) R-square for the Annual Econometric Model, is also found to be close to 1. Therefore the assessment on an annual basis also leads to a forecast outcome which provides consistent results, thus giving confidence to the econometric method. The t-ratios show most of the factors used to explain the variations in load are statistically significant.

Using the forecast values for personal disposable income, energy prices, cooling and heating degree days and dummy variables, the above parameters are used in the annual regression equation described on the previous page to generate the forecast for Hydro One Distribution load.

Appendix 3: End-Use Model

The following briefly describes the methodology used in the end-use model.

<u>Residential Sector</u>

The residential energy forecast is determined by forecasting the number of accounts times appliance saturation rates and unit energy consumption expressed in the following equation:

$$USE_{Res} = \sum_i \sum_j N_{i,j} * S_{i,j} * UEC_{i,j}$$

Where

- USE_{Res} is residential energy consumption
- N is the number of residential accounts
- S is the residential appliance saturation rate
- UEC is the unit energy consumption per end use
- I is the index for appliances (space heating, space cooling, water heater and base load)
- J is the index for customer types—year-round residential customers and seasonal residential customers

The following section describes each component of the equation in detail.

- The base-year number of households is taken from Hydro One Distribution billing system. The forecast in the growth of the number of residential accounts is based on a forecast of housing starts. The number of residential accounts is the current number of residential accounts plus the forecast of net additional accounts to be added each year.
- The base-year end-use shares (space heating, water heating and air conditioning), and fuel switching (space/water heating) information are based on Hydro One Residential Appliance Survey conducted in 2005 for year-round and seasonal customers.

- The trends for end-use shares and fuel switching over the forecasting period reflect the provincial trends from the Hydro One provincial residential end-use model, as well as information specific to Hydro One Distribution.
- The base-year end-use UEC's are based on the provincial residential end-use model with adjustments for heating degree days, cooling degree days, income, household size, square footage and household vintage.

Commercial Sector

The commercial energy forecast is based on the following equation:

$$USEcom = USEcom(-1) * (1+\text{Expected annual growth rate})$$

Where

- $USEcom$ is the commercial energy consumption for the forecast year
- $USEcom$(-1) is the commercial energy consumption for the previous year. The base year (2006) consumption is taken from the latest Hydro One Distribution billing system corrected for abnormal weather effects
- Expected annual growth rates are based on the Hydro One provincial commercial end-use model. Where appropriate, the values are adjusted to reflect specific distribution business characteristics.
- The model uses an end-use framework to provide estimates of energy use by building type. The building types include multi-residential, office, elementary and secondary school, college and universities, health, public service, retail, grocery, accommodation, recreation, religious/cultural, warehouse, commercial miscellaneous. non-building related segments and streetlight.

Industrial Sector

The industrial energy forecast is based on the following equation:

$USEind = USEind$ (-1) * (1+Expected annual growth rate)

Where

- $USEind$ is the industrial energy consumption for the forecast year
- $USEind$ (-1) is the industrial energy consumption for the previous year. The base year (2006) consumption is taken from the latest Hydro One Distribution billing system corrected for abnormal weather effects
- Expected annual growth rates are based on the Hydro One provincial industrial end-use model. Where appropriate, the values are adjusted to reflect specific distribution business characteristics.
- The model uses an end-use framework to provide estimates of energy use by industrial segments including Fishing, logging, Forestry Service, Mining, Petroleum, Food and Beverage, Tobacco, Rubber and Plastic, Textile and Clothing, Wood and Furniture, Paper and Printing, Primary Metal, Fabricated Metal Products, Transportation Equipment, Electronics etc.

Agricultural Sector

The Agricultural sector forecast is based on the following equation:

$USEagri = USEagri$ (-1) * (1+Expected annual growth rate)

Where

- $USEagri$ is the agricultural energy consumption for the forecast year
- $USEagri$ (-1) is the agricultural energy consumption for the previous year. The base year (2006) consumption is taken from the latest Hydro One Distribution billing system corrected for abnormal weather effects

- Expected annual growth rates are based on the Hydro One provincial agricultural end-use model. Where appropriate, the values are adjusted to reflect specific distribution business characteristics.
- The model uses an end-use framework to provide estimates of energy use by agricultural segments including Animal Production, Fruit and Vegetable Farming, Grain Farming, Green Housing and Floriculture and Miscellaneous etc.

Appendix 4: Weather Normalization for Total Utility Load and by Rate Class

Weather Normalization for Total Utility Load

Hydro One's weather normalization methodology for total utility load is summarized as follows.

- An equation relating daily energy and daily weather conditions is developed using the latest 4 years of data. This time frame allows the analysis to reflect the most recent load mix while having sufficient data to quantify its weather sensitivity. For example, the share of space cooling energy relative to total energy has increased rapidly over the past decade; using too long a time series of historical data may lead to significant under-estimation of the weather sensitivity of load in the summer.

- To better isolate the impact of weather, systematic changes in daily loads are identified and filtered out before the regression analysis begins. The systematic effects removed include growth trends, cyclical variations, day-of-the-week effects and holiday effects. The objective is to filter the data to weather-related load and noise (random effect).

- Different types of weather data are used in the analysis. For winter loads, weather data include temperature, wind speed and cloud opacity. For summer loads, weather data include temperature, humidity and cloud opacity. Because weather effects cumulate over several days, the temperatures for the current day as well as the previous 3 or 4 days are also used as explanatory variables in the model. The relationship between energy and weather may be represented by the following function:

Weather- Related Energy = f (Weather Conditions) + Random Term (1)

where the random term reflects any remaining variations that are not explained systematically by weather. The random term is assumed to be distributed independently, identically and normally with mean equals to zero.

- The coefficients from Equation (1) are estimated using the most recent 4 years of daily load and weather data. These coefficients indicate the sensitivity of load in the service territory relative to today's temperature, yesterday's temperature and all other weather variables included in the equation. The estimated coefficients are multiplied by the actual weather data for the corresponding weather variable in the equation to determine the estimated weather-related energy for the day. This process is repeated for each day of the period for which weather-correction is performed.

Estimated Weather-Related Energy = f (Actual Weather Conditions and Estimated Coefficients) (2)

- Equation (2) is used to determine what "normal" weather-related loads would be for each day of the year given the current mix of weather-sensitive loads in that service territory. This is done by running the equation with each of the last 31 years of daily weather data for that day plus the seven days on either side of it. The average of the estimated weather-related loads for the 15 days times 31 years (465 observations) is deemed to be the "normal" weather-related energy for that day. Using 31 years of weather history is considered adequate to approximate normal weather.

Normal Weather-Related Energy (for each day) = Average (31 years of Estimated Weather-Related Energy for that Day +/- 7 Days) 3)

- On a daily basis, the weather correction is derived as the difference between the estimated and normal weather- related energy:

  Weather Correction for Energy = Normal Weather-Related Energy – Estimated Weather-Related Energy (4)

- Weather-corrected energy is defined to be actual energy plus the weather correction in any given period. For any period that is more than one day (e.g., a month), the total weather correction is the sum of the daily weather correction.

  Weather-Corrected Energy = Actual Energy + Weather Correction for Energy (5)

- For example, a summer day for which the combination of temperature and humidity are above normal yields a negative weather correction. The weather correction in this case should be viewed as the amount to be subtracted from the above normal actual to get the weather-corrected energy. Similarly, a warm winter day would have a positive weather correction as the weather corrected value for that day should be higher than the below normal actual.

Weather Normalization by Rate Class

Weather correction by rate class is derived from weather correction for the total utility using the electric space heating and cooling shares by rate class or segment as detailed below.

- Weather correction for the total utility load is discussed above using daily energy for the utility. The amount of weather correction is measured on a daily basis.

- Using average daily temperature for each day, the daily weather correction is grouped into "weather correction for space heating" and "weather correction for space cooling". For example, if average daily temperature is -1, the weather correction for that day is allocated to "weather correction for space heating" load. The daily weather correction results are aggregated into annual or monthly weather correction estimates.

- Using load shape analysis and residential appliance saturation estimates for the utility and the region, the amount of space heating and cooling load over a year or month are estimated for each rate class. The weather correction for each rate class is calculated using the space cooling and heating load of that rate class. The methodology used is summarized as follows.

- **Residential cooling/heating load**: Residential load shapes are developed using the generic load shapes (cooling, space heating, electric water heating, etc.) from the Ontario Load Data Research Group. Based on these generic load shapes and specific appliance saturation estimates for the utility and the region, total residential space heating and cooling load are calculated. The generic load shapes may vary by region, reflecting different weather conditions across the province.

- **Non-residential cooling/heating load**: For non-residential rate classes, the generic load shapes from the Ontario Load Data Research Group (or available load shapes from Hydro One for load shapes not covered by the joint load research project) are used to calculate the cooling and heating load percentages by rate-class or segment (e.g., by SIC or industry segment). Again, these generic load shapes may vary by region, reflecting different weather conditions across the province. Some industrial segments may not be weather-sensitive; in this case the space heating and cooling loads would be zero. The corresponding percentages of space cooling and heating load multiplied by rate-class or segment load would provide the cooling and heating load of that rate class or segment.

- **Total cooling/heating load and shares**: Total space heating and cooling load for the utility are calculated by adding residential and non-residential space heating and cooling loads from above. Using this total, the shares of cooling and heating load for each rate class relative to the total cooling and heating load are calculated.

- **Weather correction by rate-class:** For each rate class, the cooling and heating weather correction amount are calculated using the total cooling and heating weather correction amount for the utility multiplied by the corresponding cooling and heating shares calculated from above. Shares of some industrial segments could be zero since they are not weather sensitive. The weather-corrected load for each rate class is estimated by adding the weather correction estimates by rate class to the corresponding (actual) load for each rate class.

Appendix 5: Methodology for Preparing Utility-Specific Load Shapes

Hydro One's method makes use of the following information:

- Generic load shapes prepared for the Ontario Load Data Research Group for residential and general service customers.
    - The residential load shapes have weather-normal profiles for 4 end-use categories (electric space heating, electric water heating, air conditioning and base load) and 4 regions (Central, East, West and North).
    - The general service customer load shapes have load profiles for about 35 industry segments using NAICS-2002 (North American Industry Classification Systems) and by number of working shifts.
- Hydro One weather normalization methodology for total utility load and by rate class.
    - Hydro One weather normalization method, which was approved by the Board in RP-2005-0020/EB-2005-0378 and EB-2005-0317, uses 4 years of daily load and weather data to establish the relationship between weather and load and the average of 31 years of weather data to define typical weather conditions.
    - Weather variables used in the weather correction analysis include temperature, wind speed, cloud cover and humidity. In addition to temperature, wind speed is important in the winter months, while humidity is important for the summer months.
    - Estimation of space heating and cooling loads for residential customers makes use of generic load shapes and appliance saturation estimates.
    - Estimation of space heating and cooling loads for general service customers makes use generic load shapes and industry classification.
- Weather-normalized load shapes for battery mats prepared by the Hydro One Load Research team using information provided by the local cable company. For the informational filing to OEB, weather-sensitive load profiles for battery mats are

required only for LDCs using future test year and not required for LDCs using historic test year in their 2006 EDR applications.

- Results of residential appliance survey undertaken by LDCs using survey questions recommended by the OEB's load research expert. For LDCs opted not to undertake residential appliance survey, estimates of appliance saturation are prepared using monthly energy patterns for each residential customer.
- Deemed street lighting and sentinel lighting load profiles approved by the OEB.
- Interval meter customer load profiles by rate class and by industry classification.
- Special tabulation of Household Equipment Survey results from Statistics Canada.
- Residential appliance survey results undertaken by former Ontario Hydro.

Hydro One's utility-specific load shape methodology is summarized as follows:

Weather correction analysis

- Weather correction analysis is performed for each region and LDC.
- For each region, weather correction analysis is undertaken using the total regional load.
- For each LDC, the weather correction analysis is undertaken for the total utility load as well as by rate class. Weather sensitive loads for space heating and space cooling are determined for each day.
- The relationship of weather sensitivity between the region and the LDC is used to calibrate the utility-specific space heating and cooling loads with the regional estimates.
- Using the weather correction analysis, generic load shapes and monthly profiles, weather-corrected loads are estimated for the total utility load and by rate class.

Residential Customers

- Using number of customers, appliance saturation and generic load profiles, the energy consumption by end-use are estimated.
- The relationship of weather sensitivity between the region and the LDC is used to calibrate the utility-specific energy consumption for space heating and cooling loads.
- The relationship of appliance saturation and housing characteristics between the region and the LDC is used to calibrate the utility-specific profiles for water heating and base loads.
- Weather-normal hourly load shapes are estimated using generic load shapes and energy consumption by end-use.
- Weather-normal energy consumption by end-use will add up to weather-normal residential rate class total.

General Service >50 KW Customers

- General service >50 kW customers are grouped by industry classification excluding interval metered customers.
- Allocation of weather correction is undertaken for industry classifications that are weather sensitive.
- Analysis takes into consideration number of work shifts for each industry classification.
- Weather-normal hourly load shapes are estimated using generic load shapes and energy consumption for each industry classification.
- Weather-normal energy consumption by industry classification will add up to weather-normal general service >50 kW rate class total.

PROJECT AND PROGRAM APPROVAL AND CONTROL

1.0 INTRODUCTION

As described in Exhibit A, Tab 14, Schedule 1, there are a number of key steps within the overall business planning cycle which are typically completed prior to the development of more detailed project and program assessments. These prerequisite steps include: needs identification, project/program prioritization, and development of preliminary work programs, based on estimates of project and program costs and benefits. Once the preliminary plans have been accepted at the proof-of-concept stage and have gone through the work program prioritization process described in Exhibit A, Tab 14, Schedule 5, detailed analysis of preferred alternatives and costs is completed for individual projects, and business cases based on the detailed analysis and cost estimates are prepared for review and approval.

2.0 PROJECT AND PROGRAM APPROVAL

Once the final investment plan proposal and associated funding requirements are established, Senior Management approves the programs included, based on the proof-of-concepts presented during the work program prioritization process. Business cases (Investment Justification Documents (IJD)), are prepared for project proposals, a template for which is provided as Attachment A to this exhibit. This ensures consistent development and assessment of proposals. The IJD template includes such factors as the need for the investment including the implications of not doing the work, the results to be obtained and the recommended solution and its cost. In determining the recommended solution, alternative approaches and project risks are considered. The factors considered include asset condition assessments and performance data as well as other relevant information concerning the long-term needs of the system. The business cases are then reviewed in a series of steps at the management and executive levels, depending on the dollar limit and significance of the investment. Projects and programs are approved consistent with the Organizational Authority Register (OAR -- see Exhibit A, Tab 8, Schedule 2). Strategic investments are reviewed and approved by the Hydro One Board.

3.0 MONITORING AND CONTROL

Each month, management monitors year-to-date expenditures and accomplishments as well as projected year-end expenditures. Deviations from plans are identified and corrective action taken. In the event that spending on a project is expected to be materially different from the amount originally approved, an Interim Review of Variance (IROV) is prepared. An IROV is essentially an amended business case that is reviewed and approved based on the revised set of circumstances (cost, scope, schedule). Approval of the IROV is also in accordance with the limits set out in the OAR. Projects which cannot be re-justified are either scaled back, cancelled or otherwise adjusted to conform to the new situation. Variances on major programs are reviewed on a monthly basis by the Operations Committee. Any resulting re-direction of resources is approved by the Chief Financial Officer and President & CEO.

Hydro One Distribution – Investment Justification

Investment Name

Investment Driver:

Title and DC number. Sentence or Paragraph describing the Investment Driver ($M for the entire business driver).

Investment Name: **In Service:** month/year

Title ($)

Investments ≥ $3.0M, in $M, 1 decimal
Investments < $3.0M, in $K, no decimals

Need: Need section will be 2 paragraphs – the need and risks mitigated

- Need for this particular investment — What is the problem/situation that is being addressed
- Implications of not doing the work — Outline specific risks mitigated and quantify where possible

Investment Summary: (Concise – total of 1-3 paragraphs)

- Context — Importance of this system or this program.
- How did we determine the work? — How did you prioritize or determine the need for specific work, studies, assessments, regulatory requirements, benchmark, any critical assumptions, etc.
- Conclusion — What is going to be done.

Results: (3-4 bullets – quantified, high level)

Expected results of the investment. Must link the work to the "needs & risks" identified above.

Costs:

Include a statement if contribution is being made to another part of Hydro One (i.e., DX to TX) and that these costs are included below. If costs are recoverable, no need to identify here as there is a separate line below.

	200X ($M)	**200X** ($M)	**Total** ($M)	**Net Present Value*:** **Profitability Index*:**
Capital and MFA				
OM&A and Removals				
Gross Investment Cost				
Recoverable (e.g., capital contribution)				
Net Investment Cost				

* NPV and PI provided for new load connections or productivity-enhancing projects.

WORK PROGRAM PRIORITIZATION

1.0 OVERVIEW

The investment prioritization process is part of the overall company planning process. (see Exhibit A, Tab 14, Schedule 1). The prioritization process converts Hydro One Distribution business values (consistent with the strategic goals set out in Exhibit A, Tab 3, Schedule 1) and key performance indicators in Table 1 into investment criteria and guidelines that are used for managing risk and facilitating trade-offs between investments. At the core of the process is a multi-criteria analysis, which is used to help decision-makers understand and quantify business risks and uncertainties so that objective decisions can be made respecting priorities.

Capital and OM&A investments are prioritized on an annual basis. The investments included in the process have been developed in response to asset, customer and business needs. The process incorporates risk tolerances consistent with corporate direction and also considers resource constraints.

The output of the prioritization process is an investment plan proposal. While this proposal is prepared at a specific time of the year, the resulting plan is modified as new risks or opportunities emerge, conditions change, and/or priorities shift throughout the year. A redirection process, described in Section 2.5 of this Exhibit, enables the incorporation of such modifications.

The investment plan proposal is composed of a list of prioritized program/project investments, both capital and OM&A. Program/project descriptions for 2008 capital investments in excess of $1 million are provided in Exhibit D2, Tab 2, Schedule 3.

2.0 INVESTMENT PRIORITIZATION PROCESS

The current investment prioritization process was implemented in 2001, in response to utility best practice and to address factors such as aging infrastructure, customer demand for higher reliability, changing regulations, funding pressures, etc. Since 2001, the process has seen continuous improvements using the experience gained in each subsequent year. For example, the prioritization methodology has been expanded over the years to cover a broader scope of program areas. Also, program execution issues such as outage availability, effective work bundling, etc. have been more fully included in the development of the proposed expenditures, which has resulted in investment proposals that are more accurate from an implementation perspective.

The prioritization process uses the business values to rank proposed investment levels in accordance to the benefits they provide, and facilitates the preparation of an investment plan proposal. This annual process consists of the following steps:

- Define business values
- Develop multiple levels of investments to meet business values while mitigating identified risks
- Determine the cost and benefits for each level
- Prioritize the levels across all areas
- Assess the results and build the investment plan

These steps are described in the remainder of this exhibit.

2.1 Business Values

The Business Values (BVs) are designed to enable the achievement of the strategic goals set out in Exhibit A, Tab 3, Schedule 1. They form the basis of the criteria used to develop investments, manage risk and facilitate trade-offs between investments.

BVs are defined by key success factors and measured by a set of key performance indicators (KPIs). The BVs and associated key success factors represent the objectives that are to be factored into the decision making, while the KPIs represent how the impact on the BVs is to be measured. The table below shows the BVs and KPIs used in 2007 to establish the 2008 investment plan proposal.

Table 1
Business Values, Key Success Factors and Key Performance Indicators

Business Value (BV)	Key Success Factor	Measure / Key Performance Indicator (KPI)
Safety and Environment	Keep our People, Service Providers and the Public Safe; Limit Impact on the Environment	• Deficiencies in Health and Safety Managed System • Public Safety • Environmental Impact
Customer	Improve Overall Customer Satisfaction	• Customer Satisfaction Survey
Reliability	Ensure Reliable Delivery of Electricity	• SAIDI • SAIFI
Financial	Meet Hydro One's Profitability Target	• Net Income • Net Present Value
Efficiency & Effectiveness	Increase Hydro One Competitiveness	• Work Program Accomplishment • Unit Cost Reduction • Competent and Skilled Staff
Reputation	Strengthen Hydro One's Reputation	• Public Profile • Shareholder Confidence
Regulatory Relationship	Meet All Compliance Standards	• Regulator's Confidence • Distribution System Code Requirements • Legal Violations

The KPIs form the basis of the multi-criteria analysis used to prioritize investments by measuring the impact on BVs if the associated investment is not made. For each impact level, there is a likelihood of the impact occurring. The process incorporates a five-point scale to determine the impact ratings for each KPI: Minor, Moderate, Major, Severe and Worst Case.

BVs, success factors and KPIs are reviewed yearly to ensure that they remain aligned with Hydro One's strategic goals. The review follows the strategy phase of the overall planning process (see Exhibit A, Tab 14, Schedule 1). Following the review, strategic goals, BVs, success factors and KPIs are formally issued to contributors to the investment prioritization process.

2.2 Multiple Investment Levels

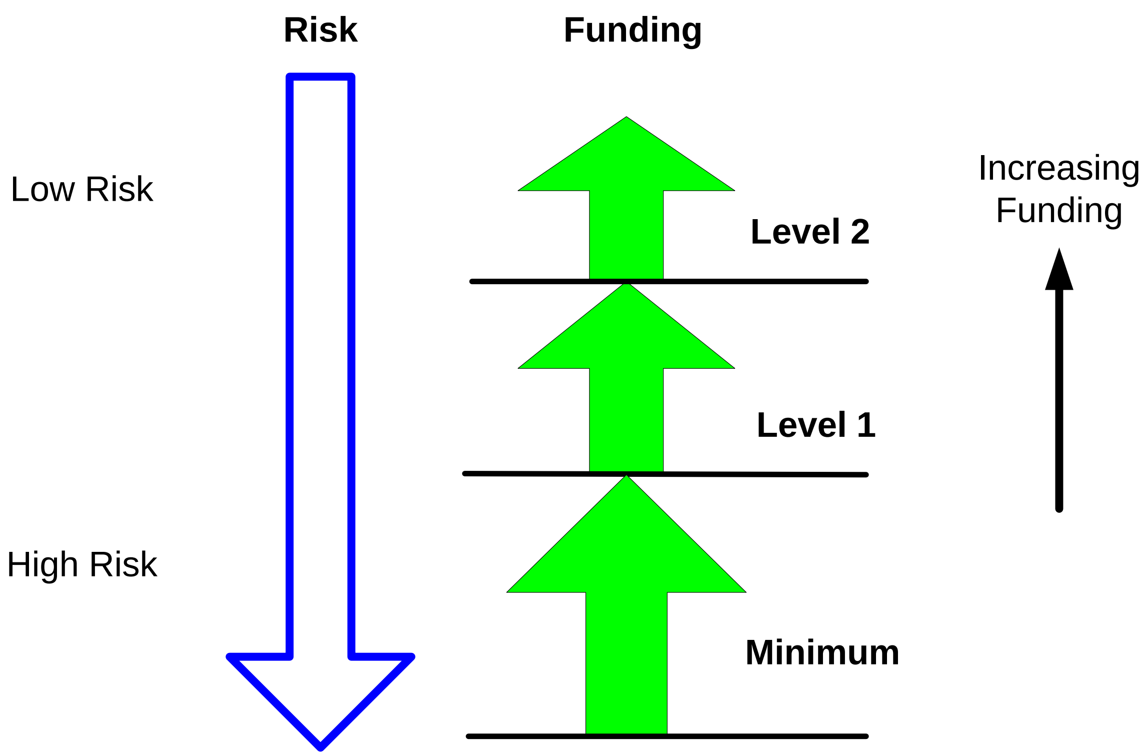
Customer, asset and business needs, risks and objectives guide ongoing planning activities. Investment proposals are developed to address these needs, risks and objectives, which are then input into the prioritization process. However, the scope and level of most investments – and the accomplishments those investments deliver – will vary depending on the level of risk mitigated. Therefore, besides prioritizing investments that address different needs, risks and objectives, there is also a need to prioritize different levels of accomplishments within an investment area.

Increasing levels of accomplishment representing decreasing levels of risk to the BVs are established for each area. For example, increasing investment funding so that 7,000 substandard wood poles are replaced in a year compared to a level of funding which results in replacement of 4,000 substandard wood poles results in a lowering of risks related to reliability and safety. In other cases, reduced accomplishment levels can create longer term sustainability issues, resulting in higher long term costs. There are also minimum levels of accomplishment which are necessary to avoid unacceptable risk to the

BVs. For example, if accomplishments fall below a certain level for a particular program, meeting applicable safety, regulatory or legal requirements may be at risk. In the example above, the prioritization process could identify that replacing less than 4,000 poles per year would represent an unacceptable reliability and safety risk. Another example would be accomplishments necessary to meet the minimum requirements prescribed by the Distribution System Code.

The approach is illustrated in Figure 1 below.

Figure 1
Accomplishment Levels versus Risk



Accomplishment levels are established and evaluated for a period of five years to allow for, among other things (see section 2.5 below), the long-term management of resources. Short-term constraints, such as scheduling of skilled staff or outages, are also considered when establishing the levels of work that are undertaken.

2.3 Investment Costs and Benefits

Total funding requirements to carry out the accomplishments established for each level of investment are determined using current year costs as the basis.

In some cases, there are identified linkages between particular investment areas which are factored in to the plans for those investment areas. For example, additional vegetation management accomplishments should over time reduce the number and extent of trouble calls and damage during storms, thus reducing the future funding required for trouble calls and storm damage. The total net cost is used in the resulting investment plan.

The benefits of each investment are determined by its level of accomplishment and its ability to mitigate risk to the BVs. The KPIs provide a common set of criteria to measure the impact, or consequence, of the investment on the BV. However, risk is the product of the consequence and the probability of occurrence, so this probability also has to be established. The process makes use of five likelihood ratings to establish probabilities: very likely, likely, medium, unlikely and remote. BV risk is identified in a two-dimension table as shown in Table 2. Using this approach, the change in risk for each BV as a result of the investment is established.

Table 2
Business Value Evaluation Matrix

	Minor	Moderate	Major	Severe	Worst Case
Very Likely (>95%)				**Unacceptable Risk Zone**	
Likely (65 to 95%)					
Medium (25 to 65%)					
Unlikely (5 to 25%)		Decreasing Risk			
Remote (< 5%)					

2.4 Investment Prioritization

The needs, objectives, accomplishments, costs, and risk assessment for each level of investment are documented. Asset managers and other stakeholders within Hydro One then review the information. The review ensures the full integration of the numerous investment proposals, and uniformity in the use of the risk assessment model.

The information provides the necessary cost and risk mitigation data required to conduct the prioritization. All investment levels are prioritized, with the exception of the minimum levels, which are automatically placed in the investment plan proposal. The prioritization methodology then gives priority to investments based on their ability to mitigate significant risk to the BVs.

A preliminary investment plan proposal is prepared based on the results of the prioritization of capital and OM&A investments. The proposal reflects considerations related to how effectively the investments mitigate risk to the BVs, and overall affordability of the proposal. The previous year's business plan is used as a reference point.

The preliminary investment plan proposal is assessed by Senior Management, where the residual risk to the business (i.e., the risk to the BVs that remains after the investments are made) is considered before the final investment plan proposal and associated funding requirements are established.

2.5 Investment Plan and Redirection

A five-year planning period is used for the investment plan proposal. A shorter period would not adequately recognize those investments that tend to deliver benefits over longer periods. This is particularly the case for investments that maintain or replace existing assets. The five-year period also allows for the longer term management of resources and allows for redirection of investments between years.

While the investment plan proposal is the product of extensive planning and analysis, it must at the same time be dynamic and flexible. Redirection may be required for a number of reasons, including changing customer needs, changing asset priorities based on new information, changing external requirements, major events (e.g., extensive storms, equipment failures), and affordability issues. All of these considerations can impact on the subsequent business planning process. This is why the actual plan that is implemented may be modified during the business planning process, and also throughout the year as new risks or opportunities emerge, conditions change, and priorities shift. This redirection of work allows adjustments to be made to the investment plans. For example, distribution line emergency restoration work required to repair damage caused by storms or equipment failures can be significant in any given year, and it is imperative to redirect the required funds and field resources from other investment areas to correct the damage.

SERVICE QUALITY INDICATORS

1.0 INTRODUCTION

Hydro One Distribution monitors and reports service quality indicators as required in Chapter 15 of the Ontario Energy Board 2006 Electricity Distribution Rate Handbook. The six customer service indicators and three service reliability indices are tracked monthly. Results are reported internally on a monthly basis. Reports are provided to the OEB annually in accordance with the 2006 Electricity Distribution Rate Handbook.

Hydro One Customer Service and Service Reliability results and targets from 2004 to 2008 are shown in Tables 1 and 2. Over the historical period, Hydro One Distribution met all OEB targets with the exception of one reliability measure in 2004 excluding *force majeure*[1] impacts.

1.1 Customer Service Indicators

Hydro One consistently tracks, analyzes and reports the six customer service indicators on a monthly basis as part of our internal performance scorecard process. This process identifies areas of concern so that they can be immediately addressed and brought back in line with OEB requirements.

Analysis of monthly and annual result trends provides valuable information for corporate planning, program planning and services management of resources.

The definitions of these indicators are provided in Section 2.1.

[1] Hydro One deems a *force majeure* to have occurred when 10% or more of Hydro One customers have been interrupted by an event. See Page 4 for further information about *force majeure*.

1.2 Service Reliability Indicators

Customer interruptions are analyzed and reported internally throughout the year.

Interruption data is collected and recorded in the Distribution Operations & Maintenance Centre (part of Ontario Grid Control Centre), through communications with field staff involved in the interruption restoration. It is input into a database system called Outage Response Management System which provides data for in-depth performance analysis to drive strategy and business investment decisions.

Interruption data is used to calculate OEB reliability indices (see Section 2.2 for definitions) monthly which are reported internally.

There is ongoing analysis of approximately 40,000 annual interruptions. Trends of frequency, duration, cause of interruptions, feeders, location, etc. are analyzed to allow prioritization of maintenance, sustainment and capital programs on the distribution system.

2.0 DEFINITIONS

2.1 Customer Service Indicators

The six Customer service indicators are as follows:

2.1.1 <u>Appointments:</u>

The percentage of appointments met (as requested in the morning or afternoon of a particular date) includes appointments for high bill investigations, engineering investigations, change service only and meter readings.

2.1.2 Connection of New Services:

The percentage of customer connections of new services completed within 5 working days from the day on which all conditions of service are satisfied.

2.1.3 Emergency Response:

The percentage of responses to emergency trouble calls (including fire, ambulance, police) met within 120 minutes for Rural utilities, and 60 minutes for urban utilities. Due to the predominantly rural nature of its distribution system, Hydro One Distribution is required to meet the 120 minutes response time. The elapsed time is measured from the call to the arrival of Hydro One qualified service personnel.

2.1.4 Telephone Accessibility:

The percentage of calls answered by the call center within 30 seconds.

2.1.5 Underground Locates:

The percentage of underground cable locates completed within 5 days. The days elapsed is measured from the customer service request until the completion of the underground cable locate.

2.1.6 Written Response to Inquiries:

The percentage of responses to customers' (or an agent of the customer) requests for written information regarding their accounts that are met within 10 days of the request.

2.2 Service Reliability Indicators

The three Service Reliability Indicators are:

2.2.1 Frequency of Interruptions (SAIFI):

The average number of times that Distribution customers served by Hydro One were interrupted in the year.

2.2.2 Duration of Interruptions (SAIDI):

The average numbers of hours that Distribution customers served by Hydro One were without power in the year.

2.2.3 Average Interruption Time (CAIDI):

The average interruption duration (in hours) of Distribution customers who were interrupted.

The above reliability indices measure all interruptions caused by planned and unplanned interruptions of 1 minute or more.

2.3 Force Majeure

Hydro One deems a *force majeure* to have occurred when 10% or more of Hydro One customers have been interrupted by an event.

An event may be a storm (usually the case), the Aug 14 blackout or any other problems that interrupt 10% or more customers and cause a change in the normal restoration business processes.

All Hydro One customers interrupted throughout the duration of the event while normal restoration business processes are suspended are counted in the determination of the numerator of the percent interrupted. The denominator is the total number of customers served at the end of the month when the force majeure occurred. Details of all *force majeure* events that have occurred from 2004 to 2006 are provided in Section 3.2.

3.0 RESULTS

The results of the six Customer Service Indicators and the three Service Reliability Indicators are attached in Tables 1 and 2 respectively.

3.1 Customer Service Indicators

Table 1 indicates customer service results, overall, remain consistent over the historical period and are better than the minimum OEB targets.

Table 1
Customer Service Indicators

Performance Measure	OEB Target	2004 Actual	2005 Actual	2006 Actual	2007 OEB Target	2008 OEB Target
Appointments (% met as agreed with customer)	**≥ 90**	**93**	**90**	**92**	**≥ 90**	**≥ 90**
Connection of New Services (% completed in ≤ 5 days)	**≥ 90**	**94**	**93**	**91**	**≥ 90**	**≥ 90**
Emergency Response (% responded to in ≤ 120 min)	**≥ 80**	**91** **90***	**86** **73***	**92** **65***	**≥ 80**	**≥ 80**
Telephone Accessibility (% answered in ≤ 30 seconds)	**≥ 65**	**74**	**72**	**77**	**≥ 65**	**≥ 65**
Underground Cable Locates (% completed in • •5 days)	**≥ 90**	**93**	**93**	**92**	**≥ 90**	**≥ 90**
Written Response to Inquiries (% responded to in ≤ 10 days)	**≥ 80**	**100**	**100**	**100**	**≥ 80**	**≥ 80**

*Emergency Response results including the impact of Force Majeure. The values without the * are the values with *force majeure* removed.

3.2 Service Reliability Indicators

Table 2 shows that through the period 2004 to 2006, SAIFI remained relatively constant at or better than the minimum OEB target, excluding *force majeure* impacts with one exception. However, in 2004, SAIFI missed the OEB target due to exceptional weather. During December 2004, six large impact weather systems passed through the province over 14 days. In total, these weather systems impacted 26% of customers and added 0.3 to our SAIFI, however no single weather system met the *force majeure* criteria. The worst storm impacted 7% of our customers. Our December SAIFI result of 0.4 is significantly higher than our seven-year historical December average of 0.2.

Table 2
Service Reliability Indicators

Performance Measure	2004 OEB Tgt	2004 Act	2005 OEB Tgt	2005 Act	2006 OEB Tgt	2006 Act	2007 OEB Tgt	2008 OEB Tgt
SAIFI *Frequency of Interruptions* (#of interruptions per customer)	• •3.0	3.1	• •3.1	2.9	• •3.1	2.9	• •3.1	• •3.1
SAIFI including *Force Majeure*		3.2**		3.9†		5.2††		
SAIDI *Duration of Interruptions* (hrs of interruption per customer)	• •9.4	6.5	• •9.4	8.0	• 8.0	7.1	• •8.0	• •8.0
SAIDI including *Force Majeure*		6.9**		14.5†		28.4††		
CAIDI *Average Interruption Time* (#of hrs per interruption)	• •3.1	2.1	• •3.0	2.8	• •2.6	2.4	• •2.6	• •2.6
CAIDI including *Force Majeure*		2.2**		3.7†		5.5††		

**See explanation in section “2004 Force Majeure Events”
† See explanation in section “2005 Force Majeure Events”
†† See explanation in section “2006 Force Majeure Events”

Over the same historical period SAIDI has varied from 6.5 to 9.4 hours. The 2004 results represent a significant improvement over OEB targets for duration of outages. The good performance was a result of fewer significant events lasting longer than 4 hours resulting in a 50% improvement in the duration values for these types of interruptions, as well as our operational focus on reliability.

The SAIDI performance over the 2004-2006 period drove a similar performance in CAIDI. Since CAIDI is dependent on both SAIDI and SAIFI (mathematically CAIDI = SAIDI / SAIFI), the reduction in SAIDI (i.e. the duration of interruptions) and the consistency of SAIFI (i.e. the number of interruptions) resulted in a reduction in CAIDI (i.e. the average interruption duration).

The consistencies in reliability (i.e. SAIDI, SAIFI and CAIDI) are credited to the focus that was placed on distribution reliability and the number of improvement initiatives that continue to be undertaken such as:

- Detailed feeder analysis to assess feeder reliability and customer impact and develop the appropriate investment recommendations,
- Assigning of crews to summer peaking storm locations to improve storm response time, and
- Scheduled work in high probability storm locations to improve restoration time.

3.3 2004 Force Majeure Events

In 2004 there was only 1 *force majeure* event that met the 10% of customers affected definition. This was the result of a storm on April 18 & 19, 2004 that interrupted 10.4 % of our customers. A violent spring storm brought high winds gusting up to 85 km/h and thunderstorms to Central and Southern Ontario. Winds were strong enough to uproot trees and ruin barns.

The effect of this storm resulted in a contribution to the annual SAIDI of 0.4 hours and annual SAIFI of 0.1 interruptions per customer, with a CAIDI of about 4.0 hours.

3.4 2005 Force Majeure Events

In 2005 there were four *force majeure* events that met the 10% of customers affected definition. The storms occurred on April 2nd, September 29th, November 10th and

November 13th. Each of those days, respectively they interrupted the following percentages of customers: 23%, 15%, 35% and 23%.

On April 2nd to 4th, 2005 a storm consisting of wet snow, freezing rain and high winds caused widespread damage in Southern Ontario, 23% or about 265,000 customers were affected.

On September 29th to 30th a fast moving storm front crossed Southern Ontario with high winds and rain/thunderstorms affecting 15% or about 172,000 customers.

In November there were two back to back fast moving storm fronts. On November 6th to 10th the first storm crossed Southern Ontario with high powerful winds and rain/ thunderstorms that affected 35% or about 409,000 customers.

The second front crossed from Georgian Bay to the Quebec border on November 13th to 17th again with high winds and snow, rain/thunderstorms affecting 23% or about 266,000 customers.

The effect of these storms resulted in a contribution to the annual SAIDI of 6.5 hours and annual SAIFI of 1.0 interruption per customer, with a CAIDI of about 6.5 hours.

3.5 2006 Force Majeure Events

In 2006 there were eight *force majeure* events that met the 10% of customers affected definition. The storms occurred on February 4th, February 16th, March 13th, July 17th, August 2nd, September 24th, October 28th and December 1st Each of those days, respectively they interrupted the following percentages of customers: 44%, 13%, 10%, 42%, 47%, 29%, 14% and 23%.

On February 4th to 8th, 2006 a storm consisting of heavy wet snow and wind (up to 60 km/hr) spread across the province from Lake Huron to Sudbury to Ottawa causing widespread damage in Southern Ontario affecting 44% or about 505,000 customers.

This was followed on February 16th to 17th with rain, freezing rain, snow and winds up to 75 km/hr affecting 13% or about 155,000 customers in an area from Windsor to Ottawa.

On March 13th to 15th a storm throughout Southern Ontario had winds gusting up to 80 km/hr, torrential rains, diving temperatures and snow squalls affecting 10% or about 120,000 customers.

The storm starting on July 17th with restoration efforts to the 22nd, was labeled by Environment Canada as the third worst storm in Canada in 2006. This southern Ontario storm of high winds (up to 80 km/hr), rain and thunderstorms that left a swath of damage about 400 km long affecting 42% or about 483,000 customers.

August 2nd to 9th, 2006 was also included in Environment Canada's third worst storm list. This storm system triggered 10 tornadoes as it hop scotched through cottage country and into Quebec affecting 47% or about 545,000 customers.

On September 24th to 30th, severe winds gusting up to 90 km/hr, started at Georgian Bay and moved east across the province affecting 29% or about 334,000 customers

October 28th to 29th saw an early winter storm consisting of snow and winds gusting up to 100 km/hr move from Georgian Bay and North Eastern Ontario to Ottawa affecting 14% or about 164,000 customers

December 1st to 3rd had snow, freezing rain and winds gusting up to 50 km/hr affecting 23% or about 264,000 customers throughout Southern Ontario.

The effect of these storms resulted in a contribution to the annual SAIDI of 21.3 hours and annual SAIFI of 2.3 interruptions per customer, with a CAIDI of about 9.3 hours.

DISTRIBUTION BENCHMARKING STUDIES

In its Decision on Hydro One's 2006 Distribution rates (RP-2005-0020/EB-2005-0378, dated April 12, 2006), the Ontario Energy Board directed Hydro One to engage an independent party to develop a list of comparable North American companies with similar business models, to submit a report on high level comparative performance and cost information for Hydro One and these companies as part of its next Distribution rate application. The Board also directed the submission of a comparison of labour rates and overtime policies amongst Hydro One, other comparative Ontario electricity distributors and other Canadian utilities as identified in the high level benchmarking study.

Accordingly, Hydro One engaged independent consultants to provide the expertise and experience needed to complete the necessary studies. The PA Consulting Group and Hay Group were selected to undertake the Distribution Benchmarking and Comparison of Labour Rates and Overtime Policy studies, respectively.

Distribution Benchmarking Study

The resulting high level Distribution Benchmarking study, Attachment A to this Exhibit, presents the results of Hydro One Distribution's performance among 13 "peer" utilities in North America, across a range of cost, reliability and safety measures. When measures are utilized which take into account the long, radial nature of Hydro One's distribution system and the low customer density of its service territory, overall performance is good to very good.

Comparison of Labour Rates and Overtime Policy Study

The Comparison of Labour Rates and Overtime Policy study is Attachment B to this Exhibit. As part of its response to the OEB directives on benchmarking from the 2006 Distribution rates proceeding, Hydro One met with stakeholders as part of the process for preparing its 2006 Transmission application to get guidance on the positions to be benchmarked and the approach to be taken in this study. Consequently, this study compares three representative utility job functions among 14 “peer” Canadian electrical utilities. In Hydro One these positions, which represent a large component of its workforce, are staffed by three different employee groups: trades (Power Workers Union), professional (the Society), and management. It should be noted that executive positions are not considered in this study as their future compensation will reflect the Government-directed implementation of its Agency Review Panel (the “Arnett Panel”) recommendations in this matter.

The benchmarking study compares the range of minimum to maximum hourly wages for each of the three representative utility job functions. The results indicate that Hydro One’s management function (Field Operations Manager position) wage is below the sample average; the professional function (Design Engineer position) wage is at about the sample average; and the trades function (Powerline Maintainer position) wage range is below the sample average minimum and above the average maximum.

In terms of overtime policies, the survey results show that Hydro One is in line with the majority of survey respondents for each of the three positions.

Customer Care Services Benchmarking

The Customer Care services delivered through the outsourcing contract with Inergi LP are not included in the benchmarking studies being conducted for this Application. These services include contact handling, billing, collections, and other back-office support activities, which were part of the Customer Service Benchmarking Report, *Review of Hydro One-Inergi Customer Service Pricing*, completed in 2005 and submitted to the Ontario Energy Board during the Hydro One Distribution 2006 rate proceeding, RP-2005-0020/EB-2005-0378. The results of the 2005 benchmarking study showed the annual prices paid by Hydro One for Inergy's services were within 1% of the average fair market value. As such, no additional benchmarking was pursued beyond that required in the Inergi agreement, which established benchmarking at years three, six and nine, of the 10-year agreement. The year six benchmarking is planned to be initiated in the last quarter of 2007.

PA Consulting Group

Hydro One

Distribution Benchmarking Study Using Information from 2004-2006

October 24, 2007

Hydro One

Distribution Benchmarking Study Using Information from 2004-2006

October 24, 2007

Prepared by: Ken Buckstaff

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1. EXECUTIVE SUMMARY

Hydro One commissioned execution of a high-level Distribution benchmarking study, with the purpose of understanding its relative position among a group of "peer" utilities across a range of cost, reliability, and safety metrics. PA Consulting Group has performed that study, with the attached report as the result. We briefly outline below the approach taken to the study, the types of results found, and some steps to be taken in the future.

Background and Study Objectives

Hydro One was asked by the Ontario Energy Board to perform a high-level benchmarking study in support of revenue requirements in a rates proceeding. That request came as part of the decision published April 12, 2006 by the OEB in response to Hydro One's Distribution Rates Application and was reinforced in the recent decision on Hydro One's Transmission Application. Hydro One took the opportunity to perform the study to meet the directive of the OEB, while at the same time investigating two specific areas within its distribution operations (vegetation management and meter reading) that may offer improvement opportunities.

Approach

The approach followed a direct series of steps designed to identify an appropriate peer panel of utilities for comparison while simultaneously selecting a group of performance measures for tracking the performance of the companies. These steps were followed by data collection from the selected peer group of companies, and summary and analysis of the resulting data. The summary consisted of development of charts and graphs showing the outcomes for the performance measures, and then review of what those results say about the performance of Hydro One.

A key element of the approach to the project was in selecting the appropriate metrics for tracking success in a distribution company characterized by a very low density service territory. A low density territory requires substantial amounts of electric system assets to serve each customer, and therefore the appropriate performance metrics are required to address that fact of the electric system. Measures based on, or normalized by, the length of distribution lines are appropriate for a company like Hydro One.

Findings and Conclusions

The overall results of the benchmark comparisons are the following:

Cost

When compared on a per-km of line basis, Hydro One's costs are in line with the norm of the group, and in some cases even leading. Their costs are higher than average for the comparison panel when measured on a per-customer basis. Where capital spending is concerned, particularly with respect to per-km metrics, the costs are below the mean for the group.

Asset Replacement Rate

Hydro One's asset replacement rate is low in comparison to the group. This is measured in terms of the amount of capital spending in relationship to the existing asset base. A very low value for the long term could indicate underinvestment in the electric system.

Reliability

When the reliability figures are normalized for the km of line, Hydro One's performance is in line with the norms of the group. Hydro One has comparatively poor reliability within the panel group, when measured by metrics such as SAIDI and SAIFI.

Safety

Safety performance for Hydro One is overall about average for the group of utilities who reported data for the study, but the results are mixed. When reviewing recordable incidents, Hydro One falls above (worse than) the average performance for the panel of companies. On the lost-time incident rate, Hydro One is significantly better than the average of the group.

Meter Reading

Meter reading costs for Hydro One are relatively low compared to the panel, when normalized by distance. When viewed on a per-customer or per-read basis, the costs are very high. This is reasonably explained by the very low density of the territory, which leads to long distances, either walking or driving, between meters for reading.

Tree Trimming

For vegetation management, the Hydro One costs are higher than the average for the comparison panel. The service territory demographics (e.g. size and density of territory, vegetation coverage, electric system configuration) substantially influence the performance results for this area.

Summary

The study has produced some useful results for the company. In particular, the results provide an accurate portrayal of the performance of the company, while at the same time demonstrating the importance of measuring and reporting performance in an appropriate manner to fit the individual situation for each utility. Hydro One's service territory has some unique characteristics, most notably its low density, and the performance of the company appears different depending on whether or not those characteristics are taken into account in measuring performance. Overall performance of the company rates as "good to very good" when performance is normalized by the volume of assets (e.g. km of line). However, when measures that are normalized by customer base (e.g. spending or customer hours per customer served) are used, Hydro One performance appears to be less efficient. The low density/rural nature of the Hydro One system leads to this, since customer-normalized metrics tend to favor higher density systems.

In using the results of this (or any other benchmarking study), it is important to understand both the benefits and limitations of the work. This is a high-level study, and it is important to take care in analyzing and applying the results, assuring a substantial degree of understanding of the underlying data and analysis.

2. INTRODUCTION

2.1 STUDY BACKGROUND

The Ontario electricity industry has undergone significant restructuring over the past seven years. On December 9, 2004, the Ontario Legislature passed the *Electricity Restructuring Act, 2004* to stabilize prices for consumers that reflect the full cost of electricity, facilitate new supply additions, and promote conservation and demand management. The act also created the Ontario Power Authority (OPA), which has a mandate to ensure an adequate, long-term supply of electricity in Ontario. Under the new market structure, wholesale electricity consumers pay a blend of regulated, contracted and wholesale spot market prices for electricity.

The Transmission and Distribution Businesses are separately regulated by the Ontario Energy Board (OEB); and cost allocation approaches are used within the company to appropriately assign costs to the Businesses. The OEB sets rates in proceedings through oral or written public hearings based on the level of revenue required to operate the regulated businesses and to earn the approved rate of return. The OEB, in its April 12, 2006 decision regarding Hydro One's Distribution Rates Application, identified a desire for Hydro One to pursue additional benchmarking studies. The OEB directed Hydro One to submit the results of these studies with the next Distribution Rates Application. A specific related excerpt from the April 12th Distribution rates decision is as follows:

> "While the Board is not prepared to order a comprehensive benchmarking study, the Board sees value in a high level benchmarking study for initial review at the next rate proceeding. The Board directs Hydro One to engage an independent party to develop a list of comparable North American companies with similar business models (transmission and/or distribution) and to report on high level comparative performance and cost information for Hydro One and these companies. In future rate cases, this information may assist with determination of areas for a more comprehensive benchmarking review. The Board does not anticipate that the high level benchmarking study will be overly costly. The Board anticipates that Hydro One will want to consult with interveners regarding the scope of the study. The independent study should be submitted as part of Hydro One's next main application for distribution rates."

With the above information as the drivers, Hydro One Networks, Inc. has prepared a filing in support of a rate review, as directed by the OEB. Hydro One engaged PA Consulting Group as the "independent party" identified above to perform a benchmark study of distribution companies with similar characteristics to Hydro One. This report summarizes the execution of that study, and the resulting conclusions.

The OEB reinforced the need to carry out performance benchmarking studies in their decision on Hydro One's 2007and 2008 Transmission Business Revenue Requirement Application and stated they expect the performance and compensation benchmarking study deficiencies in past studies will be corrected for 2009 Transmission rate filing if not possible for 2008 Distribution filing.

2.2 GOALS AND OBJECTIVES

The primary goal of the study was to provide a high-level set of benchmarks of cost and business performance for Hydro One that could be used in the 2008 Distribution rates proceeding. This involved determination of how to select both an appropriate comparison panel of utilities and an appropriate set of performance measures for use in the comparisons. Appropriate peer utilities in this case means, to the extent possible, those whose operating circumstances are similar to those faced by Hydro One, so that the resulting performance results can be compared with minimal levels of adjustment. Appropriate performance measures means a sufficient sample of measures which accurately represents the overall performance of the distribution utility, recognizing the need for a balanced view, including costs, service levels, and employee safety.

2.3 THE PROJECT TEAM

The project team that performed the study was made up of consultants from PA Consulting Group, augmented by a few of its former employees, and with input from several individuals from Hydro One. The consultants were drawn from the team that created and performed for many years the annual PA Benchmarking studies, while the Hydro One individuals were from the Performance Analysis Department within Hydro One. The support provided by Hydro One was primarily with respect to scope of the study, and to provide Hydro One operations data for comparison against those of the other utilities in the comparison panel. The PA team then executed the study, analyzed the results, and prepared this report.

The primary reason PA Consulting was selected for the engagement is because of their experience in executing benchmarking studies in the utility industry. The two primary consultants engaged in the project have between them almost 40 years of experience in performing such studies, including developing appropriate performance metrics and analyzing results across a broad array of different companies. Many of the elements of comparison for this project were built on the experiences of the project team in executing other studies in the past.

Ken Buckstaff was the primary architect and leader of an electric transmission & distribution benchmarking study which has been run annually since 1989, and similarly developed and led an annual utility customer service study since 1992. In the course of performing those studies, it was possible to build and test dozens of hypotheses about the various impacts of density, size, voltage levels and many other variables on the resulting performance of utilities.

Debi McLain has been the key person actually performing the data handling and analytics for the annual benchmarking studies described above for the past 18 years. Her deep familiarity with the kinds of data availability and potential inaccuracies is invaluable in assuring that proper comparisons are made and that appropriate data are used.

Understanding the interactions between different elements is a critical point in being able to produce appropriate benchmark studies, including the right types of performance metrics, ways to evaluate success based on individual company circumstances, and how to assure the right demographics are considered. In addition to the annual studies, the project team for this engagement has performed dozens of individual benchmark studies ranging in scope from high-level studies such as the one that is the subject of this report down to very detailed analyses of the best practices in place for such narrowly-scoped subjects as substation maintenance or construction project management. That experience makes the team uniquely qualified to execute this project for Hydro One.

2.4 ABOUT HYDRO ONE

Hydro One is a unique distribution company in many ways, from the organization and operating structure to the regulatory regime it works under to the physical circumstances of its service territory. The service territory situation particularly drives a lot of the management and operating decisions, as well a much of the results achieved in terms of costs and service levels. A few of the external circumstances which have an impact on the results achieved by the company include the following:

- Large, low-density service territory
- Weather patterns
- Tree density/vegetation
- Operating structure

Described below are some of the impacts of these features.

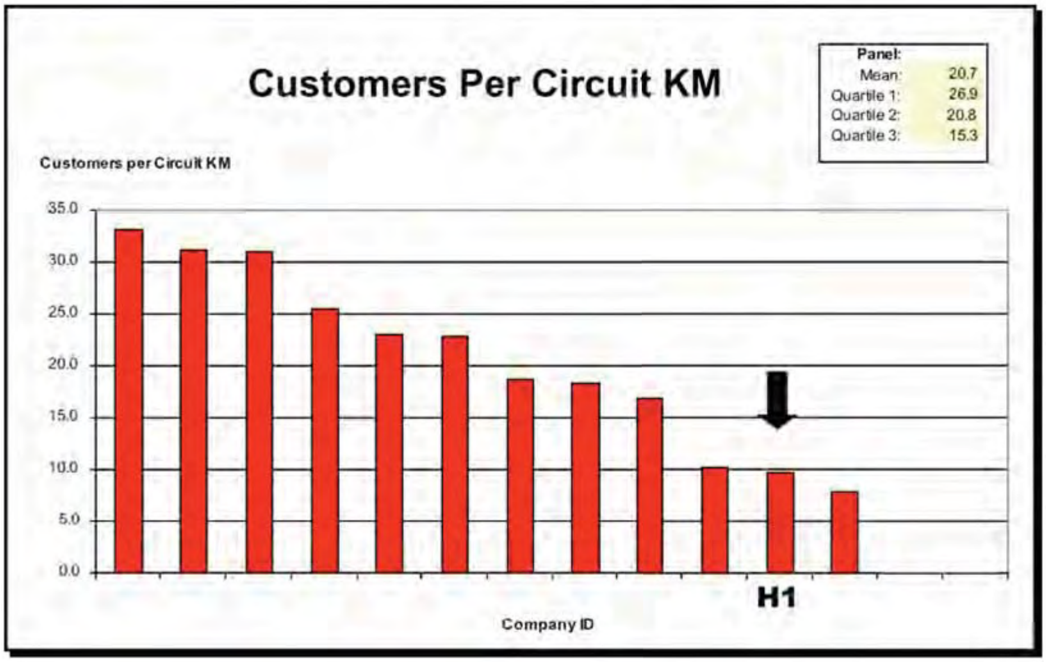
2.4.1 Large, low-density service territory

The Hydro One service territory is very large, with extended geographical areas with very few customers. In selecting utilities for comparison to Hydro One, it was a challenge to find others with the low density that characterizes Hydro One's territory. The sheer size of the territory imposes some requirements on the company for staffing in remote locations, including people, equipment, and facilities, all of which are difficult to effectively utilize at the level that would be possible in a more densely-populated area.

The chart titled "Customers per circuit km" highlights the customer density situation for the utilities in a panel of companies selected for comparison to Hydro One. As can be seen, Hydro One (black arrow) is at the low end for density, even within a selected a panel of companies with similar characteristics.

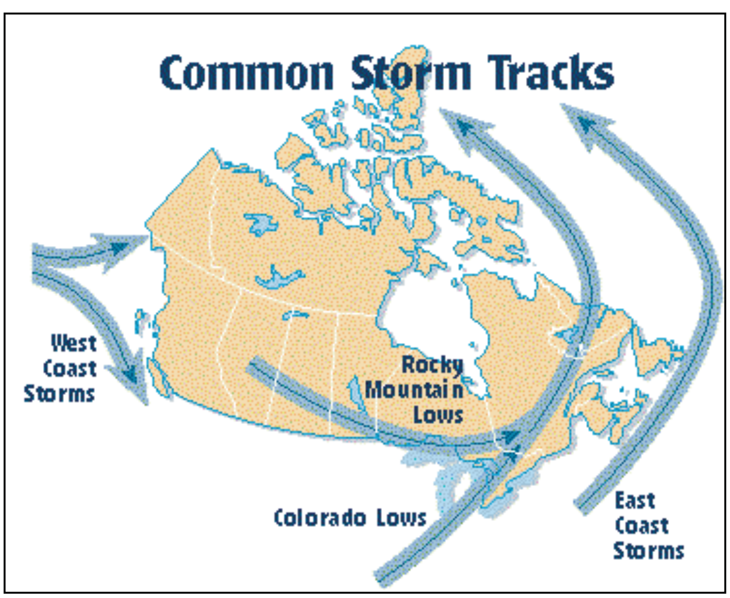
The low density of the service territory also imposes some practical realities on the design of the electric system. The costs associated with putting lines underground are economically unjustifiable for the majority of the Hydro One electric system, with long lines serving relatively few customers. Similarly, it is most economical to design the system in a low density area as a radial-feed system for most of the circuits. The net result is a radial-design, overhead-line system which has substantial exposure to weather, trees, and ordinary wear and tear that might be avoided or minimized in a different service territory.

The system design affects both the costs and reliability achievable by Hydro One. With substantial exposure comes a higher outage frequency for the system. With the long drives to get to parts of the system comes extended outage durations. The net result is poorer reliability than might otherwise be the case.



2.4.2 Weather Patterns

Hydro One is in an area of North America which experiences some weather extremes. Prevailing storm patterns that come across the Hydro One service territory include both the Rocky Mountain Lows and the Colorado Lows, as shown in the map below. Both of these affect the Hydro One customers around the Great Lakes. The Colorado Lows tend to cause the most severe damage to the Hydro One Distribution system.

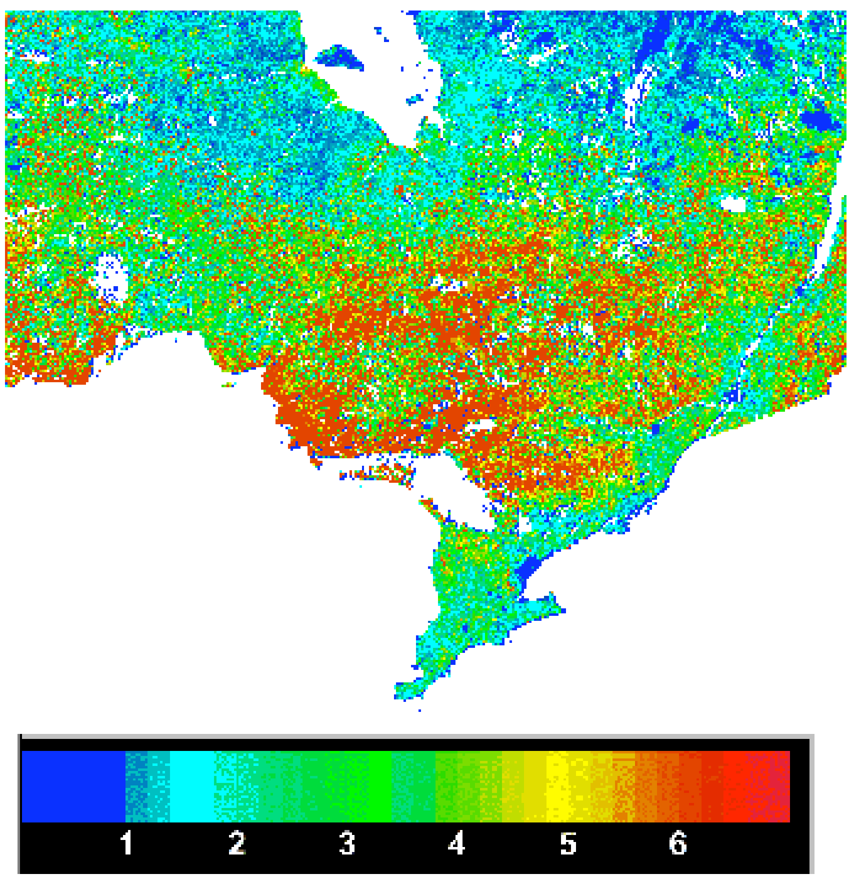


Hydro One's province-wide presence results in a situation where a major storm can actually impact multiple locations in the service territory. The net effect of these storm patterns is a regular storm frequency that is higher than many other utilities in North America experience. In turn, that high frequency and severity of storms creates reliability problems for Hydro One.

2.4.3 Tree Density/Vegetation

Another important factor in electric system operation and performance is the density of forestry within the service territory. Trees tend to have both a cost and reliability impact on an electric system. Failure to trim the trees adequately leads to reliability problems, when tree limbs contact the electric lines. Trimming the trees to keep them from affecting the lines is one of the more expensive activities in the maintenance program. Particularly with a predominantly overhead system, Hydro One's system is exposed to substantial tree-related problems, and the company is therefore required to spend significant amounts of money for this maintenance effort.

The service territory served by Hydro One is characterized by a relatively high density of trees. The leaf index map below shows the concentration of trees in Ontario. As can be seen from the map, Hydro One is affected by a large number of trees that have impact on its electric system. In the map, red (6) is the highest density, with blue (1) low density and most of the red areas in Ontario are serviced by Hydro One. As the map shows, the path of the weather patterns goes through the highest density areas.



Ontario Leaf Density

2.4.4 Operating Structure

The operating structure of the industry within Ontario has some influence on Hydro One. Because Hydro One is the largest distribution company supplying power to most rural locations and local communities that may have their own Local Distribution Company (LDC), there are some responsibilities created which might not otherwise be there. In particular, Hydro One is in the position of providing sub-transmission delivery services and utilizing its distribution network for large deliveries of power to over 30 smaller embedded utilities (LDC's) in the province. The net result of this additional responsibility is that the Hydro One distribution network has to be bigger and more robust than it would need to be to serve the needs of Hydro One alone. The need to build and maintain the line, transformation and spare assets required to service the embedded LDC's makes Hydro One's costs look higher than they might otherwise be if it also had responsibility for serving just end-use customers. The per-customer performance metrics do not always address this issue since the LDC's end-use customers are discounted and instead each LDC is treated as "one customer" for the purpose of normalizing Hydro One's results.

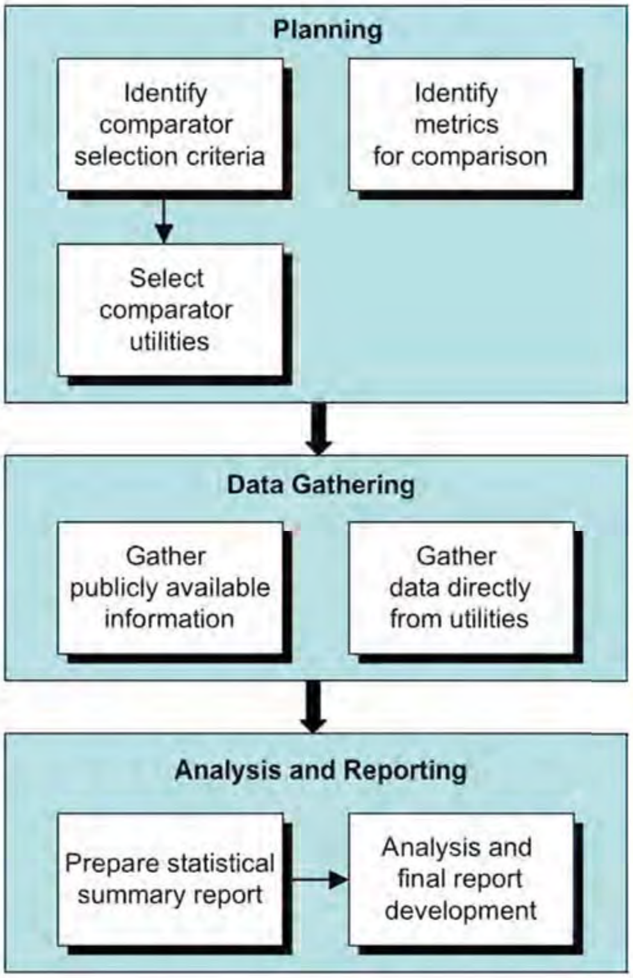
2.4.5 Summary of Introduction

As with every utility, Hydro One has some similarities to other utilities, and some unique characteristics. This introduction has attempted to identify some of the unique aspects of the Hydro One service territory and business situation. In selecting peers for comparison to Hydro One, these features have had influence on the selection criteria, in order to maximize the probability of achieving a true "peer" group. The most important of these characteristics is the low density of the service territory, since that drives the electric system design, and the need to disperse its resources over a wide area. These factors have a substantial impact on the long-term costs of operating the system, as well as the reliability performance of the system. The remainder of this report explains the benchmarking study and outcomes for Hydro One.

3. APPROACH

The approach to this study involved several steps, as shown in Figure 1 below:

Figure 1
Project Approach



The first major step in the project was a planning step, designed to determine the right companies to compare Hydro One against for performance results, and then to determine the right performance metrics for actually making the comparisons. The second major step involved collection of comparative data from all available sources, particularly the comparator companies themselves. The final step in the project was the analysis of the data gathered in the preceding step, developing conclusions leading to this final report.

3.1 COMPARATOR/PEER SELECTION

Using the basic project plan and schedule, the project began with peer selection. This required two major steps. First was development and final agreement as to the appropriate criteria for selecting peer companies. Second required actually applying those criteria against a population of utilities to determine which companies to use for a comparison panel. The key purpose was to find a collection of utilities with similarities to Hydro One, so that the affects of differences of circumstance could be minimized, and the team could focus on the differences in performance levels.

An alternative approach would have been to select from a broader array of potential comparator companies, and then attempt to adjust for the many differences among the resulting comparison panel. Given the difficulties in determining the appropriate adjustment factors for the many external variables which can affect performance, the team concluded that it was better to start with a more comparable panel to begin with.

The project team brainstormed potential selection criteria for use in determining similarity of circumstance, explored each, and then narrowed down the criteria to a relatively small group. The criteria needed to be tight enough to narrow the field of potential comparators, but loose enough to assure a broad enough panel of participants to allow robust comparison and analysis. In order to achieve this large enough final panel, it required the identification of a somewhat larger group of potential comparators than might otherwise be the case, since it is clear that some companies, when approached, would not be willing to participate in this type of study.

The final criteria included:

- Size of company, as measured by
  - Size of service territory
  - Customer Count
  - MWH Sales
  - Number of kilometers of distribution line
  - Distribution capacity
- Geography/weather characteristics (regional location)
- Customer Density
  - Customers per km of distribution line
  - Customers per sq. km
- Business structure (although here the goal was to get some similar and some not-so-similar companies)

The criteria used were as shown in the following table. The specific decision points for each of the criteria are shown in the second column of the table.

Service Territory size	More than 100,000 Sq KM
Customer Count	Between 500k and 5.2M
Customer Density	Fewer than 30 customers per Sq KM

Customers per distribution KM	Less than 40 customers per Pole KM
MWH Sales	More than 30,000,000 MWh Sales
Regional location	Some were chosen for proximity to Hydro One thus sharing weather conditions, others were chosen for similar vegetation density

For the business structure criterion, the goal was to gather some utilities with a fully-integrated transmission & distribution (T&D) wires business, and some with the functions more fully separated. In all cases the goal included companies who supply both Transmission and Distribution, but wanted a mix of operating structures for balance in the peer group.

In the case of the "MWH Sales" criterion, it was used based on publicly available data. Once the companies were selected, the number of MWH *transported* was used as a normalizing factor, rather than the MWH sales. The logic was that the MWH sales was reasonably available and useful for selection, while the MWH transported would be a better normalizing factor, and could be gathered once the study began.

A few additional criteria were suggested, but for either analytic or practical reasons, were not included. An example in this category is the condition of the distribution assets. Without a site visit/survey of each possible utility, it would be impossible to have a proper understanding of the condition of each utility's system, so that criterion, although intellectually appropriate, was rejected as impractical. Using the criteria finally selected, the project team identified a group of North American utilities that fit those criteria, and approached them to participate in the project.

Within the identified group of approximately 35 utilities, we were able to get commitments for participation from a total of 13 of them, in addition to Hydro One. Within that group of 13, not all companies were able to provide all of the data elements desired for the project, but the majority of the questions received enough answers to provide adequate information for comparisons. The group of companies who are represented in the comparison panel for the project includes the following:

- ATCO Electric
- BC Hydro
- Energie NB Power
- Fortis BC
- Hydro Quebec
- Manitoba Hydro
- National Grid
- Northwestern Energy
- Nova Scotia Power
- Oncor Energy Delivery
- Pacific Gas & Electric
- WE Energies
- Westar

Observing the final group of companies, it is a reasonable panel for comparison for Hydro One, and certainly effective for use in providing peer comparisons for the analysis.

3.2 METRIC SELECTION

Metric selection presented the next challenge to the project team. As directed by the OEB the goal was to provide a high-level set of metrics, to allow comparisons of final performance, while also allowing the team to understand differences among the utilities that drive some of the performance differences. A comprehensive set of metrics would allow all the desirable comparisons. Conversely, a brief set of metrics would make the data collection effort manageable, and thereby encourage more companies to participate, as well as meeting the OEB's guidance of a study that would not be overly costly.

The team, drawing upon years of experience in performing benchmark studies for distribution companies, established a provisional set of indicators. It covered the key areas of cost, reliability, and safety. Further refinements resulted in a final listing of metrics which were then pursued through the rest of the study. The final list is shown along with the resulting values in Section 4 of this report.

The metrics the project team decided upon fell into 4 major categories:

- Cost
  - Compared against several normalizing factors (customers, km of lines, asset base, MWh delivered, etc.)
  - Differentiating between investment (capital) versus consumption (expense)
- Asset Replacement Rates
  - Replacement rates are tracked as a means of indicating capital efficiency and asset utilization
- Reliability
  - The primary means of measuring service levels delivered
- Employee Safety
  - Measured using recordable and lost-time incident rates

At a more detailed level, some additional information was gathered about vegetation management, since that is the largest contributor to maintenance costs, and a significant contributor to reliability metrics. Similarly, some information was gathered in the area of meter reading.

The employee safety metrics identified are based on the reports done in the U.S. for OSHA, the Occupational Safety and Health Administration. OSHA specifies the reporting requirements as “recordable incidents” and “lost-time incidents”. Recordables are those incidents which are noted as safety problems, and which typically result in very minor injuries. They are “recorded” in order to highlight the frequency of potentially serious safety incidents. These incidents do not result in the employee needing to take any time off from the job. “Lost-time” incidents, conversely, are in fact injuries that do result in the employee needing to take time off. For most companies, these are much less frequent occurrences than recordable incidents, but of course, they represent more serious injuries.

In the cost and service level categories, care was taken to address the central issue of the Hydro One electric system, the fact of the very low-density service territory. In each of the areas, metrics were selected that track success based on “per-km” values. These give an accurate picture of the performance of the company in terms of the variables they can control.

The asset replacement metrics are measures of investment related to the existing asset base. In the tables in section 4 and Appendix D of this report, the asset replacement metrics are described as “excluding new business”. The point of these measures is to track the amount of money being invested to replace or rehabilitate the existing asset base, not the investment in adding new customers or capacity. To that end, the capital investment for additions of customers has been excluded from the calculation, thus leaving the “replacement capital investment”. While the measure isn’t perfect, because some amount of the replacement capital might also enhance capacity, it is directionally correct, and very useful.

3.3 DATA GATHERING

Data collection also involved a number of steps, with two primary parallel work activities. The first of these was gathering of publicly available data, through use of published financial statements, regulatory reports, and other available information. The second was gathering of data directly from the comparator companies themselves.

Gathering data directly from the target companies began with contacting each potential participant company, both to determine the right individual to work with for the project, and to determine their level of interest and willingness to gather and supply the data for the project.

Following initial contact and solicitation, the participants were provided the partially-completed data collection sheet identifying the information the project required. The companies gathered and verified the information, and submitted it for analysis and inclusion in the report. The data collection sheet provided guidelines and definitions for what costs to include, and how to summarize the data. During the course of the data collection period, it became clear that some clarifications were needed to the guidelines and instructions, and these were provided. The resulting definitions for the data collection are shown in Appendix A to the report. Appendix B provides a listing of FERC accounts that gave guidance for collecting cost data for the project.

The project team determined that the best approach to gathering accurate, representative data would be to assemble data for a 3-year period. Experience in other studies has shown that an individual year might show substantial anomalies for an individual company, both in costs and in other performance areas. For example, a significant one-year investment in construction of a major substation would inaccurately suggest that the company routinely invests large amounts of capital annually, or a large storm that would affect reliability results for that year can skew the outcome for an otherwise relatively reliable electric system. By using a 3-year figure, one-year anomalies can be mitigated. At the other extreme, trying to gather (for example) 5 years of data becomes onerous for the participating companies. 3-year figures were agreed upon as representative of recent, relevant performance, while bypassing the risks associated with a one-year assessment.

3.4 ANALYSIS AND REPORTING

The data were summarized into a statistical report (shown as appendix C to this report) showing the various performance metrics in graphical form, so that each of the companies could see where it stood on the costs and performance metrics. Analysis of the submitted data has led to the development of this report.

Within the analysis of the data that the companies provided, there was a specific need to convert the data to a single currency. The final results have been converted to Canadian dollars for all companies. The currency conversion rates were chosen to fit the three individual years for which we gathered data. Those conversion rates changed about 7% across this three-year period, from 1.22 Canadian$/US$ to 1.13 Canadian$/US$. The net result is that the Canadian companies have tended to look less and less cost-efficient over the three-year period. The exchange rates used for the three years, as provided by the U.S. Treasury Department, are the following:

2004 -- .8178
2005 -- .8759
2006 -- .8818

No adjustments have been made in the analysis for inflation of the costs during the 3-year period. Inflation would have been relatively consistent across the panel of companies, and would therefore not have a significant impact on the relative performance of the companies.

For reliability, industry standard metrics (SAIDI, SAIFI) were used, along with some designed to include the factors associated with extended lines for delivery. The standard metrics are generally comparable between companies, although there are a few potential differences. In particular, though the industry has been working to standardize, there are still differences among companies in the definition of “major events” for exclusion from reliability statistics. These have no impact on metrics that include all outages, but can have an impact where major events are excluded. Similarly, there are different definitions of “sustained” or conversely “momentary” outages. These range in duration from 1 minute to 2 minutes to 5 minutes. These different definitions typically make very little difference in the SAIDI value but they can have an impact of about 10% on the SAIFI value.

Analysis of the costs began at the top level, measuring total costs (capital plus O&M) for the entire electric system, and then splitting them out to individually cover capital and O&M. Those elements were compared against the basis of km of line, asset base, MWH transported, and number of customers. In the tables shown in section 4, the terminology “lines and subs” is used throughout the table. That is to describe the electric system in terms of distribution lines and distribution substations, which are significantly different classes of assets, although both are needed to serve customers. In the case of the asset replacement measures, separate measures were used for lines versus substations, to get an understanding of the replacement rates for the two types of asset.

4. FINDINGS AND CONCLUSIONS

4.1 FINDINGS FROM THE BENCHMARK ANALYSIS

The following table has been developed from the statistical report. The table shows the high-level results from the benchmark data collection. While the statistical report provides the detailed graphs showing all responses from the panel companies, the table represents the key summary statistics that the project team decided were the most important to use in reviewing performance. The metrics are listed in the same order here as they are shown in the statistical report in Appendix C. All monetary figures in the table are shown in Canadian dollars. Value judgments are evident in the table in the rankings. Lower rankings (e.g. 3 of 10) indicate better performance than higher rankings.

The asset replacement rates are calculated based on the capital additions for the year, excluding the portion of capital additions that went toward adding facilities for new customers. In broad terms, the remaining capital spending is designed to capture that portion of the annual capital expenditure related to replacements of existing assets, not to growth of the system to meet needs of new customers. It therefore provides an indication of the overall rate of replacement of the existing infrastructure. It is slightly overstated, to the extent that capital expenditures are used to enhance reliability or otherwise upgrade the system, rather than simply replace existing aged assets.

	Mean	Median	1st Q	Std Dev	H-1	Rank
Cost Metrics						
3-yr Avg Dist Lines & Subs Capital + O&M Spending per Pole KM	$5,774	$6,387	$4,000	$2,521	$3,707	3 of 10
3-yr Avg Dist Lines & Subs Capital Spending per Pole KM	$3,511	$3,851	$2,419	$1,402	$2,103	3 of 10
3-yr Avg Dist Lines & Subs O&M Spending per Pole KM	$2,263	$1,978	$1,534	$1,246	$1,604	4 of 10
3-yr Avg Dist Lines & Subs Capital + O&M Spending per Gross Asset Value	$0.085	$0.084	$0.080	$0.011	$0.075	2 of 11
3-yr Avg Dist Lines & Subs Capital Spending per Gross Asset Value	$0.054	$0.052	$0.047	$0.010	$0.043	1 of 11
3-yr Avg Dist Lines & Subs O&M Spending per Gross Asset Value	$0.031	$0.033	$0.025	$0.009	$0.033	6 of 11
3-yr Avg Dist Lines & Subs Capital + O&M Spending per MWh Transported	$9.48	$9.69	$9.06	$1.46	$9.49	3 of 6
3-yr Avg Dist Lines & Subs Capital Spending per MWh Transported	$5.97	$5.67	$5.32	$1.10	$5.38	3 of 6
3-yr Avg Dist Lines & Subs O&M Spending per MWh Transported	$3.51	$3.78	$2.84	$0.92	$4.10	5 of 6
3-yr Avg Dist Lines & Subs Capital + O&M Spending per Customer	$266	$259	$249	$46	$325	10 of 11
3-yr Avg Dist Lines & Subs Capital Spending per Customer	$171	$164	$142	$45	$184	9 of 11
3-yr Avg Dist Lines & Subs O&M Spending per Customer	$95	$92	$77	$29	$140	10 of 11
Asset Replacement Rates						
3-yr Avg Dist Lines & Subs Asset Replacement Rate (excludes new business)	3.11%	2.70%	2.38%	1.06%	1.97%	2 of 9
3-yr Avg Dist Lines Asset Replacement Rate (excludes new business)	2.84%	2.54%	2.20%	1.12%	2.03%	2 of 9
3-yr Avg Dist Subs Asset Replacement Rate (excludes new business)	3.67%	2.97%	2.34%	1.93%	1.65%	1 of 8
Reliability						
3-yr Avg Customer Hours per Circuit KM (Include Major Events)	121.6	118.4	90.7	58.2	160.6	7 of 10
3-yr Avg Customer Interruptions per Circuit KM (Include Major Events)	44.3	41.8	34.8	23.7	39.4	5 of 10
3-yr Avg SAIDI (Include Major Events)	5.8	4.4	3.8	4.1	16.6	14 of 14
3-yr Avg SAIFI (Include Major Events)	2.2	1.9	1.5	1.0	4.1	14 of 14
3-yr Avg Customer Hours per Circuit KM (Exclude Major Events)	56.1	65.0	33.6	28.3	69.6	6 of 9
3-yr Avg Customer Interruptions per Circuit KM (Exclude Major Events)	34.6	29.7	28.1	20.5	28.7	4 of 9
3-yr Avg SAIDI (Exclude Major Events)	3.0	2.6	2.0	1.7	7.2	12 of 12
3-yr Avg SAIFI (Exclude Major Events)	1.8	1.4	1.2	0.8	3.0	11 of 12
Safety						
3-yr Avg Recordable Incident Rate - Total Corporate	3.45	3.13	1.49	2.35	4.76	8 of 10
3-yr Avg Lost Time Incident Rate - Total Corporate	0.82	0.93	0.42	0.45	0.40	3 of 10
3-yr Avg Recordable Incident Rate - Distribution	3.94	3.04	1.61	2.41	6.60	8 of 9
3-yr Avg Lost Time Incident Rate - Distribution	1.05	0.65	0.52	1.13	0.52	3 of 9

The summary figures in the table are built on a 3-year average for each of the cost metrics. Both the 3-year values and the values showing only the most recent year were calculated during the course of the study. Given the long-term nature of capital investments for distribution assets, it was deemed important to base conclusions on the 3-year figures shown in the table.

The table provides a view of both the critical results and the variability in those results. In particular, by showing the values for mean, median, and first quartile, as well as the standard deviation, a reader can discern how the figures vary across the panel. Finally, the last two columns show the results for Hydro One on each of the metrics, and what rank that performance level places Hydro One in within the panel group.

During the course of the project, the team also looked at the costs associated with meter reading, and with tree-trimming/vegetation management. The results of that investigation are shown in the table below. In the case of tree-trimming, only about one third of the companies were able to provide the cost data for their vegetation management programs, but the information is still directionally useful. In the case of these two areas, costs were only captured for the most recent year, so unlike the numbers above, these figures are only for a 1-year period (2006), rather than a multi-year average.

	Mean	Median	1st Q	Std Dev	H-1	Rank
Meter Reading						
1-yr Meter Reading Expense per Pole KM	$200.14	$187.79	$150.48	$117.10	$160.77	3 of 8
1-yr Meter Reading Expense per Customer	$9.16	$9.07	$6.58	$3.78	$13.97	8 of 8
1-yr Meter Reading Expense per Read	$1.43	$0.87	$0.59	$1.21	$3.65	9 of 9
Tree Trimming						
1-yr Tree Trimming Expense per Trees Managed	$3.07	$2.70	$2.27	$1.89	$5.69	4 of 4
1-yr Tree Trimming Expense per Tree Trimmed	$53	$52	$39	$28	$83	3 of 3
1-yr Tree Trimming Expense per KM Trimmed	$3,392	$3,061	$2,796	$792	$4,367	5 of 6
1-yr Cycle Time Actuals	5.3	5.5	3.7	3.4	11.5	7 of 7

When viewing the 1-year figures, care is needed, since particularly for tree-trimming, the process is a long-term process, but the program can be changed quickly, leading to significant swings for an individual company from year to year. As noted, only a third of the companies could provide the data for a single year, so asking for multiple years wasn't a viable option. Even though this is a very important aspect of both costs and reliability for electric system operation, it remains a relatively poorly-measured activity within the industry.

4.2 DISCUSSION

In terms of outcomes for Hydro One, a review of the tables above suggests several observations:

- Hydro One's costs compare favorably to the peer group, particularly when measured on a per-kilometer basis. This is also true when the measurements are made on a per-asset basis or a per-kWh transported basis. As a result of Hydro One's low customer density, costs are noticeably higher than average when they are compared on a per-customer basis.
- When normalized by the circuit KM of line, Hydro One's reliability results fall into the middle of the group of companies. Hydro One's reliability is generally poor in comparison to the group when measured only by SAIDI and SAIFI.
- Hydro One's safety performance is about average for the group of companies, both at the corporate level and at the Distribution level. The recordable incident rate is higher than average, while the lost-time incident rate is better than average.
- Hydro One's meter reading costs are in the low end of the group when they are normalized by distance (pole km). When measured on a per-customer or a per-read basis, the costs appear high.
- For the tree-trimming/vegetation management area, Hydro One's costs are high in comparison to the panel. In this particular area, the number of companies with

adequate data for comparison is relatively small, but the results provide an indication of the relative position for Hydro One.

As with all utilities, the demographics of the service territory served by Hydro One have a substantial impact on their operating performance. The density (or lack thereof) of the territory drives the radial design of the electric system, and the prevailing weather patterns influence both costs and reliability levels. At the more detailed level, the high density of trees creates a need for substantial amounts of tree-trimming and brush clearance, which drives costs and reliability. When the performance is normalized for the added exposure created by the long electric lines needed to serve the territory, Hydro One's performance is in line with that of its peers.

4.2.1 Costs

The cost results for Hydro One indicate good performance in managing costs when the circumstances of the service territory and electric system design are considered. Except on a cost-per-customer basis, almost all of the overall cost metrics fall at or below the mean values for the panel of companies, and some are very low. In general terms, and with all other items held equal, this would be considered good.

4.2.2 Asset Replacement Rates

In the area of asset replacement rates, the low cost numbers provide some reason for concern. In particular, Hydro One is replacing its assets at a very low rate, both in comparison to the panel and in general. While the figures investigated are only on a 3-year average basis, if the replacement rate is indicative of the long-term capital replacement rate, it would indicate an extraordinarily long life expectancy for some of the electric system.

4.2.3 Reliability

Reliability is typically measured using metrics such as SAIDI and SAIFI. These track the average customer experience in terms of outage frequency and duration. For this study, these metrics were tracked, and then additional metrics were provided, to follow the frequency and duration of outages as normalized by km of line. Both methods of measurement have merit in this circumstance, given the exposure levels created by Hydro One's operating circumstances.

For Hydro One, using reliability metrics as modified for line length, which better represents the rural nature of the Hydro One electric system, shows Hydro One performance is average, with reasonable expectations of improvements. Using SAIDI and SAIFI metrics, the electric system reliability compared against its peers is poor on a "customer experience" basis. Given the nature of the service territory, the ability to compare favorably on the customer experience basis is very limited. It is possible to improve on the current performance, but it would be extraordinarily expensive to achieve first-quartile performance on the SAIFI/SAIDI metrics.

4.2.4 Safety

In the safety area, Hydro One's performance is average for the panel. Recordable incidents are somewhat high, while lost-time incidents are relatively low. The net is average performance. "Average" performance within the utility industry is actually quite good when compared against other industries with similar hazards, where the safety records aren't as good. In comparisons made outside of this study, the utility industry has shown to be an overall leader in terms of safety performance.

At any rate, safety is an area where the status quo is never acceptable, because even the top-performing companies can improve, and there is a clear target of having no injuries. For Hydro One, a continued emphasis on maintaining and improving on the current safety record will serve the company and its employees well.

4.2.5 Meter Reading

The costs of manually reading meters are highly affected by the service territory characteristics. In the case of Hydro One, the meter reading costs are relatively low compared to the group, when normalized by the distance meter readers have to travel (pole KM). However, when viewed on a per-customer or per-read basis, the costs are at the high end of the panel of companies. This is reasonably explained by the very low density of the territory, which leads to long distances, either walking or driving, between meters for reading.

4.2.6 Tree Trimming

Tree-trimming appears as a high-cost activity for Hydro One. The costs for Hydro One would be expected to be high, given the long distribution lines through substantially forested areas. With average tree density, the exposure levels for the extensive system would create large amounts of tree-trimming requirements. With the high tree density levels in the Hydro One territory, the exposure is that much greater.

The above comments notwithstanding, it would appear there is an opportunity to improve the overall costs of tree-trimming for Hydro One. The key metrics shown in the table above measure the costs on a per-tree or per-km basis, and could be expected to be roughly comparable across companies. However, as noted below, there are differences between utilities in the factors impacting tree trimming performance.

The only variable about the tree-trimming practices which was tracked for this study is the length of the tree-trimming cycle for each of the companies. Hydro One has by far the longest cycle time between consecutive trimming of each tree. It would be worth investigating to see whether that has led to greater difficulty in performing the trimming when the time comes for each tree or circuit. It is also conceivable that this long cycle leads to more "hot-spot" trimming than usual, which is typically more expensive than routine cycle trimming. Previous studies executed by PA Consulting have indicated that the optimum tree-trimming cycle length is nearer to 5-6 years than to the 11 currently in practice at Hydro One.

One additional area of interest for further study would be the relationship between the long cycle time of tree-trimming and the reliability results. Shortening of the cycle time will probably have the benefit of reducing the frequency of tree-caused outages for circuits and customers. It would require further investigation of the % of interruptions caused by trees, and how much those could be reduced by a differently-structured tree-trim program.

4.2.7 Summary

Overall, this benchmarking effort has provided some valuable insights for Hydro One. Clearly it has highlighted some areas of opportunity, as well as some of the circumstances that create challenges for achieving superior performance. By carefully analyzing the results, Hydro One can target some improvement opportunities. At the same time, there are issues to be considered in using the study results, as discussed in Section 5 of this report.

5. CONSIDERATIONS IN USE OF THE STUDY RESULTS

This is a high-level study, providing a comparison of Hydro One versus a panel of comparable utilities. When reviewing the results it is necessary to appreciate that several factors can affect the results. Among those factors are the shift in the US/Canadian $ exchange rate through the three year survey period of the study; the variation in the age and design of systems run by each of the utilities; variations in the provision of services (e.g. delivery across the distribution network for other distributors) by the various distribution companies; as well as potential accounting differences in the cost data provided by the companies.

As there are a limited number of truly comparable distribution operators, the comparison panel is by definition limited. However, the number of companies against whom Hydro One is compared provides a useful group against which to compare results and highlight Hydro One performance. The study can be quite useful in providing directional guidance, but should not be used to create definitive numeric targets.

As noted in section 3.4 above, the currency exchange rate between Canadian and U.S. currency changed about 7% during the course of the 3 years under study. This came on the heels of an even larger shift in the two years immediately preceding this study. This has caused the Canadian companies in the study to see their relative performance in the overall panel slip somewhat, even for those whose underlying performance really didn't change at all.

A longer-term factor influencing the comparisons is the combined impact of the variation in the age and design of systems run by each of the utilities. Put simply, the average age and demographic profile of the equipment in each utility's system will have an impact upon cost results and reliability. For instance a utility whose average equipment age is before midlife will probably be spending less on capital replacements and O&M repairs as well as have higher reliability levels than a utility whose average equipment age is well beyond the midlife time frame. Similarly, with regards to system design, if due to low population density levels a distribution system is characterized by a large proportion of radial lines, it will have lower reliability performance than a system with a larger proportion of parallel and redundant pathways to customers. PA has been unable to gather adequate data through survey techniques in past studies about age and condition of electric systems. Utility records have proven inadequate to produce "average age" information, and there is no industry standard regarding definitions of equipment condition. As noted in 3.1, it wasn't practical to perform an inspection of each company's electric system to develop an objective, consistent view of system conditions, so this factor has been entirely left out of the analysis. Such an analysis would also be a very costly exercise.

Finally, there are differences in the accounting structures between utilities, both within Canada and between Canadian utilities and U.S. utilities. These manifest themselves in differences in what is treated as capital versus what is treated as O&M, as well as in differences in depreciation rates, etc. By looking at the total of capital and O&M, the majority of impact of these differences has been negated, so this is considered a relatively minor issue for this study.

In closing, this benchmarking study has taken the steps necessary to meet the requirements of providing a high level comparison of distribution utilities for Hydro One. However, as in any benchmarking study, one must be careful in reviewing and applying these results without a substantial degree of understanding of the underlying data and analysis.

APPENDIX A: DEFINITIONS

Glossary of terms

Term	Definition
Accumulated Depreciation	a.k.a. FERC form page 219, section B, column B. The total amount of depreciation calculated for all assets which are still in service.
CAIDI	Customer Average Interruption Duration Index. Total # of Sustained Customer Hours of Interruption / Total # of Customer Sustained Interruptions.
Capital Additions	Capital additions for any of the following: to hook up a specific new customer at the distribution level to generate additional revenues, to replace in kind, to improve reliability, or to meet general increase in system load.
Clearance distances	The distance in meters between the power lines and the closest point on the tree
Corporate Safety Statistics	Include the safety statistics of your entire corporation (customer service, T&D, corporate services, administrative, etc.)
Cycle time	Years between consecutive trim of dist. circuits
Distribution Circuit KM	Physical kilometres of line multiplied by the number of circuits per line. For purposes of this survey circuit kilometres refers to both overhead and underground line. One structure kilometre with 2 circuits = 2 circuit 2 circuit kilometres
Distribution End-Use Customer	Please provide the count reported on your FERC Form 1. If you do not report to FERC, use the following definition: an entity (usually defined as a metered point of delivery) who receives electric distribution services.
Distribution Fleet Ops & Maint.	Fleet operations and maintenance expense for trucks used only by Distribution field staff.
Distribution Line KM	Physical kilometres line irrespective of the number of circuits. For purposes of this survey structure kilometres refers to both overhead pole kilometres and underground trench kilometres.
Distribution Plant in Service	FERC Accts 360 to 374 or Total Asset base for the following: Land and Land Rights, Structures & Improvements, Station Equipment, Poles, Towers & Fixtures, Overhead Conductors, Line Transformers, Services, Meters, Installation on Customer Premises, Leases.
Electric Meter Reads	Total Reads for Year. A meter read 12 times per year would contribute 12 reads to the total.
Gross Plant in Service	Original installation costs of distribution assets, before any depreciation.
Line KM	Physical kilometres of line irrespective of the number of circuits. For purposes of this survey structure kilometres refers to both overhead pole kilometres and underground trench kilometres.
Load distribution	Percent of customers served by each voltage level
Loop circuits	Circuits with more than one feed, such that an outage on a line can be mitigated by switching around the failure point.
Lost Time Incident Rate	Rate for Total Lost time Incidents calculated: ((Total of OSHA 300A Column H) x 200,000) / Total Hours Worked

Maintenance Expense	Includes FERC accounts 590 to 598 or Maintenance of Distribution Substations and Transformers, OH Line, UG Line, Street Lighting and Signals, Meter, Structures, Misc Dist. Plant and other.
Maintenance Expense (cont.)	Includes activities such as Supervision & Engineering, Vegetation Management
Meter Read Inaccuracy	Error rates per 1000 meter reads
Meter Reading Expense (Electric Only)	a.k.a. FERC account 902. O&M cost for reading meters, including scheduling, routing, and data handling as well as the physical reading.
Minimum time counted as a sustained outage (Hours)	Definition for when an outage is considered sustained, rather than momentary.
MWh Sales	Total Megawatt Hours Sold to end-use customers. (Refer to FERC Form No. 1 page 300, line 10, column d.)
MWh Transported on Distribution Circuit KM	Total MWh moved across the distribution network, whether to your end-use customers or for another utility.
Network, network circuits	Lead cable, downtown/metropolitan network.
New Business Capital Additions	Capital additions primarily to hook up a specific new customer at the distribution level to generate additional revenues. Does not include expenditures to replace in kind, to improve reliability, or to meet general increase in system load.
Number of Trees Managed	Includes all of the trees in your service territory that you monitor, trim, inventory, etc.
Number of Trees Trimmed	Only those trees actually trimmed in the given year.
Operations Expense	Includes FERC accounts 581 to 589 or Operations or Installation Distribution Substations and Transformers, OH Line, UG Line, Street Lighting and Signals, Meter, Customer Installation Expenses, Rents and other.
Operations Expense (cont.)	Includes activities such as Load Dispatching, Supervision & Engineering and Mapping & Drafting, Trouble calls, Line patrols
Radial circuits	Circuits with only one feed for the circuit, such that a line failure of any type leads to an outage for all customers "downstream" of the failure point.
Read Completion Rate	Meters that were actually read that were assigned/scheduled to be read.
Recordable Incident Rate	Rate for Total Recordable Incidence calculated: ((Total of OSHA 300A Columns G + H + I + J) x 200,000) / Total Hours Worked
SAIDI	System Average Interruption Duration Index. Total # of Sustained Customer Hours of Interruption / Total # of Customers.
SAIFI	System Average Interruption Frequency Index. Total # of Sustained Customer Interruptions / Total # of Customers.
Trouble Call Response Expense	Costs associated with incoming trouble calls, dispatch, field activity and reporting related to trouble calls.
Vehicle Accident Rate	Total of vehicle accidents or collisions to total kilometres driven calculated: (total # of accidents x 1,000,000) / (total kilometers driven)

APPENDIX B: FERC ACCOUNT DESCRIPTIONS

This appendix contains the listing of FERC account descriptions for the cost categories under study for this project. It was used by the participating companies as they gathered the cost data for Hydro One.

580 Operation supervision and engineering.

This account shall include the cost of labor and expenses incurred in the general supervision and direction of the operation of the distribution system.

Direct supervision of specific activities, such as station operation, line operation, meter department operation, etc., shall be charged to the appropriate account. (For Major utilities, see operating expense instruction 1.)

581 Load dispatching (Major only).

This account (the keeping of which is optional with the utility) shall include the cost of labor, materials used and expenses incurred in load dispatching operations pertaining to the distribution of electricity.

ITEMS

Labor:

1. Directing switching.
2. Arranging and controlling clearances for construction, maintenance, test and emergency purposes.
3. Controlling system voltages.
4. Preparing operating reports.
5. Obtaining reports on the weather and special events.

Expenses:

6. Communication service provided for system control purposes.
7. System record and report forms.
8. Meals, traveling and incidental expenses.

581.1 Line and station supplies and expenses (Nonmajor only).

582 Station expenses (Major only).

583 Overhead line expenses (Major only).

584 Underground line expenses (Major only).

Accounts 581.1 through 584 shall include, respectively, the cost of labor, materials used and expenses incurred in the operation of overhead and underground distribution lines and stations.

ITEMS

Line Labor:

1. Supervising line operation.
2. Changing line transformer taps.
3. Inspecting and testing lightning arresters, line circuit breakers, switches and grounds.
4. Inspecting and testing line transformers for the purpose of determining load, temperature or operating performance.
5. Patrolling lines.
6. Load tests and voltages surveys of feeders, circuits and line transformers.
7. Removing line transformers and voltage regulators with or without replacements.
8. Installing line transformers or voltage regulators with or without change in capacity provided that the first installation of these items is included in account 368, Line transformers.
9. Voltage surveys, either routine or upon request of customers, including voltage tests at customers' main switch.
10. Transferring loads, switching and reconnecting circuits and equipment for operation purposes.
11. Electrolysis surveys.
12. Inspecting and adjusting line testing equipment.

Line Supplies and Expenses:

13. Tool expenses.
14. Transportation expenses.
15. Meals, traveling and incidental expense.
16. Operating supplies, such as instrument charts, rubber goods, etc.

Station Labor:

1. Supervising station operation.
2. Adjusting station equipment where such adjustment primarily affects performance, such as regulating the flow of cooling water, adjusting current in fields of a machine, changing voltage of regulators or changing station transformer taps.
3. Keeping station log and records and preparing reports on station operation.
4. Inspecting, testing and calibrating station equipment for the purpose of checking its performance.
5. Operating switching and other station equipment.
6. Standing watch, guarding and patrolling station and station yard.
7. Sweeping, mopping and tidying station.
8. Care of grounds, including snow removal, cutting grass, etc.

Station Supplies and Expenses:

9. Building service expenses.
10. Operating supplies, such as lubricants, commutator brushes, water and rubber goods.
11. Station meter and instrument supplies, such as ink and charts.
12. Station record and report forms.
13. Tool expenses.
14. Transportation expenses.
15. Meals, traveling and incidental expenses.

NOTE (MAJOR ONLY): If the utility owns storage battery equipment used for supplying electricity to customers in periods of emergency, the cost of operating labor and of supplies, such as acid, gloves, hydrometers, thermometers, soda, automatic cell fillers, acid proof shoes, etc., shall be included in this account. If significant in amount, a separate subdivision shall be maintained for such expenses.

585 Street lighting and signal system expenses.

A. For Nonmajor utilities, this account shall include the cost of labor, materials used and expenses incurred in the operation of street lighting and signal system plant.

B. For Major utilities, this account shall include the cost of labor, materials used and expenses incurred in: (a) The operation of street lighting and signal system plant which is owned or leased by the utility; and (b) the operation and maintenance of such plant owned by customers where such work is done regularly as a part of the street lighting and signal system service.

ITEMS

Labor:

1. Supervising street lighting and signal systems operation.
2. Replacing lamps and incidental cleaning of glassware and fixtures in connection therewith.
3. Routine patrolling for lamp outages, extraneous nuisances or encroachments, etc.
4. Testing lines and equipment including voltage and current measurement.
5. Winding and inspection of time switch and other controls.

Materials and Expenses:

6. Street lamp renewals.
7. Transportation and tool expense.
8. Meals, traveling, and incidental expenses.

586 Meter expenses.

This account shall include the cost of labor, materials used and expenses incurred in the operation of customer meters and associated equipment.

ITEMS

Labor:

1. Supervising meter operation.
2. Clerical work on meter history and associated equipment record cards, test cards, and reports.
3. Disconnecting and reconnecting, removing and reinstalling, sealing and unsealing meters and other metering equipment in connection with initiating or terminating services including the cost of obtaining meter readings, if incidental to such operation.
4. Consolidating meter installations due to elimination of separate meters for different rates of service.
5. Changing or relocating meters, instrument transformers, time switches, and other metering equipment.
6. Resetting time controls, checking operation of demand meters and other metering equipment, when done as an independent operation.
7. Inspecting and adjusting meter testing equipment.
8. Inspecting and testing meters, instrument transformers, time switches, and other metering equipment on premises or in shops excluding inspecting and testing incidental to maintenance

Materials and Expenses:

9. Meter seals and miscellaneous meter supplies.
10. Transportation expenses.
11. Meals, traveling, and incidental expenses.
12. Tool expenses.

NOTE: The cost of the first setting and testing of a meter is chargeable to utility plant account 370, Meters.

587 Customer installations expenses.

This account shall include the cost of labor, materials used and expenses incurred in work on customer installations in inspecting premises and in rendering services to customers of the nature of those indicated by the list of items hereunder.

ITEMS

Labor:

1. Supervising customer installations work.
2. Inspecting premises, including check of wiring for code compliance.
3. Investigating, locating, and clearing grounds on customers' wiring.
4. Investigating service complaints, including load tests of motors and lighting and power circuits on customers' premises; field investigations of complaints on bills or of voltage.
5. Installing, removing, renewing, and changing lamps and fuses.
6. Radio, television and similar interference work including erection of new aerials on customers' premises and patrolling of lines, testing of lightning arresters, inspection of pole hardware, etc., and examination on or off premises of customers' appliances, wiring, or equipment to locate cause of interference.
7. Installing, connecting, reinstalling, or removing leased property on customers' premises.
8. Testing, adjusting, and repairing customers' fixtures and appliances in shop or on premises.
9. Cost of changing customers' equipment due to changes in service characteristics.
10. Investigation of current diversion including setting and removal of check meters

and securing special readings thereon; special calls by employees in connection with discovery and settlement of current diversion; changes in customer wiring and any other labor cost identifiable as caused by current diversion.

Materials and Expenses:

11. Lamp and fuse renewals.
12. Materials used in servicing customers' fixtures, appliances and equipment.
13. Power, light, heat, telephone, and other expenses of appliance repair department.
14. Tool expense.
15. Transportation expense, including pick-up and delivery charges.
16. Meals, traveling and incidental expenses.
17. Rewards paid for discovery of current diversion.

NOTE A: Amounts billed customers for any work, the cost of which is charged to this account, shall be credited to this account. Any excess over costs resulting therefrom shall be transferred to account 451, Miscellaneous Service Revenues.

NOTE B: Do not include in this account expenses incurred in connection with merchandising, jobbing and contract work.

588 Miscellaneous distribution expenses.

This account shall include the cost of labor, materials used and expenses incurred in distribution system operation not provided for elsewhere.

ITEMS

Labor:

1. General records of physical characteristics of lines and substations, such as capacities, etc.
2. Ground resistance records.
3. Joint pole maps and records.
4. Distribution system voltage and load records.
5. Preparing maps and prints.
6. Service interruption and trouble records.
7. General clerical and stenographic work except that chargeable to account 586, Meter expenses.

Expenses:

8. Operating records covering poles, transformers, manholes, cables, and other distribution facilities. Exclude meter records chargeable to account 586, Meter Expenses and station records chargeable to account 582, Station Expenses (For Nonmajor utilities, account 581.1, Line and Station Expenses), and stores records (For Nonmajor utilities, station records) chargeable to account 163, Stores Expense Undistributed (For Nonmajor utilities, account 581.1, Line and Station Expenses).
9. Janitor work at distribution office buildings including snow removal, cutting grass, etc.

Materials and Expenses:

10. Communication service.
11. Building service expenses.
12. Miscellaneous office supplies and expenses, printing, and stationery, maps and records and first-aid supplies.
13. Research, development, and demonstration expenses (Major only).

589 Rents.

This account shall include rents of property of others used, occupied, or operated in connection with the distribution system, including payments to the United States and others for the use and occupancy of public lands and reservations for distribution line rights of way. (See operating expense instruction 3.)

590 Maintenance supervision and engineering (Major only).

This account shall include the cost of labor and expenses incurred in the general supervision and direction of maintenance of the distribution system. Direct field supervision of specific jobs shall be charged to the appropriate maintenance account. (See operating expense instruction 1.)

591 Maintenance of structures (Major only).

This account shall include the cost of labor, materials used and expenses incurred in maintenance of structures, the book cost of which is includible in account 361, Structures and Improvements. (See operating expense instruction 2.)

592 Maintenance of station equipment (Major only).

This account shall include the cost of labor, materials used and expenses incurred in maintenance of plant, the book cost of which is includible in account 362, Station Equipment, and account 363, Storage Battery Equipment. (See operating expense instruction 2.)

592.1 Maintenance of structures and equipment (Nonmajor only).

This account shall include the cost of labor, materials used and expenses incurred in maintenance of structures, the book cost of which is includible in account 361, Structures and Improvements, account 362, Station Equipment, and account 363, Storage Battery Equipment. (See operating expense instruction 2.)

593 Maintenance of overhead lines (Major only).

This account shall include the cost of labor, materials used and expenses incurred in the maintenance of overhead distribution line facilities, the book cost of which is includible in account 364, Poles, Towers and Fixtures, account 365, Overhead Conductors and Devices, and account 369, Services. (See operating expense instruction 2.)

ITEMS

1. Work of the following character on poles, towers, and fixtures:

a. Installing additional clamps or removing clamps or strain insulators on guys in place.

b. Moving line or guy pole in relocation of pole or section of line.

c. Painting poles, towers, crossarms, or pole extensions.

d. Readjusting and changing position of guys or braces.

e. Realigning and straightening poles, crossarms, braces, pins, racks, brackets, and other pole fixtures.

f. Reconditioning reclaimed pole fixtures.

g. Relocating crossarms, racks, brackets, and other fixtures on poles.

h. Repairing pole supported platform.

i. Repairs by others to jointly owned poles.

j. Shaving, cutting rot, or treating poles or crossarms in use or salvaged for reuse.

k. Stubbing poles already in service.

l. Supporting conductors, transformers, and other fixtures and transferring them to new poles during pole replacements.

m. Maintaining pole signs, stencils, tags, etc.

2. Work of the following character on overhead conductors and devices:

a. Overhauling and repairing line cutouts, line switches, line breakers, and capacitor installations.

b. Cleaning insulators and bushings.

c. Refusing line cutouts.

d. Repairing line oil circuit breakers and associated relays and control wiring.

e. Repairing grounds.

f. Resagging, retying, or rearranging position or spacing of conductors.

g. Standing by phones, going to calls, cutting faulty lines clear, or similar activities at times of emergency.

h. Sampling, testing, changing, purifying, and replenishing insulating oil.

i. Transferring loads, switching, and reconnecting circuits and equipment for maintenance purposes.

j. Repairing line testing equipment.

k. Trimming trees and clearing brush.

l. Chemical treatment of right of way area when occurring subsequent to construction of line.

3. Work of the following character on overhead services:

a. Moving position of service either on pole or on customers' premises.

b. Pulling slack in service wire.

c. Retying service wire.

d. Refastening or tightening service bracket.

594 Maintenance of underground lines (Major only).

This account shall include the cost of labor, materials used and expenses incurred in the maintenance of underground distribution line facilities, the book cost of which is includible in account 366, Underground Conduit, account 367, Underground Conductors and Devices, and account 369, Services. (See operating expense instruction 2.)

ITEMS

1. Work of the following character on underground conduit:

a. Cleaning ducts, manholes, and sewer connections.

b. Moving or changing position of conduit or pipe.

c. Minor alterations of handholes, manholes, or vaults.

d. Refastening, repairing, or moving racks, ladders, or hangers in manholes or vaults.

e. Plugging and shelving ducts.

f. Repairs to sewers, drains, walls, and floors, rings and covers.

2. Work of the following character on underground conductors and devices:

a. Repairing circuit breakers, switches, cutouts, network protectors, and associated relays and control wiring.

b. Repairing grounds.

c. Retraining and reconnecting cables in manholes including transfer of cables from one duct to another.

d. Repairing conductors and splices.

e. Repairing or moving junction boxes and potheads.

f. Refireproofing cables and repairing supports.

g. Repairing electrolysis preventive devices for cables.

h. Repairing cable bonding systems.

i. Sampling, testing, changing, purifying and replenishing insulating oil.

j. Transferring loads, switching and reconnecting circuits and equipment for maintenance purposes.

k. Repairing line testing equipment.

l. Repairing oil or gas equipment in high voltage cable systems and replacement of oil or gas.

3. Work of the following character on underground services:

a. Cleaning ducts.

b. Repairing any underground service plant.

594.1 Maintenance of lines (Nonmajor only).

This account shall include the cost of labor, materials used and expenses incurred in the maintenance of distribution line facilities, the book cost of which is includible in account 364, Poles, Towers and Fixtures, account 365, Overhead Conductors and Devices, account 366, Underground Conduit, account 367, Underground Conductors and Devices, and account 369, Services. (See operating expense instruction 2.)

ITEMS

1. Work of the following character on poles, towers, and fixtures:

a. Installing additional clamps or removing clamps or strain insulators on guys in place.

b. Moving line or guy pole in relocation of pole or section of line.

c. Painting poles, towers, crossarms, or pole extensions.

d. Readjusting and changing position of guys or braces.

e. Realigning and straightening poles, crossarms, braces, pins, racks, brackets, and other pole fixtures.

f. Reconditioning reclaimed pole fixtures.

g. Relocating crossarms, racks, brackets, and other fixtures on pole.

h. Repairing pole supported platform.

i. Repairs by others to jointly owned poles.

j. Shaving, cutting rot, or treating poles or crossarms in use or salvage for reuse.

k. Stubbing poles already in service.

l. Supporting conductors, transformers, and other fixtures and transferring them to new poles during pole replacement.

m. Maintaining pole signs, stencils, tags, etc.

2. Work of the following character on overhead conductors and devices:

a. Overhauling and repairing line cutouts, line switches, line breakers, and capacitor installations.

b. Cleaning insulators and bushings.

c. Refusing line cutouts.

d. Repairing line oil circuit breakers and associated relays and control wiring.

e. Repairing grounds.

f. Resagging, retying, or rearranging position or spacing of conductors.

g. Standing by phones, going to calls, cutting faulting lines clear, or similar activities at times of emergencies.

h. Sampling, testing, changing, purifying, and replenishing insulating oil.

i. Transferring loads, switching, and reconnecting circuits and equipment for maintenance purposes.

j. Repairing line testing equipment.

k. Trimming trees and clearing brush.

l. Chemical treatment of right of way area when occurring subsequent to construction of line.

3. Work of the following character on underground conduit:

a. Cleaning ducts, manholes, and sewer connections.

b. Moving or changing position of conduit or pipe.

c. Minor alterations of handholes, manholes, or vaults.

d. Refastening, repairing or moving racks, ladders, or hangers in manholes or vaults.

e. Plugging and shelving ducts.

f. Repairs to sewers, drains, walls and floors, rings and covers.

4. Work of the following character on underground conductors and devices:

a. Repairing circuit breakers, switches, cutouts, network protectors, and associated relays and control wiring.

b. Repairing grounds.

c. Retraining and reconnecting cables in manhole including transfer of cables from one duct to another.

d. Repairing conductors and splices.

e. Repairing or moving junction boxes and potheads.

f. Refireproofing cables and repairing supports.

g. Repairing electrolysis preventive devices for cables.

h. Repairing cable bonding systems.

i. Sampling, testing, changing, purifying and replenishing insulating oil.

j. Transferring loads, switching and reconnecting circuits and equipment for maintenance purposes.

k. Repairing line testing equipment.

l. Repairing oil or gas equipment in high voltage cable system and replacement of oil or gas.

5. Work of the following character on services:

a. Moving position of service either on pole or on customers' premises.

b. Pulling slack in service wire.

c. Retying service wire.

d. Refastening or tightening service bracket.

e. Cleaning ducts.

595 Maintenance of line transformers.

This account shall include the cost of labor, materials used and expenses incurred in maintenance of distribution line transformers, the book cost of which is includible in account 368, Line Transformers. (See operating expense instruction 2.)

596 Maintenance of street lighting and signal systems.

This account shall include the cost of labor, materials used and expenses incurred in maintenance of plant, the book cost of which is includible in account 373, Street Lighting and Signal Systems. (See operating expense instruction 2.)

597 Maintenance of meters.

This account shall include the cost of labor, materials used and expenses incurred in the maintenance of meters and meter testing equipment, the book cost of which is includible in account 370, Meters, and account 395, Laboratory Equipment, respectively. (See operating expense instruction 2.)

598 Maintenance of miscellaneous distribution plant.

This account shall include the cost of labor, materials used and expenses incurred in maintenance of plant, the book cost of which is includible in accounts 371, Installations on Customers' Premises, and 372, Leased Property on Customers' Premises, and any other plant the maintenance of which is assignable to the distribution function and is not provided for elsewhere. (See operating expense instruction 2.)

ITEMS

a. Work of similar nature to that listed in other distribution maintenance accounts.

b. Maintenance of office furniture and equipment used by distribution system department.

901 Supervision (Major only).

This account shall include the cost of labor and expenses incurred in the general direction and supervision of customer accounting and collecting activities. Direct supervision of a specific activity shall be charged to account 902, Meter Reading Expenses, or account 903, Customer Records and Collection Expenses, as appropriate. (See operating expense instruction 1.)

902 Meter reading expenses.

This account shall include the cost of labor, materials used and expenses incurred in reading customer meters, and determining consumption when performed by employees engaged in reading meters.

ITEMS

Labor:

1. Addressing forms for obtaining meter readings by mail.
2. Changing and collecting meter charts used for billing purposes.
3. Inspecting time clocks, checking seals, etc., when performed by meter readers and the work represents a minor activity incidental to regular meter reading routine.
4. Reading meters, including demand meters, and obtaining load information for billing purposes. Exclude and charge to account 586, Meter Expenses, or to account 903, Customer Records and Collection Expenses, as applicable, the cost of obtaining meter readings, first and final, if incidental to the operation of removing or resetting, sealing, or locking, and disconnecting or reconnecting meters.
5. Computing consumption from meter reader's book or from reports by mail when done by employees engaged in reading meters.
6. Collecting from prepayment meters when incidental to meter reading.
7. Maintaining record of customers' keys.
8. Computing estimated or average consumption when performed by employees engaged in reading meters.

Materials and Expenses:

9. Badges, lamps, and uniforms.
10. Demand charts, meter books and binders and forms for recording readings, but not the cost of preparation.
11. Postage and supplies used in obtaining meter readings by mail.
12. Transportation, meals, and incidental expenses.

903 Customer records and collection expenses.

This account shall include the cost of labor, materials used and expenses incurred in work on customer applications, contracts, orders, credit investigations, billing and accounting, collections and complaints.

ITEMS

Labor:

1. Receiving, preparing, recording and handling routine orders for service, disconnections, transfers or meter tests initiated by the customer, excluding the cost of carrying out such orders, which is chargeable to the

Appendix C

Statistical Report - Charts & Graphs

Data updated: as of October 15, 2007

3 year values are 2004-2006, 1 year values are 2006.

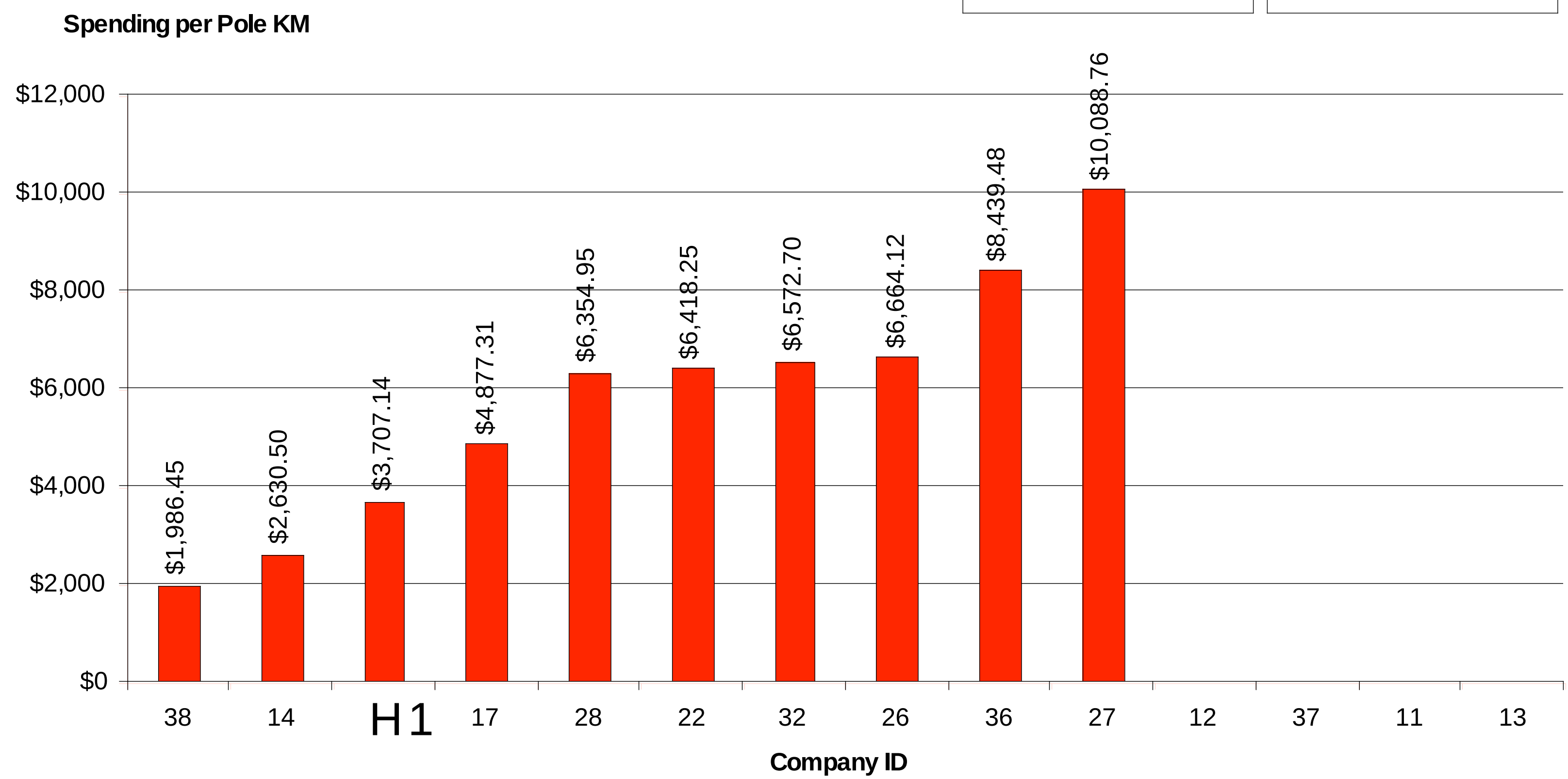
Cost Metrics

3 year values are 2004-2006, 1 year values are 2006.

3-yr Avg Dist Lines & Subs Capital + O&M Spending per Pole KM

HydroOne:	
Value:	$3,707
Quartile:	Q1
Rank:	3

Panel:	
Mean:	$5,774
Quartile 1:	$4,000
Quartile 2:	$6,387
Quartile 3:	$6,641

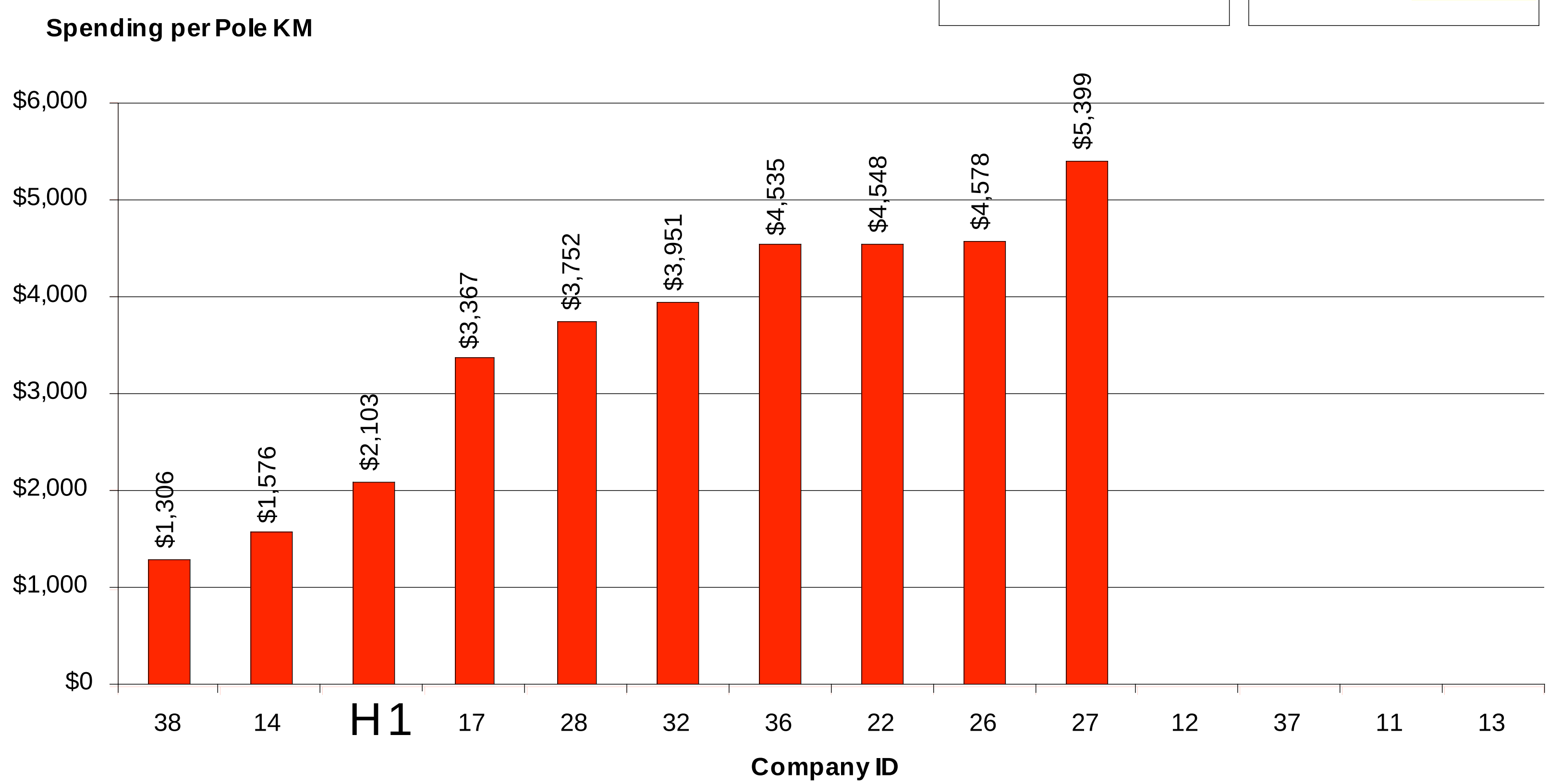


3 year values are 2004-2006, 1 year values are 2006.

3-yr Avg Dist Lines & Subs Capital Spending per Pole KM

HydroOne:	
Value:	$2,103
Quartile:	Q1
Rank:	3

Panel:	
Mean:	$3,511
Quartile 1:	$2,419
Quartile 2:	$3,851
Quartile 3:	$4,545

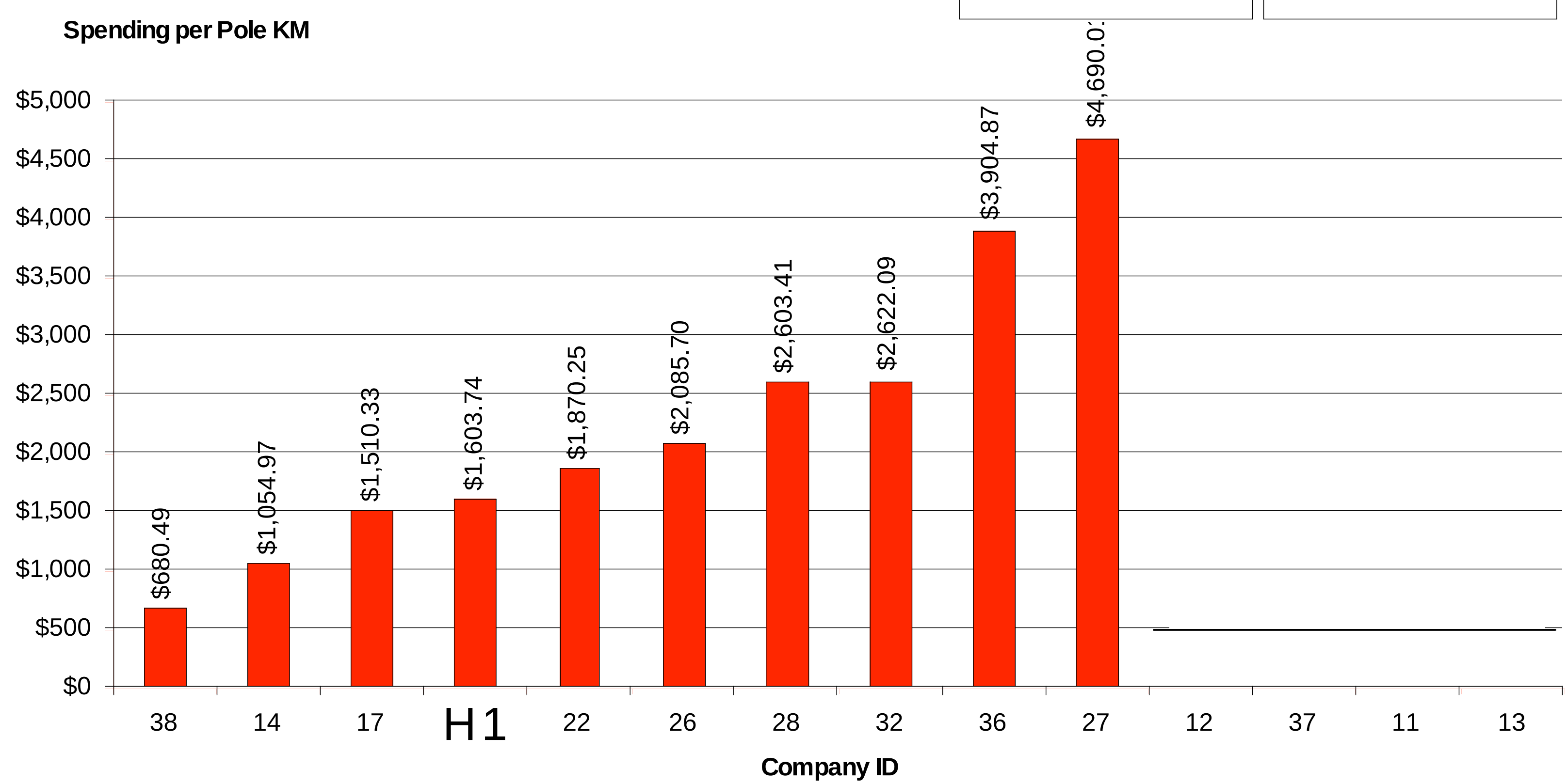


3 year values are 2004-2006, 1 year values are 2006.

3-yr Avg Dist Lines & Subs O&M Spending per Pole KM

HydroOne:	
Value:	$1,604
Quartile:	Q2
Rank:	4

Panel:	
Mean:	$2,263
Quartile 1:	$1,534
Quartile 2:	$1,978
Quartile 3:	$2,617

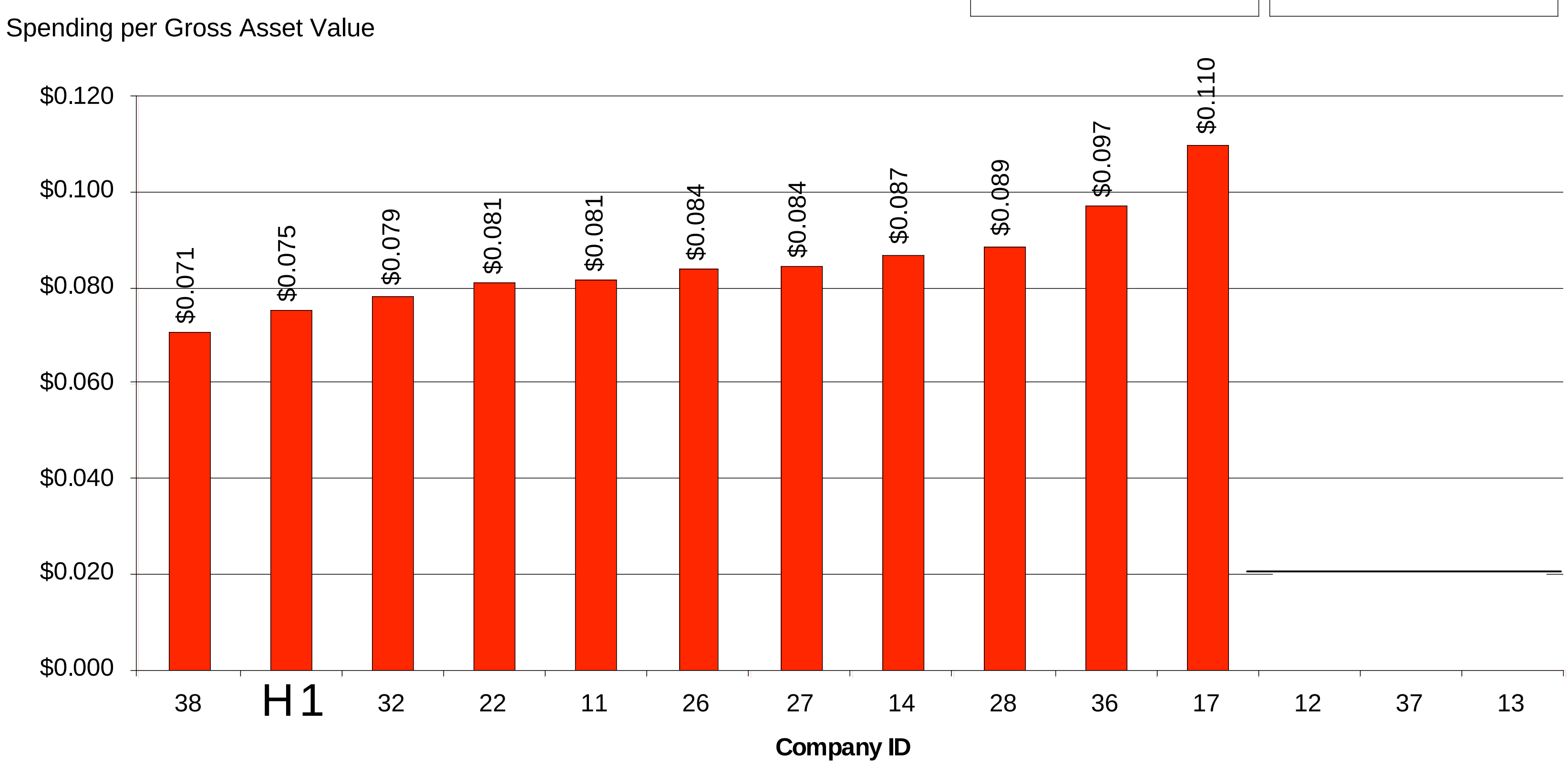


3 year values are 2004-2006, 1 year values are 2006.

3-yr Avg Dist Lines & Subs Capital + O&M Spending per Gross Asset Value

HydroOne:	
Value:	$0.075
Quartile:	Q1
Rank:	2

Panel:	
Mean:	$0.085
Quartile 1:	$0.080
Quartile 2:	$0.084
Quartile 3:	$0.088

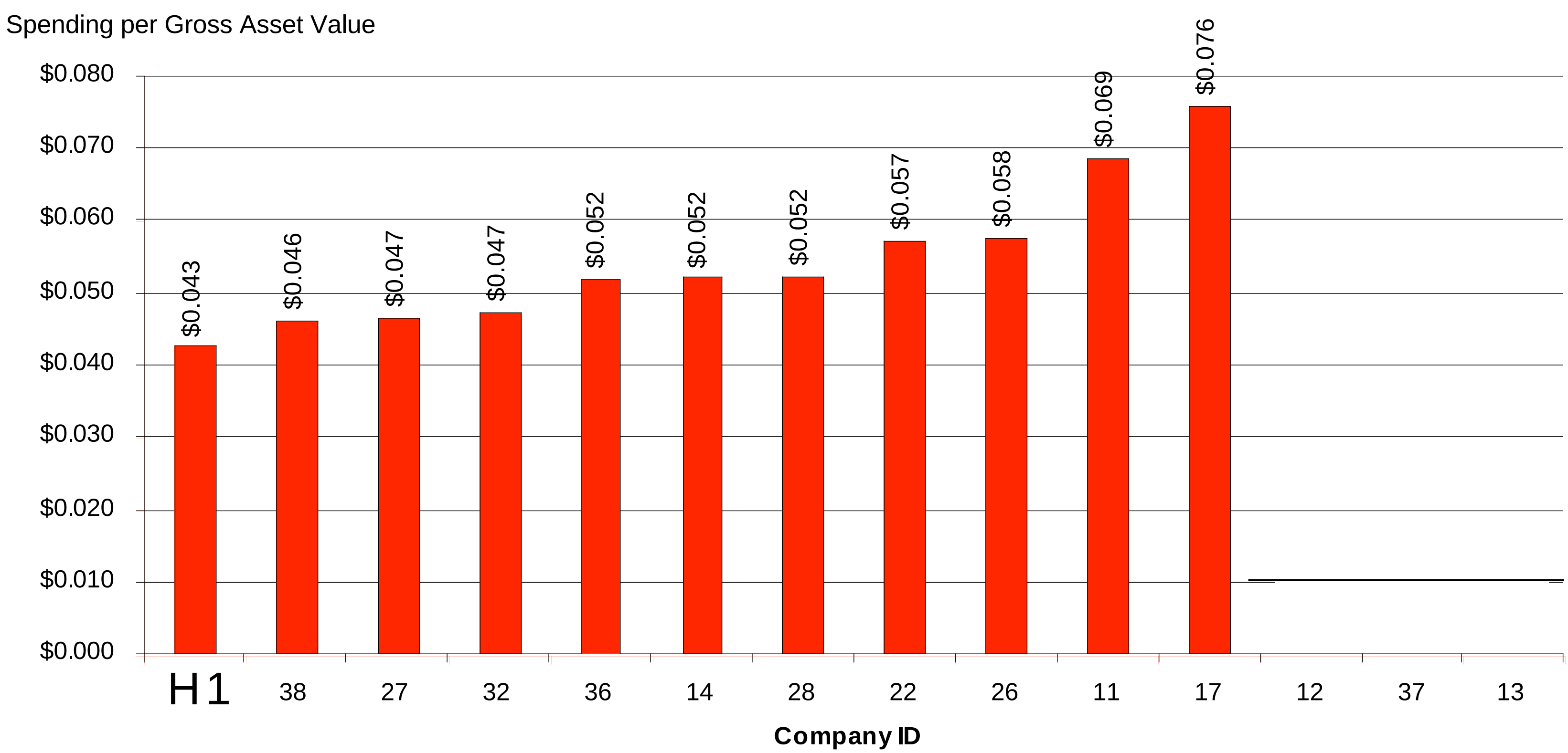


3 year values are 2004-2006, 1 year values are 2006.

3-yr Avg Dist Lines & Subs Capital Spending per Gross Asset Value

HydroOne:	
Value:	$0.043
Quartile:	Q1
Rank:	1

Panel:	
Mean:	$0.054
Quartile 1:	$0.047
Quartile 2:	$0.052
Quartile 3:	$0.058

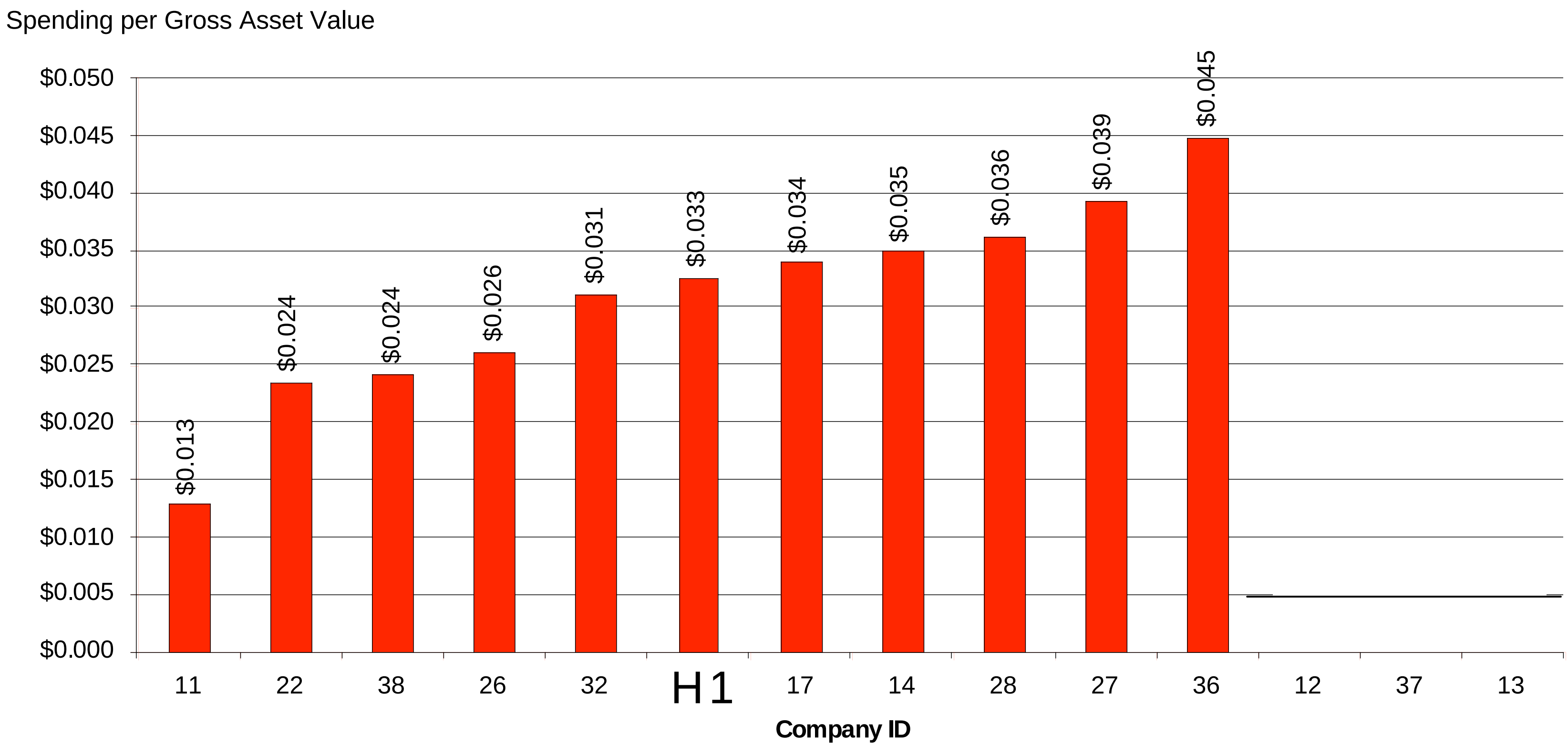


3 year values are 2004-2006, 1 year values are 2006.

3-yr Avg Dist Lines & Subs O&M Spending per Gross Asset Value

HydroOne:	
Value:	$0.033
Quartile:	Q3
Rank:	6

Panel:	
Mean:	$0.031
Quartile 1:	$0.025
Quartile 2:	$0.033
Quartile 3:	$0.036

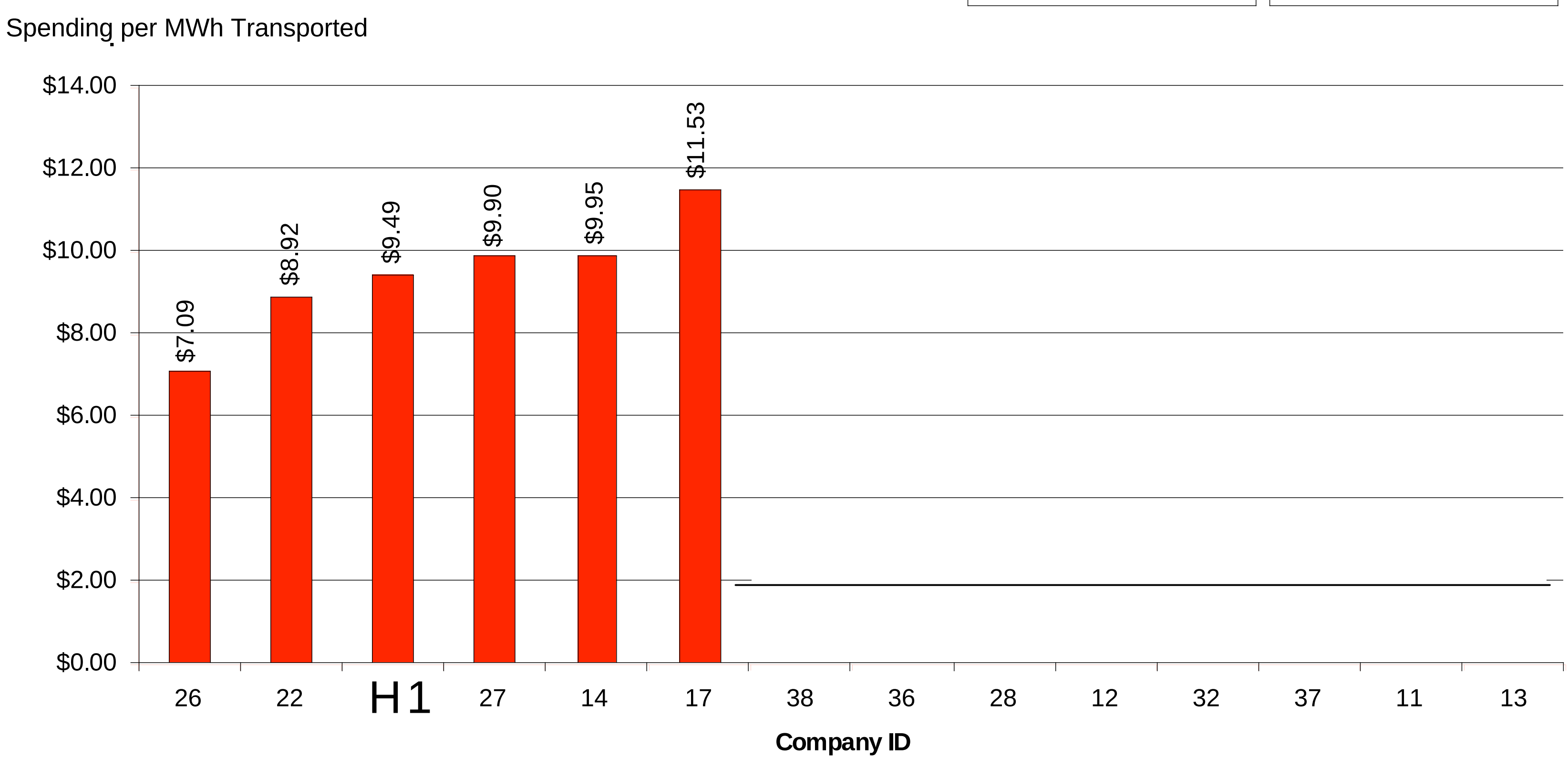


3 year values are 2004-2006, 1 year values are 2006.

3-yr Avg Dist Lines & Subs Capital + O&M Spending per MWh Transported

HydroOne:	
Value:	$9.49
Quartile:	Q2
Rank:	3

Panel:	
Mean:	$9.48
Quartile 1:	$9.06
Quartile 2:	$9.69
Quartile 3:	$9.94

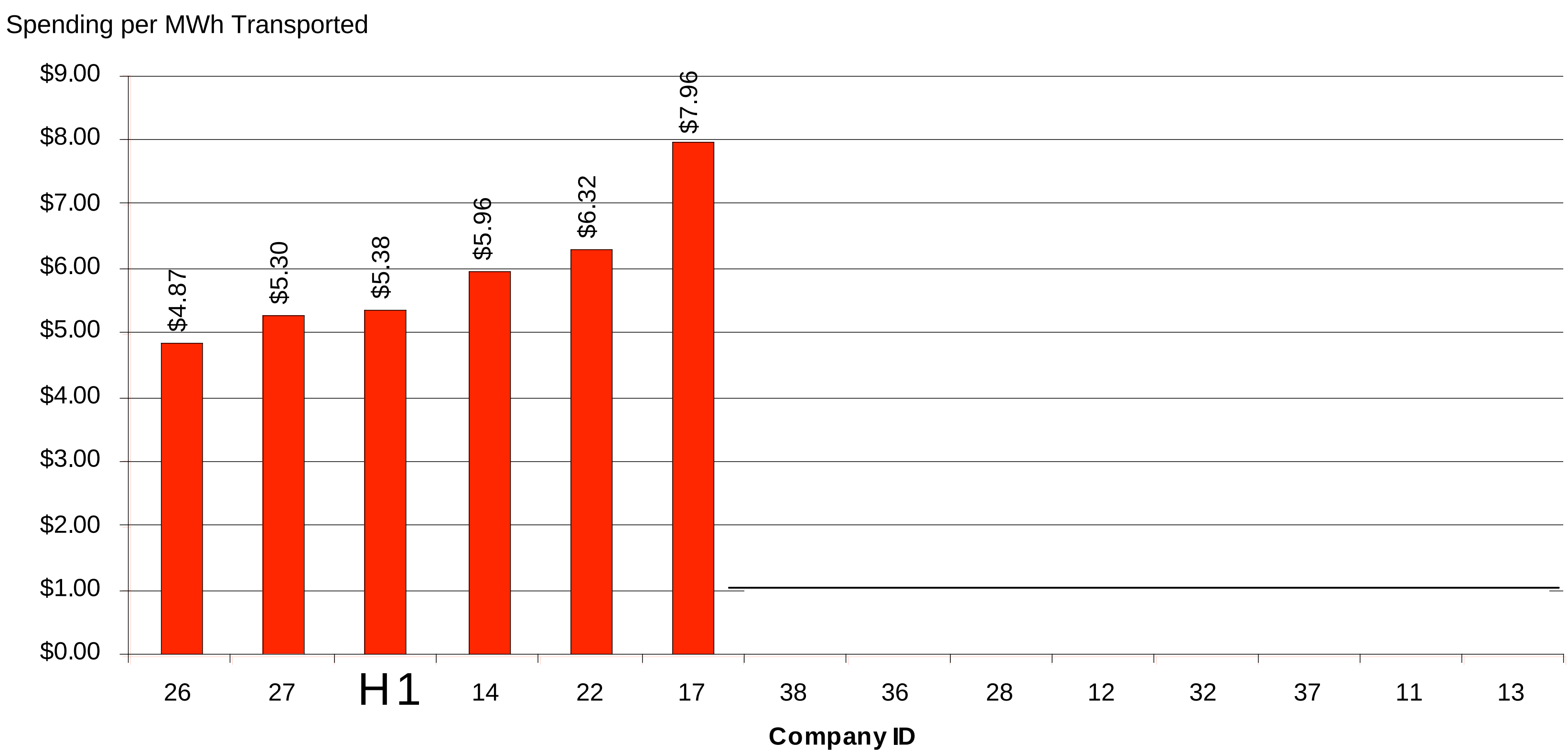


3 year values are 2004-2006, 1 year values are 2006.

3-yr Avg Dist Lines & Subs Capital Spending per MWh Transported

HydroOne:	
Value:	$5.38
Quartile:	Q2
Rank:	3

Panel:	
Mean:	$5.97
Quartile 1:	$5.32
Quartile 2:	$5.67
Quartile 3:	$6.23

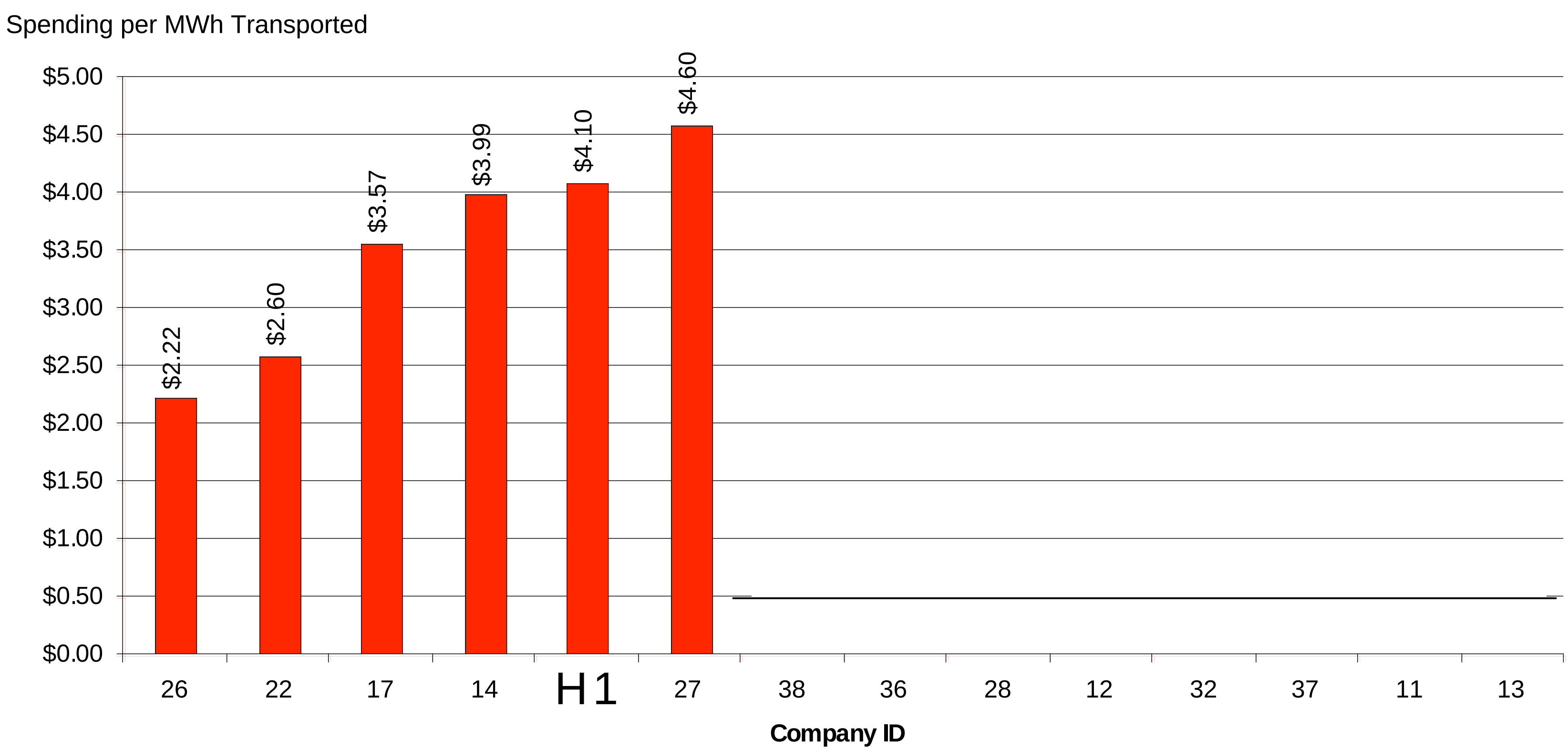


3 year values are 2004-2006, 1 year values are 2006.

3-yr Avg Dist Lines & Subs O&M Spending per MWh Transported

HydroOne:	
Value:	$4.10
Quartile:	Q4
Rank:	5

Panel:	
Mean:	$3.51
Quartile 1:	$2.84
Quartile 2:	$3.78
Quartile 3:	$4.07

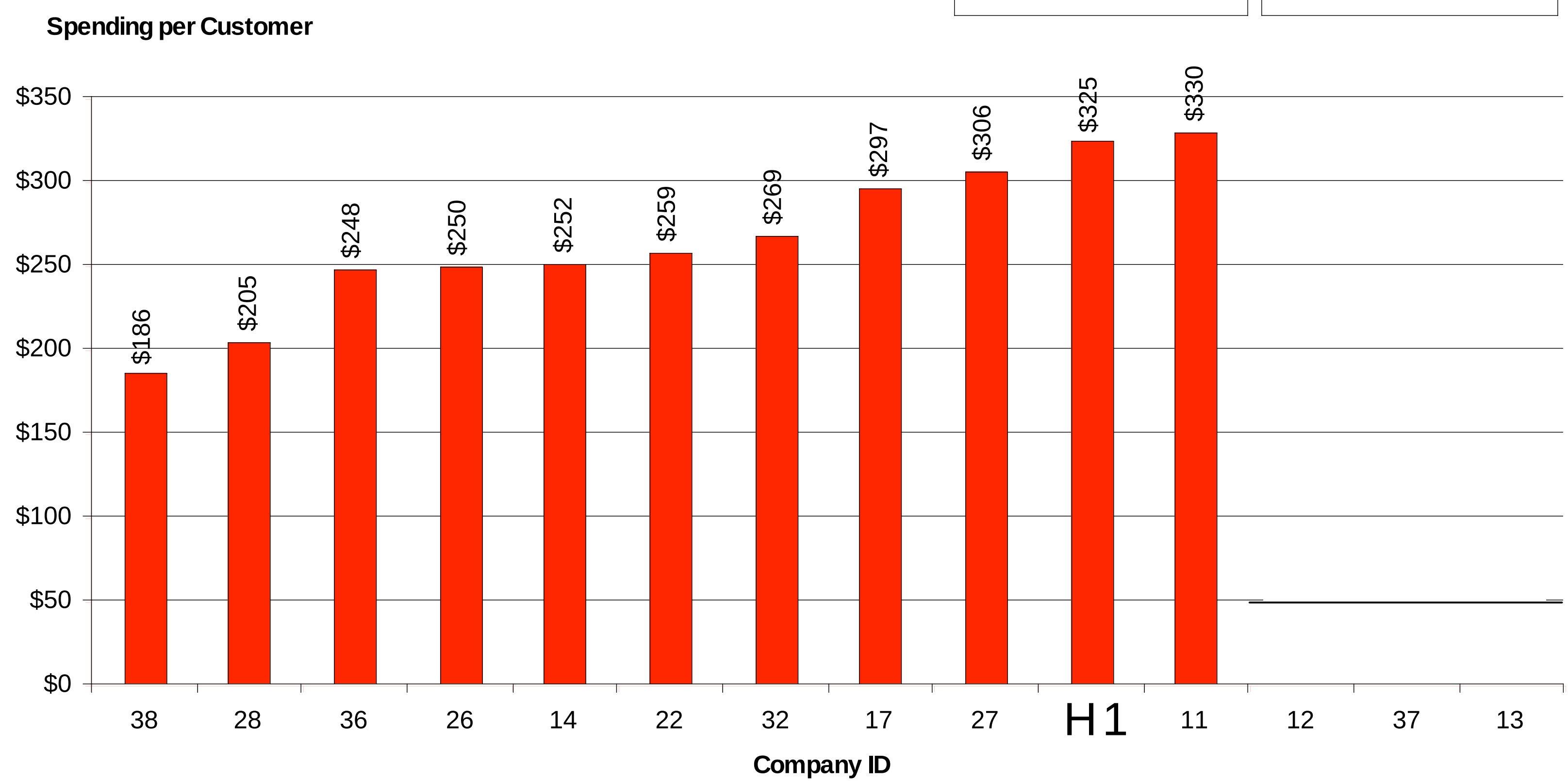


3 year values are 2004-2006, 1 year values are 2006.

3-yr Avg Dist Lines & Subs Capital + O&M Spending per Customer

HydroOne:	
Value:	$325
Quartile:	Q4
Rank:	10

Panel:	
Mean:	$266
Quartile 1:	$249
Quartile 2:	$259
Quartile 3:	$302

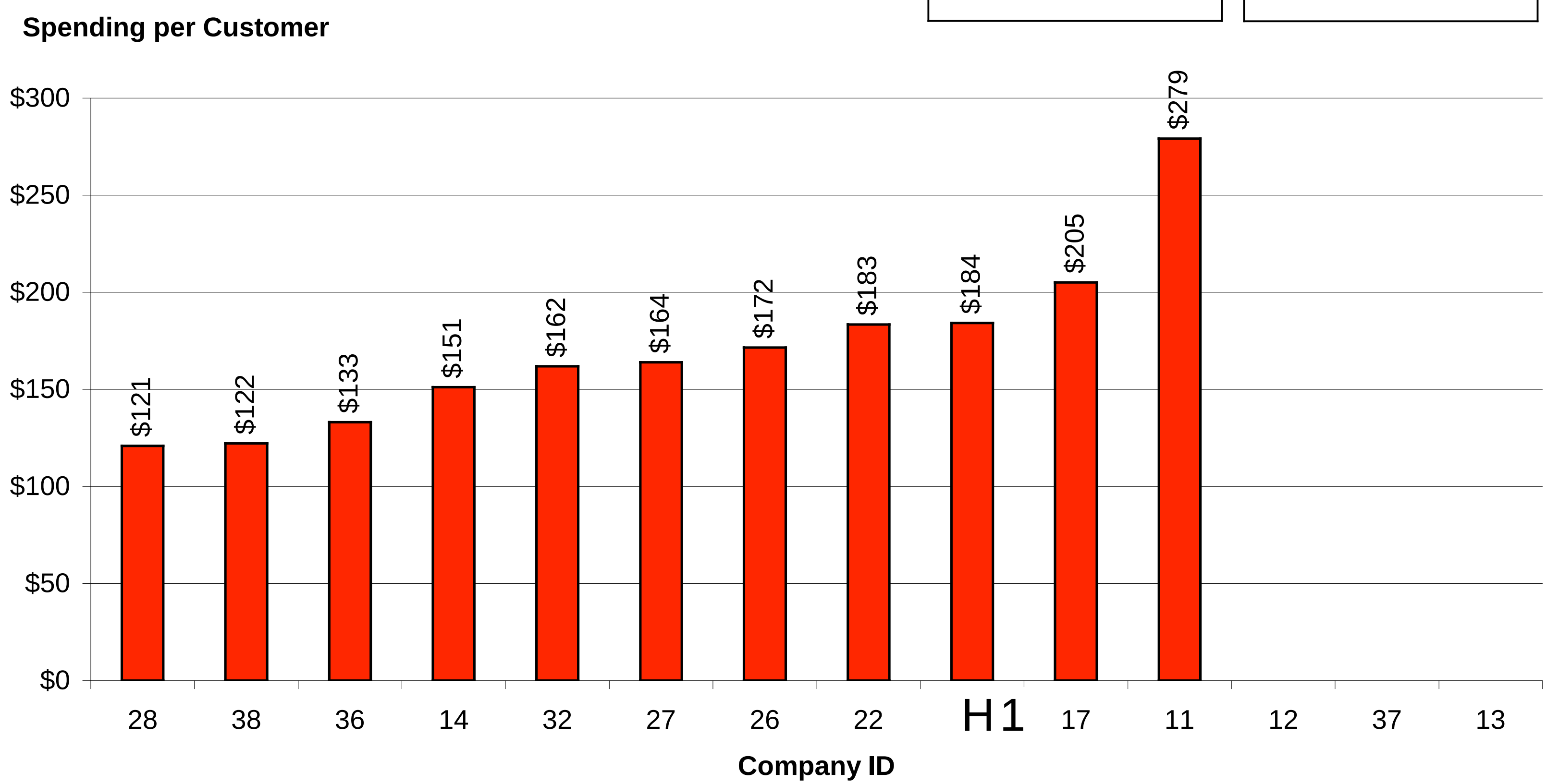


3 year values are 2004-2006, 1 year values are 2006.

3-yr Avg Dist Lines & Subs Capital Spending per Customer

HydroOne:	
Value:	$184
Quartile:	Q4
Rank:	9

Panel:	
Mean:	$171
Quartile 1:	$142
Quartile 2:	$164
Quartile 3:	$184

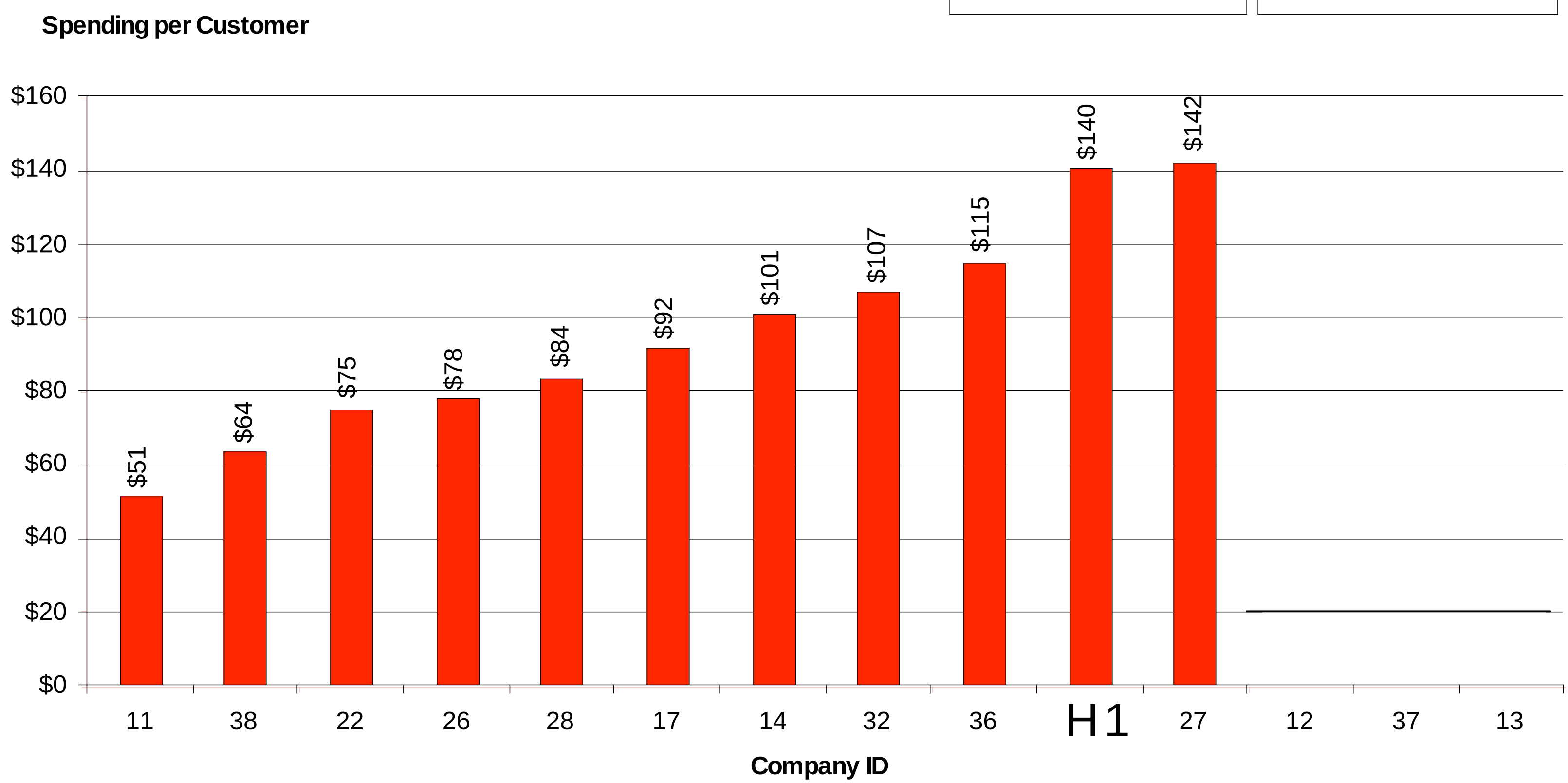


3 year values are 2004-2006, 1 year values are 2006.

3-yr Avg Dist Lines & Subs O&M Spending per Customer

HydroOne:	
Value:	$140
Quartile:	Q4
Rank:	10

Panel:	
Mean:	$95
Quartile 1:	$77
Quartile 2:	$92
Quartile 3:	$111



3 year values are 2004-2006, 1 year values are 2006.

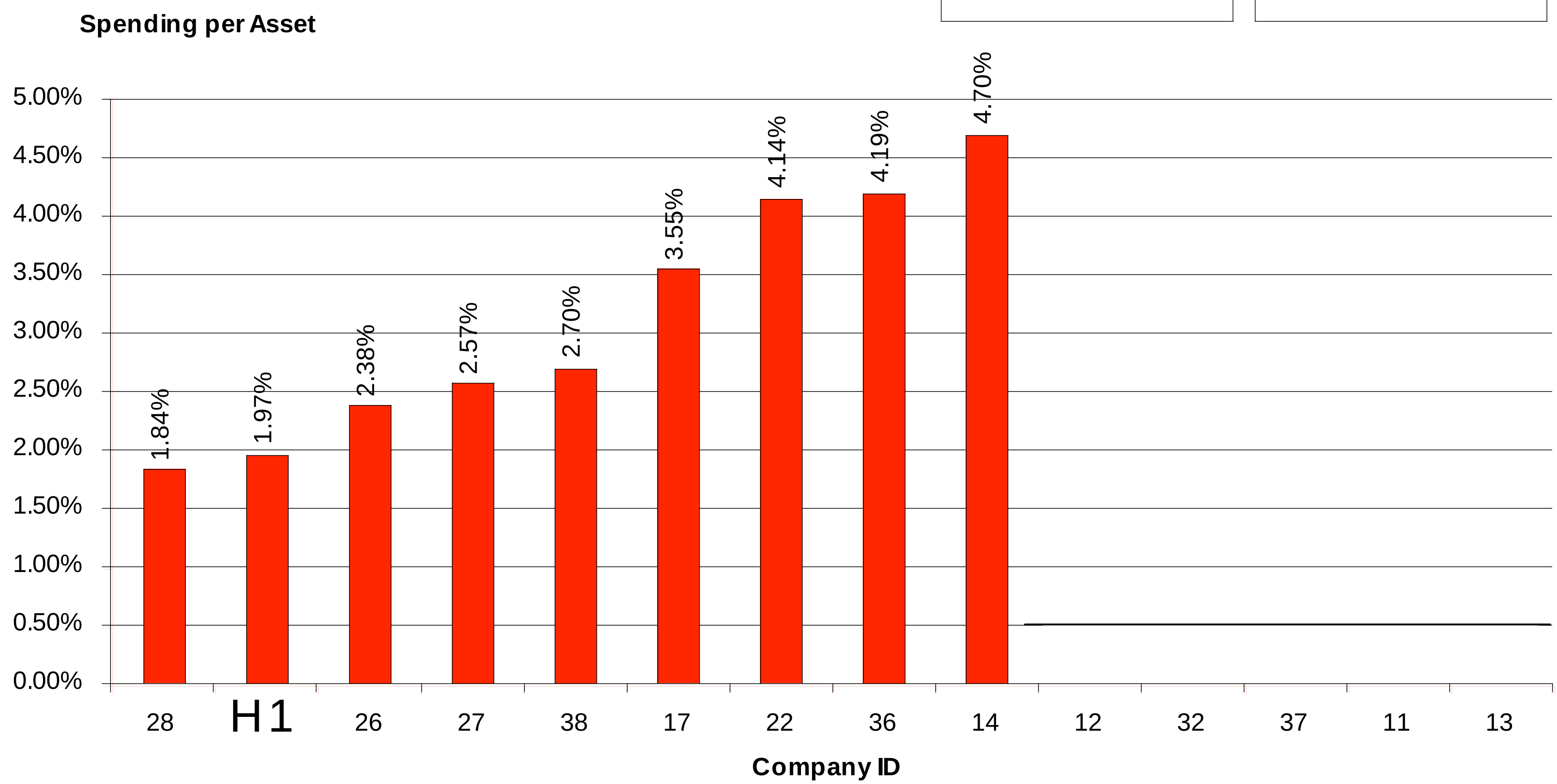
Asset Replacement Rates

3 year values are 2004-2006, 1 year values are 2006.

3-yr Avg Dist Lines & Subs Asset Replacement Rate (excludes new business)

HydroOne:	
Value:	1.97%
Quartile:	Q1
Rank:	2

Panel:	
Mean:	3.11%
Quartile 1:	2.38%
Quartile 2:	2.70%
Quartile 3:	4.14%

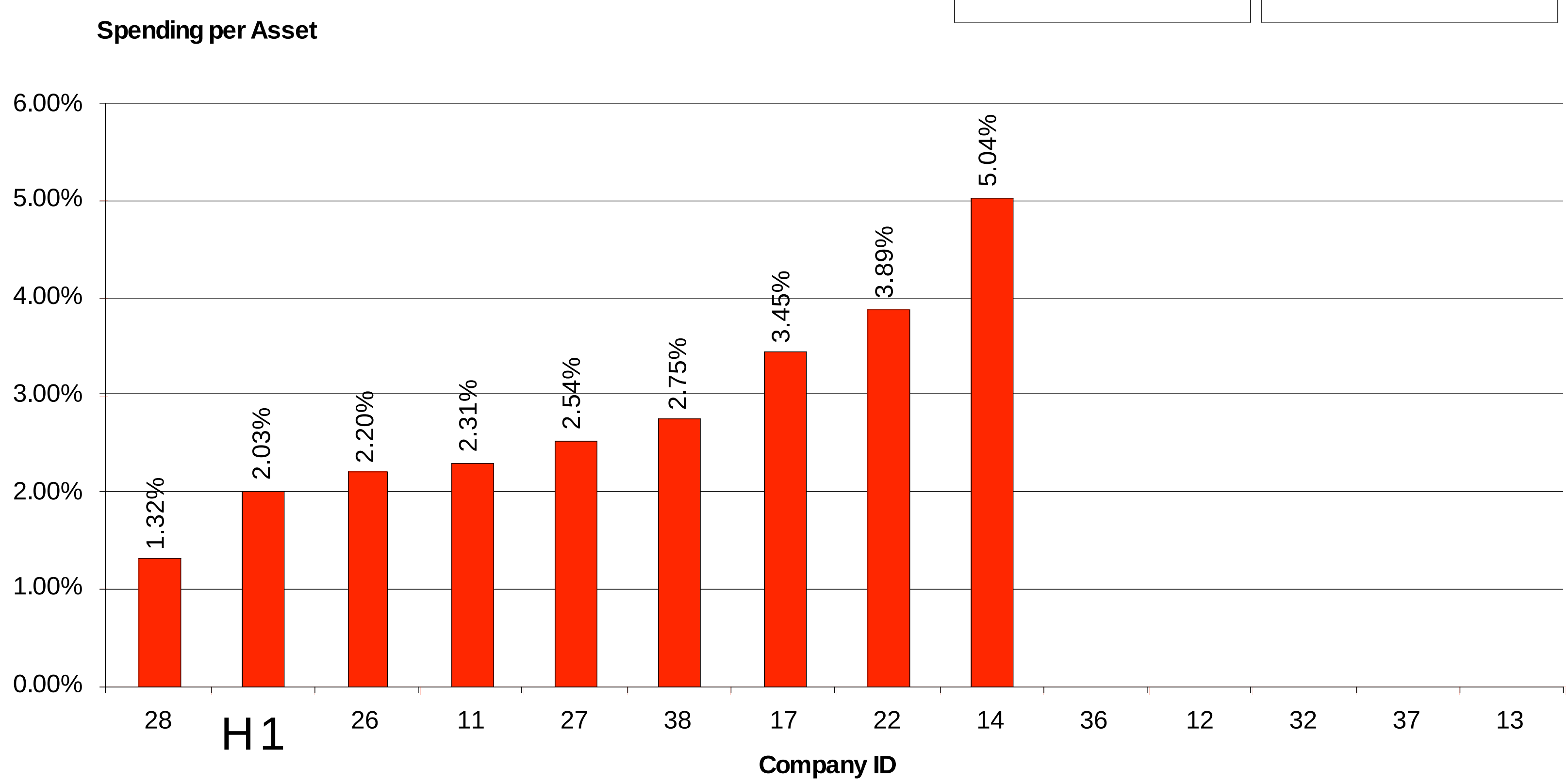


3 year values are 2004-2006, 1 year values are 2006.

3-yr Avg Dist Lines Asset Replacement Rate (excludes new business)

HydroOne:	
Value:	2.03%
Quartile:	Q1
Rank:	2

Panel:	
Mean:	2.84%
Quartile 1:	2.20%
Quartile 2:	2.54%
Quartile 3:	3.45%

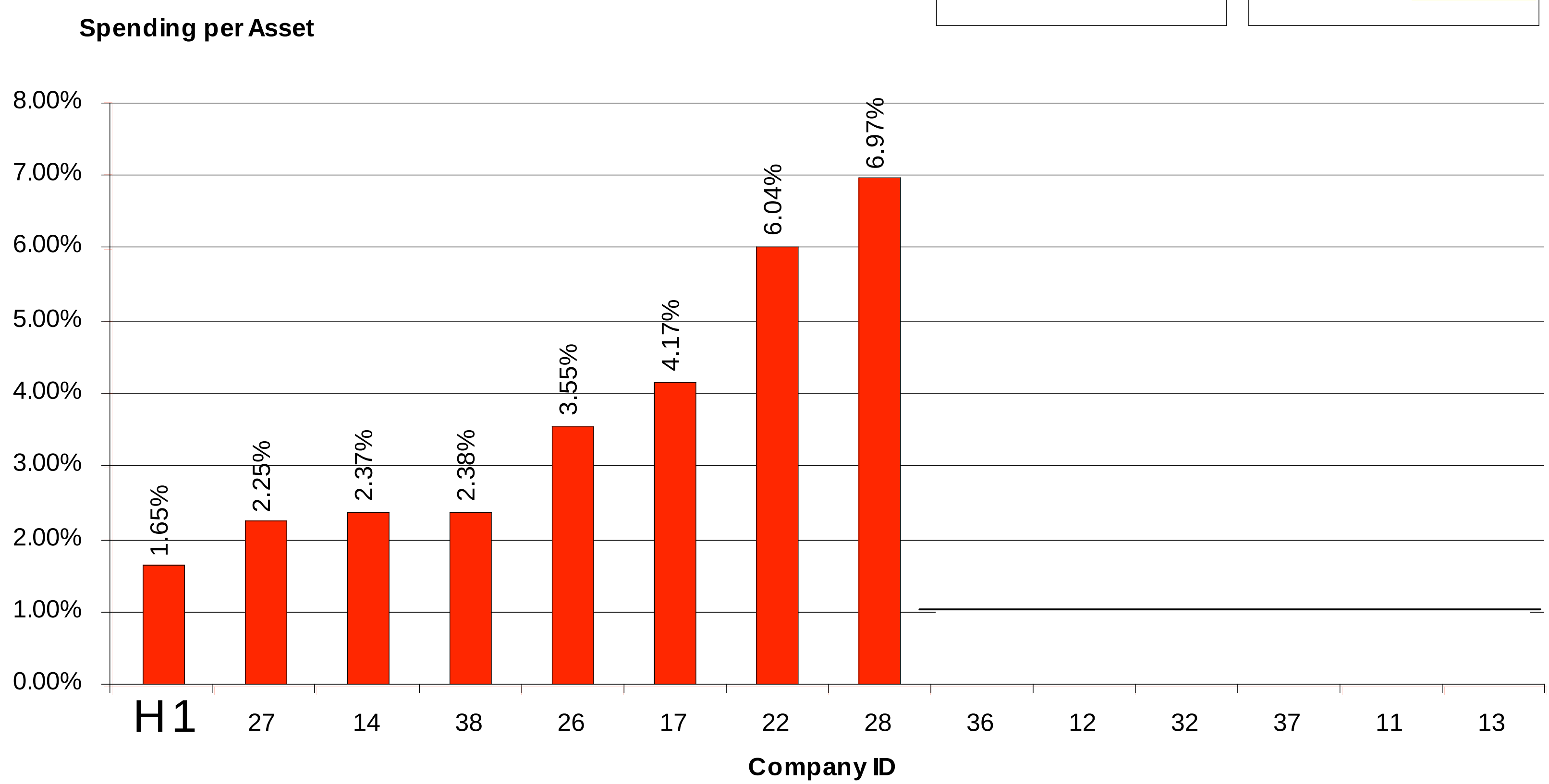


3 year values are 2004-2006, 1 year values are 2006.

3-yr Avg Dist Subs Asset Replacement Rate (excludes new business)

HydroOne:	
Value:	1.65%
Quartile:	Q1
Rank:	1

Panel:	
Mean:	3.67%
Quartile 1:	2.34%
Quartile 2:	2.97%
Quartile 3:	4.64%



3 year values are 2004-2006, 1 year values are 2006.

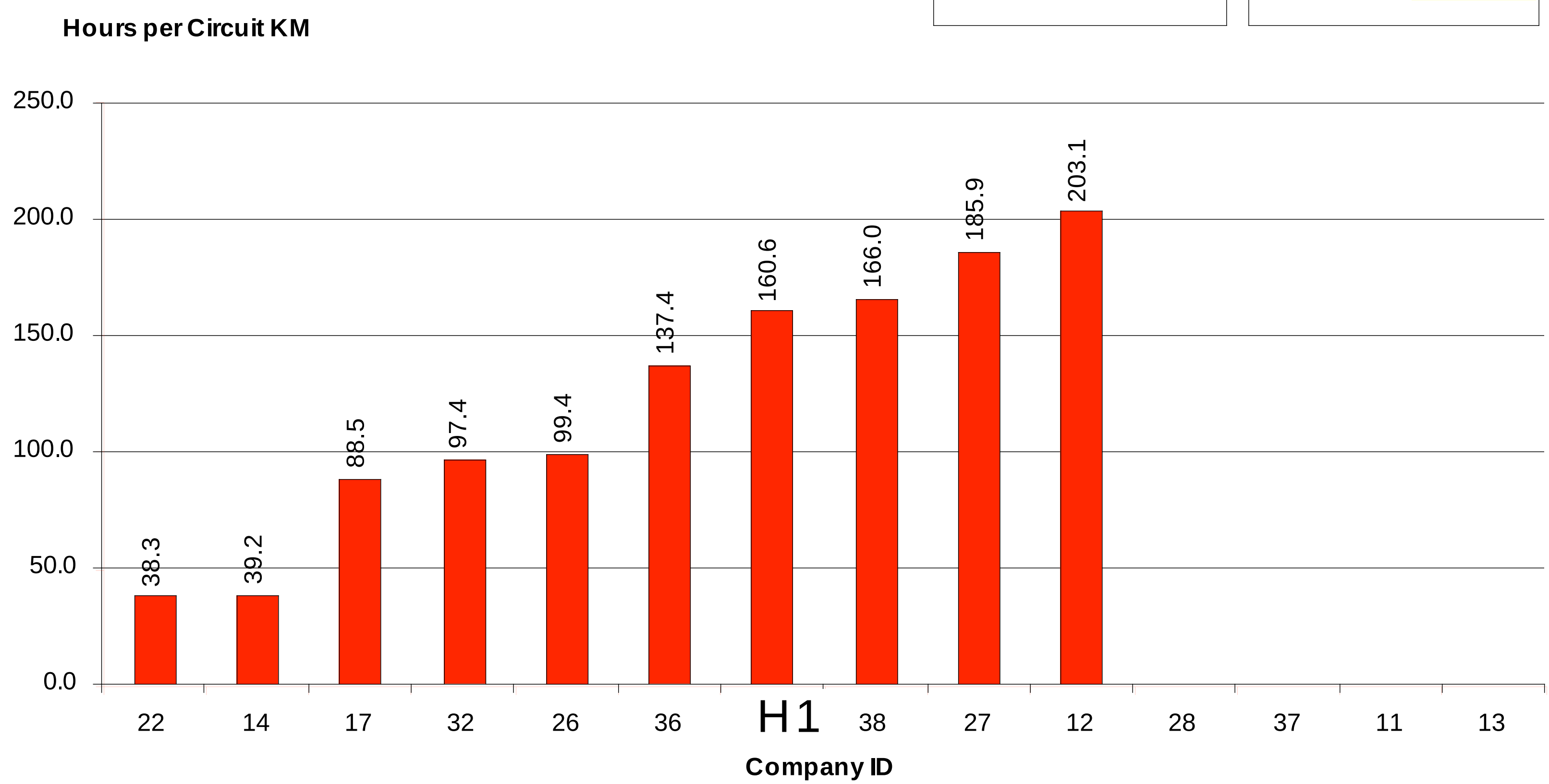
Reliability

3 year values are 2004-2006, 1 year values are 2006.

3-yr Avg Customer Hours per Circuit KM (Including Major Events)

HydroOne:	
Value:	160.6
Quartile:	Q3
Rank:	7

Panel:	
Mean:	121.6
Quartile 1:	90.7
Quartile 2:	118.4
Quartile 3:	164.7

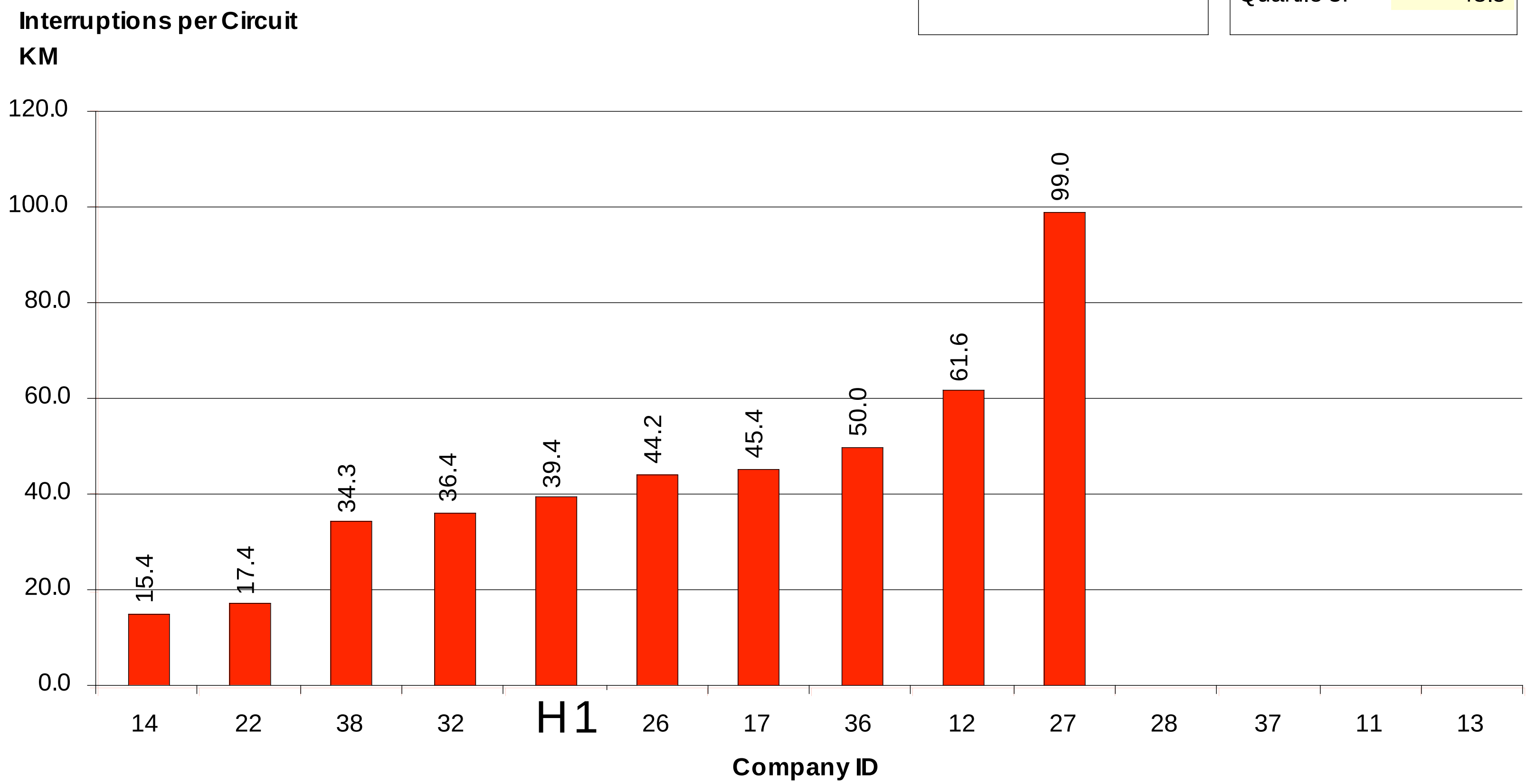


3 year values are 2004-2006, 1 year values are 2006.

3-yr Avg Customer Interruptions per Circuit KM (Including Major Events)

HydroOne:	
Value:	39.4
Quartile:	Q2
Rank:	5

Panel:	
Mean:	44.3
Quartile 1:	34.8
Quartile 2:	41.8
Quartile 3:	48.8

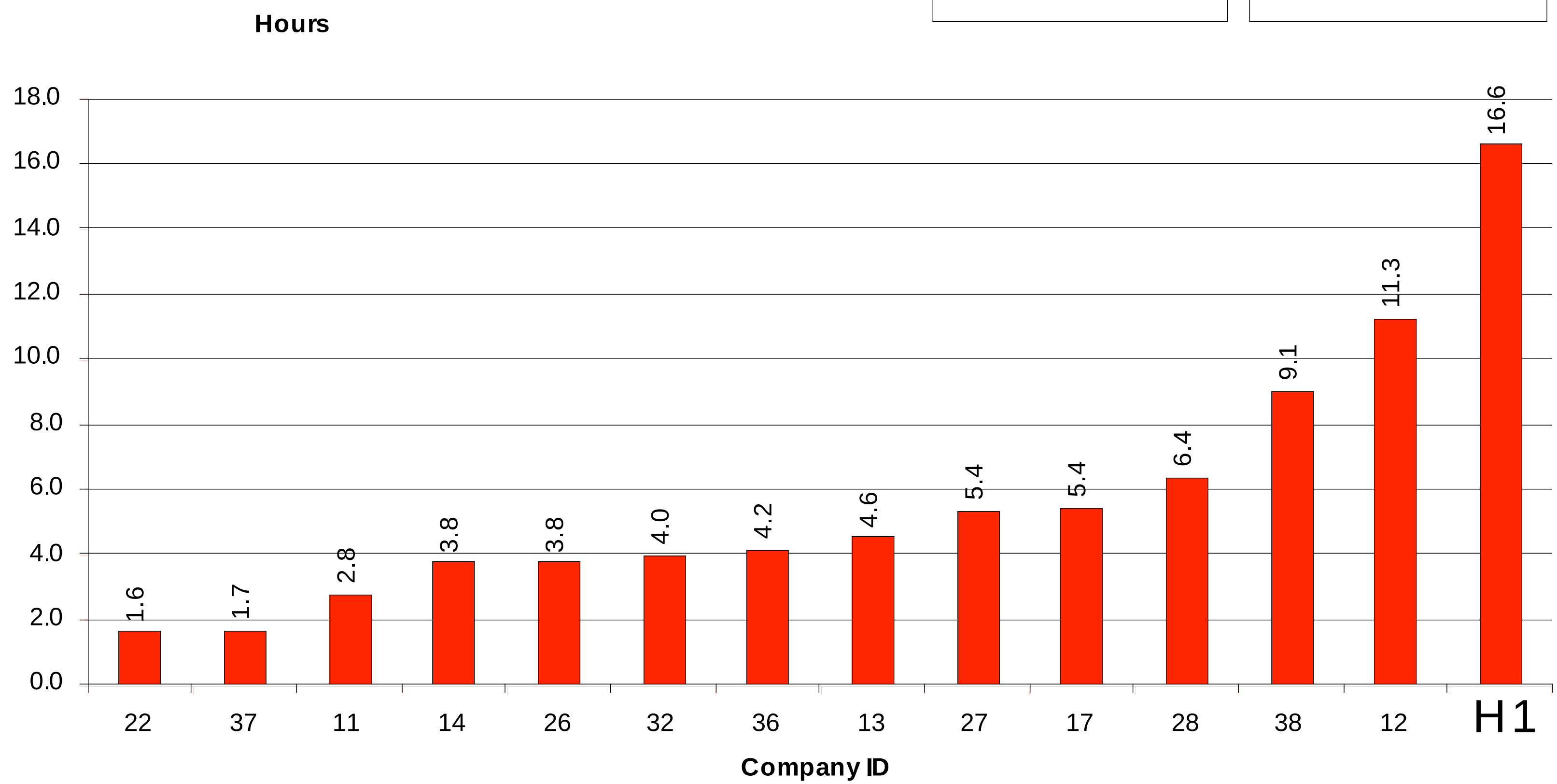


3 year values are 2004-2006, 1 year values are 2006.

3-yr Avg SAIDI (Including Major Events)

HydroOne:	
Value:	16.6
Quartile:	Q4
Rank:	14

Panel:	
Mean:	5.8
Quartile 1:	3.8
Quartile 2:	4.4
Quartile 3:	6.2

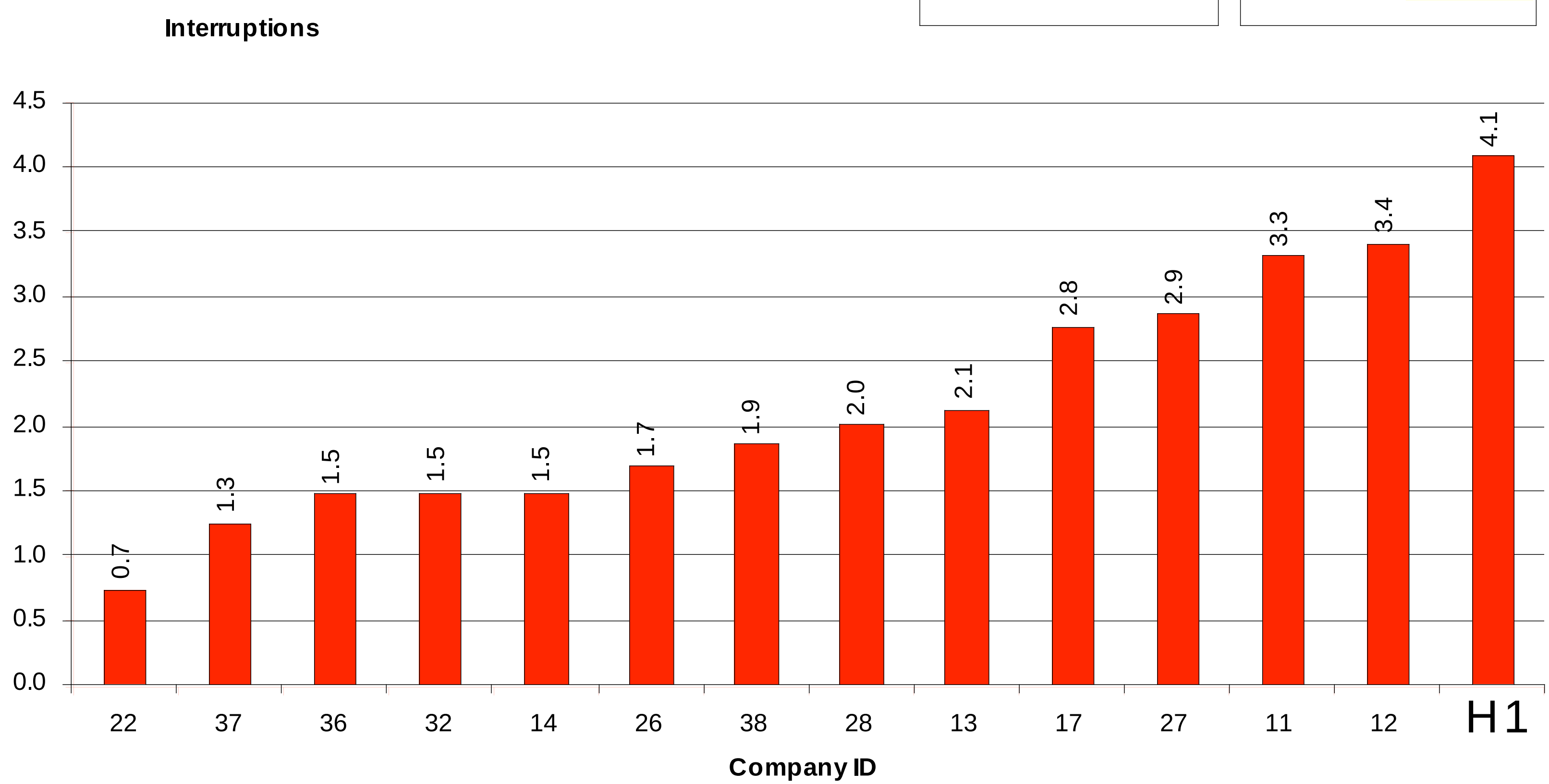


3 year values are 2004-2006, 1 year values are 2006.

3-yr Avg SAIFI (Including Major Events)

HydroOne:	
Value:	4.1
Quartile:	Q4
Rank:	14

Panel:	
Mean:	2.2
Quartile 1:	1.5
Quartile 2:	1.9
Quartile 3:	2.8

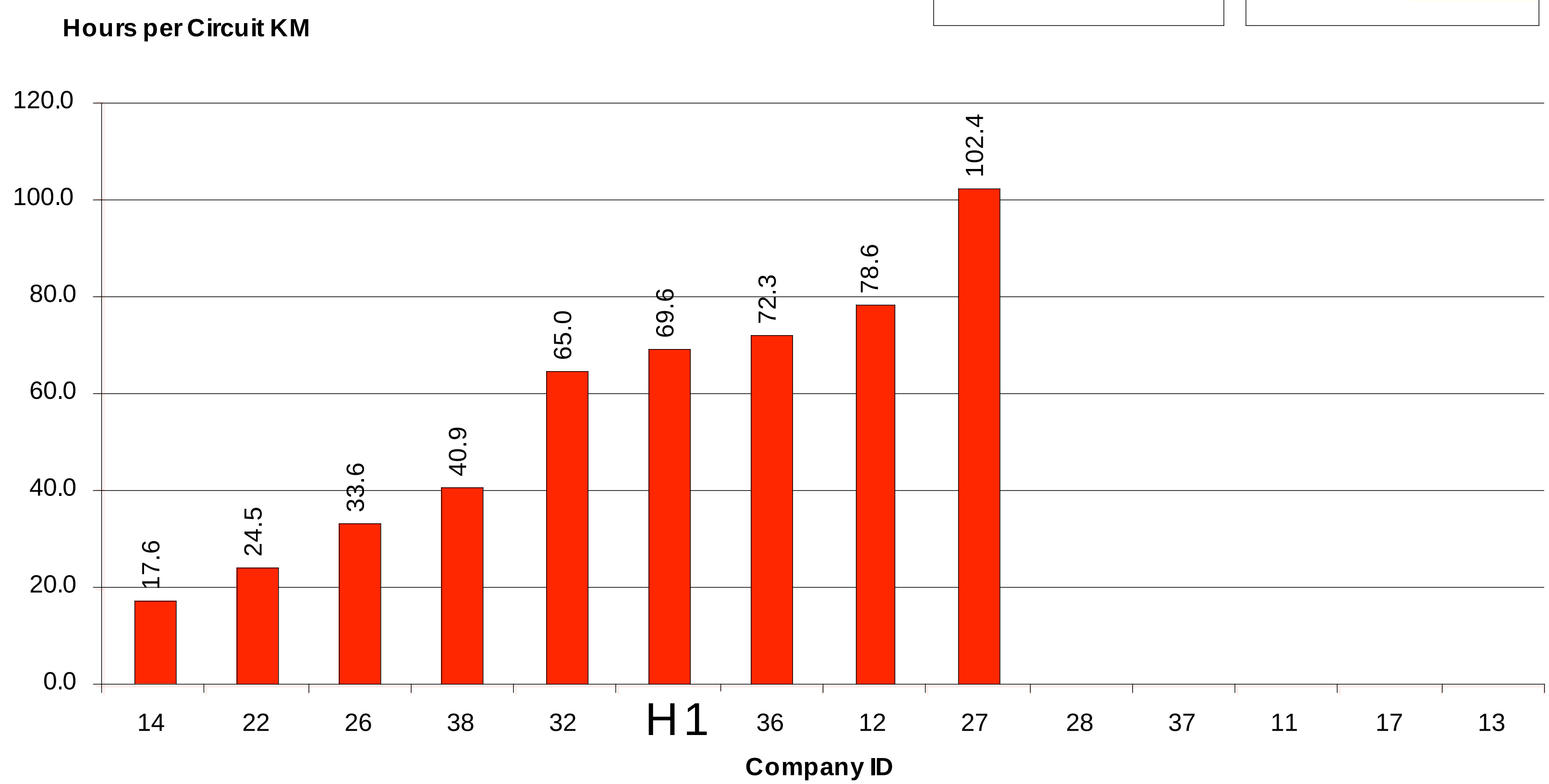


3 year values are 2004-2006, 1 year values are 2006.

3-yr Avg Customer Hours per Circuit KM (Excluding Major Events)

HydroOne:	
Value:	69.6
Quartile:	Q3
Rank:	6

Panel:	
Mean:	56.1
Quartile 1:	33.6
Quartile 2:	65.0
Quartile 3:	72.3

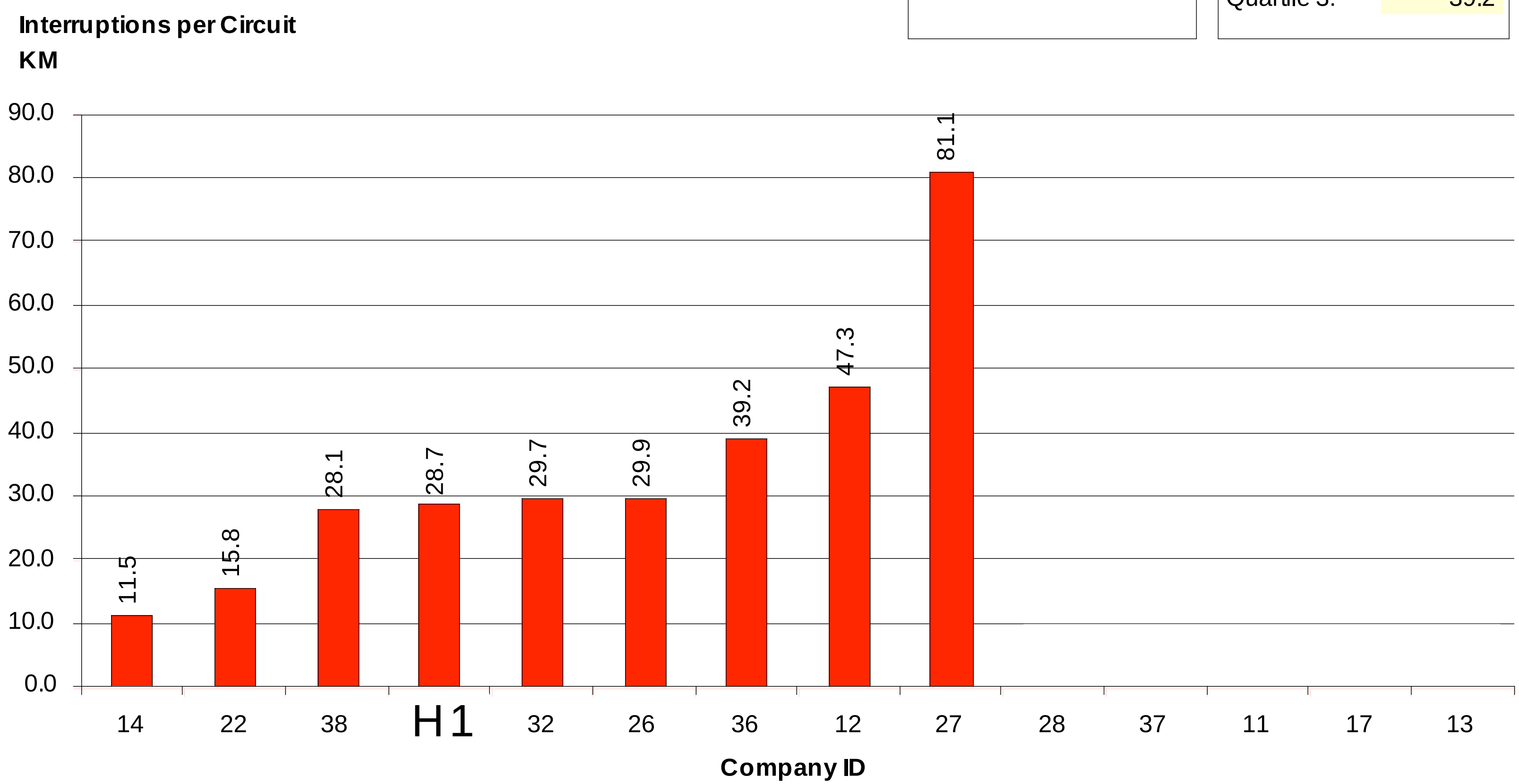


3 year values are 2004-2006, 1 year values are 2006.

3-yr Avg Customer Interruptions per Circuit KM (Excluding Major Events)

HydroOne:	
Value:	28.7
Quartile:	Q2
Rank:	4

Panel:	
Mean:	34.6
Quartile 1:	28.1
Quartile 2:	29.7
Quartile 3:	39.2

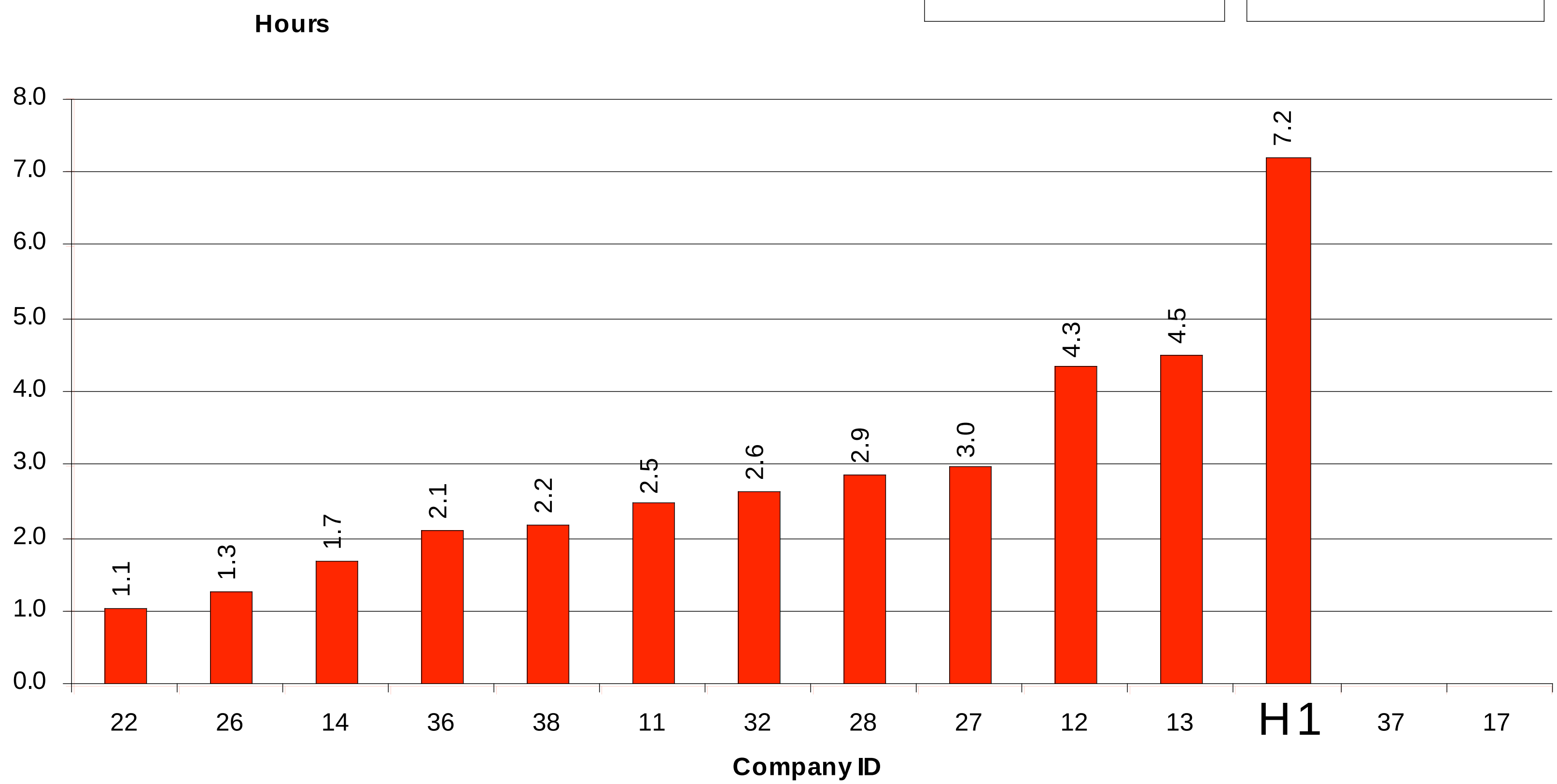


3 year values are 2004-2006, 1 year values are 2006.

3-yr Avg SAIDI (Excluding Major Events)

HydroOne:	
Value:	7.2
Quartile:	Q4
Rank:	12

Panel:	
Mean:	3.0
Quartile 1:	2.0
Quartile 2:	2.6
Quartile 3:	3.3

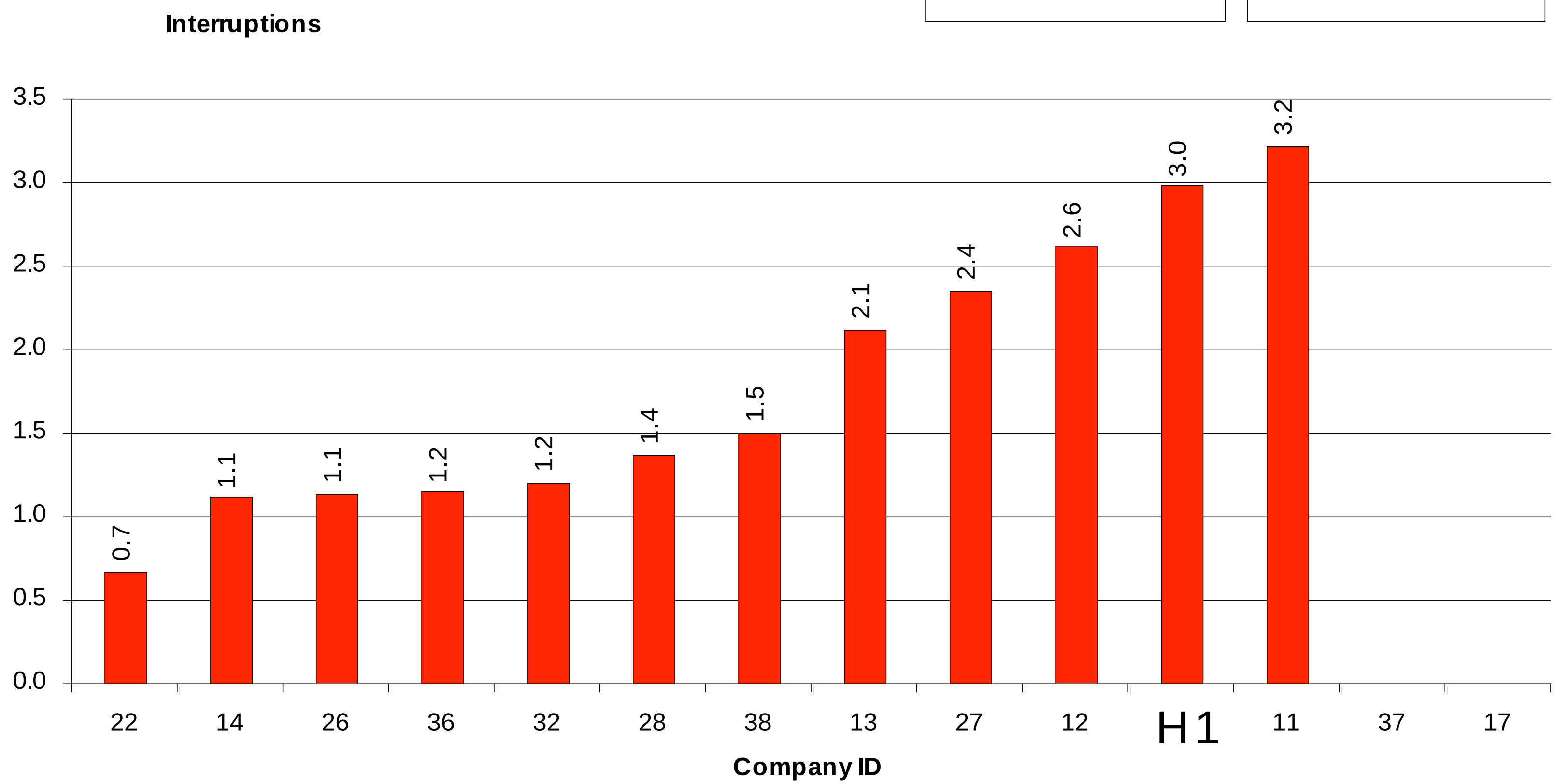


3 year values are 2004-2006, 1 year values are 2006.

3-yr Avg SAIFI (Excluding Major Events)

HydroOne:	
Value:	3.0
Quartile:	Q4
Rank:	11

Panel:	
Mean:	1.8
Quartile 1:	1.2
Quartile 2:	1.4
Quartile 3:	2.4



3 year values are 2004-2006, 1 year values are 2006.

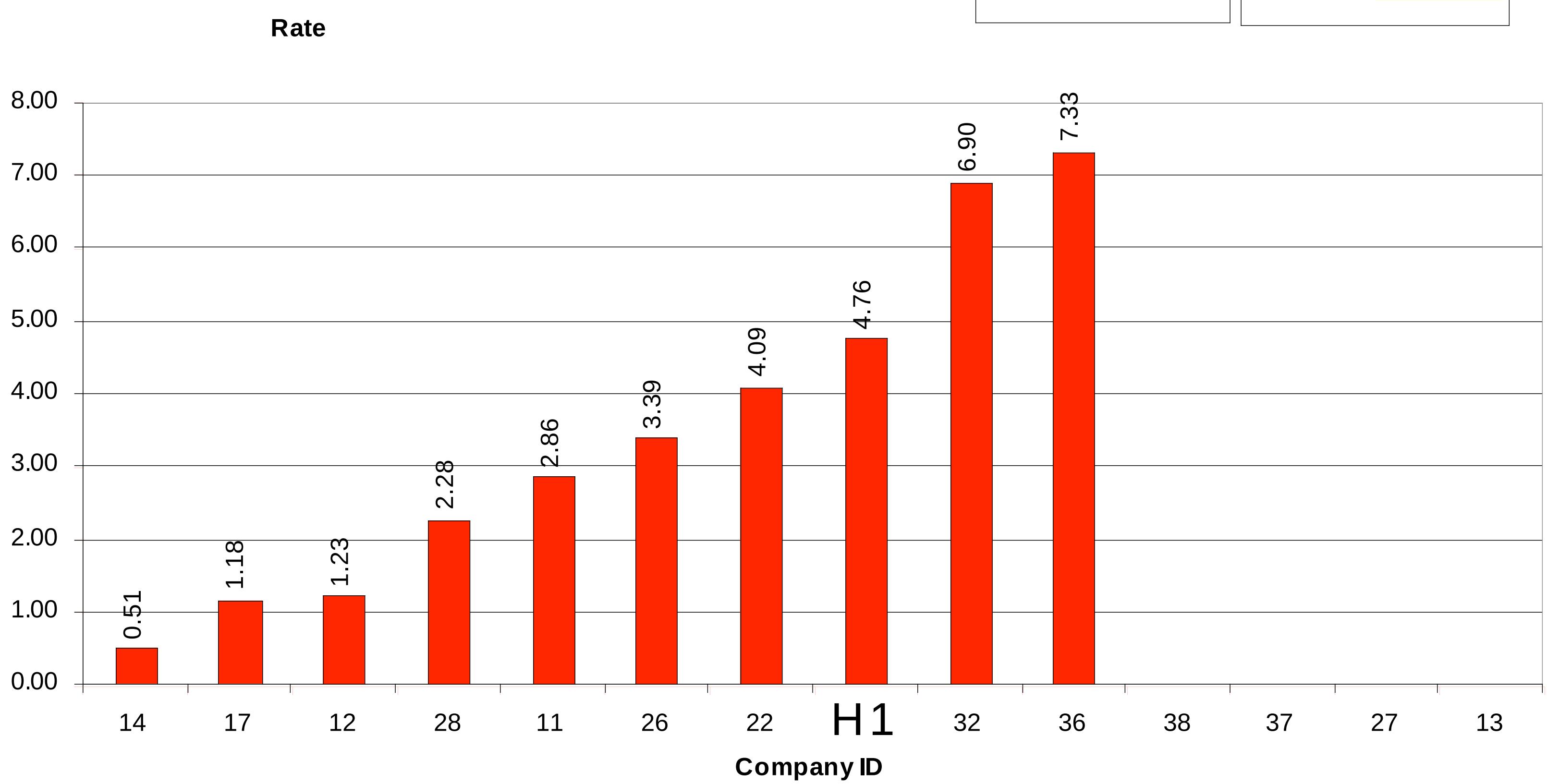
Safety

3 year values are 2004-2006, 1 year values are 2006.

3-yr Avg Recordable Incident Rate - Total Corporate

H-O	
Value:	4.76
Quartile:	Q4
Rank:	8

Panel:	
Mean:	3.45
Quartile 1:	1.49
Quartile 2:	3.13
Quartile 3:	4.59

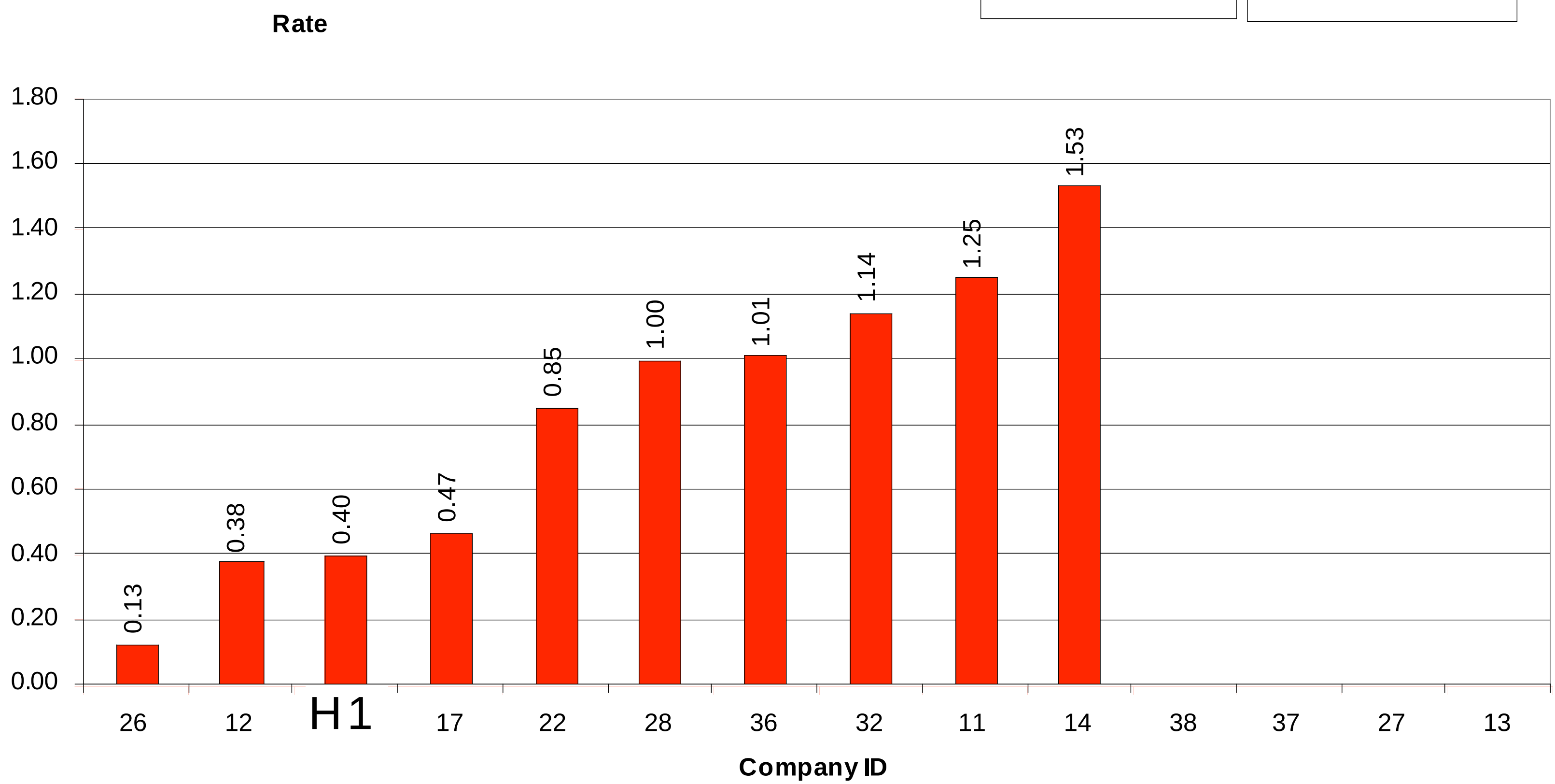


3 year values are 2004-2006, 1 year values are 2006.

3-yr Avg Lost Time Incident Rate - Total Corporate

H-O	
Value:	0.40
Quartile:	Q1
Rank:	3

Panel:	
Mean:	0.82
Quartile 1:	0.42
Quartile 2:	0.93
Quartile 3:	1.11

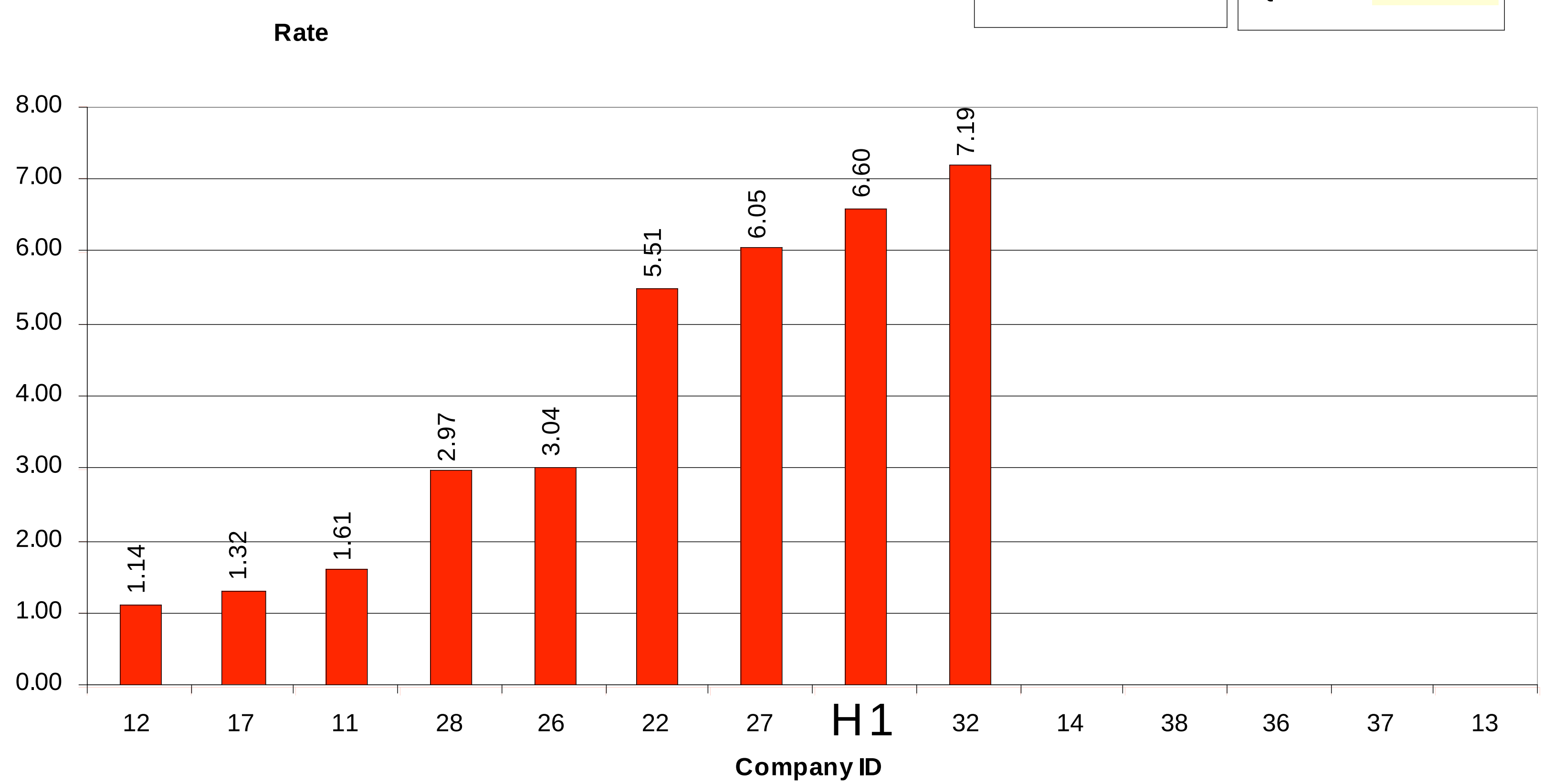


3 year values are 2004-2006, 1 year values are 2006.

3-yr Avg Recordable Incident Rate - Distribution

H-O	
Value:	6.60
Quartile:	Q4
Rank:	8

Panel:	
Mean:	3.94
Quartile 1:	1.61
Quartile 2:	3.04
Quartile 3:	6.05

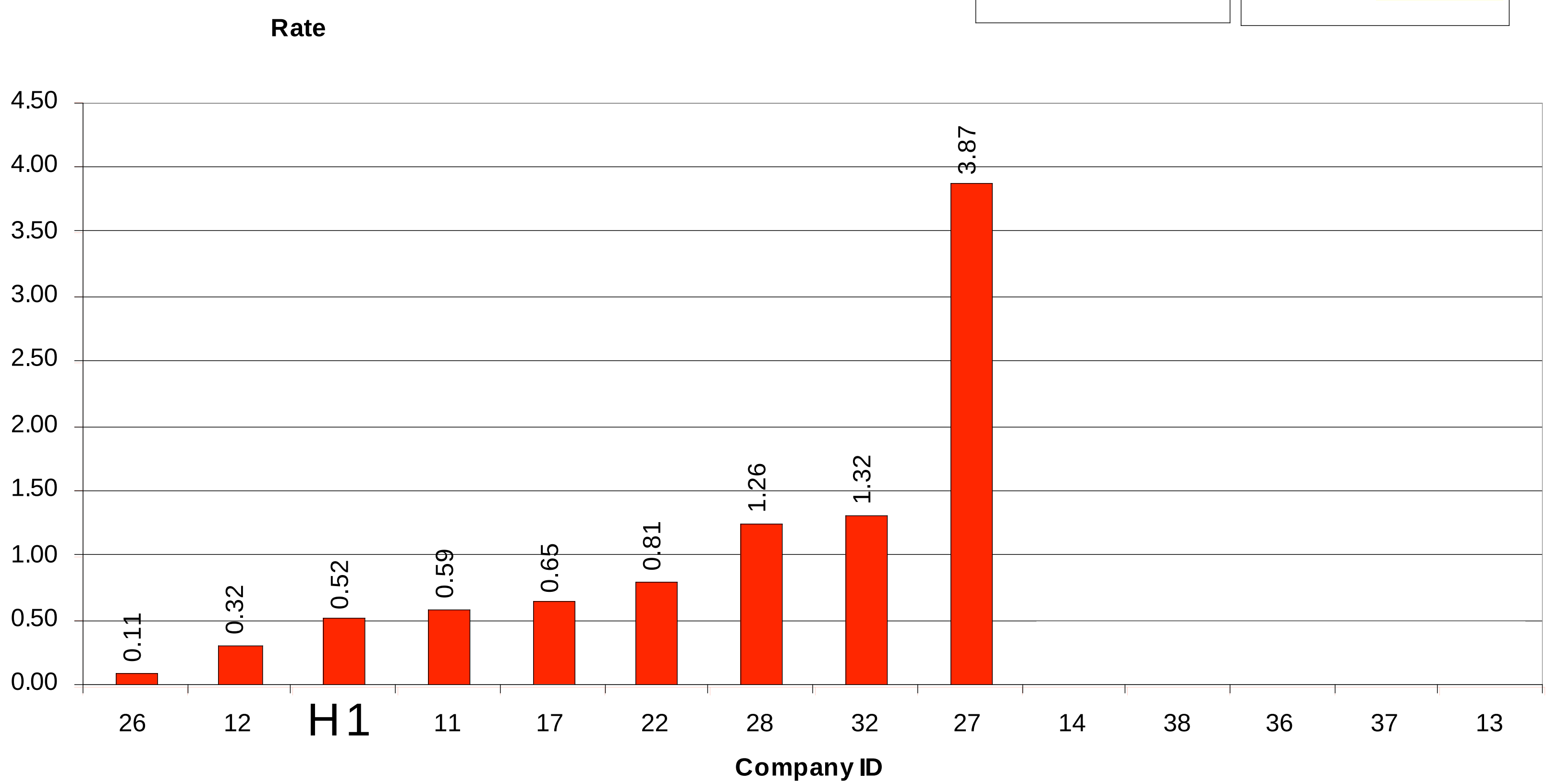


3 year values are 2004-2006, 1 year values are 2006.

3-yr Avg Lost Time Incident Rate - Distribution

H-O	
Value:	0.52
Quartile:	Q2
Rank:	3

Panel:	
Mean:	1.05
Quartile 1:	0.52
Quartile 2:	0.65
Quartile 3:	1.26



3 year values are 2004-2006, 1 year values are 2006.

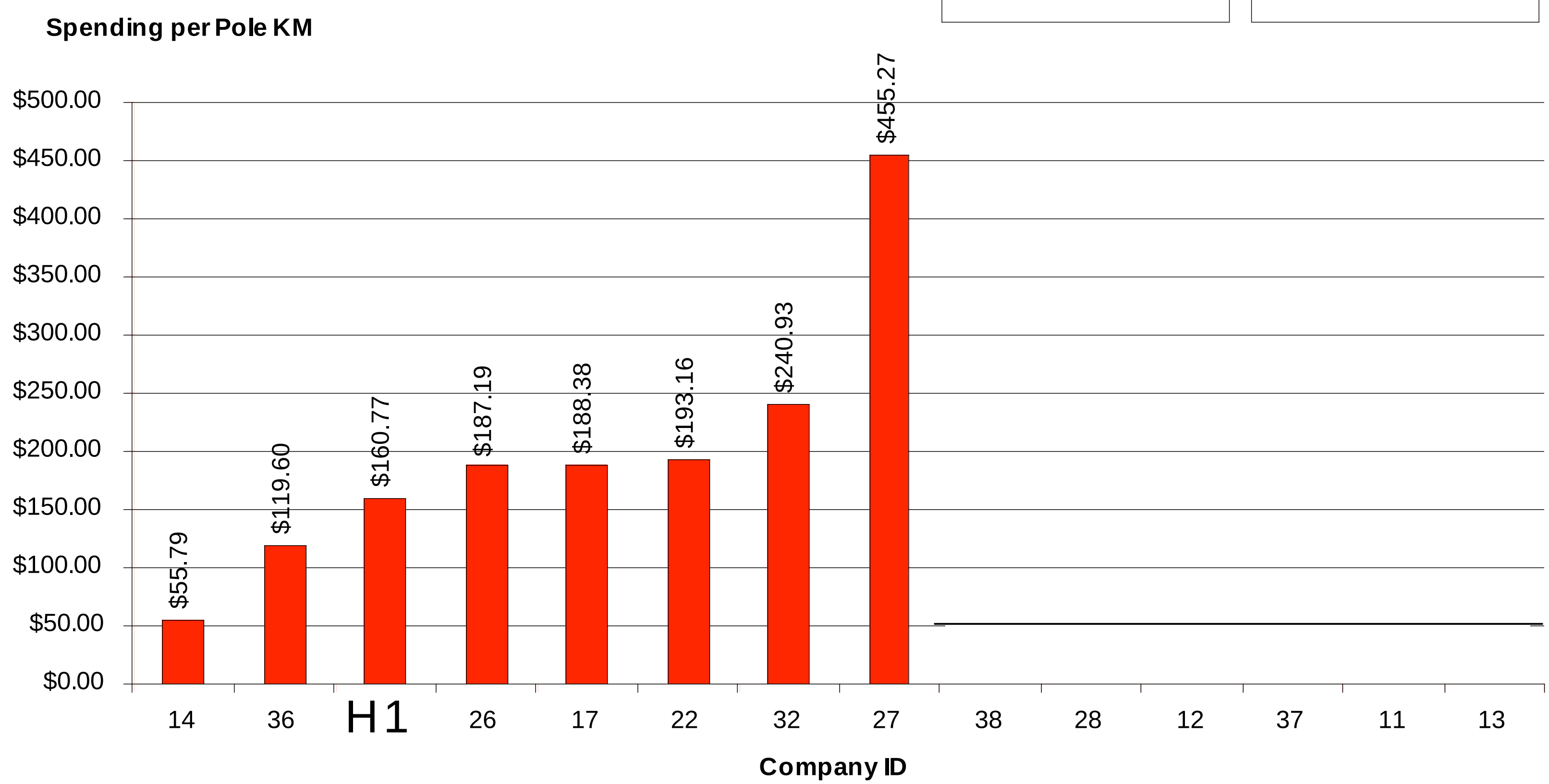
Meter Reading

3 year values are 2004-2006, 1 year values are 2006.

1-yr Meter Reading Expense per Pole KM

HydroOne:	
Value:	$160.77
Quartile:	Q2
Rank:	3

Panel:	
Mean:	$200.14
Quartile 1:	$150.48
Quartile 2:	$187.79
Quartile 3:	$205.11



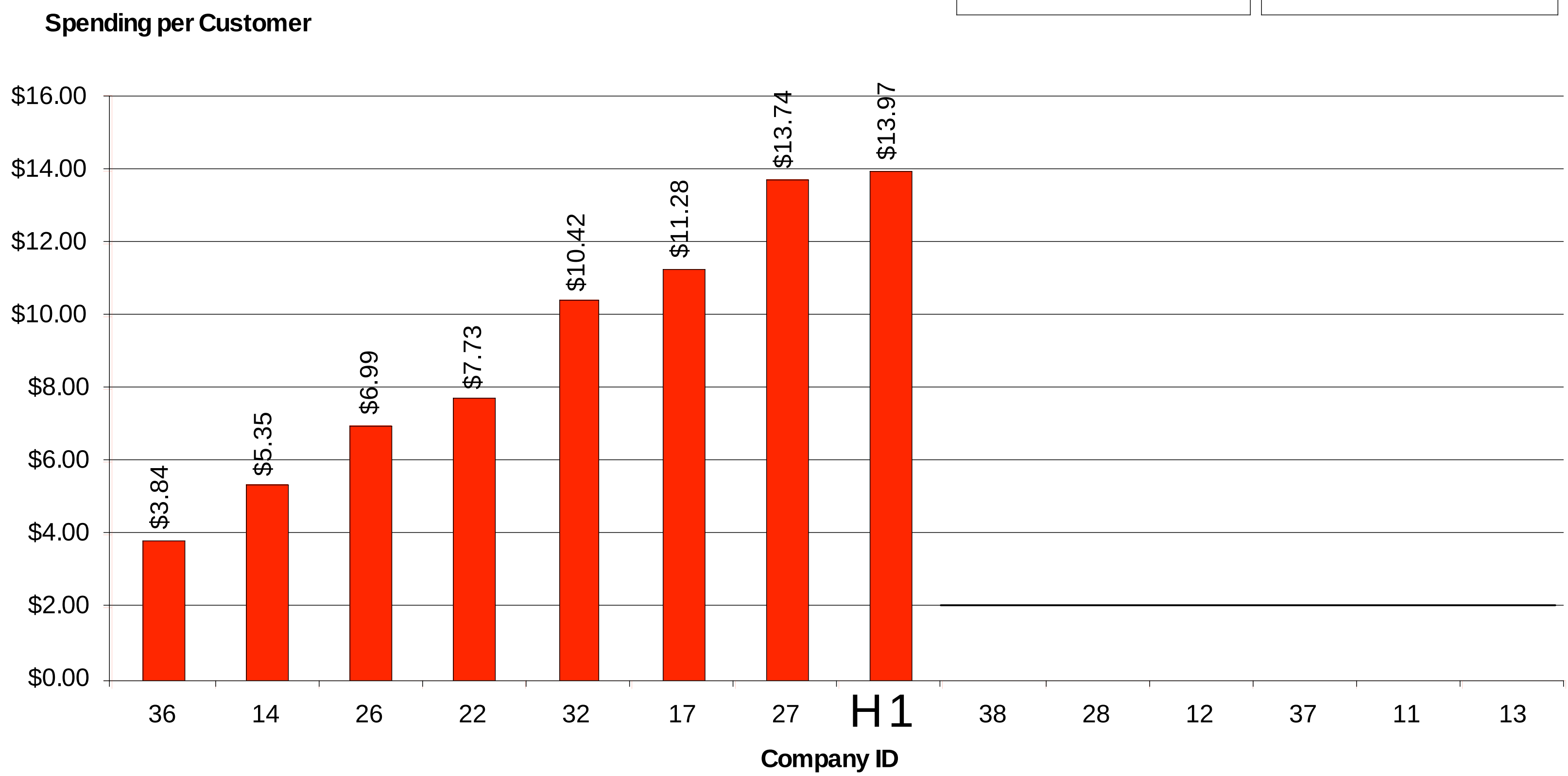
C-34

3 year values are 2004-2006, 1 year values are 2006.

1-yr Meter Reading Expense per Customer

HydroOne:	
Value:	$13.97
Quartile:	Q4
Rank:	8

Panel:	
Mean:	$9.16
Quartile 1:	$6.58
Quartile 2:	$9.07
Quartile 3:	$11.90

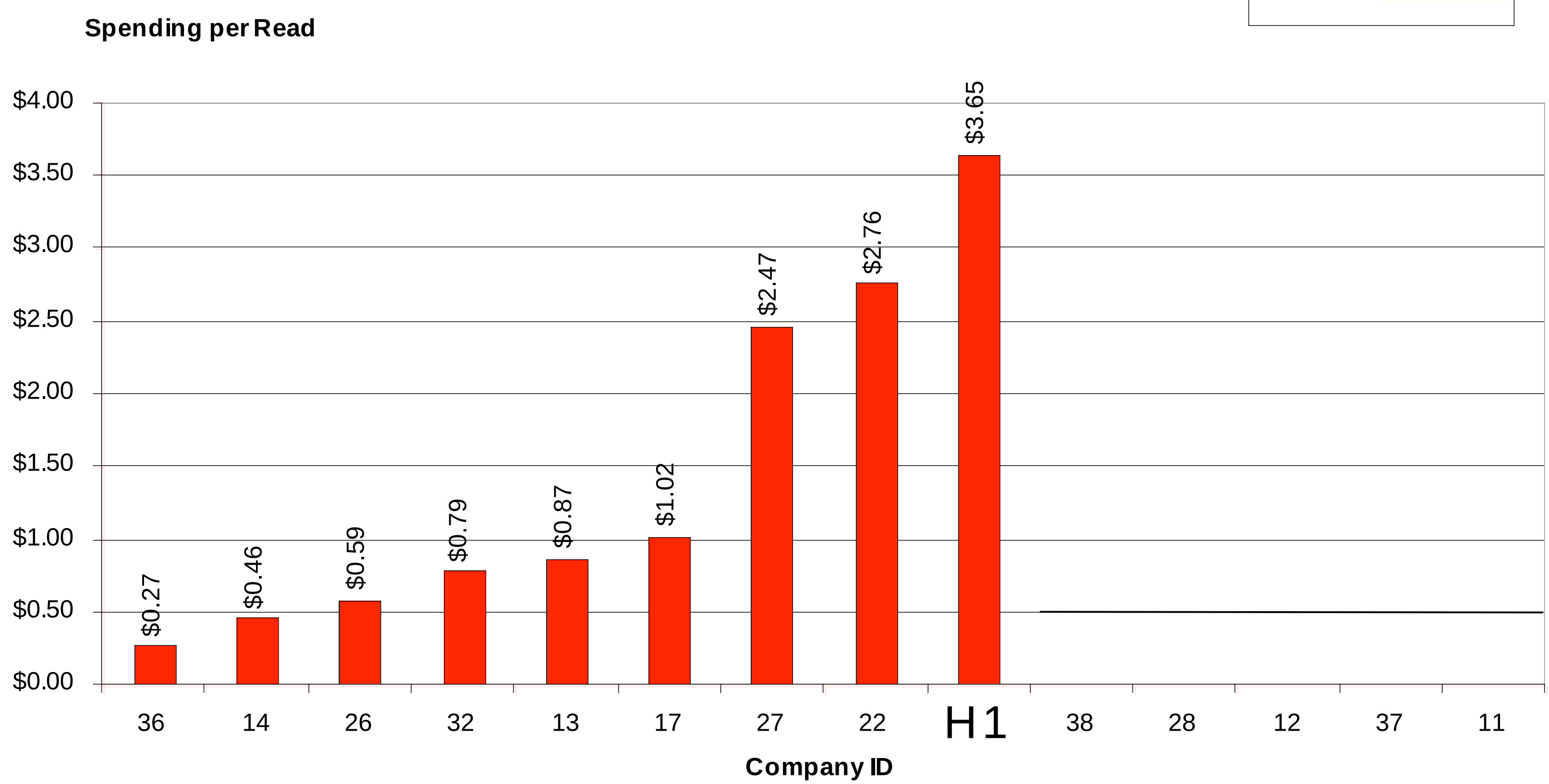


3 year values are 2004-2006, 1 year values are 2006.

1-yr Meter Reading Expense per Read

HydroOne	
Value	$3.65
Quartile	Q4
Rank	9

Panel:	
Mean:	$1.43
Quartile 1:	$0.59
Quartile 2:	$0.87
Quartile 3:	$2.47



3 year values are 2004-2006, 1 year values are 2006.

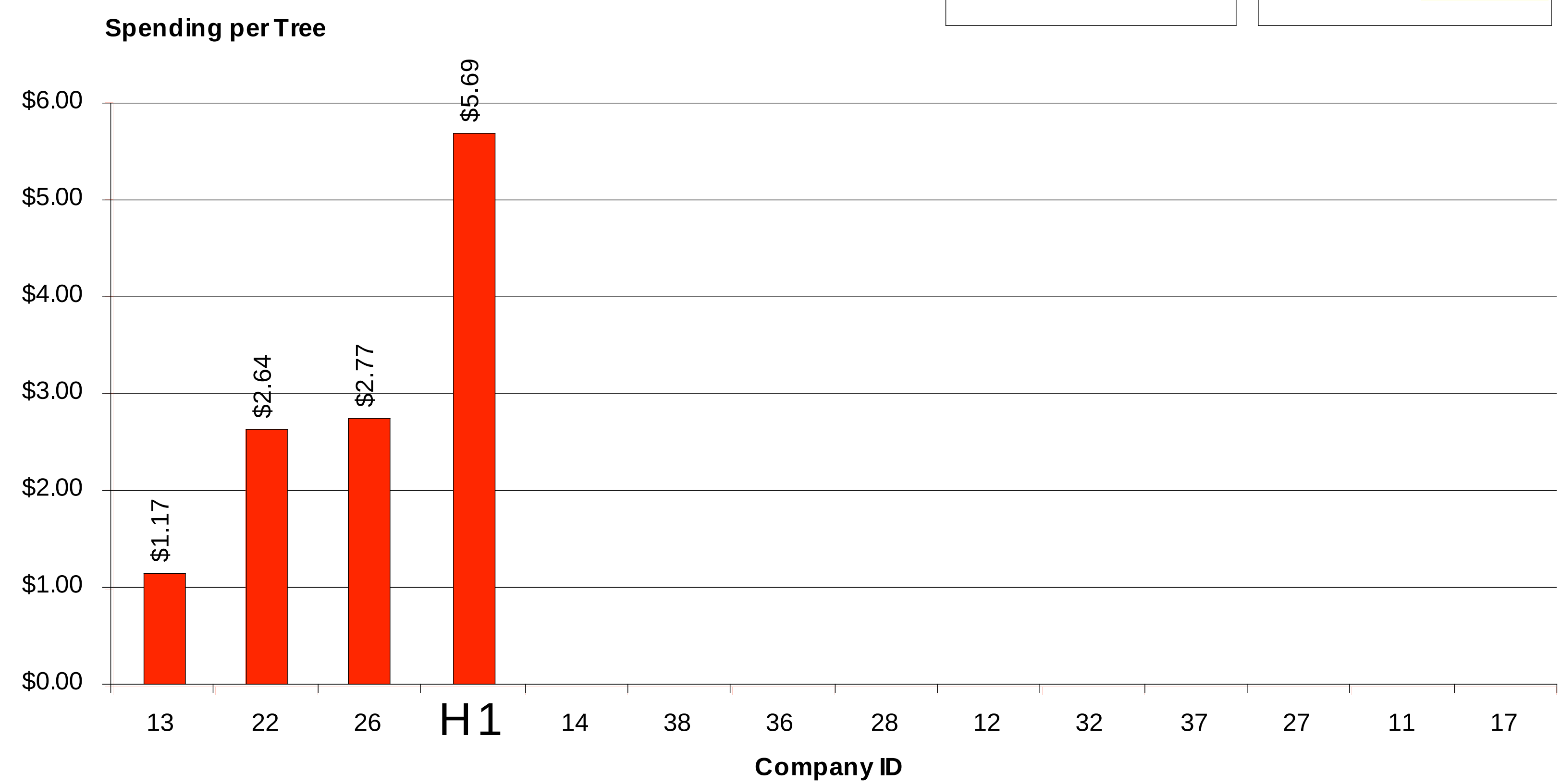
Tree Trimming

3 year values are 2004-2006, 1 year values are 2006.

1-yr Tree Trimming Expense per Trees Managed

HydroOne:	
Value:	$5.69
Quartile:	Q4
Rank:	4

Panel:	
Mean:	$3.07
Quartile 1:	$2.27
Quartile 2:	$2.70
Quartile 3:	$3.50

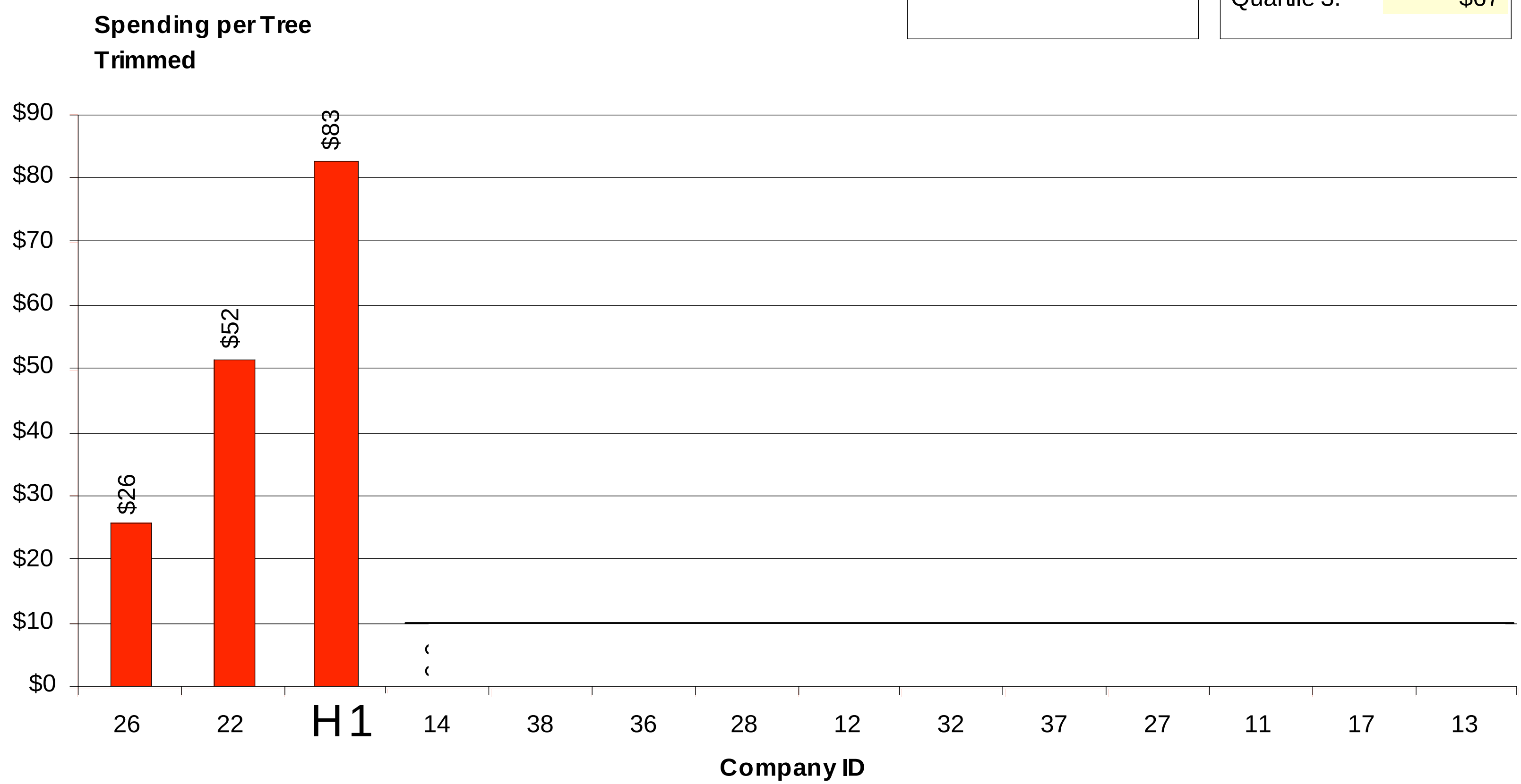


3 year values are 2004-2006, 1 year values are 2006.

1-yr Tree Trimming Expense per Tree Trimmed

HydroOne:	
Value:	$83
Quartile:	Q4
Rank:	3

Panel:	
Mean:	$53
Quartile 1:	$39
Quartile 2:	$52
Quartile 3:	$67

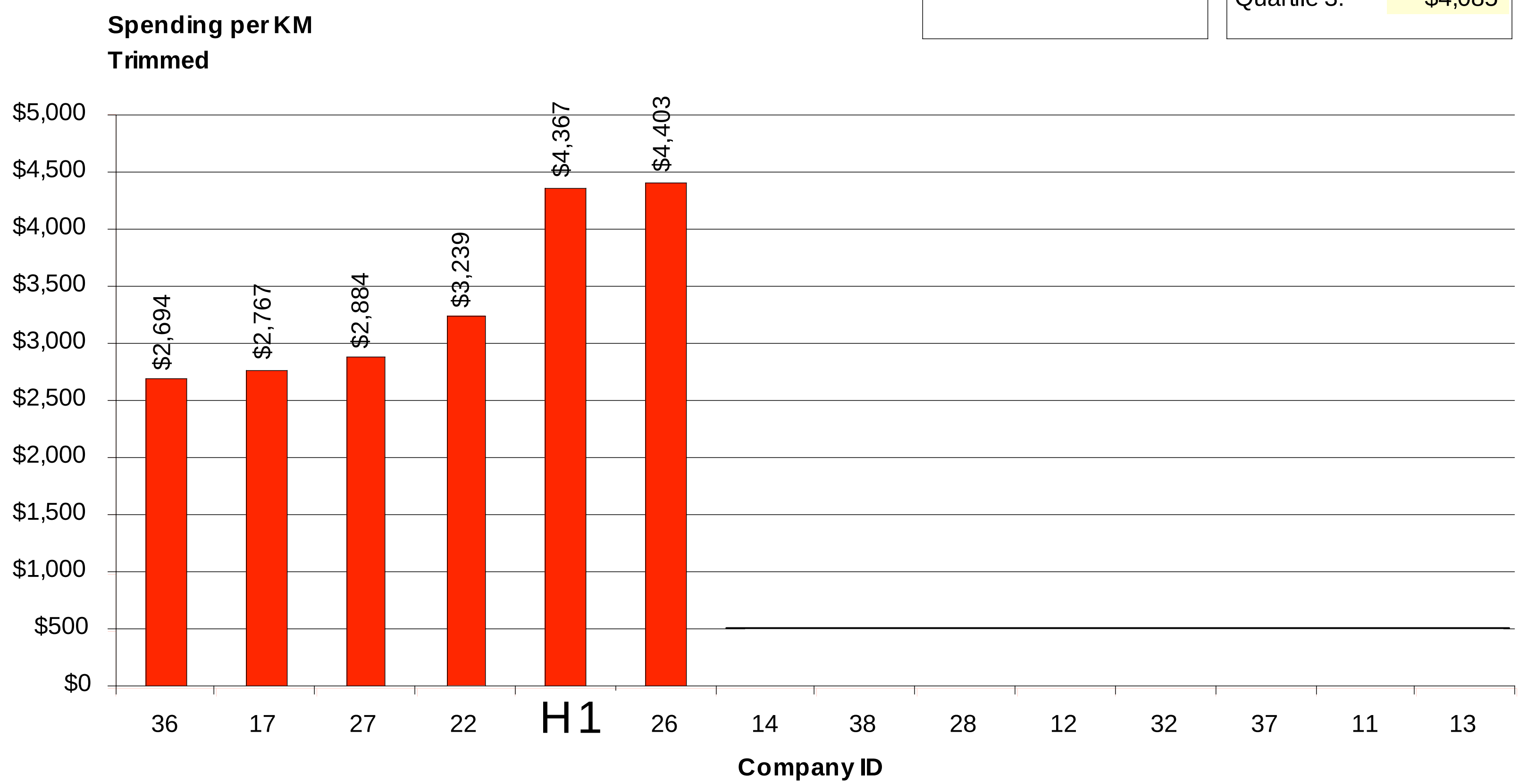


3 year values are 2004-2006, 1 year values are 2006.

1-yr Tree Trimming Expense per KM Trimmed

HydroOne:	
Value:	$4,367
Quartile:	Q4
Rank:	5

Panel:	
Mean:	$3,392
Quartile 1:	$2,796
Quartile 2:	$3,061
Quartile 3:	$4,085

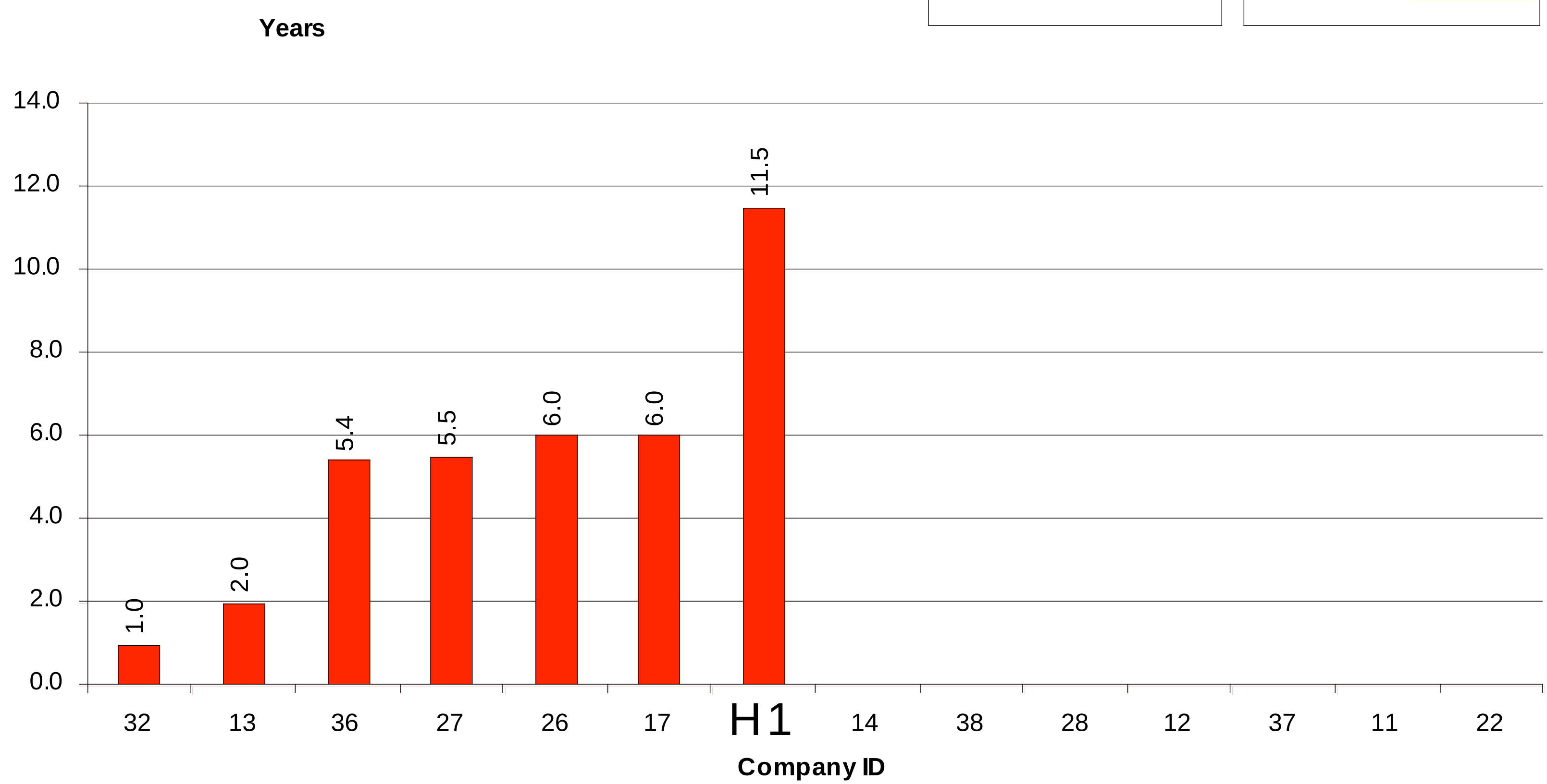


3 year values are 2004-2006, 1 year values are 2006.

Cycle Time Actuals

HydroOne:	
Value:	11.5
Quartile:	Q4
Rank:	7

Panel:	
Mean:	5.3
Quartile 1:	3.7
Quartile 2:	5.5
Quartile 3:	6.0



3 year values are 2004-2006, 1 year values are 2006.

2007 Comparison of Labour Rates and Overtime Policy

FINAL REPORT

October, 2007

Prepared By:

Karl Aboud
Stephanie Hudakoc

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Section

Appendices

I. Introduction

Purpose

The Ontario Energy Board (OEB) directed Hydro One Networks (Hydro One) to engage an independent party to, "Develop a comparison of labour rates and overtime policies amongst Hydro One, other comparative Ontario electricity distributors, and other Canadian utilities as identified in the high level benchmarking survey." As a result, Hydro One issued a Request for Proposal (RFP) from which Hay Group was selected to conduct a custom survey on labour rates and overtime policies of three benchmark positions among a selected group of organizations. The purpose of this report is to provide comparisons of Hydro One pay values relative to those of the market.

Survey Benchmark Positions

The following three positions were selected as the survey benchmark positions as they represent a large component of the workforce and are typical of job classifications across the utility industry (see Appendix A for full descriptions):

1. Field Operations Manager
2. Design Engineer
3. Powerline Maintainer

II. Executive Summary

Field Operations Manager

Hydro One is below market on both the hourly wage rate minimum and maximum. Hydro One's hourly wage rate minimum of $35.55 is 24% below the market's average of $46.92, while Hydro One's hourly wage rate maximum of $56.73 is 10% below the market average of $62.96. The Field Operations Manager at Hydro One is not eligible for overtime. Two out of the eleven market survey participants that matched to Field Operations Manager are eligible for overtime. Neither Hydro One nor any of the market survey participants have union representation for the Field Operations Manager.

Design Engineer

Hydro One is in-line with market on both the hourly wage rate minimum and maximum. Hydro One's hourly wage rate minimum of $37.22 is comparable to the market's average of $37.16, while Hydro One's hourly wage rate maximum of $53.38 is 4% above the market average of $51.55. The Design Engineer at Hydro One is eligible for overtime. Seven out of the fourteen market survey participants that matched to Design Engineer are eligible for overtime. Hydro One and four out of the fourteen market survey participants have union representation for the Design Engineer.

Powerline Maintainer

Hydro One's hourly rate wage minimum of $18.72 is considerably below the market on the hourly wage rate minimum, however the hourly wage rate maximum is above the market. Hydro One's hourly wage rate minimum of $18.72 is 30% below the market's average of $26.76, while Hydro One's hourly wage rate maximum of $36.10 is 12% above the market average of $32.31. The Powerline Maintainer at Hydro One is eligible for overtime. All of the thirteen market survey participants that matched to the Powerline Maintainer are eligible for overtime. Hydro One and all of the thirteen organizations that matched to the Powerline Maintainer have union representation.

III. Survey Participation & Organizational Profile

Reference Market

Hay Group contacted seventeen prospective organizations to be invited to participate in the survey. The selected comparator market is a statistically relevant sample, comprised of the following fourteen organizations that agreed to participate in the survey:

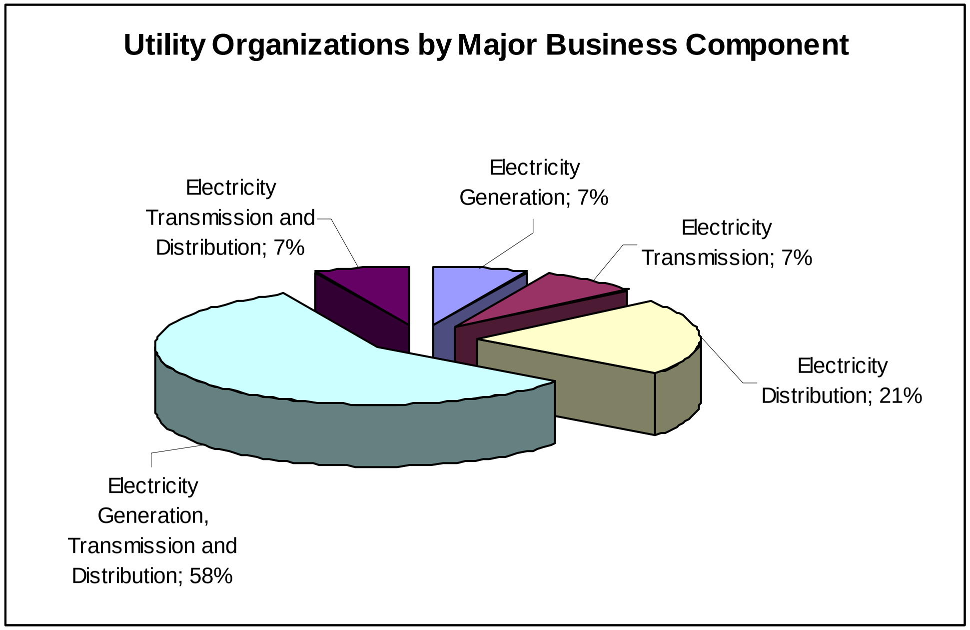
- ATCO Electric
- British Columbia Hydro and Power Authority
- EPCOR
- FortisAlberta Inc.
- FortisBC Inc.
- Hydro Ottawa Limited
- Hydro-Québec
- Manitoba Hydro
- New Brunswick Power Corporation
- Newfoundland Power Inc.
- Nova Scotia Power Inc.
- Ontario Power Generation Inc.
- SaskPower
- Toronto Hydro Corporation

Organization Profile

The average and median organizational profiles of the fourteen organizations are as follows:

Statistical Reference	Gross Revenue / Operating Budget ($Millions)	Total Assets ($Millions)
Hydro One	***$4,545.0***	***$12,234.0***
Average	$2,255.4	$9,018.1
Median	$1,456.0	$3,408.0

The chart below summarizes the major business component of the participating utility organizations:



IV. Terms and Methodology

Compensation Elements and Overtime Principles

This report provides comparative data for specific elements of cash compensation and overtime principles as defined below.

Hourly Rate Minimum – The minimum hourly wage rate that the organization is willing to pay an incumbent for the job in question.

Hourly Rate Maximum – The maximum hourly wage rate that the organization is willing to pay an incumbent for the job in question.

Number of Wage Steps – The number of hourly wage rate steps for each job, including minimum and maximum.

Standard Length of Time From Minimum to Maximum Wage Rate – The number of months an incumbent must be in the job in order to progress from the minimum to the maximum hourly wage rate.

Number of Hours in a Standard Work Week – The standard number of hours that an incumbent in the job is required to work each week.

Overtime Eligibility – Whether the job is eligible for overtime.

Overtime Wage Standards and Rates – The applicable levels of overtime rates.

Union Representation – Staff represented by a union.

Statistical References

Market data are reported using the following statistics:

P90	– **the 90th percentile**, below which 90% of the values fall (requires a minimum of 11 organizations to illustrate).
P75	– **the 75th percentile**, below which 75% of the values fall (requires a minimum of 7 organizations to illustrate).
P50	– **the 50th percentile (Median)**, below which 50% of the values fall (requires a minimum of 4 organizations to illustrate).
P25	– **the 25th percentile**, below which 25% of the values fall (requires a minimum of 7 organizations to illustrate).
P10	– **the 10th percentile**, below which 10% of the values fall (requires a minimum of 11 organizations to illustrate).
Average	– **the arithmetic mean** of all values (requires a minimum of 3 organizations to illustrate).

Methodology

Hay Group designed and sent a custom survey questionnaire. For each benchmark position, a brief profile was developed, which is included in Appendix A. Participants were asked to match positions in their organization with the benchmark position profiles and to provide more insights into their jobs, such as the number of overall reports and other accountabilities not specified in the profile. The survey also included questions regarding the organization's overtime policies. Once the completed surveys were returned to Hay Group, participants were contacted for data verification as necessary. Hay Group also initiated a number of follow-up actions to clarify information provided by the participants.

Using the Hay Job Evaluation Method, a Hay Group consultant evaluated the three Hydro One benchmark positions and the matched positions submitted from each of the survey participants. A summary of the Hay Evaluation Method is provided in Appendix B. The evaluation points assigned to each of the three Hydro One benchmark positions are as follows:

Field Operations Manager	543 Total Points (i.e., the standard Price Point for any Hydro One Band 7 position)
Design Engineer	479 Total Points
Powerline Maintainer	203 Total Points

The job comparisons from the various organizations were "point-adjusted" to account for the different aspects of the total job content, defined as Know-How, Problem Solving and Accountability.

The submitted survey data were either annual salary dollars or hourly wage rates. To eliminate any skewing of results due to different weekly hours, the results were presented as hourly wage rates rather than annual salary.

The aggregate wage rate data were adjusted to Hydro One's specific point levels of each of the three jobs in order to account for the differences amongst the matched jobs. The raw data was compiled into dollar per Hay point ratios and then multiplied by Hydro One's points.

The following example illustrates the adjustment methodology that was used, which is a standard approach by which to adjust for complexity and responsibility differences amongst generally similar jobs in the marketplace.

Example of adjustment methodology using hypothetical data:

Participants	Maximum Hourly Wage Rate Not Adjusted for Hay Points	Hay Points Assigned	Maximum Hourly Wage Rate Per Hay Points Assigned	Maximum Hourly Wage Rate Adjusted for Hay Points (i.e., Hay Points x Wage Rate Per Point)
A	50.22	469	0.107	54.61
B	60.63	450	0.135	68.71
C	60.40	539	0.112	57.15
D	59.00	438	0.135	68.70
E	58.67	469	0.125	63.80
Client	**53.48**	**510**		**53.48**
Median	59.00			63.80
Average	57.78	473		62.59
N	5			5
vs Market Average	**-7.4%**			**-14.6%**

V. Benchmark Position Survey Results

Job Evaluation Results

The table following summarizes the findings collected from the selected organizations in setting the evaluation points for each benchmark position surveyed.

Summary of Job Evaluation Results

Survey Code	Survey Position	Hydro One Evaluation	Average Market Evaluations	Comparable Job Findings
1	Field Operations Manager	543	491	– 2 have more points than Hydro One's job – 2 have similar points than Hydro One's job – 7 have less points than Hydro One's job
2	Design Engineer	479	455	– 1 has more points than Hydro One's job – 9 have similar points than Hydro One's job – 4 have less points than Hydro One's job
3	Powerline Maintainer	203	204	– 1 has more points than Hydro One's job – 12 have similar points than Hydro One's job

Survey Results

This section compares Hydro One to the average wage values, overtime policies and union representation for each of the surveyed positions.

Summary of Market Comparison

Survey Position	Hourly Wage Rate Minimum			Hourly Wage Rate Maximum			Overtime Policies		Union Representation	
	Hydro One	Market Average*	Variance from Market Average*	Hydro One	Market Average*	Variance from Market Average*	Hydro One (# yes)	Market (# yes)	Hydro One (# yes)	Market (# yes)
Field Operations Manager	35.55	46.92	-24%	56.73	62.96	-10%	0	2	0	0
Design Engineer	37.22	37.16	0%	53.38	51.55	4%	1	7	1	4
Powerline Maintainer	18.72	26.76	-30%	36.1	32.31	12%	1	13	1	13

** Market data have been adjusted at Hydro One's Hay Point Values.*

Detailed Market Comparisons

The three following tables illustrate the full array of comparable data and aggregate statistical values for each job relative to the marketplace.

Survey Position 1: Field Operations Manager

Adjusted to Hay Points at 543

	Hay Points	Adjusted Minimum Hourly Wage Rate	Adjusted Maximum Hourly Wage Rate	No. of Wage Rate Steps	Standard Length of Time From Minimum to Maximum Wage Rate (Months)	No. of Hours in the Standard Work Week
Hydro One Networks Inc.	543	35.55	56.73	0		40.0
vs. Market Average		-24%	-10%			
Market Survey Participants						
P90		*	*	*	*	*
P75		51.38	68.71	*	*	40.0
Average	491	46.92	62.96	4	72	37.9
Median(P50)		42.81	56.11	3	48	37.5
P25		39.67	53.21	*	*	37.2
P10		*	*	*	*	*
Number of Respondents	11	11	11	5	5	11

	Overtime Eligible	First Level of Overtime Rate Eligible		Second Level of Overtime Rate Eligible		Union Representation
Hydro One Networks Inc.	No	No		No		No
Market Survey Participants	Yes = 2	Yes = 2	1.5 x standard wage	Yes = 1	3.0 x standard wage	Yes = 0

Notes:

** Insufficient sample to disclose results.*

Survey Position 2: Design Engineer

Adjusted to Hay Points at 479

	Hay Points	Adjusted Minimum Hourly Wage Rate	Adjusted Maximum Hourly Wage Rate	No. of Wage Rate Steps	Standard Length of Time From Minimum to Maximum Wage Rate (Months)	No. of Hours in the Standard Work Week
Hydro One Networks Inc.	479	37.22	53.38	9	96	35.0
vs. Market Average		0%	4%			
Market Survey Participants						
P90		42.62	59.69	*	*	40.0
P75		38.65	55.33	5	*	39.4
Average	455	37.16	51.55	5	68	37.6
Median(P50)		36.99	52.40	4	54	37.5
P25		35.66	47.03	3	*	36.9
P10		31.01	43.50	*	*	35.0
Number of Respondents	14	13	14	8	7	14

	Overtime Eligible	First Level of Overtime Rate Eligible		Second Level of Overtime Rate Eligible		Union Representation
Hydro One Networks Inc.	Yes	Yes	1.5 x standard wage	Yes	2.0 x standard wage	Yes
Market Survey Participants	Yes = 7	Yes = 3 Yes = 4	1.5 x standard wage 2.0 x standard wage	Yes = 2 Yes = 1	2.0 x standard wage 3.0 x standard wage	Yes = 4

Notes:

** Insufficient sample to disclose results.*

HayGroup®

Survey Position 3: Powerline Maintainer

Adjusted to Hay Points at 203

	Hay Points	Adjusted Minimum Hourly Wage Rate	Adjusted Maximum Hourly Wage Rate	No. of Wage Rate Steps	Standard Length of Time From Minimum to Maximum Wage Rate (Months)	No. of Hours in the Standard Work Week
Hydro One Networks Inc.	203	18.72	36.10	9	72	40.0
vs. Market Average		-30%	12%			
Market Survey Participants						
P90		*	35.67	*	*	40.0
P75		32.56	34.40	6	60	40.0
Average	204	26.76	32.31	5	41	38.9
Median(P50)		26.91	32.82	5	54	40.0
P25		20.58	29.75	3	24	37.5
P10		*	28.44	*	*	37.1
Number of Respondents	13	9	13	9	9	13

	Overtime Eligible	First Level of Overtime Rate Eligible		Second Level of Overtime Rate Eligible		Union Representation
Hydro One Networks Inc.	Yes	Yes	1.5 x standard wage	Yes	2.0 x standard wage	Yes
Market Survey Participants	Yes = 13	Yes = 2 Yes = 11	1.5 x standard wage 2.0 x standard wage	Yes = 1 Yes = 1	2.0 x standard wage 3.0 x standard wage	Yes = 13

Notes:

** Insufficient sample to disclose results.*

VI. Discussion/Analysis

The data collected for each of the three benchmark positions included the minimum and maximum hourly wage rates that an organization is willing to pay an incumbent for the job in question, overtime eligibility and policies, and union representation. Each of these factors is important for any organization as they provide the framework for making salary decision. The following results were found for each of the benchmark positions:

Field Operations Manager

Hydro One is below market on both the hourly wage rate minimum and maximum. Hydro One's hourly wage rate minimum of $35.55 is 24% below the market's average of $46.92, while their hourly wage rate maximum of $56.73 is 10% below the market average of $62.96. The Field Operations Manager at Hydro One is not eligible for overtime, while two out of the eleven market survey participants that matched to Field Operations Manager provide their job overtime. Neither Hydro One nor the market survey participants have union representation for the Field Operations Manager.

Design Engineer

Hydro One is in-line with market on both the hourly wage rate minimum and maximum. Hydro One's hourly wage rate minimum of $37.22 is comparable to the market's average of $37.16, while their hourly wage rate maximum of $53.38 is 4% above the market average of $51.55. The Design Engineer at Hydro One is eligible for overtime, while seven out of the fourteen market survey participants that matched to Design Engineer provide their job overtime. Hydro One and four out of the fourteen market survey participants have union representation for the Design Engineer.

Powerline Maintainer

Hydro One's hourly rate wage minimum of $18.72 is considerably below the market on the hourly wage rate minimum, however the hourly wage rate maximum is above the market. Hydro One's hourly wage rate minimum of $18.72 is 30% below the market's average of $26.76, while their hourly wage rate maximum of $36.10 is 12% above the market average of $32.31. The Powerline Maintainer at Hydro One and all thirteen market survey participants is eligible for overtime. Hydro One and all of the thirteen organizations that matched to the Powerline Maintainer have union representation.

VII. Conclusion

The custom survey of labour rates and overtime policies collected data on each of the three benchmark positions from fourteen organizations. Each submission was reviewed by Hay Group and job evaluation comparisons were made to account for the differences of the jobs. The market data was adjusted at Hydro One's Hay point values for each of the three jobs to account for these differences.

For the Field Operations Manager, Hydro One is below market on both the hourly wage rate minimum and maximum. For the Design Engineer, Hydro One is in-line with market on both the hourly wage rate minimum and maximum. For the Powerline Maintainer, Hydro One's hourly rate wage minimum is considerably below the market on the hourly wage rate minimum, however the hourly wage rate maximum is above the market.

Hydro One's overtime eligibility, overtime policies and union representation seem generally similar to the norms of the market survey participants.

Appendix A Benchmark Position Profiles

1. Field Operations Manager

Responsible for the provision of a wide range of electrical services such as connections, upgrades and emergency repairs, construction program and project activities within a specific geographic zone. Manage and supervise staff, organize schedule and assign routine and special duties to clerical, technical, trades and engineering staff, providing instruction, guidance and inspections as necessary to ensure work quality and accuracy and conformity to governing regulations.

Representative Activities / Responsibilities

1. Supervise Operations Centre technical activity by planning and directing the day-to-day prevention and maintenance to lines, new customer connects, service upgrades and new construction.
2. Supervise Operations Centre office, ensuring the appropriate processes related to accounting and clerical activities associated with the billing and collection of authorized charges relative to the installation of services and/or revenue from sale of power, the maintenance of area stores and accounting for tools and office equipment.
3. Responsible for the environmental practices and compliance with approved legislation by ensuring that adequate security, fire and safety measures are taken and precautions are observed in the Operations Centre; and personnel are provided adequate training, workloads are monitored and measures are taken to maintain operating efficiency.
4. Participate in meetings of both local and province-wide scope and contribute to the formulation of new or revised policy affecting Provincial Lines and Zone operations.
5. Provide advice and recommendations on service capabilities, price, service levels and other deliverables as part of negotiation of Service Level Agreements or Contracts.
6. Assist with the customer service requirements by providing advice to customers relative to their electrical problems, interpreting wiring code, drawing attention to hazards, dealing with complaints, and advising new customers on new construction, rates and application procedure and costs. React to storm activity through ensuring efficient restoration of power grid to associated customers.
7. Manage assigned work processes, monitor, evaluate and recommend changes and/or improvements to ensure efficient and effective completion of work. Ensure necessary Transport and Work Equipment is available for the efficient completion of the work.
8. Interact with municipal and ministry officials (Ministry of Transportation, Ministry of Labour, Ministry of Environment), as single point of contact for customer and contractual issues.

Typical Reporting Relationship

Reports to a Superintendent of Lines.

2. Design Engineer

Responsible for the development of structural/mechanical/electrical designs for major and/or complex transformer, switching, frequency changer and condenser stations projects, and all associated systems. Achieves the concepts, layouts, and requirements as specified for the project and provides technical guidance and work supervision to junior engineers.

Representative Activities / Responsibilities

1. Collaborate with development/construction/operations staff in the various phases leading to the final design, prepare sketches, instructions and other data as required for drawing production, and provide advice and guidance as required throughout.
2. Responsible for examining concepts, equipment and material tenders to ensure that design, equipment, or purchase agreements, meet the intent and requirements of the structural/mechanical/electrical design and collaborate with various groups within and external to the company to complete any necessary changes.
3. Investigate and aid in the resolution of design problems that arise during construction by visiting field locations and providing design revisions as required.
4. Recommend the need for new or revised design standards and assist in their development.
5. Provide expert advice and guidance as a design “specialist”, to various internal and external parties on designs pertinent to transformer, switching, frequency changer, and condenser stations, and the switchyard features of generating stations.
6. Periodically supervise staff assigned to assist on major or complex projects, attending to the assigning of work or areas of responsibility.
7. Requires eight to ten years of practical experience in the respective design field to ensure familiarity with the practical approaches, methods and techniques pertinent to structural/mechanical/electrical design for stations projects, and appreciation of the application and characteristics of various types of station equipment, and the requirements for drawing production, standards and practices. Also requires field experience to fully appreciate construction and installation practicalities.

Typical Reporting Relationship

Reports to a Supervisor.

3. Powerline Maintainer

Responsible for performing duties as necessary to work on the construction and maintenance of transmission and distributed lines and associated apparatus, using a range or mechanical and electrical skills and knowledge. Typically reports to Union Trades Supervisor.

Representative Activities / Responsibilities

1. Understand and has a working knowledge of the limits and capacities of electrical apparatus, hydraulic equipment and motorized vehicles, such as radial boom derricks, aerial devices, tension-stringing equipment and portable generators, and make minor repairs.
2. Understand and is familiar with operating procedures, standards manuals associated with the trade, and procedures related to the use of live-line tools and equipment.
3. Erect towers, poles and structures for power lines; install conductors and associated apparatus.
4. Perform maintenance of service, troubleshoot and restore electrical power during emergencies to municipal, industrial and rural customers.
5. Install, connect, troubleshoot and repair underground, submarine and overhead conductors to service customers.
6. Repair and maintain power line towers, poles, structures and conductors at various heights.
7. Install, operate and maintain line apparatus, i.e., transformers, regulators, reclosures, sectionalizers, capacitors, airbreak switches and fused cutouts.
8. Perform approved live-line work using live-line tools, rubber gloves and barehand techniques.
9. Install various types of metering equipment including power meters, current and potential transformers for municipal, industrial and rural customers.

Typical Reporting Relationship

Reports to a Union Trades Supervisor.

Appendix B Hay Guide Chart-Profile Method

Our Hay Guide Chart-Profile Method is a worldwide standard that has been used in thousands of profit and non-profit organizations around the world to evaluate jobs at every level and for all types of work. It is comprised of four standardized factors:

Know-How

This Guide Chart measures the total of every kind of knowledge and skill, however acquired, needed for acceptable job performance. It consists of three dimensions:

- practical procedures and knowledge, specialized techniques, and learned skills;
- the real or conceptual planning, coordinating, directing, and controlling of activities and resources associated with an organizational unit or function; and,
- active, practicing, person-to-person skills in the area of human relationships.

Problem Solving

This Guide Chart measures the thinking required in the job by considering two dimensions:

- environment in which the thinking takes place; and,
- challenge presented by the thinking to be done.

Accountability

This Guide Chart measures the relative degree to which the job, performed competently, can affect the end results of the organization or of a unit within the organization. It reflects the level of decision-making and influence of the job through consideration, in the following order of importance, of:

- nature of the controls that limit or extend the decision-making or influence of the job;
- immediacy of the influence of the job on a unit or function of the organization; and,
- the magnitude of the unit or function most clearly affected by the job.

DISTRIBUTION LINE LOSS

1.0 INTRODUCTION

This exhibit presents a discussion on the types of line losses, the reason they exist, an estimate of the technical and non-technical line loss associated with Hydro One's Distribution System as a whole, recommended Distribution Loss Factors and how Hydro One manages distribution line losses.

The term "distribution line losses" refers to the difference between the amount of energy delivered to the distribution system from the transmission system and the amount of energy customers are billed. Distribution line losses are comprised of two types: technical and non-technical (the description of each type is presented in the sections below).

It is important to know the magnitude and causality factors for line losses because the cost of energy lost is recovered from customers.

As a result of the composition and scale of the Hydro One distribution system it is not economic to provide metering and the supporting processes capable of measuring line losses directly. Since energy meters do not total data for the same periods, and load varies over time, a direct measurement of actual losses is not feasible. Instead, Hydro One relies on studies which are designed to calculate the magnitude, composition and allocation of system losses based on annual aggregate metering information for energy purchases, energy sales and system modeling methods. These studies are conducted with the assistance of industry experts in this field to ensure appropriate scientific methods and modeling techniques are utilized in establishing the magnitude, composition and allocation of losses.

This exhibit also addresses the three directives from the 2006 Distribution rates proceeding RP-2005-0020/ EB-2005-0378 related to losses, which are discussed in Exhibit A, Tab 17, Schedule 1 and repeated below for convenience:

1. The Board is of the view that either a less expensive metering program, or a second effort to evaluate line losses using current load data and local experience, may provide loss factor estimates that are more acceptable and credible to stakeholders.

2. The Board does accept the submissions of intervenors regarding the expected benefits of the $4.75 million expenditure and directs Hydro One to include in its next main rates case filing a budget and a work plan to implement all the cost-effective line-loss reduction suggestions contained within the Kinetrics study. If Hydro One concludes that any of the recommendations in the Kinetrics study should not be implemented, it must clearly demonstrate the reasons for that position, and an accompanying budget and work plan for its preferred implementation plan.

3. The Board expects Hydro One to continue its efforts to refine line loss factors as they affect the bills of individual LV customers

2.0 TECHNICAL LOSSES

Technical losses on distribution systems are primarily due to heat dissipation resulting from current passing through conductors and from magnetic losses in transformers. Losses are inherent to the distribution of electricity and cannot be eliminated.

Hydro One issued a Request for Proposals (RFP) to carry out an independent assessment of technical losses on Hydro One's distribution system. The work was awarded to Kinectrics Inc., a leading authority on distribution systems and distribution losses in particular.

The report prepared by Kinectrics and entitled "2007 Recalculation of Distribution System Energy Losses at Hydro One" is presented in Appendix A of this Exhibit. Consistent with the requirements of the first Board directive noted in Section 1.0, the Kinectrics report uses new load profiles that became available in 2006 for determining customer group (i.e. Sub-Transmission, Primary, and Secondary) losses, as well as considering new customers that were identified as part of the work to update the study.

This report forms the basis for Hydro One's estimates on the magnitude, composition and allocation of losses on the System. The report establishes the Distribution Loss Factors (DLFs) for the various customer groups and also provides the rationale for Hydro One's distribution loss reduction program.

Hydro One owns primarily a rural distribution system with some pockets of urban development. Hydro One's distribution system technical losses are estimated to be 5.86 percent of the energy delivered to the distribution system and consist of estimated 5.26 percent for losses incurred in the distribution system and 0.6 percent of losses that relate to transformer losses at transmission stations and high-voltage distribution stations, which supply the distribution system.

Losses occur on subtransmission lines, distribution lines, station transformers, distribution transformers and secondary services to customers. Transformer losses include no-load losses that are independent of transformer loading and load losses that are dependent on the loading.

2.1 Comparison of Typical Urban vs Rural Losses

The losses breakdown by equipment components for the distribution system of typical urban and rural utilities is shown in the table below. Typical urban area losses are 3.6, on average, of energy sold and can range from 2 percent to 5 percent. Typical rural area losses are 7.3 percent, on average, of energy sold and can range from 4 percent to 10 percent.

Table 1: Typical Urban vs. Rural Losses by Equipment*

Component	**Estimated Loss as a Percentage of Energy Sold**	
	Typical Urban	**Typical Rural**
Subtransmission lines	0.1	0.7
Station power transformers	0.1	0.7
Distribution lines	0.9	2.5
Distribution line transformers no load	1.2	1.7
Distribution line transformers load	0.8	0.8
Secondary lines	0.5	0.9
Total	3.6	7.3

* From Table 4 on page 46 in Attachment A, "2007 Recalculation of Distribution System Energy Losses at Hydro One."

2.2 Hydro One Losses Estimate

Hydro One's distribution system losses, as determined by the Kinectrics study presented in Appendix A, are summarized in the table below.

Table 2: Hydro One Losses Estimate by Equipment*

Component	Estimated Loss as a Percent of Energy Sold
Subtransmission lines	2.24
LV Distribution station transformers no load	0.21
LV Distribution station transformers load	0.19
Distribution lines	1.49
Distribution line transformers no load	0.78
Distribution line transformers load	0.16
Secondary lines	0.19
Total	**5.26**

* From Table 1 on page 1 in Attachment A, "2007 Recalculation of Distribution System Energy Losses at Hydro One." Note: This table does not include transformation losses (0.6%) from transmission stations and high-voltage distribution stations (HVDSs), which are included in Hydro One's Total Distribution Loss Factors.

The total annual energy loss in Hydro One's distribution system is estimated to be about 5.26 percent of the energy sales, which compares to a value of 5.05 percent in the 2005 Kinectrics study. The main reason for the difference is attributed to the use of improved load profile information used with the current study. This is in line with typical losses incurred by other utilities considering Hydro One's mix of rural and urban customers.

3.0 NON-TECHNICAL LOSSES

Non-technical losses occur as a result of theft, metering inaccuracies and unmetered energy. The following sections are a discussion on each of these items.

3.1 Theft of Power Losses

Theft of power is energy delivered to customers that is not measured by the energy meter for the customer. This can happen as a result of meter tampering or by bypassing the meter.

Hydro One manages theft of power by inspection of the meter for tampering or bypassing during meter reading activities, monitoring anomalies during bill preparation and in cooperation with police activities.

3.2 Metering Inaccuracies Losses

Losses due to metering inaccuracies are defined as the difference between the amount of energy actually delivered through the meters and the amount registered by the meters. All energy meters have some level of error which requires that standards be established. Measurement Canada, formerly Industry Canada, is responsible for regulating energy meter accuracy.

Hydro One manages energy losses due to metering inaccuracies through a meter accuracy verification program.

3.3 Unmetered Losses

Unmetered losses are situations where the energy usage is estimated instead of measured with an energy meter. This happens when the loads are very small and energy meter installation is economically impractical. Examples of this are street lights and cable television amplifiers.

3.4 Estimate of Non-Technical Losses

Non-technical losses have been established by reviewing losses from theft, meter inaccuracies and unmetered energy in other jurisdictions. Based on the Kinectrics analysis which included reviewing the non-technical losses value from utilities across North America, United Kingdom and Australia, a value of 1.2% was recommended as a reasonable estimate. This is the same value as in the previously filed 2005 Kinectrics report.

4.0 LOSS ALLOCATION

To appropriately allocate the cost of losses to the different rate classes applied to distribution customers, it is necessary to estimate the losses in Hydro One's distribution system attributable to sub-transmission, primary distribution and secondary distribution sub-systems.

Within each of the sub-transmission, primary distribution and secondary distribution groups of customers, there are differences among the losses incurred by customers in relation to the energy used. For example, delivering electricity to a customer at the end of a long secondary distribution line would entail more loss than a customer using the same amount of electricity upstream on that line.

Although different customers will have characteristically different loss factors, individual customers are not billed by individual loss factors. It is not practical to accurately measure or model each specific customer's loss factor. Therefore, losses are allocated to customers based on those customers using similar elements of the distribution system, and they are billed at a Distribution Loss Factor (DLF) based on the losses incurred by that entire group.

The estimated values for the DLF for each of the customer classes are based on the Kinectrics study presented in Appendix A of this Exhibit.

4.1 Sub-transmission System Customers

To serve sub-transmission class customers, electricity flows through sub-transmission feeders, which operate at relatively high voltage levels that range between nominal voltages of 44kV and 13.8 kV. Since lines operating at higher voltage levels experience less energy loss per amount of energy delivered than lower voltage lines, serving sub-transmission class customers generally involves lower losses as a percent of energy delivered, compared to customers served from lower voltage facilities. Almost all distribution customers will be served from a feeder that originates from the sub-transmission system, so their DLF will include the losses from sub-transmission equipment.

Consistent with the third Board directive noted in Section 1.0, Hydro One asked Kinectrics to provide a study to identify site specific losses for sub-transmission connected (i.e. LV) customers and will include the results of this study in the evidence to be submitted as part of the rates portion of this Application to be filed in October 2007.

4.2 Primary Distribution Customers

These customers are connected to primary distribution lines, which function at voltage levels ranging between 12.5 kV and 2.4 kV. At these lower voltages, for every unit of energy delivered, primary distribution lines generally lose more energy (per length of line) than sub-transmission lines. Moreover, most primary class customers are served through Low Voltage Distributing Stations (LVDS), who in turn receive supply from the sub-transmission system further upstream. Energy is lost within both the LVDS transformers and in the lines emanating from them. This results in more energy lost per amount delivered to this Primary class of customers than to Sub-transmission customers.

4.3 Secondary Distribution Customers

These customers receive electricity after it has passed through the sub-transmission system, primary distribution lines and LVDSs. This results in several stages of transformation before being sent at low voltage through secondary distribution lines that operate at voltages as low as 120/240V. Pole-top, pad-mount and underground step-down transformers that step-down voltage from primary distribution system to the secondary distribution system generally lose more energy per quantity delivered than do low voltage distribution stations. The pole-top, pad-mount and underground transformers function at much lower load factors because they serve less diverse groupings of lower-volume customers (e.g. a small number of residences). Therefore, they often operate at little or no load, though still drawing power for their operation thus sustaining relatively high losses per energy delivered. In addition to all the losses associated with the transformation to the secondary voltage, the secondary distribution lines themselves lose a substantial amount of energy per unit delivered.

The total losses attributable to the secondary distribution customers also include the losses in the sub-transmission and primary distribution systems upstream in the delivery chain. As a result, these customers generally incur higher losses per unit delivered than any other customer class.

4.4 Comparison of the Estimated Total Loss Factor with the Total Loss Factor in the Existing Rate

The table below compares Total Loss Factors (TLF), applicable to the existing rates, with the ones estimated in the Kinectrics study for the three customer classes.

Table 3: Comparison of Existing TLF with TLF from Revised Study*

Customer Type	TLF in Existing Rates	Estimated TLF from 2007 Study
Embedded LDC and Subtransmission Customers	3.4%	4.4 %
Primary Customers	6.1%	7.4%
Secondary Customers	9.1%	10.0%

* From table on page viii in Attachment A, "2007 Recalculation of Distribution System Energy Losses at Hydro One."

TLFs include the Distribution Loss Factor (DLF) and the 0.6% for transformer station losses.

For all the customer classes the TLFs based on the Kinectrics study results are higher than the TLFs included in the existing rate. The difference is due to the use of an improved methodology which includes losses of detailed system elements thereby providing more accurate results for the different customer classes and total distribution losses.

Hydro One has been applying practices and continues to apply practices that mitigate financial impacts on future rates to the extent that it is economically feasible. These practices are described below.

5.0 HYDRO ONE LOSS MANAGEMENT

5.1 General Practices

Hydro One manages losses in the following ways, where it is cost-effective to do so:

1. Technical evaluation of projects - When Hydro One evaluates projects, the cost of losses is considered in selecting the preferred alternative. Standard planning practices include the development of options, which would reduce system losses. These include consideration of more efficient and larger conductors, distribution at higher voltages, phase balancing and power factor correction where it is economical to do so.

2. Voltage conversion projects – In many cases, by-passing and thus providing capacity relief for distribution stations by supplying some of the incremental loads from high voltage feeders (typically 27.6 kV) is considered as an alternative, with benefits of loss reduction. These projects are also considered as an alternative when distribution stations need to be replaced due to end of life considerations.

3. Reducing load on heavily loaded feeders – Unloading heavily loaded feeders by installing capacitors, or transferring load to alternate feeders or new feeders can also be an effective means of reducing losses and is utilized, where economic.

4. Ongoing System Loading Reviews – This is standard planning practice that identifies system performance, assets where loads are approaching rated capacities and identifies opportunities for loss reductions. Resulting projects may include phase balancing, voltage improvement, power factor correction, voltage

upgrades, conductor upgrades and larger system modifications. The system planning approach is outlined in Exhibit C1, Tab 2, Schedule 3.

5.2 Specific Initiatives

The existing Hydro One distribution system was designed and built assuming specific load growth rates and loading patterns. However, in some cases these assumptions do not materialize as forecasted. As a result, some feeders end up loaded in a sub-optimal manner from a perspective of minimizing losses. This situation presents an opportunity to further minimize losses on the Hydro One distribution system.

To uncover the extent of these opportunities Hydro One contracted Kinectrics in 2005, as part of 2006 Distribution rates proceeding RP-2005-0020/EB-2005-0378, to identify cost effective initiatives for Hydro One to reduce its distribution system losses. The 2005 Kinectrics study identified $12.75 million in economical investments that could be made to reduce line losses. In the 2006 Distribution rates proceeding Hydro One Distribution proposed $8 million in economic loss reduction initiatives, which have been substantially completed as part of the CDM program, as discussed in Exhibit D1, Tab 3, Schedule 5. The $8 million expenditure was based on the practicalities (available resources and equipment) to achieve a program of this magnitude involving numerous designs, with the intention of follow-up assessments concerning the feasibility of completing the remaining high level loss reductions identified by Kinectrics.

As part of the follow-up exercise, Hydro One requested Kinectrics to confirm their estimate of economic loss reduction initiatives based on new load profile data that became available in 2006 and greater detailed information on the Hydro One distribution system. The updated estimate of economic loss reductions is included in the 2007 losses study provided in Attachment A to this Exhibit. The updated Kinectrics' study has identified economic loss reductions to be about $6.5 million. The updated Kinectrics' scope of work is consistent with Hydro One's loss reduction initiatives that are underway, and as such, no further specific loss reduction initiatives, over and above the on-going efforts described in Section 5.1 above and in the paragraph below, are proposed in this Application.

Hydro One Distribution currently evaluates all relevant aspects of the distribution system including conductor size, loading, phase balance and other situations with a view to minimizing losses, as described in Section 5.1. Kinectrics' 2007 study recommendations on the benefits of changing out conductors will be incorporated into our general practices, where appropriate. Hydro One will also undertake a review of purchasing agreements to ensure that the purchasing practices do obtain the most cost effective transformers, taking into consideration Kinectrics' work on this topic.

KINECTRICS

2007 RECALCULATION OF DISTRIBUTION SYSTEM ENERGY LOSSES AT HYDRO ONE

Kinectrics Inc. Report No: K-013111-001-RA-0001-R01

July 27, 2007

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Kinectrics Inc. Report No.: K-013111-001-RA-0001-R01

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Dated: July 27 2007

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REVISIONS

Revision Number	Date	Comments	Approved
R01	July 27 2007	Added a sentence stating that implementation of the loss reduction program began in 2006.	

2007 RECALCULATION OF DISTRIBUTION SYSTEM ENERGY LOSSES AT HYDRO ONE

Kinectrics Inc. Report No.: K-013111-001-RA-0001-R01

July 27, 2007

EXECUTIVE SUMMARY

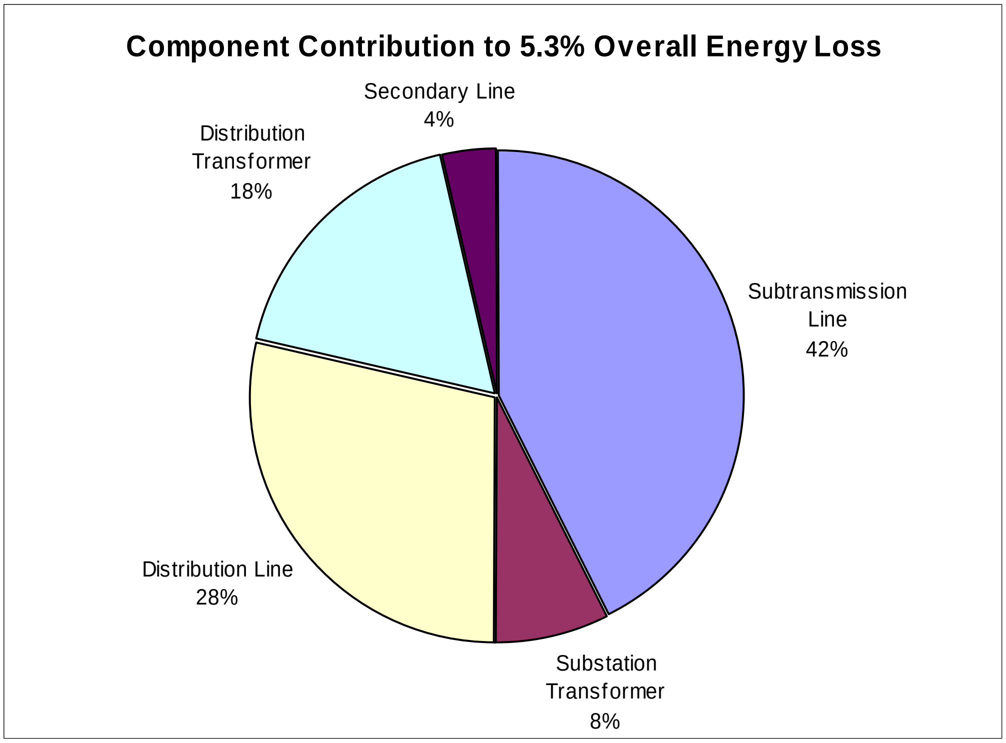
As part of the support for the rate application to the OEB, Hydro One requested a study of the energy losses on its electric power distribution system. The project included an overall assessment of technical energy losses on various components of the distribution system, an allocation of losses to three different rate classes resulting in distribution loss factors for each class, and development of a program to reduce energy losses. The original project report was filed in 2005.

In 2006, new data became available for load profiles. Some results from detailed circuit modeling of loss savings from capacitors and load balancing also became available. This report recalculates the energy losses based on the new information.

The high level system modeling using system component inventories, updated class load profiles and loading data from 2005 and 2004, has shown that the best estimate of the annual energy loss in Hydro One distribution systems is 5.3% of energy sales, with an outside range of 4.1 to 6.4% based on input parameter sensitivity modeling. The contribution of different system components to this total is shown in the pie chart on the following page.

The distribution system energy loss has been allocated to the major rate classes to produce several technical loss factors. The estimate for non-technical losses has been added to produce an estimate of the distribution loss factor (DLF). The supply facilities loss factor has then been added to produce an estimate of the Total Loss Factors (TLF). The comparison of these new TLFs with those that have been used previously is shown in the table on the following page. The changes are due to the improved load profile data.

The recommended loss management program for Hydro One is based on a combination of shunt capacitor installation and phase balancing. A program with an overall benefit to cost ratio of 2.2 to1 has been designed based on a combination of $5.1 million in capital spending on shunt capacitors, $1.3 million in O&M costs on phase balancing over the next two years. Hydro One Networks commenced work on this program in 2006. The benefits of changing out conductor and improving distribution transformer efficiency and sizing have been estimated and these areas are recommended for further detailed costing study by Hydro One.



Customer Type	TLF in Present Rates	New Estimate of Technical Losses (2007 study)	New Estimate of DLF (2007 study)	New Estimate of TLF (2007 study)
Embedded LDC and Subtransmission Customers	3.4%	2.6%	3.8%	4.4%
Primary Customers	6.1%	5.6%	6.8%	7.4%
Secondary Customers	9.1%	8.2%	9.4%	10.0%

* Note: The TLFs include technical losses and non-technical losses on the distribution system and the supply facilities loss factor (0.6%) for losses on the transmission system supply transformer. In the Present Rates in column 2 the non-technical losses are estimated as 10% of the technical losses. In the new 2007 analysis in columns 4 and 5, non-technical losses are included as 1.2% of the energy sold.

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1 CONCLUSIONS AND RECOMMENDATIONS

1.1 OVERALL TECHNICAL LOSS ESTIMATE

A high level computation in this 2007 study using the latest system component inventories, updated class load profiles and component loading data has shown that the best estimate of the annual energy technical loss on Hydro One distribution systems is 5.3% of energy sales, with an expected range of 4.1 to 6.4%.

The change in the estimated breakdown of loss by power system component is shown in the following table. The largest changes are in power and distribution transformer load losses, and distribution and secondary line losses. These changes are primarily caused by the change in load profiles used in the calculation.

Table 1 Estimated Energy Loss

Component	2005 Study Estimated Loss as a Percent of Total Energy Sold	2007 Study Estimated Loss as a Percent of Total Energy Sold
Subtransmission Lines	2.33	2.24
Power Transformers No Load	0.21	0.21
Power Transformers Load	0.12	0.19
Distribution Lines	1.18	1.49
Distribution Transformers No Load	0.78	0.78
Distribution Transformers Load	0.19	0.16
Secondary Lines	0.24	0.19
Total	5.05	5.26

1.2 TOTAL LOSS FACTORS

The change in Total Loss Factors (TLFs) calculated based on these technical losses are shown in the following table and compared to the previous TLF values used by Hydro One.

Table 2 Calculated Total Loss Factors

Customer Type	TLF in Present Rates	New Estimate of Technical Losses (2007 study)	New Estimate of DLF (2007 study)	New Estimate of TLF (2007 study)
Embedded LDC and Subtransmission Customers	3.4%	2.6%	3.8%	4.4%
Primary Customers	6.1%	5.6%	6.8%	7.4%
Secondary Customers	9.1%	8.2%	9.4%	10.0%

* Note: The TLFs include technical losses and non-technical losses on the distribution system and the supply facilities loss factor (0.6%) for losses on the transmission system supply transformer. In the Present Rates in column 2 the non-technical losses are estimated as 10% of the technical losses. In the new 2007 analysis in columns 4 and 5, non-technical losses are included as 1.2% of the energy sold.

1.3 TECHNICAL LOSS REDUCTION PROGRAM

The expected benefits of the proposed distribution loss reduction program are summarized in the table below. These estimates are based on the characteristics of the Hydro One distribution system and the avoided costs for generation, transmission, and distribution based on the OEB's Total Resource Cost Guide. The costs and benefits of the program over the next two years have been included. The present value of the benefits for these programs has been calculated over twenty years. The overall benefit to cost ratio of the program is 2.2 to1. Hydro One Networks commenced work on this program in 2006.

Table 3 Loss Reduction Program Summary

Program	Maximum Reduction in Annual Energy Loss GW-hr	Avoided Energy and Demand Costs PV $M	Cost of Program $M	Profitability Index
PF Correction Capacitors - install cap banks on 278 feeders	9.8 *(53)**	8.7 *(52.9)*	5.1 *(10.3)*	1.7 *(4.2)*
Phase balancing - balance 314 circuits -2 years of a 6 year program	7.6 *(15)*	5.2 *(11.4)*	1.3 *(2.2)*	4.0 *(5.4)*

* Note: The values from the study filed in 2005 are shown in brackets and smaller font for comparison. The large change in the capacitor program is due to the change in assumed load profile reducing the number of circuits on which large capacitor banks could be installed. The large change in the phase balancing program is also due to a reduction in the estimated circuits that can achieve significant energy savings in the next two years.

1.4 REVIEW OF LOSS MODELING AND LOSS REDUCTION ANALYSIS

The detailed loss modeling techniques used by Hydro One have been reviewed and found to be appropriate.

The estimate of potential loss reduction on the Hydro One system has been revised to reflect the latest load profile information available.

The benefits of changing out conductor and improving distribution transformer efficiency and sizing have been estimated and these areas are recommended for further detailed costing study by Hydro One.

Program	Maximum Reduction in Annual Energy Loss GW-hr	Avoided Energy and Demand Costs PV $M
Conductor Change Out - 1 km of 8 circuits - 2 yeas of a ten year program	2.0	5.4
Transformer Sizing and Efficiency - normal replacements for two years	6.8	6.4

2 INTRODUCTION

In 2005 Kinectrics prepared a report on the annual energy losses on the Hydro One distribution system. In 2006 new data on the load profiles of the different customer classes and a few distribution circuits became available. Furthermore the results of detailed circuit modelling conducted by Hydro One on the reduction of losses through installation of capacitor banks and phase load balancing also became available. This report includes results of a recalculation of the energy losses and potential savings including the new information. All the other information on which the estimate of energy losses is based remains the same. The previous report filed in 2005 is included as Appendix A for convenience in making comparisons.

As well as recalculating the results of the previous report, this report presents the results of new analysis into the potential energy savings from reconductoring, and changing distribution transformer purchasing and loading procedures.

There were four major project tasks:

- Review Existing Methods of Loss Modeling and Loss Reduction Analysis
- Recalculate Capacitor and Phase Balancing Savings
- Estimate Savings of Improved Efficiency Distribution Transformers
- Estimate Savings of Conductor Replacement for Loss Reduction
- Review Cost Models for Loss Reduction

3 REVIEW EXISTING METHODS OF LOSS MODELING AND LOSS REDUCTION ANALYSIS

3.1 SUMMARY OF NEW INFORMATION

The new data on load profile that became available in 2006 consisted primarily of load profiles for a company wide aggregation of all customers within a specific customer class and the total for all classes. This aggregation of all customers together produces a smooth load profile that is representative of the entire Hydro One system and the heavier loaded transmission and subtransmission lines. This load profile is smoother than can be expected on distribution circuits. The most appropriate load and loss factors, based on the best available data, are shown in Table 4, along with the values used in the 2005 report for comparison.

The load profiles for secondary lines are based on data of specific load classes or groups of similar load classes. The load profile for each component is a combination of the profiles of all the customer classes that use that component weighted by the proportion of energy sold in a year to each of those classes. Two alternative load profiles are given for distribution lines, because the heavier loaded lines will have a smoother profile than the lightly loaded lines. Examples of both of the recommended load profiles for distribution lines have been found in the limited data available from a distribution station automation field trial. The power transformer load profiles are different for HONI transformers and customer transformers because of the different data for the load classes served by these two types of transformer.

Table 4 Recommended Load and Loss Factors

Component	2005		2007	
	Load Factor	Loss Factor	Load Factor	Loss Factor
Secondary Lines – Residential Rural	0.367	0.179	0.46	0.23
Secondary Lines – Residential Urban	0.367	0.179	0.48	0.25
Secondary Lines - Seasonal	0.165	0.076	0.40	0.18
Secondary Lines – Farms	0.510	0.303	0.43	0.22
Secondary Lines – General Service <5 MW	0.517	0.329	0.58	0.35
Distribution Transformers	0.422	0.226	0.40	0.175
Distribution Lines – Average	0.422	0.226	0.40	0.175
Distribution Lines – Heavy Loaded	0.422	0.226	0.56	0.33
Power Transformer – Customer	0.715	0.521	0.70	0.49
Power Transformer – HONI	0.715	0.521	0.40	0.175
Subtransmission Line	0.715	0.521	0.66	0.45

3.2 HYDRO ONE'S DETAILED CIRCUIT MODELING

Hydro One has conducted detailed modeling of distribution circuits to identify the circuits requiring load balancing and the optimal locations for installation of the capacitor banks and to confirm the savings estimated in the Kinectrics report in 2005. The result of detailed modeling on 240 circuits was provided for use in this project. From this detailed modeling, potential capacitor bank installations have been identified on 122 of the circuits with an average reduction in peak loss of 5.6 kW. Load balancing opportunities have been identified on 158 circuits with an average reduction in peak loss of 8.5 kW per circuit.

The majority of the recommended capacitor bank installations are 150 kVar. Comments by the technical staff doing the modeling indicate that the most frequent reasons that larger banks cannot be installed is that they would produce a leading power factor when the load is 30% of the peak or lower. Another common limitation is that the phase unbalance in Var flow limits the size of one phase of the bank. The unbalance in the Var flow is caused by unbalanced currents or unbalanced power factors.

The detailed modeling was conducted using a commercial software package (PSS ADEPT) to calculate the loss at peak load. Load can be balanced by moving single phase connections. Capacitors can then be added to reduce the loss. The optimal capacitor location is sometimes selected by the software program but often has to be chosen by trial and error. The loss at peak load is then converted to an energy loss by multiplying by a loss factor. The models are checked for potential voltage problems from the application of the capacitors.

The choice of loss factor has a major impact on the estimate of energy saved. The peak power savings are estimated quite accurately by the software, limited only by the accuracy of the input data. Suspicious input data have been confirmed by requests for field verifications. However, the most appropriate value for the loss factor is not well known. It depends on the load profile of the circuit, that is on how the current varies from hour to hour over the entire year.

A review of the individual circuit models and the comments of the analysis technicians, has found that the modelling techniques for the detailed circuit models are appropriate.

Examination of the model files and comments by the modelers indicates the following modeling techniques were used:

1. A power factor of 0.95 is assumed for all loads (0.9 for summer peaking)
2. A loading of measured peak+10% is assumed
3. Loads are lumped at the ends of most lines
4. Phase balancing is assumed to have been completed
5. The loss at peak load is calculated with PSS ADEPT
6. Capacitor is sized to produce no leading PF at 30% of peak load
7. Energy loss is calculated from loss at peak with a loss factor of 0.33 at first, now 0.23 to match the value used by Kinectrics in the 2005 report.

The techniques listed above were evaluated by Kinectrics and the results of the detailed modeling were compared to the 2005 high level analysis by Kinectrics.

Technique 1 is reasonable. The power factors of the loads in the models are a large source of uncertainty. The power factor is known for a few of the large loads, but for most loads it is assumed to be 0.95. Although the best information available indicates that this is the overall average power factor for Hydro One distribution circuits, there is a wide range. Assuming 0.95 will limit the size of capacitor bank that is recommended for circuits whose actual power factor is less. This will not produce uncertainty in the estimated energy savings, since the smaller bank will actually be installed. On circuits whose actual power factor is 0.99 there may be high voltage problems after the capacitor bank is installed. The model will not predict this voltage problem because it is assuming a lower power factor. This will produce some error in the estimate of energy savings, since the capacitors on these circuits will need to be reduced in size or removed.

Technique 2 is reasonable. It accounts for the measurement not necessarily being on peak day.

Technique 3 is reasonable. It will over estimate loss for single phase lines by a factor of 1.5, but 80% of loss is on three phase lines. It will not significantly over estimate the loss savings on three phase lines because only a small fraction of the load is distributed along the line. It will not over estimate the energy savings because most capacitors are installed on three phase lines, producing no saving on single phase lines.

The loads in the model distributed according to the connected kVA which is known for each switch. The loads are then scaled so that the current at the station matches the measured data. The larger loads that have individual load data available are not scaled. This is a reasonable procedure.

Technique 4 is reasonable, but Kinectrics previous estimate did not assume this. The effect of applying this to the Kinectrics estimate depends on the amount of final imbalance. If perfect balance were achieved, the Kinectrics estimate of loss savings from capacitors would be decreased by 33%. In the studied circuits (240) the final imbalance is 5%. At this imbalance the Kinectrics loss savings estimate would be reduced by 30%.

Technique 5 is reasonable.

Technique 6 is reasonable but uncertain. The Barrie field trial data shows minimum load ranging from 0.16 to 0.61 but most are within 0.3 to 0.4. Based on this data the detailed study assumption of 0.3 is probably best.

Technique 7: the loss factor is probably reasonable. The major source of uncertainty in the estimate of energy savings from the detailed modeling is the loss factor used to calculate the annual energy saving from the peak power saving calculated by the detailed model. The loss factor varies with different load profiles on different circuits. Measured data is available on only a few circuits. It indicates that the annual load factor can vary from 0.33 to 0.63 and the corresponding loss factor can vary from 0.12 to 0.41 (data from the Barrie Automation Field Trial at Midhurst, Angus, and Drayton DSs). The average was a load factor of 0.5 and a loss factor of 0.27.

The previous load profile used by Kinectrics was built up from customer load profiles, with no smoothing due to diversity and had a load factor of 0.49 and a loss factor of 0.23. It produced the correct amount of energy sold when used in the total system model, with little alteration of the peak loading on the circuit. It is therefore appropriate for a "typical" circuit. However, capacitors are used only on heavier loaded circuits which will have a smoother profile.

The conclusion is that there is some uncertainty regarding the most appropriate loss factor to use. The loss factor of 0.23 used previously is probably too low. It could be as high as 0.41 or more. A value of 0.33, which was used originally in the detailed studies, is recommended for the heavier loaded circuits where capacitor banks are installed.

3.3 METHOD OF SELECTING CIRCUITS FOR DETAILED ANALYSIS

Hydro One's present method of identifying lines for analysis is to select the lines with the largest imbalance, that also meet a minimum current level criteria and to select the circuits with the largest currents. This method has been used because each circuit is analyzed for both imbalance and capacitor bank application. Some of the circuits analyzed are therefore not expected to require a capacitor bank since they are being analyzed primarily for imbalance.

To select the most likely circuits for capacitor bank application, it should be the circuits with the worst power factors, the highest minimum loads, and the longest three phase lines with the least branching; but the circuits with these characteristics are not known. These circuits could be indicated by using the circuits with the largest minimum loads. These are also not known. They could also be indicated by the circuits with the largest loads in MW or MVA. This is the best, feasible approach given the presently available data. Using the peak power level is a slight improvement on using current to select circuits to study since the higher voltage lines will be able to accept a capacitor bank at a lower current level than the lower voltage lines. Alternatively a different minimum current level could be used for different voltages.

4 RECALCULATION OF OVERALL TECHNICAL LOSS ESTIMATE

Based on the new information on load profiles the overall technical loss estimate has been recalculated in 2007. The calculation method remained the same as earlier estimates in 2005 and is described in Appendix A. The results of the recalculation are shown in Table 5. The previous estimates are shown in smaller font and italics.

Table 5 Summary of Loss Estimation Results

	Peak Power (delivered by component) (MW)	Annual Energy (delivered by component) (GW-h)	Power Loss at Peak (MW)	Power Loss at Peak (% of total)	Annual Energy Loss (GW-hr)	Annual Energy Loss (% of total)	Annual Energy Loss as % of total energy sold
Subtransmission Line	8,950 *8,600*	34,100 *35,000*	220 *200*	30 *34*	877 *913*	43 *46*	2.24 *2.33*
Power Transformer No Load	5,060 *3,270*	19,800 *20,500*	9.4 *9*	1.3 *2*	82 *82*	4.0 *4*	0.21 *0.21*
Power Transformer Load	5,060 *3,270*	19,800 *20,500*	24 *11*	3 *2*	73 *48*	3.5 *2*	0.19 *0.12*
Distribution Line	4,710 *4,530*	18,900 *18,750*	382 *233*	52 *40*	585 *461*	28 *23*	1.49 *1.18*
Distribution Transformer No Load	3,780 *4,290*	16,900 *16,900*	35 *35*	4.7 *6*	304 *304*	15 *15*	0.78 *0.78*
Distribution Transformer Load	3,780 *4,290*	16,900 *16,900*	29 *37*	3.9 *6*	63 *74*	3.1 *4*	0.16 *0.19*
Secondary Line	3,480 *4,290*	16,800 *16,800*	37 *62*	5.1 *11*	76 *93*	3.7 *5*	0.19 *0.24*
Totals			740 *587*	100 *100*	2,060 *1,976*	100 *100*	5.26 *5.05*

The total annual energy delivered by the subtransmission lines is less than the total purchased from the transmission grid (39,165 GWh) because some of the energy purchased flows through high voltage substations supplied directly from 115 kV. Similarly the total energy delivered by distribution lines is less than the energy delivered by distribution transformers and secondary lines plus the primary customers because some of those distribution transformers are directly connected to 27.6 kV subtransmission lines in south west Ontario.

5 RECALCULATION OF TOTAL LOSS FACTORS

The method for calculation of the total loss factors (TLFs) has not changed from the previous 2005 computation and is described in Appendix A.

The data for the total energy sales to each customer class was 19,089 GWh to embedded LDC and Subtransmission, 3,249 GWh to primary customers (considered to be three phase farm, three phase general service and acquired large users) and 16,827 GWh to secondary customers. The total energy of 39,165 GWh is therefore sold 48.7% to embedded LDC and subtransmission, 8.3% to primary customers and 43% to secondary customers.

The method will be illustrated with an example for primary customers. The total annual energy loss on subtransmission lines and power transformers (877 +82+73 from Table 5) is 8.3% allocated to primary customers. Since only primary and secondary customers use the distribution lines that loss (585 from Table 5) is allocated to primary customers at 16.2% (3249/(3249+16827). The allocation of loss is then 180 GWh (0.083 x (877+82+73)+0.162 x 585). The technical losses are then 5.6% (180/3249). Adding 1.2% for non-technical losses gives a distribution loss factor (DLF) of 6.8%. Adding 0.6% for the supply facilities gives a total loss factor (TLF) of 7.4%.

This TLF would apply to primary customers whose energy meter is on the high voltage side of the customer's transformer. If the energy meter is actually on the low voltage side of the customer transformer then the TLF must be increased by the average distribution transformer loss of 0.94% of energy sold (.78+.16 from the last column of Table 5). This would increase the TLF for these customers from 7.4% to 8.3%.

Table 6 shows the effect of the recalculation based on the new information.

Table 6 Comparison of TLFs

Customer Type	TLF in Present Rates	New Estimate of Technical Losses (2007 study)	New Estimate of DLF (2007 study)	New Estimate of TLF (2007 study)
Embedded LDC and Subtransmission Customers	3.4%	2.6%	3.8%	4.4%
Primary Customers	6.1%	5.6%	6.8%	7.4%
Secondary Customers	9.1%	8.2%	9.4%	10.0%

* Note: The TLFs include technical losses and non-technical losses on the distribution system and the supply facilities loss factor (0.6%) for losses on the transmission system supply transformer. In the Present Rates in column 2 the non-technical losses are estimated as 10% of the technical losses. In the new 2007 analysis in columns 4 and 5, non-technical losses are included as 1.2% of the energy sold.

The 1.2% estimate for non-technical losses is the same figure used in the previously filed report in 2005. It is applied to all customer classes evenly because all customer classes contribute to non-technical losses. For customers supplied at high voltage this can be in the form of inadvertent blowing of a potential transformer fuse or in the form of meter tampering. At lower voltages meter tampering and meter by-pass both occur.

6 RECALCULATION OF CAPACITOR AND PHASE BALANCING SAVINGS

In 2005 Kinectrics estimated the potential savings from the installation of capacitor banks and from balancing phase currents on Hydro One distribution circuits. This estimate was made using the best information available at the time. Since that time Hydro One has obtained more detailed load profile information and performed detailed modeling on 482 circuits. This detailed modeling has provided more information that can be used to refine the estimate of the total potential energy savings. The most significant new information for capacitor savings studies is that 28% of the circuits already have optimally sized capacitor banks installed.

In addition to the new customer class load profiles provided by Hydro One, Kinectrics has analyzed load profile data for a sample of Hydro One distribution circuits. This analysis combined with the new customer class load profiles has provided new information that suggests that the load profile used by Kinectrics for distribution lines in the previous study, may not have been representative of all Hydro One circuits.

The results of the detailed individual circuit modelling did not confirm the estimated savings described in the Kinectrics report from 2005. A comparison is shown in the following table.

Table 7 Comparison of Potential Savings Estimates

Saving type	Detailed Hydro One Models	Kinectrics 2005 Report Estimate
Load Balancing Annual Energy Savings (GWh)	5.9	15
Capacitor Annual Energy Savings (GWh)	9.6	53

It has been determined that several factors lead to the differences in the preliminary estimates of energy savings and the estimates in the detailed modeling including:

- 28% of circuits already having capacitors installed
- Assumed load profiles (affects the size of the capacitor banks recommended, and energy saved per kW peak loss saved)
- Assumed phase balance
- Number of circuits balanced

The largest difference in the capacitor savings estimate is the size of the recommended capacitor banks. A major source of this difference is that the Kinectrics estimate included all the heavily loaded circuits. When the 2005 Kinectrics estimate was made, there was no solid indication of how many circuits, or which ones, had capacitors installed; and it was thought that many of the previously existing capacitor banks had been removed, leaving very few in service.

A review has been made of the results of the detailed modeling on 100 circuits that were also part of the Kinectrics preliminary estimate. Comments of the technical staff doing the detailed modeling indicate that at least 28% of these circuits already had capacitor banks installed and could not handle more. Another 42% showed minimal potential savings for a variety of reasons, including severe VAr imbalance, very short lines, or very branched topology.

The detailed modeling has provided this new information that was not available at the time of the Kinectrics estimate. It is still not known how representative the 28% and 42% figures are of all the circuits at Hydro One. It is possible that if the 28% represents the 28% most heavily loaded circuits, which would not be surprising since these circuits would benefit the most from capacitors for both voltage support and loss reduction. If this is correct then the Kinectrics estimate should be lowered by removing some or all of the heavily loaded circuits.

Another source of the difference in the estimates is in different assumptions about load profile. The Kinectrics estimate assumed that capacitor banks would be sized to balance the Var flow at a load of 50% of peak. This is assuming a relatively flat load profile. The detailed modeling was done using a 30% of peak criteria. The effect of the different assumption is that the detailed modeling will size a capacitor bank at 60% (30/50) of the value in the Kinectrics estimate. This means that where Kinectrics would use a 300 kVar capacitor the detailed modeling procedure would only use 150 kVar. Very little load profile data is available to test these assumptions. Examples of both lower limits (50% and 30%) are in the available data.

The detailed modeling of savings from phase balancing has revealed that there is very little correlation between the initial unbalance and the amount of saving possible. A similar lack of correlation exists with load current, and even the two combined. This is caused by the large number of confounding factors that are unknown except in a detailed study of a specific circuit. These confounding factors include line branching and load distribution. Since the previous Kinectrics estimates were based on assumptions that the savings would be dependent on unbalance and current, a new methodology of estimating savings from phase balancing was required and will be developed in section 6.2.

6.1 RECALCULATION OF ENERGY SAVINGS FROM CAPACITOR INSTALLATION

The changes in the modeling assumptions for estimating the annual energy savings from the installation of capacitor banks are summarized in Table 8. The assumed load profile used in the new estimate is for heavily loaded distribution lines.

Table 8 Changes to Assumptions for Kinectrics' 2005 Estimate in Kinectrics' 2007 Estimate

	Study Filed in 2005	2007 Study Revised Estimate
Circuits with existing Capacitors	0%	28%
Load Profile – Load Factor	0.49	0.56
Load Profile – Loss Factor	0.23	0.33
Phase Balance	Uncorrected	Corrected
Minimum load (% of peak)	50%	30%

Using this new information the estimate of potential savings from capacitor bank installation has been revised.

The new overall analysis predicts 0 circuits for 600 kVar (assuming the 11 circuits that would take this large a capacitor already have them installed) 12 circuits for 450 kVar saving 1.3 GWh, 40 circuits with 300 kVar saving 2.5 GWh and 226 circuits with 150 kVar saving 6.7 GWh.

Using the PV of the savings calculated in the previous Kinectrics report (not including environmental costs) and the estimated cost of capacitor banks, the cost information shown in the final three column of Table 9 have been calculated. A $1 million cost for detailed circuit modeling to size individual capacitor banks on specific circuits has been divided proportionally among the bank sizes.

Table 9 2007 Revised Estimate of Potential Energy Savings from Capacitor Bank Installation

Capacitor Bank Size (kVar)	Number of Circuits	Energy Saved (GWh)	$ Saved (k$)	$ Cost (k$)	Profitability Index
150	226	5.9	5,263	4,080	1.3
300	40	2.5	2,230	762	2.9
450	12	1.4	1,250	239	5.2
600	0	0	0	0	
Total	278	9.8	8,743	5,081	1.7

The uncertainty in the estimate of energy savings is quite high. The loss factor uncertainty can vary the estimated savings by 30% either higher or lower. Other sources of uncertainty are insignificant in comparison.

6.2 RECALCULATION OF ENERGY SAVINGS FROM PHASE BALANCING

The new method for estimating the total potential savings from load balancing has been based upon the results of the detailed studies done to date. The detailed studies have analyzed 482 circuits and found savings from load balancing in 256 circuits with an average savings of 8.2 kW at peak load. Circuit loading data bases show that there are at least 250 circuits in the Hydro One system with more than 37% unbalance and more than 50 amps of load current. These are likely candidates for load balancing. Only 58 of these circuits have been modelled in the detailed study. These 58 circuits averaged a savings of 9.6 kW at peak.

If the new peakier load profile, used in the capacitor savings estimate, is also applied to this peak saving then the annual savings per circuit are estimated to be 24.2 MWh per circuit balanced. Using the PV of the savings calculated in the previous Kinectrics report (not including environmental costs) this would result in a total savings of $16,450 per circuit balanced. Compared to an estimated cost of $3,000 to balance the circuit and $955 to do the detailed modeling, this work would have a profitability index of 4.0.

The total number of circuits on which the losses can be improved by balancing the phase currents is not known and cannot be accurately predicted because it would require detailed modelling of all circuits. In the completed detailed modelling of 482 circuits, the total savings has been calculated to be 5.9 GWh. The latest circuit loading data base has 750 circuit with significant phase unbalance and significant load current (>20% unbalance and >50 Amps). Planned circuit modelling over the next 6 years will identify which circuits will benefit most from load balancing.

If the results on the circuits modelled to date are extrapolated linearly then the total estimated savings would be at least an additional 4.9 GWh of savings in addition to the 5.9 GWh on the circuits already modelled, for a total estimated energy saving of 10.8 GWh per year. The additional 4.9 GWH is assuming only the 192 circuits with the worst balances (>37%) but not yet modelled in detail will result in significant energy savings. This is a conservative estimate since many of the circuits with a significant imbalance but less than 37%, will be modelled and found to have potential savings as has been the case in the circuits already modelled in detail.

7 ESTIMATION OF SAVINGS FROM IMPROVED EFFICIENCY DISTRIBUTION TRANSFORMERS

Distribution transformers are a significant source of energy loss. This loss can be minimized by the design of the transformer and by carefully planning the loading of the transformer.

The design of the transformer includes many parameters that can be adjusted to reduce losses including: core size and material which affect the constant no-load loss and conductor size and material that affect the load loss, which varies. The losses inherent in the transformer design can be adjusted by the "cost of losses formula" that is used in the tendering document in the transformer purchasing process. The formula adds to the purchase price the expected present value of both no-load and load losses over the life of the transformer, so that different bids by manufacturers can be compared on a total cost of ownership basis. This process produces a transformer design that minimizes the life time cost, but does not minimize losses.

Kinectrics has recently recommended that Hydro One change the cost of losses formula so that it reflects the OEB approved avoided cost of losses for evaluation of conservation and demand side management programs. Separate values for rural and urban transformers are shown in Table 11 because the rural transformers serve fewer customers and therefore tend to be lightly loaded and their overall efficiency is thus more dependent on no-load losses. The actual cost of losses formula is :

$$TOC = CAPCOST + CNLL \times NLL + CLL \times LL$$

Where:

TOC	is the total cost of ownership ($)
CAPCOST	is the capital cost of the transformer ($)
CNLL	is the cost of no load losses ($/W)
NLL	is the no-load loss of the transformer (W)
CLL	is the cost of load losses ($/W)
LL	is the load loss of the transformer at rated load (W)

Table 10 Transformer Purchasing Cost of Losses Formula

Application	Loss Type	1997 ($/W)	New ($/W)
Rural	No-load	5.2	15.06
Rural	Load	0.9	2.75
Urban	No-load	7.4	15.06
Urban	Load	3.9	8.6

The energy savings from the change to the "new" formula depend on the actual loading of the individual transformers, and the effects of reducing each type of loss on the capital cost of each manufacturer's transformer design.

As an example, in a 50 kVA single phase pad mount, an amorphous steel core could reduce the no load losses by about 30% or 31.5W but at a cost of about $200 (ref DOE study). This is 6.3$/W which would lower the total ownership cost under the new cost of losses formula but raise it under the 1997 formula. The new formula will therefore allow for the use of amorphous cores, reducing no load losses by 30%.

Considering load losses, the resistance of copper wire is 36% less than similar size aluminum wire so its losses are 36% less, however it costs more. This is partially mitigated by copper windings needing a smaller, less expensive core because core opening is smaller for the same ampacity of winding. As an example (Ref DOE study) consider a 50 kVA padmount with aluminum windings which has a core cost of $275 and winding cost of $116 and compare with a transformer with copper windings at $246 core cost and $216 winding cost. The reduction of 36% in losses (239W) comes with a price increase of $71 or 0.3$/W. In this example case both versions of the cost of losses formula will result in the use of copper windings. The larger CLL value will encourage the use of larger conductors in the winding to reduce load losses, until this is balanced by the increase in capital cost of the copper used and the larger core required by the larger windings, and the increased no load loss of the larger core.

A reasonable expectation may be that the load losses will be reduced in proportion to the amount of capital money (increase in capital cost) that the manufacturer can spend on them. The new loss cost formula would give the manufacturer twice as much capital cost to spend on reducing load losses of urban transformers and three times as much for rural, compared to the old formulas. Weighting these by the proportion of urban and rural customers at Hydro One, this could result in a reduction in load losses by a factor of 0.51.

The overall effect of the recommended cost of losses formula is therefore expected to be a reduction of 30% in the no load losses and a reduction of 50% in the load losses. Using the total system no load and load loss values from Table 6 this would be a savings of 91 GW-h and 31 GW-h per year, when all transformers on the system have been replaced.

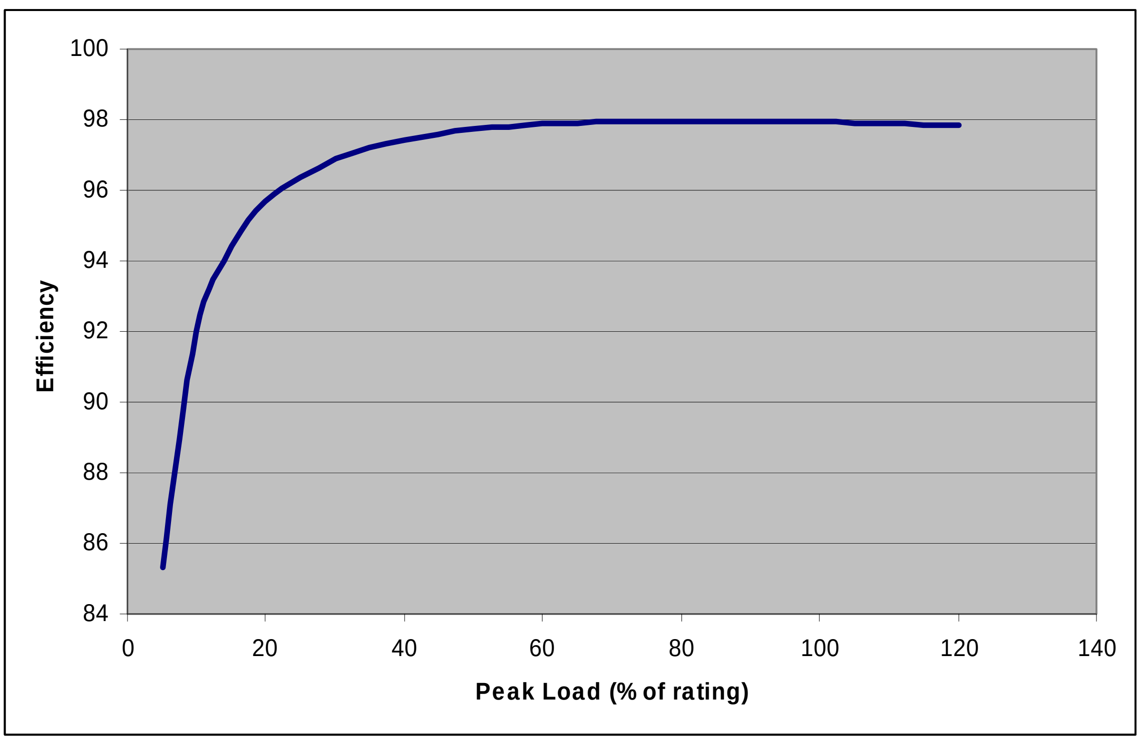
No matter what cost of losses formula is used in transformer purchasing specifications, the actual losses that occur will depend on how the transformer is loaded. Most transformers are designed for maximum efficiency at a constant 50% load. A previous study (Ref 2) found that on average Hydro One distribution transformers where loaded between 20 and 40% at peak load. The reasons for this are complex. Although the cost of losses would be reduced by using smaller transformers, the cost of inventory for stocking more sizes of transformers would be higher and partially off set the cost reduction in losses. The cost of transformer change outs when load grows unexpectedly, such as the construction of another house nearby, would also increase.

Independent of these non-technical considerations, it is necessary to accurately predict what the peak load will be on a transformer for any new load. This is done by considering the type of loads expected and the diversity of the loads. Load diversity is the reduction in the actual peak power drawn by the load below the sum of the peak power of the individual loads. There are two processes at Hydro One at the present time for sizing transformers based on type of load and load diversity. The 1992 Overhead Line Design Standard uses a procedure based on a table of “unit values” which are selected for each load on the transformer and then the transformer is sized on a separate table of total unit values and transformer kVA size. The diversity is taken into account in the construction of the second table, where the kVA/unit value varies from 10 to 1.9. Although no background information is given in the standard, one unit value appears to be equivalent to about 3 kW of load.

The Underground Line Design Standard has a different procedure for sizing pad mount transformers based on a diversity curve. Modifications to this procedure have recently been made by Kinectrics to bring the 1973 curves up to date. If the recommendations are adopted the recommended kVA for a single house will be reduced and larger load diversity will be assumed. Both of these will result in smaller recommended transformer sizes and increased loading, but the difference is typically 20% which will not increase the average peak load to 50% of rating.

A typical relationship between peak load and efficiency is shown in Figure 1. Notice that the realistic load profiles used in the calculation of Figure 1 (Load factor 0.49, loss factor = 0.23) make the maximum efficiency occur at a peak load of 80% of rating. The same transformer at a steady load will give a maximum efficiency at 50% of rating. Loading this transformer (25 kVA pole mount, single phase, 8.32/4.8 kV, NLL=0.26%, LL=1.71%) at 30% results in an efficiency of 96.9%, which means 3.1% of the energy carried is lost. Increasing this by 20% to 36% loading would only increase the efficiency to 97.2%. The expected savings in annual losses due to using the new diversity charts is estimated to be 9.7% of the present load loss. Using the present load loss from Table 5 this would be a savings of 7 GW-h.

Figure 1 Distribution Transformer Efficiency as a Function of Loading



Note: Efficiency has been defined as the energy output expressed as a percentage of the input energy .

The small overall savings in losses created by purchasing more efficient transformers and loading them appropriately is therefore estimated to be 91+37+7 = 135 GW-h per year. This is 36% of the 367 GW-h lost now in distribution transformers. It is a substantial saving but it can only be achieved by replacing all distribution transformers. Since this is a major investment, in the order of $900 million, it can only be done as the transformers reach their end of life over the next 40 years. The estimated savings over 20 years if all were replaced in the first year are only $119 million for a profitability of 0.13. If the transformers are replaced as they wear out then there are no additional costs to saving 3.4 GW-h more each year. This would be 67 GW-h after 20 years and a present value of the savings would be $28 million.

This cost analysis has been made on the basis of an estimate of the direct cost of the transformer. This direct cost cannot be accurately predicted because the cost of a transformer is based on a competitive tendering process. The price of efficient transformers depends on the cost of labour and materials at the time on the order and also on the number of other utilities specifying a similar transformer. There is a large price penalty for buying transformers that are not standard products and mass produced for many other buyers.

In addition to the direct costs of the transformer there are other costs associated with changing to more efficient transformers, particularly amorphous core transformers which have lower no-load losses. The amorphous steel cores saturate at lower levels of magnetic flux, and therefore the cores must be larger. This makes the overall transformer significantly larger and heavier. When a transformer is replaced an assessment must be made of the condition of the wood pole on which it is mounted. If the pole strength is not adequate then a new pole must be installed, considerably increasing the cost of the transformer replacement. This situation would happen more frequently if heavier transformers are used.

Other sources of costs in switching to more efficient transformers include, writing new specifications and purchasing documents, new work procedures to handle the heavier transformers, increased stocking, warehousing and transportation charges.

Kinectrics has not been able to include all of the costs in the estimate since they are dependent on the internal business processes at Hydro One and on the market for distribution transformers. It is recommended that Hydro One conduct an internal study of the cost of changing to more efficient transformers and compare the costs with the benefits presented in this report.

8 ESTIMATION OF SAVINGS FROM CONDUCTOR REPLACEMENT FOR LOSS REDUCTION

Distribution line losses can be reduced by replacing small conductors with larger ones. This is particularly cost effective if a larger conductor is chosen when the line is built, because then there are fewer extra costs other than the cost of conductor. However, often larger conductors require stronger poles and more guying which increase the costs. The following analysis calculates when changing out conductor on an existing line can be cost effective.

The conductor costs, obtained from a manufacturer's website (Southwire) in October 2006 are shown in the following table.

Table 11 Conductor Data

Conductor	Cost ($/conductor- km)	Resistance (ohms/km)	Ampacity (Amps)
#2 ACSR	840	0.8501	200
1/0 ACSR	1,260	0.5351	275
3/0 ACSR	1,990	0.3363	365
336 MCM ASC	3,660	0.1683	565
556 MCM ASC	5,660	0.1017	775

The resistance values are from Hydro One Line Design Standard 1992. The ampacities are summer values from the same source. Winter ampacities are approximately 22% higher.

The installed cost of stringing new conductors has been estimated by Hydro One, based on recent projects, at between $200,000 and $250,000 per km of three phase line. The costs are high because the line being reconductored is usually the first km of the circuit, close to the substation, where the poles carry more than one circuit and require replacement to have adequate mechanical strength to handle the larger conductors.

The cost of poles and hardware on a new three phase distribution line has been estimated at 35$/m (Ref 4) or $38/m adjusted to 2007 dollars. The extra cost of using larger poles, smaller pole spacing and heavier guying has been estimated as 18 $/m for medium conductor sizes (556, 750) and 30$/m for the largest (1033) in new construction. For retrofit situations where stronger poles and guys are required the full 38+18(or 30)=$56(68)/m cost would apply. The conductors themselves would cost another $19/m (5.66 x 3 + 1.9) or $26/m for the largest size. The total estimated cost for new construction would then be $75/m (56+19) or $94/m (68+26). This is an additional $19m for changing the new design to a larger conductor. When compared with the $225/m for reconductoring an existing line, it is clear that although using larger conductors in new construction might often be cost effective, retrofitting to larger construction can be expected to be cost effective in very few cases.

In the energy loss calculations, the resistance of the conductor has been increased at higher loading levels because the resistance increases at higher temperatures. The adjustment factors are shown in the following table (Ref 5). The annual load profile for Hydro One was used to calculate the fraction of the year at each conductor temperature assuming the annual peak load was at the thermal capacity of the line (90 ºC). For conductors loaded at less than the thermal capacity at peak, the resistance was adjusted a lowered amount, in proportion to the fraction of the peak load squared. In the final analysis the temperature correction was only a few percent of total ownership cost if peak currents were less than 200 amps. It could be as high as 20% at 500 amps.

Table 12 Conductor Resistance Temperature Adjustment

Temperature (ºC)	Multiplying Factor	Fraction of Time
0	0.92	0
10	0.96	0
20	1	0
30	1.04	.008
40	1.08	.09
50	1.12	.28
60	1.16	.45
70	1.20	.15
80	1.24	.02
90	1.28	.002

The costs of losses over a twenty year planning period were added to the capital cost to obtain a total ownership cost. The cost of losses in each year was calculated using the energy and power costs provided by the OEB (Ref 6). The expected conductor life is greater than forty years. If a forty year planning period had been used the present value of the savings would be 25% higher. If a ten year planning period is used the values would be 34% lower.

New load profile data (8760 hrs) was obtained in 2006 and an overall load factor of 0.66 and loss factor of 0.45 was calculated from these data. Since the load profile data was from the entire load of Hydro One, these profiles are suitable to apply to subtransmission lines but not distribution lines. Distribution lines have less load diversity and therefore "peakier" load profiles. A load factor of 0.56 and loss factor of 0.33 have been estimated for heavily loaded distribution lines. These are the same values used in the calculation of energy savings from capacitor banks. Using the lower values reduces the total ownership costs by 20% at 500 amps and 10% at 200 amps.

In the figures of total ownership cost shown below, the load growth is assumed to be 1% per year and the financial discount rate is 9.3%. The total ownership cost is the capital cost plus the present value of the expected cost of the losses.

Figure 2   Total Ownership Cost at Low Current Levels

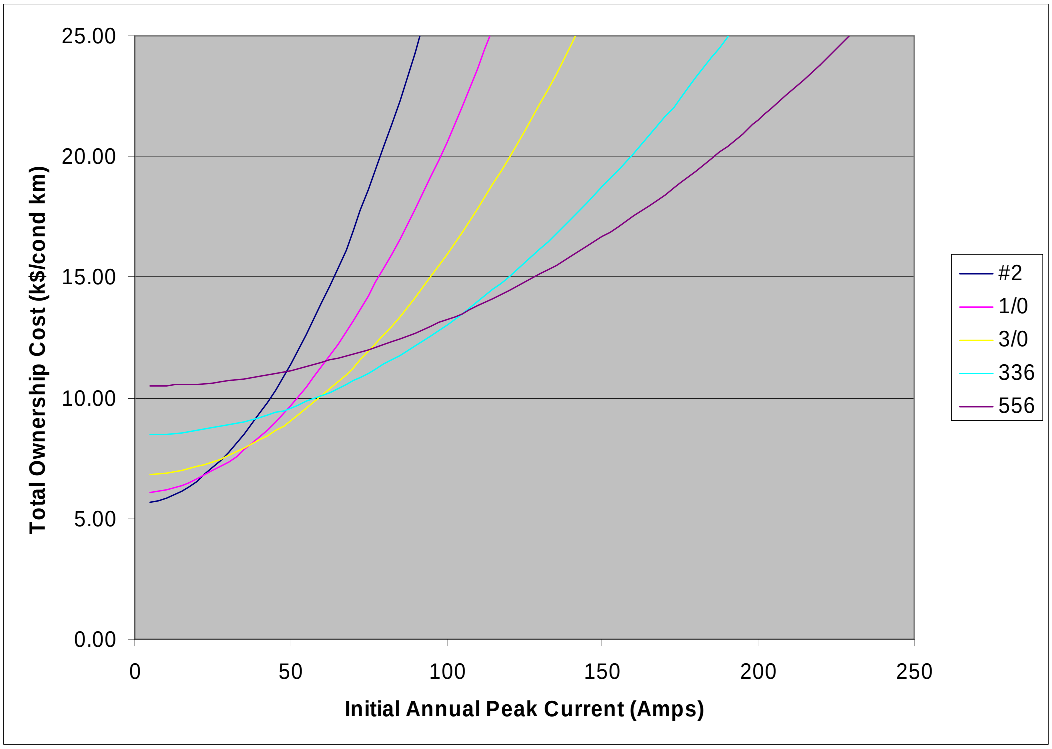


Figure 3   Total Ownership Cost at High Current Levels

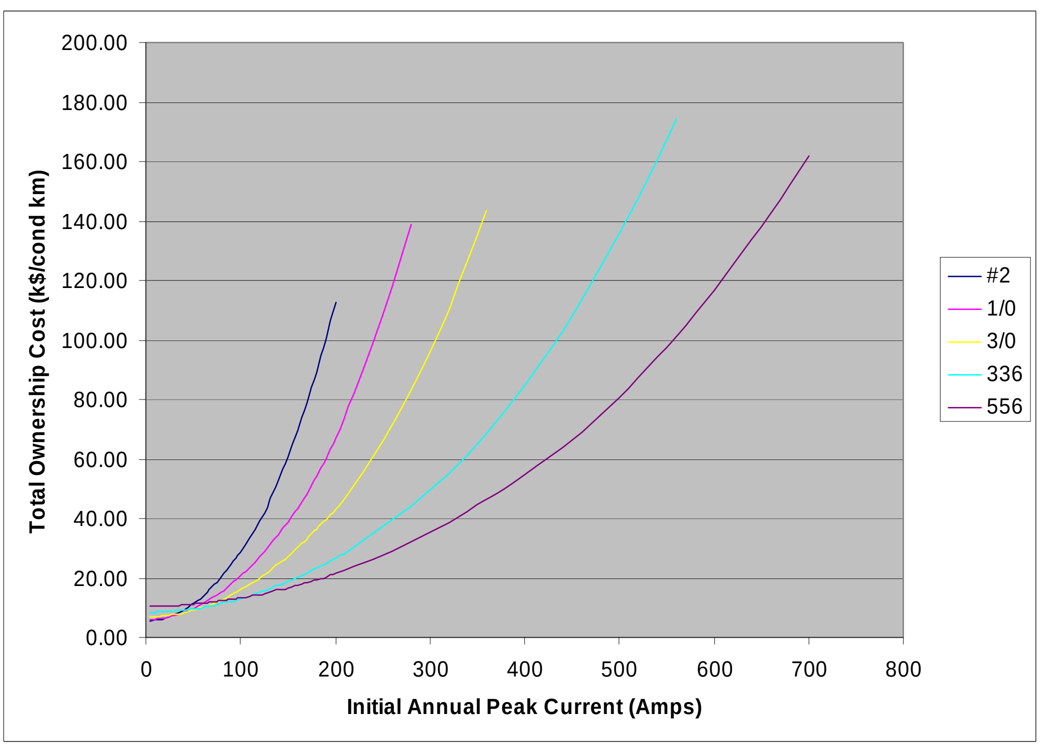


Figure 2 illustrates that the cost of losses dominates over the capital cost of the conductor at any significant load. For example the 336 conductor has an installed capital cost of $8.5/m (the vertical intercept) and even at a peak load of 34% of rating (190 amps) the total ownership cost is triple at $25/m. This means that even in urban areas where the voltage drop is not limiting, large conductors should be used to minimize the total ownership cost. At the present time the largest conductor routinely used at Hydro One, 556 MCM ASC, should be used whenever the expected peak current is greater than 100 amps. However, if larger poles and guys are required, increasing capital cost for the larger conductor by $10/conductor–m in new construction, then the lower load limit for 556 conductor increases from 100 amps to 230 amps.

In order for a retrofit change in conductor size to be cost effective, the reduction in the total ownership cost in Figure 2 or 3 (vertical distance between the curves) must be greater than the reconductoring cost. Using the reconductoring cost for Hydro One of $225/m of line gives a breakeven point of $75/conductor km.

A single step in conductor size was found to never be cost effective.

Figure 4 Profitability of Conductor Change Out to Reduce Losses

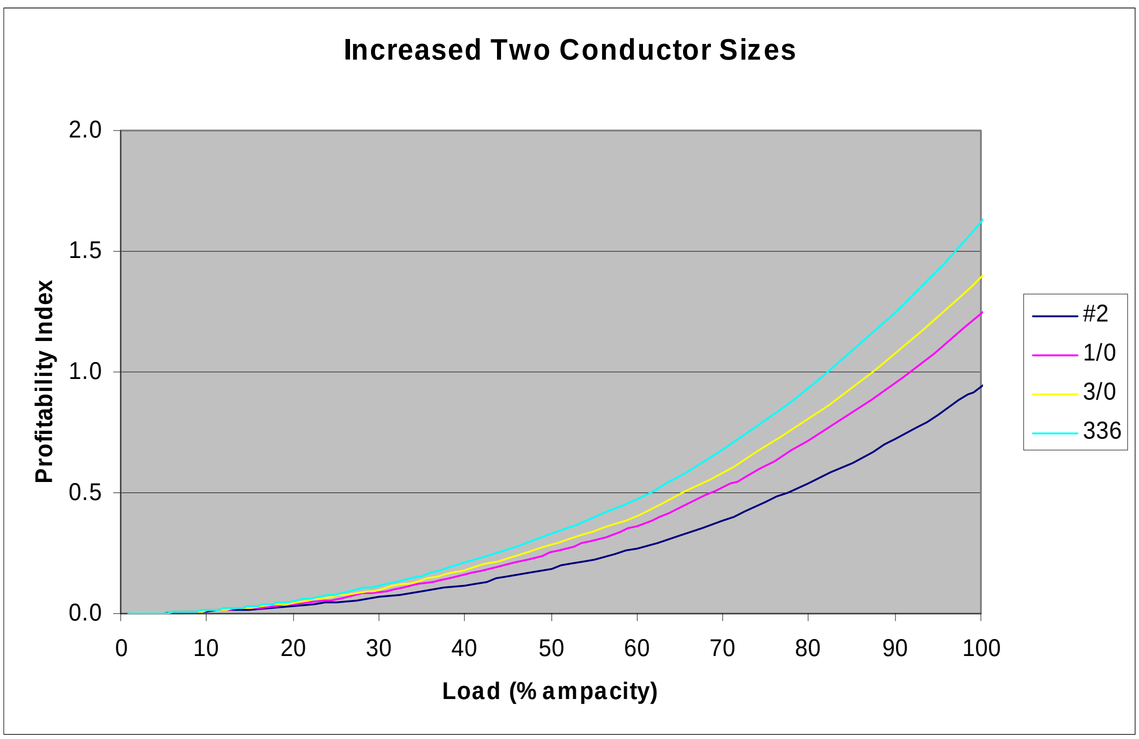


Figure 4 shows the profitability index (ratio of the present value of savings to the cost of reconductoring) of replacing a conductor with one two sizes larger in the standard Hydro One conductor set, as a function of the initial load on the smaller conductor. A reasonable decision criterion is to use a profitability of at least 1.5 to indicate that a line should be reconductored. This gives some room for error in the estimate and still ensures that the project is profitable. In Figure 4 the criterion is met only for 336 conductor when the peak load is more than 95% of the ampacity of the line. The curve was calculated with a twenty year study period. If a forty year period is preferred then a criteria of a profitability ratio greater than 1.2 is equivalent. This would give the same % loading as a profitability ratio of 1.5 calculated for a forty year period. If a ten year period is preferred then the criteria should be a profitability ratio of at least 2.2 and no conductor would ever be replaced as a cost effective way to reduce losses.   A single step in conductor size was never cost effective.

The values in the figures were calculated using the "peakier" load profile of distribution lines. If the smoother load profile of subtransmission lines is used then the % load at which a profitability of 1.5 achieved decreases by about 10% to a load of 85% of ampacity for the 336 conductor.

In order to estimate the potential loss savings for all of Hydro One, data on the % loading of 1245 rural distribution feeders in 2003 was examined. The results are shown in Table 13. It indicates that conductor change out would be cost effective on 3% of the circuits. The data could not determine how much of each circuit could be reconductored. The loading data only applies to the section closest to the substation.

Table 13   Loading on Hydro One Distribution Circuits

% Ampacity	# circuits	% of circuits
80 – 90%	57	4.5%
90 – 100%	43	3.5%
> 100%	39	3.1%

The detailed cost and benefits from reconductoring can only be calculated for specific circuits. Increasing conductor size by two steps can require the use of larger poles and crossarms. Increasing conductor size outside of the normal conductor set would result in many increased costs for Hydro One, including purchase of equipment that can string the heavier conductors and increased inventory costs for more conductor and connectors. In individual cases there are often alternative methods for reducing the losses, such as rebuilding a parallel single phase line as a three phase line, or reconfiguring adjacent circuits to lower the load.

It is recommended that Hydro One conduct a detailed study of its circuits loaded greater than 95% to determine the most cost effective means of lowering the losses.

9 COST MODELS FOR LOSS REDUCTION

There are a number of options for the appropriate cost model with which to identify loss reduction projects that should be implemented in the present business environment. It is different for different stakeholders.

It might be considered that cost of losses are all incurred by customers as they put the load on the system and they determine the timing of the loads which result in peaks and highest losses. The customer however, does not control the voltage at which they are served or the distance of line to their facility. Distributors also have a substantial influence through their network configuration, thresholds for capacity reinforcement and the loss levels of the network equipment they install. Losses could therefore be considered to be controlled by both the customer and the distribution company.

Peak losses have a direct impact on the demand and therefore on the distribution plant required, and thus have direct costs to the distribution company in terms of requiring additional capital equipment and costs associated with the loss-of-life of station transformers. Losses incur costs on the utility such as:

- requirement to increase the size of assets on the network to transport units which will be lost further into the network.
- Cost to maintain the system for incremental kW
- cost of facility to handle higher loads
- cost to maintain assets with higher capacity
- cost of allocating losses to customers

Given the above, it can be argued that although there is no energy cost of losses to utilities, there is a cost of demand losses. System components have to be planned, designed operated and maintained to handle the losses of downstream components. The cost to transfer an extra unit of power is borne by the utility without direct compensation from the customer. This cost is a component of the capital operation and maintenance budgets and must be included in the rate base

For the utility, the cost of energy losses is a pass through cost, and therefore does not affect them financially. This consideration implies that there are no benefits that accrue to the utility if it decreases the system losses. However, the utility is allowed to earn a return on its capital investment in the system. If that capital investment is made to reduce losses, then there is a financial return to the utility for decreasing losses. This consideration implies that the benefits to the utility are substantial and independent of actual loss savings achieved. The security of the return on investment causes the latter consideration to out weigh the former, resulting in a net benefit to the utility for implementing loss reduction programs. The cost effectiveness of the reduction in losses is not an issue for this stakeholder.

For society as a whole, the reduction of losses increases the cost efficiency of the society, decreases resource depletion, decreases pollution and decreases the investment in generation facilities with its attendant financial risk. If the cost of losses is less than the cost of program implantation then the cost of electricity is reduced creating a better business climate and reducing the cost of living. However, there may be net societal benefits even if the cost of program implementation is above the cost of energy saved.

For the individual customers who purchase electricity the major effect is on the price of electric energy. If the cost of losses is less than the cost of program implantation then the cost of electricity is reduced. A cost model for this stakeholder would probably not include environmental costs.

For each stakeholder, the costs that should be included in the cost model are different. The table summarizes the various costs and which stakeholder requires them to be in the cost model.

The relative value of the various costs as recommended by the OEB Total Resource Cost Guide (Ref 6) using the avoided cost method are shown in the following table.

Table 14 Cost for Inclusion in Cost Model

Cost	$/kWh	Distribution Utility	Society	Customer
Energy Cost	0.066		✔	✔
Generation Capacity Cost	0.018		✔	✔
Transmission Capacity Cost	0.0014	✔	✔	✔
Transmission Loss Cost	0.002	✔	✔	✔
Distribution Capacity Cost	0.0018	✔	✔	✔
Distribution Loss Cost	0.006	✔	✔	✔
Environmental Costs	0.019		✔	

In Table 15 capacity costs were converted from $/kW to $/kW-h, for the purposes of comparison, by multiplying by the ratio of energy sold to peak power for the Hydro One distribution system (0.000245). When this is done it is clear that the energy cost is about 57% of the total avoided cost, or 69% if the environmental cost is not included.

In this report all of the costs have been included except the environmental cost. The environmental costs represent about 16% of the total.

10 REVISED TECHNICAL LOSS MANAGEMENT PROGRAMS

10.1 POWER FACTOR CORRECTION USING SHUNT CAPACITORS

The most recent loss analysis has indicated a potential for saving and forms the basis of the capacitor installation plan. The 2007 estimate indicates that shunt capacitor banks could be applied to 278 Hydro One feeders (12 with 450 kVAR units, 40 feeders with 300 KVAR banks and 226 feeders with 150 kVAR banks). When fully implemented these capacitors would result in annual energy savings of approximately 9.8 GW-hr, about a 0.5% reduction in distribution system energy losses. This translates to a 20-year Present Value of savings in the order of $8.7M. The capital and labor cost for these installations in a two year program, including the cost of analysis to determine optimal locations would be $4.1M for a profitability index of 2.1.

Additional loss reduction could be achieved with the installation of switched capacitor banks which would match the connected kVAR to the variations in the load. Since this loss reduction method would require control schemes to monitor voltage levels, time of day and / or status of switching equipment, the costs would increase substantially, and will require further investigation in future.

10.2 FEEDER PHASE BALANCING

The distribution network consists of approximately 400 “sub-transmission feeders” and 2700 “distribution” feeders. A considerable part of the Hydro One distribution system consists of single-phase residential loads, making the power flow in three-phase main feeders difficult to balance. The total I^2R loss in the three phases of an unbalanced system is higher than that of a balanced system, and therefore, a concerted effort to balance phases, can result in loss reduction. Phase imbalance is often expressed as the maximum phase current minus the average of the phase currents divided by the average of the phase currents. At the present time phase imbalances at the distribution stations on the worst third of the Hydro One feeders are in a range of 30% to 100 % indicating considerable room for improvement.

The recommended phase balancing program will target the 250 already identified circuits and the worst 192 of Hydro Ones’ distribution feeders yet to be identified over a 6-year period. It is estimated that at full implementation, balancing of these feeders will result in a 10.8 GW-hr annual energy saving. Since unbalance will recur with the passage of time, the benefits from this phase balance were estimated assuming a decline in energy savings over a 20 year period.

Considering only the first two years of this program, 250 circuits have already been identified and 64 more can be anticipated within two years, for a total of 314. This will result in an energy saving of 7.6 Gwh per year. The 20 year present value of avoided costs is about $5.2M. The cost to implement the phase balancing over a two year period would be $0.94M, for a profitability of 5.5.

10.3 CONDUCTOR CHANGE OUT

The sizing of distribution conductors and cables is normally determined by considering the thermal capability of the conductors and cables, and by the amount of voltage drop from source to the receiving-end. Hydro One's long rural feeders are generally voltage-drop limited as opposed to ampacity limited. Another consideration, however, is cost of losses related to the conductor size selected. The larger the conductor size, the lower are the losses. Larger conductors require more capital expenditures and a balance must be found when sizing the conductors. The conductor size is typically optimized, through the planning process, when a feeder is initially installed. However, as the system evolves and conditions change from original plans, occurrences of sub-optimally sized conductors will materialize. Conductor change out on sections of a feeder that are heavily loaded can provide loss improvements. There are also other techniques for lowering the losses by lowering the load.

It is recommended that Hydro One conduct a detailed study of its circuits loaded greater than 95% to determine the most cost effective means of lowering the losses.

10.4 TRANSFORMER SIZING AND EFFICIENCY

The series and shunt resistance and reactance of distribution transformers result in significant losses on distribution systems. The consumption of reactive power by transformer reactance introduces higher reactive current flow in the primary circuits, which contributes to the system losses. Distribution system losses can be reduced by properly sizing the distribution transformers.

Transformer no-load losses are constant and depend on the size of the transformer installed and the loss formula to which it was purchased. Decreasing the transformer rating will decrease the no-load losses. On the Hydro One system it is notable that on many feeders, the actual peak load on the feeder is only 20 to 40 % of connected kVA. This implies that the connected kVA is unnecessarily high and a reduction in transformer sizes would not overload the smaller transformers. Consideration would have to be given to the cost of inventory for stocking smaller transformer sizes.

The 2007 loss analysis indicates that the optimal specification and sizing of distribution transformers could yield an estimated present value of savings over twenty years of $119 M.

Kinectrics has not been able to include all of the costs in the estimate since they are dependent on the internal business processes at Hydro One and on the market for distribution transformers. It is recommended that Hydro One conduct an internal study of the cost of changing to more efficient transformers and compare the costs with the benefits presented in this report.

10.5 SUMMARY OF BENEFITS

Lowering distribution system delivery losses will reduce overall system demand and provide additional network capacity for growth. Since system delivery losses are currently passed on to all customers, improvements in this area will benefit all customers.

The expected benefits of the proposed distribution loss reduction program are summarized in the table below. The benefits of the capital expenditures over two years are present valued over twenty years.

Table 15 Economic Benefits

Program	Maximum Reduction in Annual Energy Loss GW-hr	Avoided Energy and Demand Costs* $M	Cost of Program $M	Profitability Index
PF Correction Capacitors - install cap banks on 278 feeders	9.8	8.7	5.1	1.7
Phase balancing - balance 314 circuits -2 years of a 6 year program	7.6	5.2	1.3	4.0

* Note: Present valued over a twenty year period

11 REFERENCES

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2. Stephen Cress, George Anders, “Distribution Loss Evaluation and Minimization”, Kinectrics Report 8119-011-RA-0001-R00, March 25, 2002

3. Kerry Diehl, “How HSVCs Improve Power Quality and Reduce Distribution Costs”, Electricity Construction and Maintenance January 2002

4. Ray Piercy, “Distribution System Configuration Study”, Kinectrics report 8307-010-RA-0001-R00, 2001

5. IPCEA Publication S-66-524, NEMA WC7-1971

6. Total Resource Cost Guide, Ontario Energy Board, September 8 2005

12 APPENDIX A 2005 Kinectrics Report K-011568-0010RA-0001-R00

1. CONCLUSIONS AND RECOMMENDATIONS

1.1 OVERALL LOSS ESTIMATE

A high level computation using the latest system component inventories and loading data has shown that the best estimate of the annual energy technical loss in Hydro One distribution systems is 5.05% of energy sales, with an expected range of 3.9 to 6.1%.

The loss breakdown by power system component is shown in the following table.

Component	**Estimated Loss as a Percent of Total Energy Sold**
Subtransmission Lines	2.33
Power Transformers No Load	0.21
Power Transformers Load	0.12
Distribution Lines	1.18
Distribution Transformers No Load	0.78
Distribution Transformers Load	0.19
Secondary Lines	0.24
Total	5.05

1.2 DISTRIBUTION LOSS FACTORS

The Distribution Loss Factors (DLFs) calculated based on these technical losses are shown in the following table and compared to the previous DLF values used by Hydro One.

Customer Type	**DLF in Present Rates**	**Total Estimated DLF**
Embedded LDC and Subtransmission Customers	3.4%	4.4%
Primary Customers	6.1%	6.8%

Secondary Customers	9.1%	9.6%

The DLFs in the above table include the technical and non-technical losses on the distribution system and an allowance of 0.6% for loss in the transmission system.

1.3 TECHNICAL LOSS REDUCTION PROGRAM

The expected benefits of the proposed distribution loss reduction program are summarized in the table below. These estimates are based on the characteristics of the Hydro One distribution system and the avoided costs for generation, transmission, distribution and environmental impacts. The present value of the benefits has been calculated over twenty years. The overall benefit to cost ratio of the program is 5:1.

Program Savings

Program	Maximum Reduction in Annual Energy Loss GW-hr	Avoided Energy Demand and Environmental Costs PV $M
PF Correction Capacitors - install cap banks on 660 feeders requiring 300kVAr or more	53	52.9
Phase balancing - balance 750 circuits	15	11.4

Program Costs

($'000s)				
Distribution Network Loss Reduction	**2004/2005**	**2006**	**2007**	**Total**
PF Correction Capacitors		2,600	7,700	10,300
Phase balancing		700	1,500	2,200
Reconductoring		100	na	100
Transformer Size and Efficiency		150	na	150
Total				12,750

2. INTRODUCTION

As part of the support for the rate application to the OEB Hydro One has requested a study of the technical line losses on its electric power distribution system. The project included an overall assessment of technical energy losses, an allocation of loss to different types of customers resulting in distribution loss factors (DLF) for each type, and development of a program to reduce energy.

Energy losses on power systems can be divided into two broad categories, technical losses and non-technical losses. The majority of this report deals with technical losses, however a brief discussion of non-technical losses is provided in section 2.2.

2.1 DEFINITION OF TERMS

Distribution Loss Factor (DLF)
A factor used to increase the measured energy from a customer's meter to account for losses in the delivery of the energy. Strictly speaking it should be a value with no units such as 1.08 but it is often expressed as a percentage using just the decimal part, for example 1.08 is expressed as 8%. It includes technical losses, an adjustment for theft and other non-technical losses and the supply facilities factor.

Supply Facilities Factor
A value added to the DLF to account for loss in the transmission system. This has been previously estimated to be 0.6% by Hydro One.

Technical Losses
Power or energy used in the components of the system that delivers electricity to the customer's meter. This includes conductor losses that depend on resistance and current and transformer losses that include a conductor loss and a core loss. The core loss does not vary with loading.

Power losses are expressed in kW or as a % of the loss at peak load.
Energy losses are expressed in kW-h per year or as a % of the total energy sold in a year.

Non-technical Losses
Includes all unaccounted for energy other than technical losses. This can occur through theft, meter inaccuracies, billing errors etc.

Loss Allocation
When technical losses are not averaged over all customers on the system they are divided into parts and each part assigned (allocated) to a different customer or group of customers. The loss allocation can be either power or energy losses, but usually it is energy losses. It can be expressed in kW-h or as a % of energy sold to that customer or group of customers in a year. The loss allocation is often used as a basis for a DLF. The DLF for a specific customer group can be calculated by adjusting for the amount of energy sold to that group and adding a factor for non-technical losses and the supply facilities factor.

Loss Factor
A factor used to convert the power loss at peak load to the average power loss. It depends on the details of the load profile, i.e. how the load changes with time. It is often estimated based on an equation involving the load factor as follows:

$$\text{Loss Factor} = p \times \text{load factor} + (1-p) \times \text{load factor}^2$$

The constant "p" in this equation depends on the load profile. It is typically 0.3 for subtransmission systems, 0.2 for distribution lines, and 0.15 for distribution transformers and secondary circuits.

Load Factor
A factor used to convert peak power to average power. It is the ratio of the average power to the peak power.

2.2 NON-TECHNICAL LOSSESS

Non-technical losses occur as a result of the difference between the amount of electricity distributed to customers and the amount that is actually paid for. These losses occur because of the following:

- Theft, fraud, meter tampering/bypassing
- Faulty meters - resulting in the amount of electricity used being under-recorded.
- Incorrect records, billing errors

Published figures for the level of non-technical losses in North America are very difficult to obtain. In California "unaccounted for energy" is defined as the difference between the energy purchased and the energy sold in a utility service territory after accounting for imports, exports and technical line losses. This includes the first three categories of non-technical loss listed above. Estimates from different utilities range from 3.9 to 5% of energy sales. (Ref 3).

Published figures for theft alone in the United Kingdom estimate levels at 0.2 to 1% of energy sold (Ref 1) and the upper limit of this range is used in Australia by regulatory commissions as a reasonable estimate in the calculation of distribution loss factors (Ref 2).

Any distribution loss factor calculated from technical loss allocation must be increased to cover all forms of non-technical loss. In the past Hydro One has used a figure of 10% of the technical losses to estimate non-technical losses. With technical losses at approximately 6% of energy sold this represents only 0.6% of energy sales as an estimate for non-technical losses. This is well below (<15%) of the published figures for utilities in North America and is less than that used in Australia or most of the United Kingdom. A more reasonable estimate for theft and other non-technical losses would by 1.2% of energy sales. This figure has been adopted in this report.

3. OVERALL TECHNICAL LOSS ESTIMATE

3.1 METHOD

There are two basic methods that can be used to calculate technical energy losses, a method based on subtraction of metered energy purchased and metered energy sold to customers and a method based on modeling losses in individual components of the system.

The method based on subtraction of energy sold from energy purchased is the traditional method outlined by the OEB. This method is not appropriate for Hydro One because of the extensive metering system that would be required and does not now exist. The existing meters do not total energy over the same time periods because they are manually read at fairly long intervals. More expensive metering would be required. Energy meters are also not installed at all intermediate levels of the system where they would be required to allocate losses to different types of customers.

The method of loss estimation based on modeling losses in individual components of the system has been used in this report in order to be able to allocate different amounts of loss to different types of customer within Hydro One. The following method was applied to each system component (subtransmission lines, power transformers, distribution lines, distribution transformers, secondary lines):

1. Identify different types of the component that would have different losses (e.g. different transformer ratings, line voltage levels, secondary line lengths etc.)
2. Assume a load profile for each component type (hours per year at each load level)
3. Calculate from the load profiles, values for load and loss factors for each component
4. Estimate the number of each type of component in the Hydro One system
5. Calculate the total loss at peak load and the annual energy loss.

The energy loss computation requires information on several basic factors: the inherent loss of the component, the profile of time varying load on the component, and the population of such components on the Hydro One system. The following sections describe the details of the loss computation for each separate type of component.

3.1.1 Subtransmission Lines

The number of subtransmission circuits at each voltage level and the total circuit length was available from spreadsheet “PSDB_Feeders_2005_07_14.xls” obtained in July 2005. There are 300 circuits at 44 kV, 221 circuits at 27.6 kV and 42 circuits at 13.8 kV. Circuits that are metered at the transformer station and/or owned by other utilities were not included. The 44 kV circuits were divided evenly into two different types, 44 kV in a developed rural area (surveyed lines and concession roads) and 44 kV in a sparse load rural area. The total length of subtransmission line was 15,800 km, obtained from Dx asset inventory numbers. A linear feeder topology was used for all types with four sub-stations per circuit in the developed rural areas and with two stations per circuit in all other types. An average value of conductor resistance was used based on the proportion of conductor sizes used in Hydro One. The circuit topology and the conductor sizes were based on an examination of Hydro One circuit maps.

The Hydro One load data spreadsheet (DNAMLoadingNov11.xls) provided the frequency distribution of total peak load on all sub-transmission circuits (78.7% of rating on average). The average peak loading was used in the calculation, adjusted to give the 2004 energy sold, obtained from "Dx Losses Customers Info.xls", but the resulting loss was multiplied by an adjustment factor to account for the actual distribution of peak loading obtained from the load data spreadsheet. The factor was calculated as the weighted average of the ratio of the per unit loadings squared.

Load loss at load levels other than the peak load was calculated by multiplying the load loss at peak load by the ratio of the square of the currents.

3.1.2 Power Transformers

The most recent load data for Hydro One substations was available in a data base "TLL Database_Apr_18_release.mdb", obtained in April 2005, as the sum of the load on all circuits of a substation. The total number of substation transformers was obtained from a text file, "Dx transformers .doc" provided by Hydro One in July 2005.

Typical load and no-load loss data for power transformers was available from a detailed study of 170 power transformers in Hydro One Networks. The differences in percentage loss between different voltage levels and MVA size was negligible so all transformers were assumed to be the average size.

The number of customers with power transformers was obtained from the "TLL Database_Apr_18_release.mdb", obtained in April 2005. Some of these customers are metered on the high voltage side of their transformers and the transformer loss should therefore not be included in the Hydro One loss estimate. The exact number of these customers is not known but examination of many circuits diagrams discovered that most LDC customers are metered on the high side and most other customers are not. Therefore all non-LDC customer transformers were included and no LDC customer transformers.

The energy sold through substation and customer power transformers was available from a spreadsheet "Dx Losses Customers Info.xls" provided in July 2005. The data was from 2004. This is the most recent data available. The total number of transformers, the total energy sold and the resulting peak load on the transformers was compared with data from previous calculations to ensure that it was reasonable.

The average peak loading was used in the calculation of transformer losses but the resulting load loss was multiplied by an adjustment factor to account for the actual distribution of peak loading obtained from the database. The factor was calculated as the weighted average of the ratio of the per unit loadings squared. The total loading was adjusted to give the correct annual energy sales through each type of power transformer.

Daily load profiles were obtained from data (based on load studies in the 1980s) for the different customer classes (residential, seasonal, farm, general <5 MW). This is the most recent load profile data available. The aggregate load profiles for the different types of customer are not expected to have changed significantly since this data was obtained. These daily load profiles were combined using the appropriate number of each type of customer for Hydro One into a total daily load profile. The Hydro One monthly load profile was combined with the total daily load profile to give a total number of hours at each load level in steps of 10% per unit. These hours were used to convert peak values into annual energy for both loss and energy delivered.

Load loss at load levels other than the rated load was calculated by multiplying the load loss at rated load by the ratio of the square of the currents.

3.1.3 Distribution Lines

Five different types of distribution line were modeled, based on voltage level (4.16, 8.3, 12.5, 25, and 27.6 kV). The number of each type was obtained from the spreadsheet "PSDB_Feeders_2005_07_14.xls" obtained in July 2005 and the frequency distribution of total load on each circuit was obtained from the data base "TLL Database_Apr_18_ release.mdb". A topology of a three phase main trunk with single phase laterals was used, with three main trunk sections and 25 lateral sections. The conductor sizes and lengths of each section were estimated based on examination of Hydro One maps. Loads were assumed to be evenly distributed. The total length of distribution line was 103,600 km, obtained from the Dx asset inventory numbers

The average peak loading for each circuit type was used in the calculation, adjusted to give the correct energy sold in 2004, but the resulting load loss was multiplied by an adjustment factor to account for the actual distribution of peak loading. The factor was calculated as the weighted average of the ratio of the per unit loadings squared. The same factor was used for all types.

The loss was also adjusted by factors to account for the distribution of imbalance between phases on the circuits (obtained from the April database) and for the assumed power factor of 0.92. The power factor assumption was based on a small sample of circuits for which measured values were obtained for other detailed projects in recent years.

Load loss at load levels other than the peak load was calculated by multiplying the load loss at peak load by the ratio of the square of the currents.

3.1.4 Distribution Transformers

Sixty different types of transformer were modeled, including twelve different kVA sizes in five high voltage ratings. The no load and load losses for each type of transformer was obtained from a Kinectrics data compilation which is based on manufacturer's data.

The total number of distribution transformers was 470,543, available from the Dx asset inventory numbers. The number of transformers at each voltage level was calculated using the proportion of circuit km at each voltage level (from the April database) and the distribution of transformer sizes was obtained from previous studies of Hydro One circuits in the Kingston area.

The average peak load on each transformer was assumed to be the same for all types since there was no data to support differences. The average peak load was calculated to give the total energy sold to retail customers in 2004. The average peak loading for each type was used in the calculation but the resulting load loss was multiplied by an adjustment factor to account for the actual distribution of peak loading. The factor calculated for distribution lines was used for distribution transformers because the frequency distribution specific to transformers was not available.

Load loss at load levels other than the rated load was calculated by multiplying the load loss at rated load by the ratio of the square of the currents.

3.1.5 Secondary Lines

Five types of secondary line were modeled: residential year round (urban and rural), residential seasonal, farm and general. Three phase farm and large customer general classes were assumed to be metered close to the transformers without the use of Hydro One secondary circuits.

All were assumed to be 120/240 Volt secondary except general which was assumed to be 600/347 Volts.

Most secondary lines were assumed to be directly from the transformer with no secondary bus as described in the Hydro One Line design standard and were assumed to use 3/0 Al triplex conductor. Urban customers were assumed to have eight customers per transformer and a secondary bus parallel to the road and then a perpendicular service drop.

The lengths of line were assumed to be 15m, 50m, 75m, 25m, and 10m respectively for the different types of customer. The maximum in the line design standard is 75m. Farms are usually shorter than residences because a primary line is run back from the road. General customers have shorter secondary lines because the meter is usually installed close to the transformer before the secondary is split to provide multiple main load locations.

The proportion of customers in each type was obtained from the “Dx Losses Customers Info.xls” spreadsheet.

3.2 RESULTS

The overall technical loss results are shown below in Table 1. The overall loss estimate is 5.05% of energy sold. This is the sum of the annual losses (1,976 GWh) divided by the total energy sold by Hydro One in a year (39,165 GWh). This total energy does not include the energy sold by Hydro One to non-embedded LDCs and non-embedded direct customers. These customers are supplied through dedicated subtransmission lines that are metered at the transformer station. All the losses in those lines are accounted for by the customer since they occur downstream of the revenue meter.

The loss percentage may appear to be high compared to urban utilities and low compared to most rural utilities. Hydro One's loss percentage is dependent on the composite rural/urban nature of their system and the fact that Hydro One serves many customers directly from their subtransmission system. The losses in Hydro One are higher than those in urban utilities because of the large rural area served by Hydro One. Rural areas have longer power lines with fewer customers per kilometer of line which increases the line losses. Distribution transformer losses also tend to be higher in rural utilities because of the minimum practical size of distribution transformer and the lack of load diversity when it only supplies a single customer.

The losses in Hydro One appear lower than most rural utilities because Hydro One provides 48% of its energy sales to customers at the subtransmission level, without use of distribution lines, distribution transformers and secondary conductors. This is a much larger percentage than most rural utilities because Hydro One serves local distribution companies. This means that 48% of the energy does not flow through the components of the system that produce half of the losses.

Another consequence of the high proportion of energy sold at the subtransmission level is that a larger proportion of Hydro One's losses occur at this level (46%) than would be typical of most utilities. This makes the portion of loss attributed to other components look smaller. For example, the 5% of the loss occurring on secondary lines is more typically 10% for other utilities.

The energy delivered through the sub-transmission lines (35,000 GWh) is less than the total sold (39,165 GWh) because some of the energy is sold through high voltage substations supplied directly from the 115 kV transmission system.

Table 1 Summary of Loss Estimation Results

	Peak Power (delivered by component) (MW)	Annual Energy (delivered by component) (GW-h)	Power Loss at Peak (MW)	Power Loss at Peak (% of total)	Annual Energy Loss (GW-hr)	Annual Energy Loss (% of total)	Annual Energy Loss as % of total energy sold
Subtransmission Line	8,600	35,000	200	34	913	46	2.33
Power Transformer No Load	3,270	20,500	9	2	82	4	0.21
Power Transformer Load	3,270	20,500	11	2	48	2	0.12
Distribution Line	4,530	18,750	233	40	461	23	1.18
Distribution Transformer No Load	4,290	16,900	35	6	304	15	0.78
Distribution Transformer Load	4,290	16,900	37	6	74	4	0.19
Secondary Line	4,290	16,800	62	11	93	5	0.24
Totals			587	100	1,976	100	5.05

The total annual energy delivered by the subtransmission lines is less than the total purchased from the transmission grid (39,165 GWh) because some of the energy purchased flows through high voltage substations supplied directly from 115 kV. Similarly the total energy delivered by distribution lines is less than the energy delivered by distribution transformers and secondary lines plus the primary customers because some of those distribution transformers are directly connected to 27.6 kV subtransmission lines in south west Ontario.

4. CALCULATION OF DISTRIBUTION LOSS FACTORS

The total loss percentage is calculated with reference to the total energy sales. However, when a DLF is applied, it is only applied to the portion of the total sales actually delivered to a particular customer group. In order to fully recover the costs for losses allocated to the group the DLF must be larger than the loss expressed as a percentage of total energy sales.

To calculate the DLF for the subtransmission customers (embedded LDC's, embedded directs and Transmission class customers) the first step is to calculate the fraction of the total energy sold that is sold to this group (19,089 / 39,165) which is 0.48 of the total. This fraction of the loss on the subtransmission lines and power transformers must be allocated to these customers (0.48 x (913+82+48)) which is 500 GWh. The DLF from technical losses alone is then 2.6% (500 / 19,089). Adding 1.2% for non-technical losses such as theft gives a final DLF of 3.8%. This can be compared with the previous DLF for this group which was 2.8%. Most of the difference is that the previous 2.8% DLF only included 0.28% for non-technical losses. When the supply facilities factor of 0.6% is added to account for loss in the transmission system the total DLF is 4.4%.

To calculate the DLF for primary voltage customers a similar procedure is used. They purchase 8.3% of the energy sold through subtransmission and 16.2% of the energy sold through distribution lines. Their allocation of loss is therefore 161 GWh (0.083 x (913+82+48) + 0.162 x 461). And the DLF due to technical losses is 5.0% (161 / 3249). Adding 1.2% for non-technical loss such as theft gives a DLF of 6.2%. When the supply facilities factor of 0.6% is added to account for loss in the transmission system the total DLF is 6.8%.

Secondary customers purchase 43% of the energy sold through subtransmission, 84% of the energy sold through distribution lines and 100% of the energy sold through distribution transformers and secondary lines. Their allocation of losses is therefore 1307 GWh (0.43 x (913+82+48) + 0.84x461 + 304 +74 + 93). The part of the DLF created by technical losses is 7.8% (1307 / 16,833). Adding 1.2% for non-technical losses such as theft gives a DLF of 9.0%. When the supply facilities factor of 0.6% is added to account for loss in the transmission system the total DLF is 9.6%.

The following table compares the previous DLF's used by Hydro One, with the new DLFs calculated in this study.

Table 2 Comparison of DLFs

Customer Type	DLF in Present Rates	Technical Losses part of DLF	Total Estimated DLF
Embedded LDC and Subtransmission Customers	3.4%	2.6%	4.4 %
Primary Customers	6.1%	5.0%	6.8%
Secondary Customers	9.1%	7.8%	9.6%

The DLFs in Table 2 include the 0.6% supply facilities loss factor.

5. SENSITIVITY STUDY

The assumed values for various parameters in the model that produced the global system loss estimate have been varied over their reasonable range to determine the probable error in the total estimate.

Table 3 Sensitivity Study Results

Parameter	**Value used**	**Maximum**	**Minimum**	**Range in Total Loss (as a % of estimated loss)**
Conductor size in main sections	556 AL and 336 AL	556 AL	336 AL	±12%
Factor adjusting for peak loading differences from average [note1]	1.8	+10%	-10%	±8%
Load level	normal	+10%	-10%	±6%
Load profile (load factor)	0.5	0.7	0.35	±4.5%
km of distribution line	103,000 km	+10%	-10%	±4%
Distribution line current imbalance	24% average	+10%	-10%	±4%
km of subtransmission line	15,800 km	+10%	-10%	±2.5%
Transformer no load loss	power 0.14% dist. 0.27%	+10%	-10%	±2%
Number of distribution transformers	470,000	+10%	-10%	±1.5%
Split of circuits between developed and rural 44 kV	50/50	70 / 30	50 / 50	±1.3%
Split of line lengths between developed and rural 44 kV	50/50	35 / 65	50 / 50	±1.2%
Transformer load loss	power 0.4% dist 1.4%	+10%	-10%	±1%
Number of power transformers	1425	+10%	-10%	±1%
Topology of subtransmission lines	both	Linear	branched	±0.7%
Length of secondary line	42,500 km	+10%	-10%	±0.7%
Resistance of secondary line	0.35ohms/km	+10%	-10%	±0.6%
Number of secondary circuits	925,000	+10%	-10%	±0.6%

Note 1 The factor adjusting for peak loading differences from the average converts the loss calculated from the average loading on the circuits or transformers into the actual loss created by the distribution of loading.

The cumulative effect of all the parameter sensitivities, some positive and some negative is expected to be ±22% of the estimated loss in GW-h or ±1.11% of the energy sold. This is a practical estimate of the probable range, not a “worst case”.

6. TECHNICAL LOSS MANAGEMENT PROGRAMS

Technical losses on distribution systems are primarily due to I^2R losses in conductors and magnetic losses in transformers. Losses are inherent to the distribution of electricity and cannot be eliminated but may be minimized. In order to properly manage the inevitable losses it is necessary to understand the relative impact of different sources of losses. The largest source of losses is not always the easiest to reduce. Some sources can be reduced more cost effectively than others.

Canadian Electricity Association Technologies research has developed loss estimates for "typical" urban and rural distribution systems as shown in Table 4 below. Hydro One has primarily rural distribution with some pockets of urban development. Independent assessments of Hydro One's distribution system losses indicate that technical losses are in the order of 4.4% of the energy delivered to the distribution system. This represents annual energy losses of approximately 1,700 GW-hr. Losses occur on 3-wire subtransmission lines, 4-wire distribution lines, station transformers, line transformers and secondaries to customers. Transformer losses include no-load losses that are independent of transformer loading and load losses that vary with loading. The breakdown of these losses from the various causes is shown in Table 4.

Table 4 Typical Loss Values

	Estimated Loss as a Percent of Energy Sold		
Component	**CEATI Typical Urban**	**CEATI Typical Rural**	**Hydro One***
Subtransmission Lines	0.1	0.7	2.33
Power Transformers	0.1	0.7	0.33
Distribution Lines	0.9	2.5	1.18
Distribution Transformers No Load	1.2	1.7	0.78
Distribution Transformers Load	0.8	0.8	0.19
Secondary Lines	0.5	0.9	0.24
Total	**3.6**	**7.3**	**5.05**

* Note: This table does not include the non-technical losses or the supply facilities factor that is included in Hydro One's total Distribution Loss Factors.

Management of system losses is an on-going consideration in the planning, design, operation, purchase, upgrading and replacement of Networks' distribution facilities and equipment. Nonetheless, Networks believes that there is an opportunity to achieve incremental economic reductions in distribution system delivery losses through targeted investment programs. Modest reductions in losses can yield considerable benefit in terms of avoided cost of energy and demand.

Studies of Hydro One distribution losses have indicated that there are several methods that can be practically and economically applied to reduce distribution losses. These include:

1. Power factor correction using shunt capacitors
2. Balancing of load on phases
3. Reconductoring lines which presently have under-sized conductors
4. Installing properly sized high-efficiency transformers

Each method is limited in the amount of energy that can be saved as well as a penetration limit on the number of Hydro One sites that would be amenable to the particular loss reduction method. Furthermore each method has an associated cost of implementation. Table 5 shows the results of demand and energy savings that were achievable in applying loss reduction methods to particular Hydro One feeders. The Profitability Index is provided as an indicator of how the reduction in the cost of losses relates to the investment required to achieve these savings. The Profitability Index is calculated as the net present value of the savings in loss costs over twenty years divided by the cost of the loss reduction method.

Table 5 Effects of Loss Minimization Techniques Applied to Example Feeders

Loss Reduction Technique	Reduction of Peak Losses (% Peak Feeder Losses)	Reduction of Loss Costs (% Feeder Loss Costs)	Profitability Index
Capacitor application	3.1%	3.2%	4.2
Phase Balancing	2%	1.6%	5.4
Reconductoring	30%	29%	1.4
Re-sizing Distribution Transformers	2.3%	4.1%	0.1

6.1 DESCRIPTION OF THE PROGRAM

The Distribution Network Loss Reduction Program will involve identifying and implementing projects where incremental investments will result in an overall economic benefit to customers by reducing system delivery losses.

The three major areas offering the best economic opportunities are described below and information on the project costs and financial benefits is provided:

- ***Power Factor Correction using Shunt Capacitors***

  Feeder power factors in the Hydro One distribution network are typically in the range of 0.85 to 0.95, depending on time of year, mix of customers, and customer usage patterns. Power factor correction can be achieved through application of shunt capacitor banks. Capacitors reduce feeder losses by providing reactive power compensation near the load, thereby reducing the current flow in the line. The challenge in capacitor application involves the determination of the location, size, number and type of capacitors to be placed in the system. Fixed and/or switched capacitors can be used in the system. Fixed shunt capacitors provide constant reactive power compensation and are suitable for loads having approximately constant reactive power requirements. Switched shunt capacitors are used in cases of load variability since they allow more flexibility in controlling the losses and voltage drop. Hydro One purchases rack mounted capacitors with pre-installed oil switches. Targeting feeders with the known poorest power factors will generate the highest contributions to loss reduction DSM.

A preliminary analysis has indicated a potential for saving and forms the basis of the capacitor installation plan. It indicates that shunt capacitor banks could be applied to 660 Hydro One feeders (70 feeders with 600 kVAR banks, 150 with 450kVAR units, and 440 feeders with 300KVAR banks). When fully implemented these capacitors would result in annual energy savings of approximately 53 GW-hr, about a 3.0% reduction in distribution system energy losses. This translates to a 20-year Present Value of savings in the order of $53M. The capital and labor cost for these installation in a two year program, plus analysis to determine optimal locations would be $10.3M. These costs and benefits are summarized in Tables 6 and 7 below.

Additional loss reduction could be achieved with the installation of switched capacitor banks which would match the connected kVAR to the variations in the load. Since this loss reduction method would require control schemes to monitor voltage levels, time of day and / or status of switching equipment, the costs would increase substantially, and will require further investigation in future.

- ***Feeder Phase Balancing/System Configuration***

The distribution network consists of approximately 400 “sub-transmission feeders” and 2700 “distribution” feeders. A considerable part of the Hydro One distribution system consists of single-phase residential loads, making the power flow in three-phase main feeders difficult to balance. The total I^2R loss in the three phases of an unbalanced system is higher than that of a balanced system, and therefore, a concerted effort to balance phases, can result in loss reduction. Phase imbalance is often expressed as the maximum phase current minus the average of the phase currents divided by the average of the phase currents. At the present time phase imbalances at the distribution stations on the worst third of the Hydro One feeders are in a range of 30% to 100 % indicating considerable room for improvement.

The phase balancing program will target the worst 750 of Hydro Ones’ distribution feeders in a 2-year period. It is estimated that at full implementation, balancing of these feeders will result in a 15GW-hr annual energy saving. Since unbalance will recur with the passage of time, the benefits from this phase balance were estimated assuming a decline in energy savings over a 20 year period. With this assumption, the 20 year present value of avoided costs is about $11M. The cost to implement the phase balancing over a two year period would be $2.2M.

- ***Re-conductoring***

The sizing of distribution conductors and cables is normally determined by considering the thermal capability of the conductors and cables, and by the amount of voltage drop from source to the receiving-end. Hydro One’s long rural feeders are generally voltage-drop limited as opposed to ampacity limited. Another consideration, however, is cost of losses related to the conductor size selected. The larger the conductor size, the lower are the losses. Larger conductors require more capital expenditures and a balance must be found when sizing the conductors. The conductor size is typically optimized, through the planning process, when a feeder is initially installed. However, as the system evolves and conditions change from original plans occurrences of sub-optimally sized conductors will materialize. Reconductoring of sections of a feeder that are heavily loaded can provide loss improvements.

Though not often highly profitable, reconductoring can be very effective in reducing losses on circuits that are particularly overloaded. As a portion of the distribution loss reduction program a study will be conducted to identify the Hydro One feeders that are prime candidates for reconductoring with profitability greater than one.

- ***Transformer Sizing and Efficiency***

The series and shunt resistance and reactance of distribution transformers result in significant losses on distribution systems. The consumption of reactive power by transformer reactance introduces higher reactive current flow in the primary circuits, which contributes to the system losses. Distribution system losses can be reduced by properly sizing the distribution transformers.

Transformer no-load losses are constant and depend on the size of the transformer installed and the loss formula to which it was purchased. Decreasing the transformer rating will decrease the no-load losses. On the Hydro One system it is notable that on many feeders, the actual peak load on the feeder is only 20 to 40 % of connected kVA. This implies that the connected kVA is unnecessarily high and a reduction in transformer sizes would not overload the smaller transformers. Consideration would have to be given to the cost of inventory for stocking smaller transformer sizes.

The low profitability index in Table 5 indicates that the cost of replacing existing transformers is typically beyond the benefits achieved. This illustrates that distribution transformers must be sized appropriately on initial installation in order to achieve minimal transformer losses.

Therefore, a portion of the distribution losses program will include a review of transformer sizing practices including the cost-of-losses formula, loss-of-life, load growth and inventory considerations. The intent is to minimize future losses by ensuring correct sizing and the purchase of transformers with the highest efficiency that can be justified by a total life-time cost consideration.

Benefits

Lowering distribution system delivery losses will reduce overall system demand and provide additional network capacity for growth. Since system delivery losses are currently passed onto all customers, improvements in this area will benefit all customers.

The expected benefits of the proposed distribution loss reduction program are summarized in the table below. These estimates are based on the characteristics of the Hydro One distribution system and are present valued over a twenty year period.

Table 6 Economic Benefits

Program	Maximum Reduction in Annual Energy Loss GW-hr	Avoided Energy Demand and Environmental Costs PV $M*
PF Correction Capacitors - install cap banks on 660 feeders requiring 300kVAr or more	53	52.9
Phase balancing - balance 750 circuits	15	11.4

* Note: Present valued over a twenty year period

Table 7 Program Budget

($'000s)				
Distribution Network Loss Reduction	**2004/2005**	**2006**	**2007**	**Total**
PF Correction Capacitors		2,600	7,700	10,300
Phase balancing		700	1,500	2,200
Reconductoring		100	na	100
Transformer Size and Efficiency		150	na	150
Total				12,750

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APPENDIX A LOSS MANAGEMENT PROGRAM BACKGROUND, ASSUMPTIONS AND COMPUTATIONS

A1. Expected Technical Losses at Hydro One

Hydro One is a distribution utility with a mixed service area consisting of both rural and small urban areas. A recent study conducted by utilities in North East North America concluded that the technical losses of typical urban utilities range from 2% to 5% of energy sold and for typical rural utilities technical losses range from 4% to 10% of energy sold (Ref 4). It also concluded that the achievable level of energy efficiency is not the same for all utilities but varies depending on the details of the service territory and the past design practices. Present estimates of the technical losses at Hydro One have been in the range of 3.9% to 6.1% of energy sold (section 3). These estimates are for technical losses and do not include non-technical losses, such as theft.

A2. Available Loss Reduction Technologies and Approaches

The techniques that are most applicable to a specific utility system depend on which types of losses are the most significant on that specific system. There are no techniques that will be best in all circumstances. The amount of loss reduction that should optimally be implemented depends on the societal expectations, economic constraints, and competing values such as improved asset utilization. Improving asset utilization reduces overall capital costs but it increases the loading on equipment which also tends to increase losses.

There are two main sources of losses, conductors and transformers. Transformer losses can be reduced by design or loading changes. Design changes can be achieved by using lower loss steel in the transformer core, or by using windings with lower resistance, either by using copper instead of aluminum or by using larger wires or both. Since transformer losses depend on the design they can only be reduced by replacing a transformer with high losses with one with lower losses. Since transformers are expensive this is only feasible if done slowly as transformers are replaced for other reasons, such as age or under capacity.

The following methods can be used to lower conductor losses:

1. Using copper instead of aluminum
2. Using larger conductors
3. Using more transformer stations (shorter low voltage lines)
4. Using three phase lines instead of single phase
5. Installing capacitor banks
6. Balancing the load between conductors on the same line
7. Reducing peak loads by active or passive load control
8. Installing distributed generation

Some of these are methods that utilize capital costs and are basically unable to be retrofit on existing systems (3), some utilize capital costs but can be retrofit (1,2,4,5,7,8) and some utilize operations costs (6).

Choice of which method to implement first depends on both the technical efficiency (how much energy can be saved) and the economic efficiency (will savings be larger than costs). Previous studies have shown that the most cost effective methods are capacitor installation and phase balancing.

A3. Application of Loss Reduction to Hydro One

A3.1 Identification of Most Suitable Techniques

The most suitable techniques are efficient in both technical and economic terms.

The **installation of capacitors** reduces losses by correcting the power factor of the loads and thus reducing the current required to supply the same power and energy. The current flow in distribution feeders can be decomposed into active and reactive components. Applying a shunt capacitor, at the load end of the feeder, injects the capacitive current that results in reduction of the net reactive current. This result in a reduction of the overall line current and the effective apparent power at the load seen from the feeder. Therefore, as the current of the feeder is decreased, the conductor losses will be reduced. Moreover, the voltage at the load end is boosted which may allow better service to the customers. The amount of loss reduction achievable depends on the initial power factor. Ideally the best evaluation technique would be to measure the power factor on all circuits and calculate the current reduction that can be achieved on each circuit. However, at Hydro One the power factor is not measured on all circuits. A previous detailed study on eight Hydro One circuits found power factor varies from 1 to 0.92 with an average of 0.94.

Another suitable technique for loss reduction in Hydro One is **balancing the load** between conductors on the same circuit. Since many of the loads are on single phase lines it is never possible to get a complete balance. However, the latest data shows that the average imbalance on Hydro One distribution circuits is 26%. This means that the highest or lowest conductor current is 26% different than the average current. The balance of current between the phases is not a static quantity. It varies from one year to the next as loads grow, are added or removed from the system. Phase balancing is therefore a maintenance activity that needs to be done on a regular basis. The cost implementing this loss reduction technique is therefore a maintenance cost rather than a capital cost. An analysis of this loss reduction method is included in this report so that this method can be compared to the installation of capacitors and a suitable balance can be struck between implementing the two techniques.

A3.2 Estimation of Potential Energy and Peak Power Savings

The total potential for energy savings due to **capacitor banks** has been estimated from typical circuits. If an average power factor of 0.94 (ref cress) is assumed to be typical of the existing circuits then the most recent load data indicates that capacitor banks of at least 150 kVAr could be installed on 1560 of the 2700 circuits, assuming a minimum load of half the peak. With the assumed 0.94 power factor, this is estimated to reduce distribution line losses by 85 GW-h per year.

The kW savings in different loading periods has been estimated as follows based on modeling of typical circuits at each voltage level. The minimum single capacitor bank has been assumed to be 150 kVAr

	Winter			**Summer**			**Shoulder**	
	On peak	**Mid Peak**	**Off Peak**	**On Peak**	**Mid Peak**	**Off Peak**	**Mid Peak**	**Off Peak**
Hours	**602**	**688**	**1614**	**522**	**783**	**1623**	**1305**	**1623**
150kVAr	4.93	2.89	1.44	4.42	2.63	1.36	3.14	1.27
300kvAr	10.41	6.10	3.05	9.33	5.56	2.87	6.64	2.69
450kVAr	26.54	15.56	7.78	23.80	14.19	7.32	16.93	6.86
600kVAr	63.28	37.10	18.55	56.74	33.82	17.46	40.37	16.37

The potential energy and peak power savings from **phase balancing** has also been estimated based on analysis of typical circuits at each voltage level. It was assumed that after balancing the circuit would still be 10% unbalanced since this is an achievable minimum.

# Circuits Balanced	**Energy Savings per circuit MW-h**	**Peak Power Savings per circuit KW**
25	104	48
47	89	38
67	81	36
99	69	30
148	57	24
251	42	18
351	34	15
451	30	13
551	26	11
651	23	10
751	21	9

The decreasing energy savings per circuit is caused by the circuits with the largest imbalance being selected first. The first 25 circuits have 100% imbalance. By the last few rows of the table the 100 circuits between each row are moving from 30% unbalance to 10% unbalance.

Peak kW Saved in Different Time Periods

	Winter			Summer			Shoulder	
# Circuits Balanced	**On peak**	**Mid Peak**	**Off Peak**	**On Peak**	**Mid Peak**	**Off Peak**	**Mid Peak**	**Off Peak**
25	26.9	16.3	8.2	25.0	14.9	7.7	17.8	7.2
47	21.3	12.9	6.5	19.8	11.8	6.1	14.1	5.7
67	20.2	12.2	6.1	18.7	11.2	5.8	13.3	5.4
99	16.8	10.2	5.1	15.6	9.3	4.8	11.1	4.5
148	13.4	8.2	4.1	12.5	7.4	3.8	8.9	3.6
251	10.1	6.1	3.1	9.4	5.6	2.9	6.7	2.7
351	8.4	5.1	2.6	7.8	4.7	2.4	5.6	2.3
451	7.3	4.4	2.2	6.8	4.0	2.1	4.8	2.0
551	6.2	3.7	1.9	5.7	3.4	1.8	4.1	1.7
651	5.6	3.4	1.7	5.2	3.1	1.6	3.7	1.5
751	5.0	3.1	1.5	4.7	2.8	1.4	3.3	1.4

A3.3 Extent of Application of Loss Reduction Methods and Expected Achievable Savings

To estimate the savings that could be easily achieved by installation of **capacitor banks** it can be assumed that heavily loaded circuits will have a power factor of a maximum of 0.96. This is a conservative figure based on the known power factors. Assuming a minimum installation of 150 kVAr and a minimum load of half of the peak load, any circuit with a peak load of more than 1000 kW would have enough reactive power to install a capacitor bank. Circuits with more than 2200 kW load could have 300kVAR of capacitors installed, circuits with more than 3000 kW could have 450 kVAr of capacitors, and circuits with more than 4500 kW peak load could have 600kVAr of capacitors installed. The most recent circuit load data indicates there are 70 circuits that could have 600kVArs, 150 that could have 450 kVArs, 440 with 300kVArs and 900 that could have 150kVAr banks. This is a total of 1560 circuits with at least 150kVars. With the 0.96 pf assumption, the estimated energy savings in distribution line losses are 71 GW-h per year. Limiting the number of circuits to those which require the largest banks will increase the profitability index. If capacitors are applied to the 600 worst circuits, then 70 circuits with 600kVAr, 150 circuits with 450 kVAr, and 380 circuits with 300 kVAr could be installed. The estimated savings would be 50 GW-h per year. More capacitors could be installed if the power factor and minimum load of heavily loaded circuits was measured.

To estimate the savings that could actually be achieved by **load balancing** the diminishing returns evident in the table above have been taken into account. A reasonable level would be determined by the economic analysis. The savings from balancing last only a few years and gradually decrease in each year as the balance becomes poor again. A 20 year linear decrease is a reasonable assumption. In this case a 2 year program to balance the worst 750 circuits is proposed. This would save 15 GW-h per year at initial full implementation.

A3.4 Economic Analysis

The savings from the loss mitigation techniques were computed using the Avoided Cost methodology in the Navigant "Avoided Cost Analysis for the Evaluation of CDM Measures" report dated June 14, 2005.

Savings were computed both including and excluding environmental impacts using Table 23 and 21 of the Navigant Report respectively. Savings were further expressed as Present value over twenty years by applying a discount factor of 9.3% and an escalation factor of 2.5% to the tabulated values.

Distribution demand was evaluated at $6.5/kW however this value is expected to be high since it was computed by the Navigant localized method. Savings were computed neglecting the Distribution Demand factor and are provided in the Table below.

Savings for the mitigation techniques were computed over a 20 year period.

Capacitors were assumed to be installed 25% in 2006 and 75% in 2007. In the year of installation only half the energy savings of the banks installed in that year were received. In 2008 all the savings from all units was considered and these savings continued on to 2026.

Installed capacitor costs were considered to be as follows:

150kVAR	$14,500
300kVAR	$15,300
450kVAR	$16,000
600kVAR	$16,800
900kVAR	$19,500

250 circuits were considered to be **balanced** in 2006 and 500 additional in 2007. The per circuit cost of balancing was considered to be $3000 including one day's time for a bucket truck, crew and a technologist. Only half of the savings was considered in the year of installation. A factor was applied to reduce the energy savings in subsequent years to account for the gradual loss of the impact of balancing.

Avoided Energy and Demand Costs including Environmental Costs

Program	Reduction in Annual Energy Loss GW-hr	Avoided Energy Costs PV $M	Avoided Energy and Generation Demand Costs PV $M	Avoided Energy, Generation and Transmission Demand Costs PV $M	Avoided Energy, Generation , Transmission and Distribution Demand Costs PV $M
PF Correction Capacitors - install cap banks on 660 feeders requiring 300kVAR or more	53	45.7	51.4	52.0	52.9
Phase balancing - balance 750 circuits	15	9.9	11.1	11.3	11.4

Note: Present value calculated over a twenty year period

Avoided Energy and Demand Costs without Environmental Costs

Program	Reduction in Annual Energy Loss GW-hr	Avoided Energy Costs PV $M	Avoided Energy and Generation Demand Costs PV $M	Avoided Energy, Generation and Transmission Demand Costs PV $M	Avoided Energy, Generation , Transmission and Distribution Demand Costs PV $M
PF Correction Capacitors - install cap banks on 660 feeders requiring 300kVAR or more	53	40.2	45.8	46.5	47.3
Phase balancing - balance 750 circuits	15	8.6	9.9	10.0	10.2

Note: Present value calculated over a twenty year period

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STAKEHOLDER CONSULTATION REPORT

1.0 OVERVIEW

In mid 2007, Hydro One designed a process for consultation and two-way dialogue with stakeholders to assist in its preparation of the 2008 Distribution Rate Application. This Exhibit reports on the stakeholder consultation process and provides a summary of the discussions held during three interactive sessions. Based on previous experience with such applications, the involvement of stakeholders was recognized as critical to developing a submission that reflected the broad interests and concerns of Hydro One distribution customers and stakeholder constituencies. Stakeholder consultation is also integral to satisfying the Ontario Energy Board (OEB) directive to be mindful of, and guided by, concerns raised by intervenors when preparing rate applications.

To assist in developing, implementing and facilitating this process, Hydro One retained Haussmann Consulting Inc. (HCI). This firm was selected through a competitive Request For Proposals process held in spring 2007. The stakeholder consultation process was subsequently implemented, with sessions being held in July, September and October 2007.

The purpose of the consultation process was to inform stakeholders and customers about Hydro One's application, the key issues and challenges facing its distribution business, and to learn about stakeholder issues. This was achieved through a series of interactive forums that allowed Hydro One and stakeholders to discuss and explore questions and potential areas of agreement and concern around key application-related issues. The goal was to improve the quality and completeness of the pre-filed evidence and to minimize the issues to be addressed at the OEB hearing.

Based on the potentially large number of interested stakeholders and their diverse range of resources and interest levels, two consultation approaches were chosen to meet the needs of various audiences. The consultation program consisted of: (1) stakeholder discussion sessions and (2) Web/Email Information. In addition, informal dialogue (e.g., email, telephone conversations) continued throughout the process between Hydro One staff and the stakeholders.

An initial list of stakeholders was developed based on previous participation in Hydro One rate proceedings. In total, twenty stakeholder organizations were represented at one or more of the discussion sessions. These included several local distribution companies; energy industry associations and unions; consumer and environmental advocacy groups; First Nations and one municipality. Groups advised about the Web site included Hydro One's large distribution customers and local distribution companies (LDCs).

Input received during the consultation sessions was documented, analyzed and addressed, where possible, at the discussion session, in notes of meeting, and through commitments to consider addressing or providing specific information in the application. Stakeholder input had a direct influence on the content of Hydro One's application with respect to the application approach, types of information provided and the level of detail.

Overall, Hydro One believes the stakeholder consultation process was effective in achieving many of its stated objectives. This belief is supported by the evaluation comments submitted by stakeholders who participated in the process. Their evaluations indicated that the process met their expectations and was well documented. A complete summary of the stakeholder evaluation comment sheets is found in Attachment 2 of Appendix G.

2.0 CONSULTATION PRINCIPLES AND OBJECTIVES

The following principles and objectives were developed at the outset of the process to guide the consultation design and implementation. These were reviewed with the Hydro One Customer Advisory Board (CAB), which provides advice and counsel to Hydro One management on how best to provide service to customers while meeting shareholder and regulatory requirements. The CAB consists of Hydro One distribution and transmission customers and energy industry groups. The principles and objectives were also reviewed with stakeholders at the outset of the first consultation session, and were posted on the Hydro One Web site.

2.1 Principles

- Hydro One engaged in the stakeholder consultation process in good faith with a view to facilitating and streamlining the upcoming OEB proceeding associated with this application.
- Hydro One received and considered all submissions and comments made by stakeholders, but retained control over the process of developing its application.
- All consultations were carried out on a without-prejudice basis.
- The facilitator documented and reported the discussions and any agreements reached with stakeholders.
- Agreements reached were to be submitted to the OEB as part of Hydro One's evidence.

2.2 Objectives

- Build on the stakeholder understanding of Hydro One distribution's business created through the stakeholder consultation processes for the recent Distribution and Transmission rate applications.

- Ensure stakeholder concerns and views are identified, understood and considered in the preparation of Hydro One's rate application.
- Provide insight, advice, and feedback to Hydro One on any concerns, values, information and preferences regarding all aspects of Hydro One distribution's operations.
- Act as a forum for the exchange of information and views.
- Assist Hydro One to anticipate and respond to stakeholder and customer views and preferences.
- Resolve as many issues as possible prior to the Hydro One submission to the OEB.
- Minimize the distribution business issues to be heard by the OEB.
- Reduce the time and cost associated with the OEB hearings.

3.0 CONSULTATION PROCESS

Building on these principles and objectives, a consultation plan was developed that included stakeholder sessions, and a communications strategy. The communications strategy included the use of e-mail and the company's web site to provide information to Hydro One stakeholders and to invite input at key points throughout the process.

Hydro One worked with Haussmann Consulting Inc. to design a process that would provide maximum opportunity to educate stakeholders about Hydro One's business and receive feedback on key areas of the application. For stakeholders, the plan allowed flexibility so that they could obtain information on the topics of most interest to them, and participate in a full discussion of issues of concern. The proposed approach was discussed with the Hydro One CAB on June 25, 2007. Overall, the CAB was supportive of the proposed approach.

3.1 Participants

Key stakeholder groups including intervenors from previous Hydro One rate proceedings, LDCs and large distribution customers were invited to participate in the first two stakeholder sessions via an invitation letter (Appendix A) and a follow-up e-mail. For the third session, an email invitation was sent to stakeholders. Approximately, forty groups were invited to participate in the stakeholdering sessions. Hydro One believes that those invited were representative of the interests of the majority of its distribution stakeholders.

First Nations political and treaty organizations were invited to participate in the consultation process. Hydro One did not propose a separate consultation process specifically designed for the First Nations, because the nature of the proceeding, which focused on Revenue Requirement, Cost Allocation and Rate Design, did not warrant such an approach. As this is a distribution rate proceeding, there are no land issues or treaty rights that would be affected by Hydro One's proposal for adjustment to its distribution rates.

Those who were not able to attend were invited to monitor the process through the company's web site and to provide input at key points throughout the process.

Stakeholder participation was guided by a Terms of Reference (see Appendix B). Funding guidelines were also developed to assist eligible intervenors (see Appendix C). The funding guidelines were based upon the Ontario Energy Board's Practice Direction on Cost Awards (October 2005) document.

3.2 Stakeholder Consultation Sessions

Three consultation sessions were held in July, September and October 2007. These sessions were timed to coincide with key milestones in the development of the distribution application. The first session focused on the Hydro One revenue requirement. Sessions 2 and 3 addressed cost allocation and rate design.

Session #1 was held on July 18, 2007 at the Metropolitan Hotel in Toronto. Thirteen people attended representing twelve stakeholder organizations (see Appendix D for list of participants). The session consisted of presentations describing Hydro One's business strategy, an overview of the revenue requirement application, Hydro One performance relative to comparable utilities, the most recent three-year trend, the 2006 actual OM&A and capital expenditures, and future needs and expectations, all of which support the rationale for the revenue requirement in the Hydro One application. Each presentation was followed by a discussion period, which provided stakeholders an opportunity to ask questions, comment on the presentations and proposed approach to the revenue requirement calculation, and to identify issues and information that were most important to them.

Session #2 was held on September 5, 2007 at the Metropolitan Hotel in Toronto. Twelve people attended representing eleven stakeholder organizations (see Appendix F for list of participants). Hydro One presented a summary of its August revenue requirement filing including its total revenue requirement and the average total bill impact, an overview of the OEB cost allocation methodology adapted to suit Hydro One distribution system characteristics, and a review of its current customer classes with some proposed principles for reducing the existing 281 classes to a more manageable number. This presentation was followed by an exercise in which stakeholders indicated how the existing classes might best fit into ten new customer classes. The remainder of the session was devoted to a presentation on the steps involved in rate harmonization and a workshop discussing principles and practices of rate harmonization.

Session #3 was held on October 15, 2007 at the Metropolitan Hotel in Toronto. Fourteen people attended representing twelve stakeholder organizations (see Appendix G for list of participants). Hydro One presented its proposals with respect to new customer rate classes and mapping from existing rate classes, the cost allocation results, rate harmonization and customer bill impacts.

3.3 Web/E-Mail Information

Recognizing the vast geographic area served by Hydro One and the large number of potentially interested stakeholders spread over this area, Hydro One launched a 2008 Distribution Rate Application Web site. The intent was to provide interested stakeholders the opportunity to monitor the consultation process and to provide input at key points throughout the consultation.

The 2008 Distribution Rate Application Web site (http://www.hydroonenetworks.com/en/regulatory/) was launched on July 13, 2007. The Web page was updated regularly and contained background information, documents and presentations made available at the stakeholder discussion sessions and the meeting notes.

An invitation to participate in the Web consultation activities was sent to large distribution customers, LDCs, as well as intervenors not able to participate in the discussion sessions.

4.0 SUMMARY OF DISCUSSIONS

Hydro One developed an agenda for the first stakeholder consultation session based on areas of interest expressed at previous distribution rate consultation sessions, and topics on which Hydro One was seeking direct input from stakeholders to enhance the application. The topics discussed at the July session are outlined below. Detailed Notes of Session #1 are attached as Appendix D.

Topics presented and discussed at the first stakeholder session included:

- **Hydro One Business Strategy:** Laura Formusa, President and Chief Executive Officer (Acting), Hydro One Inc., presented the company's overall business strategy and engaged in a discussion with stakeholders about Hydro One values and priorities.

- **Rate Application Overview:** Joe Toneguzzo, Director, Major Applications, presented an overview of the two-step process Hydro One is following in preparing its Distribution Rate Application.

- **Benchmarking, Reliability and Service Quality:** Carm Altomare, Manager, Performance Analysis, described benchmarking studies currently underway; major performance measurement drivers; and customer service indicators and performance. Barb Allen, Manager, Customer Care assisted by responding to some stakeholder questions about Hydro One customer satisfaction survey methods.

- **Distribution Incentive Regulation Proposal:** Andy Poray (Director, Regulatory Policy) and John Todd (Elenchus Research Associates) described and solicited participation in a Hydro One Distribution Incentive Regulation Working Group (IRWG) to help design an incentive regulation specifically to meet Hydro One distribution needs.

- **Major Investment Programs and Key Drivers (OM&A and Capital):**
  - Rick Stevens, Director, Smart Meter Project described the Smart Meter Program and the implementation plan to 2010; and
  - George Juhn, Manager of Distribution Development and Lines Sustainment, presented an overview of the remaining investment programs required by Hydro One and included in the revenue requirement.

- **Shared Services:** Ian Innis, Director, Corporate Planning and Regulatory Finance (Acting), provided an overview of OM&A and Capital expenditures associated with the Shared Services and Other category of Hydro One's business.

- **Revenue Requirement:** Ian Innis also presented an overview of the 2008 Distribution Revenue Requirement. Specific financial data were not available at the time, but financial parameters and assumptions in the 2008 filing, compared to the 2006 approved values were presented, and factors identified that would contribute to an increase or provide an offset to the Distribution rate change.

Stakeholder input at the first session assisted Hydro One to anticipate areas of interest that would be addressed during stakeholder Session #2. These included:

- Cost allocation methodology; and
- Rate harmonization methodology and impacts.

In addition, stakeholders showed interest in participating in a Hydro One Incentive Regulation Working Group (IRWG), which would assist in the development of an incentive regulation mechanism suitable for Hydro One and possibly other distributors. Prior to the first meeting of the IRWG, the Ontario Energy Board launched a similar consultation initiative. Therefore, the Hydro One IRWG was disbanded so that participants could devote their time and energy to participate in the OEB process.

At the second stakeholder session, discussion focused on the cost allocation methodology, the principles relevant to reducing the number of Hydro One customer classes to a manageable number, and principles and practices of rate harmonization. Using a template provided, stakeholders mapped how they proposed customer classes should be transitioned from the existing classes to a smaller number of new classes. For the rate harmonization discussion, stakeholders were asked to answer six questions regarding the OEB guidelines for rate harmonization, bill impacts, timelines, loss factors, mitigation, equity considerations, and rate structure considerations (see Appendix E for Rate Harmonization Design Process Questions).

Stakeholder feedback received at Session #2 suggested that the parameters and principles for delineating customer classes should include (see Session #2 Notes, page 10):

- Energy consumption levels
- Value of assets used
- Types of assets used
- Type of service provided at user gate
- Similarity with other LDC classes / fairness
- Ease of understanding
- Management simplicity.

When transitioning existing customer classes to new rate classes, most stakeholders (see Session #2 Notes, page 14):

- Favoured the elimination of the Seasonal class;
- Proposed applying a density delineation to the General Service customer class;
- Supported renaming Urban Residential, Residential High Density and Residential Normal Density to better describe the categories, e.g., Residential High, Medium and Low;
- Proposed moving the existing classes General Service (energy billed) and General Service (demand billed) into the new classes, General Service (primary) and General Service (secondary);
- Urged Hydro One to consider the impacts associated with creating new customer classes and propose appropriate mitigation where required; and,
- Agreed that new customer classes should be phased-in with minimal disruption to customers.

There were also a number of divergent views expressed regarding the Farm Classes. Some saw a need to retain the Farm classes; others supported migrating them to the General Service and/or Residential Normal Density classes. In addition, the need to maintain Rural Rate Assistance was debated by some stakeholders and there was some discussion of changing the 50 kW threshold for the General Service class.

The specific stakeholder comments, and questions raised through this process and Hydro One responses are reflected in the Detailed Notes of Session #2 attached as Appendix F.

The third stakeholder session was focused on presenting Hydro One's proposals with respect to new customer rate classes and mapping from existing rate classes, the cost allocation results, rate harmonization and customer bill impacts.

Much of the dialogue following the presentations related to clarification of the information presented. With respect to customer classes and cost allocation methodology, comments from stakeholders covered the following:

- Clarification of the process related to defining density classes and moving customers from lower to higher density classes (see Session #3 Notes, pages 5, 6 and 21);
- The revenue-to-cost ratio target of 1.2 for Urban General Service energy-billed (UGe) class and the target ratio of 1.08 for the General Service energy-billed (GSe) class were viewed as too high. (see Session #3 Notes pages 8, 14 and 22);
- The Sub-transmission (ST) class revenue-to-cost target ratio of 1.8 was still seen as too high (see Session #3 Notes pages 10 and 22); and,
- Hydro One was urged to consider setting rural rates at a level consistent with the original Rural Rate Assistance legislation that once specified rural rates should not exceed 115% of the provincial average for residential rates (see Session #3 Notes page 10).

The presentation on rate harmonization and customer bill impacts prompted the greatest amount of discussion. The presentation slides illustrated impacts at average consumption levels with maximum and minimum total bill impacts. Customers with higher and lower usage patterns could face different bill impacts, and stakeholders wanted to understand the range of impacts within each class for various consumption levels and the elements contributing to rate impacts (see Session #3 Notes pages 15, 16, 19, 21 and 22). There was concern expressed that more consideration should be given to customers who may be faced with high bill increases because they fall outside the average consumption range (see Session #3 Notes pages 11-13).

Effectively communicating these changes to customers who will see a significant increase in the distribution component of their electricity bill was discussed at length. It was noted that the rationale should include references to the need to achieve equity with other customers, historic underpayment for services relative to cost, OEB directive to apply the cost allocation methodology and phasing-in of increases to mitigate bill impacts. However, one stakeholder noted that, while the rate increases may be equitable within the Hydro One customer base, some customers would find their rates rising well above those for comparable users in nearby areas served by other LDCs.

The various methods, which could be used to notify customers were also discussed. Hydro One indicated there was an urgency to provide this information early, in order to allow affected customers an opportunity to participate at the OEB process should they wish. Notification options and pros/cons were discussed at length (see Session #3 Notes pages 11-13).

The specific stakeholder comments and questions raised through this process, and Hydro One responses, are reflected in the Detailed Notes of Session #3 attached as Appendix G.

5.0 CONCLUSION

Hydro One initiated the stakeholder consultation process to meet the objectives described in Section 2.2. Based on the discussions that took place, the consultation process met these objectives. Hydro One believes that the enhanced understanding by stakeholders of Hydro One operations and business practices resulting from the dialogue at these sessions should significantly reduce the effort required by Hydro One to explain its distribution business during the OEB proceeding. Hydro One also obtained a good understanding of stakeholder issues and concerns through the consultation process.

Stakeholder input assisted Hydro One to better understand and address stakeholder concerns in the following areas:

- The prioritization of investments;
- Rationale for demand capital and sustaining requirements;
- Customer satisfaction and reliability benchmarking, including identification of comparator utilities;
- Performance versus increases in expenditures, including effect of 2006 storm activity on Hydro One reliability measures;
- Investment justification documentation for capital projects equal to or greater than $1 million, including summaries of project needs and results; and
- Identification of new standards, codes or compliance requirements that affect Hydro One's distribution operations.

With respect to rate harmonization and impact management, Hydro One concluded from its dialogue with stakeholders that:

- The 10% total bill impact is a key guideline to follow, but consideration could be given to adding a maximum dollar impact if the 10% rule hindered achievement of harmonization within a reasonable period. It was noted that a rate increase between $3 and $5 per month is used by other utilities as a guideline to ensure low-income customers are not unduly affected.
- Rates should be harmonized as quickly as possible being mindful of customer impacts and ensuring bill impact guidelines are met.
- The number of customer classes should be simplified taking into consideration the principles discussed, including consistency with the class structure of other LDCs but expanded to accommodate Hydro One's unique customer characteristics.
- All customer classes should have a common fixed + variable rate structure.

- A weighted average probably should be used to determine a new class loss factor when combining different classes and loss factors into a new class.
- There is a need to present bill impacts at various levels of consumption for each customer class and to explain what drives the impacts.

Stakeholder input helped Hydro One to refine and shape the elements of its distribution rate application and helped to ensure that customer and stakeholder concerns were understood and addressed.

6.0 LIST OF APPENDICES

APPENDIX A – Stakeholder Invitation Letters
APPENDIX B – Participant Terms of Reference
APPENDIX C – Funding Guidelines
APPENDIX D - Session #1 Meeting Notes – July 18, 2007
APPENDIX E – Designing the Rate Harmonization Process (worksheet)
APPENDIX F – Session #2 Meeting Notes – September 5, 2007
APPENDIX G - Session #3 Meeting Notes – October 15, 2007

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June 25, 2007

Sample Stakeholder Invitation Letter

Re: Hydro One Networks 2008 Distribution Rate Application

Hydro One Networks has begun to prepare its 2008 Distribution Rate Application for submission to the Ontario Energy Board (OEB) for implementing approved rates in mid-2008. The application will be developed and filed in two stages. The portion seeking approval for the revenue requirement will be submitted on August 15, 2007 and the cost allocation and rate design portion will be filed in October 2007.

In July, Hydro One will be initiating a stakeholder consultation program to assist us in the development of the application. Important aspects of the application include determining the work program spending that underlies the 2008 revenue requirement, as well as Hydro One's proposal to simplify its rate structure and harmonize the rates for customers of acquired utilities. The purpose of this letter is to invite you to participate in this process.

The goal for the consultation program is to create a forum for key stakeholders and Hydro One to discuss issues related to the Distribution Rate Application, and to identify areas of agreement and concern to assist in shaping the pre-filed evidence. Many stakeholders will have participated in the 2006 distribution rate consultation process. Hydro One intends to build on the experience gained during those sessions and subsequent OEB proceedings. The main objectives for this consultation program are to:

- inform key stakeholders about the approach and methodology used to determine revenue requirement, cost allocation and rate design;
- provide a preview of the application, including the numbers;
- provide stakeholders a range of opportunities to identify concerns on all aspects of the application;
- ensure stakeholder concerns and views are identified, understood and considered in the preparation of the application.

A report summarizing the key areas of discussion, agreement and concern raised through the consultation process will be included in the application.

Stakeholder Representation:

Hydro One will hold a series of discussion sessions with key stakeholders, including but not limited to groups who have participated in previous Hydro One Networks distribution rate proceedings. Stakeholders invited to participate will represent a diverse range of interests including consumer advocacy and environmental groups, energy industry associations; Aboriginal organizations, local distribution companies and large distribution customers.

Consultation Sessions:

The stakeholder process will consist of a minimum of three formal stakeholder sessions between July and October 2007 in the Toronto area. The preliminary topics for the three consultation sessions are as follows:

1. Hydro One business strategy and the revenue requirement (RR) components;
2. Principles of cost allocation (CA) and rate design (RD); and
3. CA/RD application and impacts.

The first stakeholder session is scheduled for July 18, 2007 at the Metropolitan Hotel, 108 Chestnut Street, Toronto, 8:30 a.m. to 4:30 p.m. (a continental breakfast will be available at 8:00 am). During this one-day session we will present and discuss:

- Hydro One business strategy;
- application development process;
- major investment programs and key drivers;
- benchmarking;
- overall 2008 revenue requirement;
- stakeholder issues and concerns.

This is the only planned meeting at which stakeholders can provide input to the revenue requirement portion of the application before it is submitted on August 15. Subsequent sessions are planned for mid-September and October, and Hydro One will consider holding additional sessions if warranted. Stakeholders will be able to follow the consultation process by visiting the Hydro One web site (www.HydroOneNetworks.com) and provide their comments by email or direct mail. All presentation materials will be posted on our web site. Comments received through these avenues will be considered fully and integrated into the stakeholder meetings, as well as in the final reporting.

Background Information:

This letter is accompanied by a Participant Terms of Reference and Funding Guidelines. The final agenda and presentation materials will be forwarded to participants in advance of the session. Please note that, if you were qualified to receive funding for the 2006 Distribution Rate Application or the 2007/2008 Transmission Rate Application stakeholder consultation processes, you are not required to apply again. It will be sufficient to indicate that you will be participating and submitting funding requests at the time you register to participate in this process.

If you have any additional questions about this process please contact Ms. Enza Cancilla, Manager, Public Affairs at 416-345-5892 or by email: Enza.Cancilla@HydroOne.com. ***Please confirm your attendance at Session #1 by contacting Jessica Pontone by email at*** Jessica.Pontone@HydroOne.com ***or at 416-345-5938 by July 13, 2007.***

Sincerely,

Susan Frank
Vice President and Chief Regulatory Officer

Enc.

Stakeholder Consultation
2008 Distribution Rate Application

Participant Terms of Reference

Background
Hydro One Networks Inc. (Hydro One) is a company committed to business excellence. Building positive and lasting relationships with stakeholders is key to our success. To continue to build these relationships, Hydro One is undertaking a stakeholder consultation process to assist in the preparation of its 2008 Distribution Rate Application to the Ontario Energy Board (OEB). This process will involve a number of consultation sessions and a project website. The purpose of the consultation sessions is to provide a forum for dialogue between Hydro One and key stakeholders and customers to discuss, clarify and prioritize key topics related to the application. These consultation sessions, along with any submissions received through the website, will be considered in the development of the content of Hydro One's submission to the OEB.

Stakeholder Consultation Principles
- Hydro One is entering into the stakeholder consultation process in good faith with a view to facilitating and streamlining future OEB proceedings related to the application;
- Hydro One will receive and consider all submissions made by stakeholders, but will retain control over the process of developing its application;
- All consultations are carried out on a without-prejudice basis;
- A neutral facilitator will document and report the discussions and any agreements reached with all or some stakeholders;
- Agreements reached will be submitted to the OEB as part of its evidence.
- This process will build upon stakeholder consultation sessions held in 2005 and 2006 for Hydro One's most recent Distribution and Transmission Rate applications.

Goal
The goal for the stakeholder sessions is to create a forum for key stakeholders and Hydro One to discuss issues related to Hydro One's 2008 Distribution Rate Application and to identify areas of agreement and concern to shape the pre-filed evidence. To further this mandate, participants are asked to:
- Represent the various views of their customers/constituencies;
- Assist Hydro One to understand their goals and issues through participation in a process of open dialogue and submissions.

Objectives

- Inform and update key stakeholders about our distribution business, and the approaches and methodology used to determine revenue requirement, cost allocation and rate design;
- Give stakeholders a range of opportunities to provide input and feedback on all aspects of the application;
- Ensure stakeholder concerns and views are identified, understood and considered in the preparation of the application;
- Act as a forum for the exchange of information and views;
- Assist Hydro One to anticipate and respond to stakeholder and customer views and preferences; and
- Clarify and scope as many issues as possible prior to the Hydro One submission to the OEB.

Membership

Participants have been invited from key stakeholder groups, namely: intervenors from previous Hydro One rate proceedings, energy and environmental associations, Local Distribution Companies, major customers and Aboriginal political organizations.

Hydro One believes that those invited are representative of the interests of the majority of its stakeholders. Stakeholder discussion sessions may be limited in size to ensure adequate time to fully explore issues.

Alternate Members

It is Hydro One’s intention that the same stakeholder representatives be actively involved throughout the process. This continuity will aid in the effectiveness of the process. In the event a participant is unable to attend one or more meetings, one designated alternate may be assigned to take their place. In the event that a participant and their alternate are both unable to attend a meeting, input may be submitted to Hydro One in writing.

Roles and Responsibilities

Hydro One

- Provide adequate background information to enable participation;
- Provide overview/presentations of key discussion topics;
- Act as a resource for main discussion and breakout sessions;
- Inform stakeholder how consultation has influenced Hydro One application.

Stakeholder Representatives

- Review Hydro One material presented;
- Identify key issues;
- Provide and present input, advice and feedback on issues relating to Hydro One's transmission rate application;

Stakeholder Discussion Session Details

- Meetings are to be convened at the request of Hydro One;
- At least three 1 or 2-day sessions (July, September and October) are envisioned;
- All meetings will be held in the Greater Toronto Area;
- The input received during the Hydro One consultation will be used solely for the purpose of developing the 2008 Hydro One Distribution Rate Application.

Working Group Meetings/Subcommittees

If, during the course of the consultation sessions, it is apparent that additional time to explore an issue(s) would be of benefit, subcommittees may be convened to discuss a specific issue/topic for a predetermined period of time. If required, facilitation and reporting resources will be provided for subcommittee meetings.

Consultation Process Support

Haussmann Consulting Inc. (HCI) has been retained to provide third party facilitation and reporting of consultation sessions. Assistance in identifying issues where discussion will be of benefit, exploring stakeholder views, and identifying any common ground are key parts of the facilitation role.

HCI will prepare meeting notes that document discussions and stakeholder submissions received during this process, as well as any areas of agreement that are reached between Hydro One and stakeholders. Where stakeholders take firm positions on an issue, this will be recorded if the stakeholder is willing to be identified in the notes. If an organization wishes to go on the record with a detailed position, this should be confirmed in writing to Hydro One. These formal responses, along with stated positions will be reflected in the final consultation report that will form part of the Hydro One submission to the OEB.

Participant Funding

Funding may be provided for participants who qualify for funding under the *Funding Guidelines* attached. No other participant funding will be offered. Those who have qualified for funding during previous consultation processes (2005 Distribution and

2007/2008 Transmission Rate Applications) do not need to re-qualify if their circumstances remain the same. In these cases, a short statement of intent to participate and a request for funding should be forwarded to the contact below.

Duration of the Consultation Period

The purpose of this consultation is to provide an opportunity for Hydro One-stakeholder dialogue during the time in which Hydro One is preparing its 2008 Distribution Rate Application. The Application will be developed and filed two stages: Revenue Requirement in August 2007 and Cost Allocation / Rate Design in October 2007.

Additional Consultation Opportunities

Parties who are not available to attend or cannot be accommodated in the stakeholder consultation sessions are encouraged to follow the process and submit comments through the Hydro One Web site (www.hydroonenetworks.com).

Accountability:

- Responsibility for the stakeholder consultation program rests with Susan Frank, Vice President and Chief Regulatory Officer, Hydro One Networks Inc.
- Participants are to be governed according to the policies/procedures of their respective organizations. In the event that agreements are reached during the consultation process, they must be consistent with relevant policies of the respective organizations and must be supported by written documentation from the organization.

Hydro One Contact

Should you have any questions about this document or the consultation program, please contact:

Ms. Enza Cancilla
Manager, Public Affairs
Tel: 416-345-5892
Fax: 416-345-6984
Email: enza.cancilla@HydroOne.com

Stakeholder Consultation

2008 Distribution Rate Application

Funding Guidelines

In order to facilitate dialogue with its stakeholders, Hydro One Networks Inc. (Hydro One) will provide funding to assist qualifying stakeholders to participate in its 2008 Distribution Rate Application stakeholder consultation process. The funding criteria that will be used are based upon those found in the Ontario Energy Board's (OEB) most recent Practice Direction on Cost Awards (October 2005).

Eligibility

- Hydro One will determine which stakeholders are eligible for funding. This will normally be limited to intervenors who have participated in past Hydro One distribution or transmission rate proceedings.
- Transmitters, wholesalers, generators, distributors, electricity retailers and marketers of natural gas and gas storage companies (either individually or in a group), parties with a direct commercial or business interest, the Ontario Power Authority and the Independent Electricity System Operator are not eligible for funding.
- Municipal or provincial government staff or representatives are not eligible for funding.
- Funding will be provided only to stakeholders participating in the discussion sessions.
- The burden of establishing eligibility for funding is on the party applying for support. Interested parties must provide Hydro One with a statement justifying their eligibility.
- Stakeholders who have previously qualified to receive funding for the 2006 Distribution Rate Application or the 2007/2008 Transmission Rate Application stakeholder consultation processes, are not required to apply again. It will be sufficient to indicate in writing to Hydro One that your organization will be participating and submitting claim forms.

Funding Principles

- Only one representative from each stakeholder organization will be funded. Alternates must be designated in advance and Hydro One notified.
- Groups with common interests are encouraged to combine their participation, or show cause as to why separate funding is justified.
- Funding will be provided for meeting preparation, attendance, travel to and from meetings, reasonable out-of-pocket expenses, and follow-up, as necessary, based upon the rates outlined in the OEB's Cost Award Tariff, with an agreed upon cap for preparation time not to exceed an amount equal to the meeting time. See OEB Cost Award Tariff at: http://www.oeb.gov.on.ca/documents/practice_directions_costawards_appa.pdf)
- Preparation time will not be reimbursed unless the stakeholder attends the discussion session for which preparation time was spent.

Funding Process

- Reimbursement for costs claimed will require the use of a Hydro One-approved form (see Attachment 2: Hydro One Disbursement Claim Sheet and the Preparation/Attendance sheet.)
- Requests should be submitted not later than 30 days following the completion of each meeting/workshop.
- Parties should submit their request for financial support to:

  Glen MacDonald, Senior Advisor – Regulatory Review
  Regulatory Affairs
  Hydro One Networks Inc.
  8th Floor, South Tower
  483 Bay Street
  Toronto, ON M5G 2P5
  Fax: 416-345-5913

Hydro One Contact

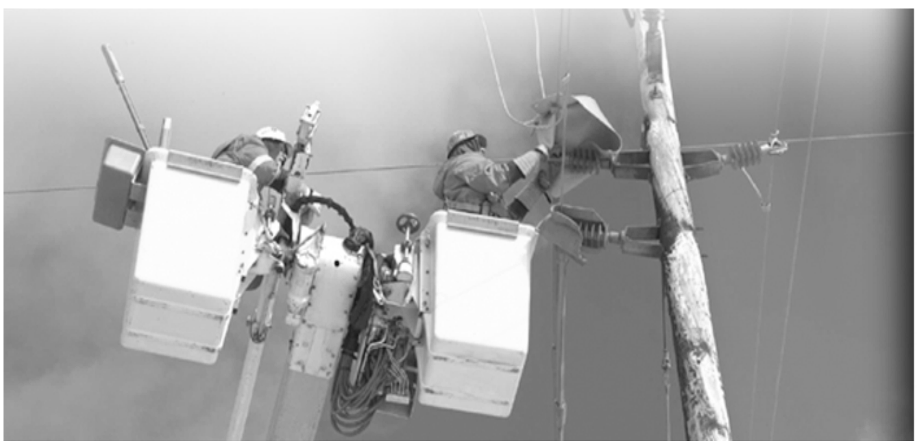
Should you have any questions about this document, please contact:
Enza Cancilla
Manager, Public Affairs
Tel: 416-345-5892
Fax: 416-345-6984
Email: enza.cancilla@HydroOne.com

Stakeholder Consultation
2008 Distribution Rate Application

Stakeholder Session #1
Meeting Notes

Metropolitan Hotel
Mandarin Ballroom, Lower Level
108 Chestnut Street, Toronto

July 18, 2007



Prepared for:
Hydro One Networks Inc.
483 Bay Street
Toronto, Ontario
M5G 2P5

Prepared by:
Haussmann Consulting Inc.
435 Roehampton Ave.
Toronto, Ontario
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Attachments:

1. Agenda and Participant List

HAUSSMANN CONSULTING

1. BACKGROUND

Hydro One Networks Inc. has begun to prepare its 2008 Distribution Rate Application for submission to the Ontario Energy Board (OEB) for rates effective mid- 2008. There will be one application that consists of two parts: a revenue requirement component which will be submitted on August 15, 2007, followed by a cost allocation and rate design component, which will be submitted in October 2007.

In July 2007, Hydro One initiated a stakeholder consultation program to assist in the development of this application. The main objectives of the consultation program are to develop a shared understanding and prioritization of the key issues affecting the application, with an aim to resolving or reducing the scope of as many issues as possible prior to the OEB process. All consultation activities are carried out on a without prejudice basis.

Hydro One invited key stakeholders who have participated in previous Hydro One Networks rate proceedings to participate in a series of discussion sessions. Additional information about the consultation process is posted on the Hydro One distribution rate application Web site at: http://www.hydroonenetworks.com/en/regulatory/2008_distribution_rate_application.
This document reports on the first of these discussion sessions, which took place on July 18, 2007.

1.1 Welcome and Introductions

Chris Haussmann of Haussmann Consulting Inc. (HCI) welcomed participants, thanked them for their attendance and introduced himself as facilitator for the workshop. In attendance were representatives from the City of Timmins, Energy Probe, Essex Power, Federation of Ontario Cottagers' Associations, Grimsby Power, Innisfil Hydro Distribution Systems, Ontario Power Generation, Power Workers Union, Pollution Probe, Society of Energy Professionals, the Union of Ontario Indians and the Vulnerable Energy Consumers Coalition. Also present were Hydro One staff, and their consultants, Elenchus Research Associates and the HCI facilitation team.

The full list of participants, together with the agenda, is provided in Attachment #1.

1.2 Process Overview

Chris reviewed the proposed agenda, which was structured to enable Hydro One to provide participants with information and an opportunity to discuss various aspects of Hydro One's business that relate to the Distribution Revenue Requirement. Stakeholder Session 1 was comprised of a series of presentations, which delivered this information in an interactive manner. The entire session was conducted in plenary. There were two changes to the agenda:

- Barb Allen (Manager, Customer Care) responded immediately after lunch to questions that stakeholders posed in the morning relating to the manner in which customer satisfaction is measured; and

- Rick Stevens (Director, Smart Meter Project) made his presentation on the Smart Meter Program before George Juhn (Manager, Distribution Development and Lines Sustainment) made his presentation on Major Investment Programs.

The objectives for Stakeholder Session 1 were to:

- Inform key stakeholders on the approach and methodology Hydro One is using to determine the revenue requirement;
- Preview the application;
- Afford stakeholders with a range of opportunities to identify any concerns relating to the key issues driving revenue requirement; and,
- Ensure stakeholder concerns and views are identified, understood and considered in the preparation of the application.

Chris then introduced Susan Frank (Vice President & Chief Regulatory Officer), who welcomed participants and thanked them for taking the time to attend the session. Susan encouraged participants to raise their concerns and questions. Hydro One sees the session as a dialogue and views stakeholder input as an opportunity to improve the application. She indicated that Hydro One staff also will be available for further discussion "offline".

2. PRESENTATIONS AND DISCUSSION

The following sections provide brief descriptions of the presentations made by Hydro One staff. Questions of clarification and discussion following each presentation are summarized in bullet form. Points in *italics* represent responses or comments from Hydro One or its consultants. All session 1 presentation slides are available on the Hydro One distribution rate application Web site at: http://www.hydroonenetworks.com/en/regulatory/2008_distribution_rate_application.

2.1 Hydro One Business Strategy

Laura Formusa (Acting President & Chief Executive Officer) reiterated that stakeholder consultation is an important part of the rate application process. Hydro One is committed to supporting open and transparent discussion on the issues. Laura provided an overview of the current direction of Hydro One and its key accomplishments:

- Hydro One's mission is to be the best transmission and distribution company in North America measured in terms of safety, customer service and reliability, while focusing on the development and retention of its employees and creating shareholder value. Hydro One is committed to achieving customer satisfaction ratings of 90% across all segments and first quartile status with respect to reliability relative to comparable utilities. Restoring employee pride and respecting the public's trust is also a top priority.
- Hydro One is proud to have received the Edison Electric Institute Emergency Recovery Award for the restoration of service to customers after three major storm events in the summer of 2006. Such events underscore the need for rigorous and proactive vegetation management.
- Hydro One's initiatives associated with conservation and smart meters are important because they support provincial energy and environmental goals, help Hydro One customers meet these goals,

and provide Hydro One with a new opportunity to speak to customers. Hydro One's Conservation and Demand Management (CDM) program has resulted in energy savings of 100 million kWh since 2005 and demand for electricity during peak periods has been reduced by almost 11 MW. Hydro one is on track to install 1.3 million smart meters by 2010. The CDM and smart meter programs have resulted in Hydro One being ranked 26th of 50 corporations (and third among Canadian utilities) by Corporate Knights magazine based on environmental, social and governance indicators.

- Hydro One supports the Province of Ontario's Renewable Energy Standard Offer Program (RESOP) through the Ontario Power Authority's (OPA's) initiative for small projects (under 10MW) using renewable sources, such as solar, wind, biomass and water power. Hydro One has received over 700 requests for assessments. Hydro One has been unable to respond to all requests in a timely manner due to limited availability of the required expertise to conduct these assessments. Hydro One is improving its ability to respond to applications more quickly through training of additional staff and accessing external consulting service providers.
- Hydro One is listening to customers in all forums, and wants to sustain or increase the level of service, while changing some services to meet government policy objectives and environmental obligations.
- Hydro One understands that it must be a good steward of the assets with which it has been entrusted and the natural environment within which it operates; it must maintain the public trust; and, its customers must feel that they are getting value for money.

The following questions were asked/points were clarified in ensuing discussion:

- Is it Hydro One's objective to be the number one Ontario LDC in terms of CDM over the next three years?

  We probably are number one, and if not, are in the lead in terms of our program achievements to date. It is not absolute targets but the way we operate the business which will lead us to be number one. All our LDC colleagues are striving towards that goal and this competition will benefit all Ontarians.

- In terms of targets over the next three years, is it Hydro One's goal to achieve an absolute reduction in your LDC customers' peak day demands? Do you have a target to achieve an absolute reduction in their electricity consumption?

  We are not targeting a definitive number. Despite population growth, overall load growth is flat in the province. That means that average consumption per customer has been decreasing as a result of our CDM programs. Targets are nice, but CDM should become a way of life and a way of doing business.

- Over the next three years, what is your CDM budget? How much of it will be financed through rates and how much do you hope to get from the OPA?

  The OPA is taking the lead in terms of the programs they manage and finance. Hydro One takes guidance from the OPA with respect to developing budgets for CDM programs, and is taking the *lead in terms of what we think our customers want and need. It is important for the OPA to listen to the LDCs, who know their customers best, when designing their programs. We have to be as innovative as possible. Each of us has something to bring to the table over the next three years. We are not simply relying on the OPA to tell us what programs to roll out and deliver.*

- Is Hydro One independently funding CDM initiatives through their own rates and, if so, from what part of the rates will that be derived? How do you justify double charging customers by receiving funds on CDM initiatives from rates and from the OPA? What are you planning on doing with the Lost Revenue Adjustment Mechanism (LRAM)? Are you just looking at re-basing and foregoing any lost revenue?

  We are working through the OPA only. We are not proposing that separate CDM projects go into the rate base for this application. Our programs will be delivered through the funds that the OPA is managing. We do take into account in our load forecasts the conservation targets set by the OPA. That will continue.

  We are not applying for an LRAM because we do take into account the conservation that we anticipate our customers will achieve in our load forecast.

- Hydro One has done a great job with CDM. Why is Hydro One not participating in the 10/10 program?

  Hydro One is participating in the 10/10 program.

- Can you speak to your philosophy on consolidation of rates and harmonization related to the utilities you acquired in 1999-2000?

  The major storms that Hydro One had to cope with last year, and the associated forestry and restoration costs incurred, took place in the heavily treed areas of Northeastern Ontario. In southern Ontario we have 3-5% tree coverage so there is not a lot of that cost burden across the customer base. In southern Ontario we are worried about jobs, reliability and affordable rates for primary homes and businesses, not supplying power to million dollar cottages in "recreational" areas. Hydro One still carries a line rate that is 20% higher than the average for all the other LDCs in Ontario. How are you looking at managing increasing forestry/vegetation costs across the customer base?

  Both the harmonization question and the second question (which is about whether there should be regional rates based on the user pay principle rather than uniform rates across the province) are rate design issues. These issues will be addressed in the September and October stakeholder sessions. We believe these are critical issues and we want to get your views before we go to our Board and the OEB. The OEB is doing a great deal of work in the area of cost allocation and rate design. Hydro One must work within the governance structure the OEB provides to develop regional rates.

- We talk about achieving greater efficiencies through consolidation and regionalization, but everybody keeps going to the OEB for more money. We have a rate base in which customers in one area are subsidizing customers in another; for example, the rate base in southern Ontario likely includes a 30% OM&A on forestry in northern Ontario. There are still many efficiencies to be achieved through further consolidation and regionalization, but this is inhibited by the current rate making process which creates artificial rate bases across different sectors of the province with different service requirements. Rates for some service areas should not subsidize rates in other service areas.

This is a rate design issue that will be addressed in the September stakeholder session. Hydro One agrees that there are further efficiencies to be obtained across the entire distribution sector. We are all trying to do that.

We hear your viewpoint, but do not necessarily share it. The regional issues of north versus south, east versus west or farmers versus cottagers have been debated for decades. We have a diverse province, and serve a diverse customer base and communities that all make a contribution to the province.

- Rural rates have a much bigger impact on rates and the cost of power for ordinary customers across the province than storm restoration. Where should load-serving entities (LSE) go from Hydro One's point of view?

  This has not been a key focus in the company. As the debate grows, we will certainly be involved. Our general view is that this is not the right time for LSEs. The market has not evolved to the extent that customers would benefit from an LSE approach. Andy Poray is the expert on this within Hydro One and would be glad to talk to you.

2.2 Application Overview

Joe Toneguzzo (Director, Major Applications) provided an overview of the application and its time-line. Hydro One will identify where there are increasing work and cost pressures and where other factors are contributing to cost reductions. Joe described the key cost drivers for the revenue requirement and rates filing. He also described Hydro One's approach to the planned rates filing submissions. The filing will be structured and include information consistent with the 2005 Distribution submission.

The 2008 Distribution rate application to the OEB will be filed in two parts. The revenue requirement will be filed on August 15, 2007. Hydro One has not yet completed the internal approvals process for its business plan and a meeting with the Hydro One Board is scheduled for August 10. This is a key step in finalizing the application and meeting the August 15 OEB filing deadline for the Revenue Requirement submission. Given this challenging time-line, specific Revenue Requirement figures will not be available for this meeting or before the filing date. The rates portion of the application will be filed in the latter part of October 2007. Rate design and cost allocation will be discussed during Stakeholder Session 2 in September before going to Hydro One's Board of Directors on October 3, 2007. There will be a final stakeholder session in mid October to discuss customer impacts of the rate design. Our intention is to move towards harmonization and consolidation of the 270 rates Hydro One currently has, and to ensure that rates more accurately reflect the costs of providing distribution service to specific customer groups. The target Distribution rate reset date is mid-2008.

The following questions were asked/points were clarified in ensuing discussion:

- Given your two-part filing, when do you anticipate that the OEB will be starting the clock on their guidelines/processes: between the two filings or after the second filing?

  Hydro One hopes that the clock will start on August 15, 2007. However, Hydro One and the OEB have not finalized those details yet. We do not think that we can meet the May reset date and think a June or July 2008 reset date is more likely. The issue is complicated by the fact that the OEB also has to deal with many other LDCs who may be submitting 1-part or 2-part filings.

- Did you receive OEB approval for the list of the consolidated LDCs that you purchased and that you will be re-basing to the harmonized rates?

  No, there was no criterion established by the OEB for deciding which utilities would be re-based in 2008.

- Regarding harmonization, the OEB has traditionally indicated that there should not be a rate increase greater than 10% to a specific customer group or level. Will it be difficult for Hydro One to limit the rate increase to no more than 10% when harmonizing the rates?

  Yes, for some groups it will be a challenge. Hydro One will have to stage the increase over time. With harmonization of rates, the overall revenue requirement remains the same. Rates in one area will increase while they decrease in another area. The issue is, "Who is paying what rates?" Hydro One is not asking for more revenue due to harmonization. Hydro One recognizes that there are customers and communities who are paying too much today and their rates must be brought down. Other customers and communities are not paying enough. Susan Frank asked the stakeholders how long the harmonization of rates should take. She also asked stakeholders to suggest (by the September Stakeholder Session) alternate approaches or rules that could be considered other than the10% rule.

- If rates are increasing even after Hydro One has acquired 87 utilities in order to achieve increased efficiencies, what efficiencies have really been achieved?

  The increased efficiencies are at a higher level. We would have to determine what the total cost was of running those utilities plus Hydro One versus the cost of running Hydro One now that these utilities have been integrated into our system. Early estimates from industry working groups suggested an overall benefit in the order of $200M could be achieved depending on scenarios assumed.

- When it acquired other LDCs with lower rate bases, Hydro One effectively blended those rate bases into its own, which has the effect of lowering the overall blended rate base. The OEB and the provincial government must consider the over-riding principles of harmonization and ask whether this is what they want.

We must look at overall efficiencies and we agree that the cost profiles will change. Through cost allocation and rate design, we can address these changes by making rates more cost reflective. This question can be better addressed during Stakeholder Session 2 in September.

- Will Hydro One identify only the total corporate revenue requirement in the August filing; or, will there be a breakdown of the revenue requirement by categories such as shared facilities, shared distribution lines, and the associated revenue required to serve individual customer segments? For example, right now we are paying $0.63/KW for shared low voltage (LV) lines. Is that going to be separated out in your revenue requirement or will you only show the corporate total?

  Only the total revenue requirement will be filed on August 15. However, once the revenue requirement is established, we can describe the allocation of costs to the various rate classes.

- If customer satisfaction does not meet objectives (e.g., in the call centre), will you increase staff to achieve the objectives?

  Hydro One would not necessarily increase staff. We would look at changing a business process or introducing new technology, such as an Interactive Voice Response system, or looking for other low cost options that may not result in an immediate increase in staff or cost. Depending on the options, there may be an increased cost to improve customer satisfaction ratings.

- With respect to distributed generation, most of these connections are or will be in Hydro One's service territory. The OEB is struggling with the issue of standby rates for distributed generation. You probably know more about the cost characteristics than the OEB since you have the lion's share of distributed generation.

  Last week, the OEB published a series of discussion papers on distributed generation and impacts to rates. Hydro One recognizes that standby rates certainly are a key issue.

2.3 Benchmarking, Reliability and Service Quality

Carm Altomare (Manager, Performance Analysis) described the two benchmarking studies that the OEB has directed Hydro One to conduct. Benchmarking is primarily a vehicle to identify best practices in order to enable process improvement. Distribution benchmarking studies are being conducted currently by P.A. Consulting and results are not yet available. Carm also discussed Hydro One's two major performance measurement drivers: OEB performance standards; and, customer expectations and performance goals identified in the Hydro One Five Year Plan. There are six customer service metrics and three customer reliability metrics. Since the last Hydro One Distribution filing, there have been no changes to the OEB's service quality indicators for customer service and reliability.

Carm provided an overview of the customer service indicators, illustrating the OEB minimum targets and Hydro One's performance over the past three years (2004 – 2006). In most cases Hydro One meets or exceeds OEB targets.

Hydro One's performance for System Average Interruption Frequency Index (SAIFI) and System Average Interruption Duration Index (SAIDI) are consistently stable year-over-year when excluding *force majeure* events. *Force majeure* events have a significant effect on service quality and emergency response. Carm also provided detailed overviews of system reliability and related trends, including new distance-based metrics and comparisons to similar utilities.

Hydro One's Five-Year Plan is to improve customer satisfaction to 90% or better in all segments, to meet or exceed the OEB's Service Quality targets (where this helps achieve the 90% customer satisfaction level), and to achieve top quartile reliability in Distribution when compared against similar utilities.

The following questions were asked/points were clarified in ensuing discussion:

- At what point do you start planning for and "building in" *force majeure* events?

  Hydro one has always planned for an average number of force majeur *events. As Laura Formusa indicated, Hydro One was honoured with an Edison Electric Institute award for its storm restoration work in 2006. Hydro One has a great deal of experience planning for and responding to these types of events. We monitor weather patterns and place staff on call if a force majeure event is anticipated. Our service staff also communicate and cooperate with staff from other utilities when major storms are imminent. Most of these storm events are the result of strong winds and extreme weather that come from the southwest and cross Ontario between Georgian Bay and the Ottawa Valley. This weather pattern has recently tended to move a little further south, so impacts may be different in the future. Our revenue requirement does include some costs to respond to storms.*

- Do you exchange information or have a comparison with Florida in terms of storm restoration?

  The P.A. Consulting benchmarking study will include information on reliability in Florida. Hydro One liaises with Florida to explore what they do, and sometimes our lines people do assist them to restore their system. Hydro One is trailing Florida's reliability performance but there are some regional differences that also need to be considered (e.g., tree density in Ontario is greater than in Florida).

- What were the comparator utilities that were included in the benchmarking studies?

  This is part of the P.A. consulting study. The comparable utilities they are looking at are those that have a similar business model and the same geographic issues we have, so that we are comparing similar companies. The P.A. consulting study will include a list of the utilities.

- It looks like some of the OEB customer service targets are below customer expectations. Are there particular areas where this happens?

  Yes, for example, customers want Hydro One to respond faster with respect to telephone accessibility than OEB targets. With effort in this area, overall customer satisfaction numbers are expected to improve. We can negotiate appointments during force majeure *events but customers understand that it will take time to restore power. Technical questions to the call centre now get redirected to technical operators. For example, land developers now have a direct number they can call to ask technical questions. This improves satisfaction and efficiency.*

- When comparing SAIFI and SAIDI measures, are Hydro One numbers included in the composite of utilities that you compare against and therefore affecting the trends?

  No, there are no composites used in these SAIFI and SAIDI comparisons. These trends relate to quartile performance of all industry participants.

- Do you consider Canadian utilities outside of Ontario as "comparable utilities" in the benchmarking studies?

  Yes, utilities operating in British Columbia, Québec, New Brunswick, Nova Scotia, and parts of Alberta, Saskatchewan and Manitoba with service areas that have trees are considered to be comparable. Furthermore, we are trying to break down all provincial utilities into regional data. By doing this, we can compare different regions within Canada, to regions within Ontario.

- How long have you been tracking urban LDC reliability performance data (slides 17, 18)? Can we access these data?

  Hydro One has been tracking urban LDC performance for several years. We started to do so when we began working on the OEB's second generation Service Quality Regulation initiative. Hydro One does not create the data itself. It comes from the data the LDCs file with the OEB. Hydro One then gets the data from the OEB website where it is publicly available.

  It was also noted that there is no uniform definition of urban and that the definition Hydro One uses is "an area where there are at least 3,000 customers and a density of at least 60 customers/km." Hydro One believes that it should respond to urban customers more quickly than rural customers and that this may become a regulatory requirement in the future. About 50% of the reliability problems experienced in urban pockets are "loss of supply" problems stemming from the system (e.g., a rural feeder line outside the urban area, a station or a transmission problem). If loss of supply situations were removed from the data, Hydro One's reliability performance would be higher. Loss of supply data is not consistently reported in LDC data, although this is an OEB requirement. The OEB is considering requiring LDCs to report reliability both with and without loss of supply data.

- When you exclude *force majeure* in the Hydro One data, do you also exclude *force majeure* for the comparators?

Yes, but the problem is that no two utilities use exactly the same definition for force majeure. *The Canadian Standards Association uses the term "prominent event" which is similar to our definition of* force majeure. *In any event, variations in definitions do not change the numbers significantly.*

- Given the changing climate, and the trend to move towards more of a user-pay model, have you considered changing your conditions of service by requiring the use of underground lines in high vegetation areas? This might increase capital costs but reduce ongoing maintenance costs. For retrofits the cost may be quite high, but for new installations the cost might not be as high as one would think.

  Underground lines have been installed in some locations, but this is a very expensive and a technically difficult option. There are other options. For example, in areas prone to lightening strikes, we can put surge arrestors on the primary line or erect sky wire to improve reliability.

  The Federation of Ontario Cottagers' Associations noted that constructing underground lines on the Canadian Shield would be very expensive.

  Hydro One has a policy that describes standards and requirements for the underground lines. It has not been looked at for a while.

2.4 Hydro One Distribution Incentive Regulation Proposal for 2009/2010

Andy Poray (Director, Regulatory Policy) and John Todd (President, Elenchus Research Associates) discussed the proposal to establish a stakeholder Incentive Regulation Working Group (IRWG) to enable a collaborative approach on incentive regulation that is appropriate for Hydro One. Hydro One and stakeholders need to think through and identify the issues early, before the OEB comes out with its policy paper on third generation incentive regulation. It is expected soon and the program will move quickly towards implementation. Participating in the IRWG would allow stakeholders to take the lead in policy development, identify options for incentive regulation in the electricity Distribution sector and proactively contribute to the OEB's thinking and direction.

Hydro One is not seeking consensus; rather, it is looking for input via the IRWG from stakeholders regarding issues, and options. Issues to be addressed include: principles of incentive regulation, design alternatives, and evaluation criteria. John Todd requested that:

- Stakeholders who want to participate in the IRWG identify themselves; and,
- Stakeholders who were not present today but who may be interested in participating in the IRWG be identified.

The proposed process includes: a process meeting in late July, where interested stakeholders meet and agree on the terms of reference and other items; three or four options development meetings in August and September; and, preparation of a working group report to be included in the October filing. Hydro One will provide the usual participant funding for this consultation process.[1]

The following questions were asked/points were clarified in ensuing discussion:

- Will Hydro One file its own Distribution Incentive Regulation proposal (as opposed to the IRWG report) as part of its 2008 OEB application or will this come as a separate application to the OEB at a later time?

  Given the time constraints, we will likely submit both the IRWG report (which will contain options) and our recommendations as part of the October filing. Our hope is that the methodology would be agreed to, so that we could apply that methodology for 2009 without having another separate hearing. We are open to ideas about a more efficient path.

- The time constraint is due to how late the OEB got started on thinking about 3rd-generation incentive regulation mechanisms (3GIRM). The OEB seems to think that 3GIRM may not necessarily meet all Hydro One requirements. It would be advantageous to have as much commonality as possible between what the OEB is doing and Hydro One's approach.

  Hydro One is concerned that it may not hear from the OEB until late in the process. We should be proactive and provide input to them via the IRWG before the OEB begins to develop fixed ideas.

- Could you review the price cap index that Dr. Mark Lowry is thinking about?

  He is taking a classic price cap approach using comparators to come up with productivity factors. Price adjustments are made for cost driver inflation and offset by productivity. The approach does take into account that electric utilities face largely fixed costs not necessarily related to volume throughput fluctuations (e.g., resulting from weather conditions) or even long term trends. It is dependent on a United States database of comparators, which may not be appropriate for Ontario or Hydro One.

  The model is not clear on how long the period of adjustment will be – is it a three-year or five-year performance-based regulation (PBR)? Will we start off with a cost of service in the first year with adjustments in every year based on that first year's cost of service, or will there be a requirement to file information on projected expenditures for each year of the period (i.e., the English and Australian models)? So we are not clear as to what the model will be and which model would be preferable to Hydro One, given what we envision happening down the road.

- What do you mean in slide 3 by "process to be included in the August 15 filing"?

[1] A number of stakeholder groups expressed interest in participating in the IRWG and an initial meeting was held. However, Hydro One cancelled this initiative on August 3, 2007 after the OEB announced a consultation process to develop the 3rd Generation Incentive Regulation for all LDCs that is very similar to the IRWG process proposed by Hydro One.

We will simply inform the OEB in the August 15 filing that this IRWG process is in place and that they can expect a report in late October when the cost allocation and rate design portion of the Application is filed.

At this point in the discussion, the presenters asked stakeholders whether, given that the OEB is committed to incentive regulation, this IRWG process is worth engaging in or whether it would be better to await the outcome of the OEB's 3GIRM process? They urged stakeholders to provide proactive input to the OEB so that the industry is not simply reacting to OEB discussion papers.

- It was noted that when the first Distribution Rates Handbook was produced, it was called the PBR Handbook. There was more consideration put into developing the PBR side of the rates, which turned out to be a disaster. It never went anywhere. In the second generation PBR, the Consumers Association brought in a United States expert who stated that PBR schemes all eventually turn into cost of service regulations. This initiative will be challenging and its success will likely be minimal.

  Yes, but the OEB has indicated its intent to develop an incentive regulation for electric distribution companies.

- The IRWG process seems like a worthwhile exercise because it is always better to shape your future, if possible. What level of familiarity or expertise is Hydro One looking for to serve on the IRWG?

  It was explained that stakeholders do not need a great deal of expertise to join the IRWG. If needed, Hydro One can provide background material. The key criterion is whether stakeholders think this is a good process and have the interest to be engaged. It would also be helpful to have some diversity on the IRWG in order to get as many points of view as possible.

  This initiative has the potential to be a demonstration case for stakeholders taking a proactive approach. It may change the way the industry does things in the regulatory environment. Stakeholders were asked to express their interest or identify others who may be interested to John Todd or Andy Poray.

2.5 Customer Satisfaction Survey

Barb Allen (Manager, Customer Care) addressed questions initially raised by stakeholders during the morning session relating to customer satisfaction. She was responsible for implementing the customer satisfaction survey, which asked customers how satisfied they were with Hydro One service. The survey was conducted in 2003 and then repeated in 2006. Customers had the opportunity to complete the survey over the telephone or online.

The following questions were asked/points were clarified in ensuing discussion:

- What comparator utilities were used in the customer satisfaction survey?

Researchers contacted people in every province of Canada with the same survey that was used with Hydro One customers. Respondents were asked to rank overall satisfaction with their utility. Hydro One discovered there was a best practice satisfaction level of 89%. This helped us set our goal of 90% customer satisfaction for 2010.

- How are responses weighted in the customer satisfaction survey?

  In customer satisfaction surveys, traditional survey research techniques are used to weight the survey sample to reflect the makeup of the Hydro One customer base (e.g., residential, small business, seasonal, agricultural). But there is no weighting of the final survey result; they are simply a consolidation of responses to the top two boxes in the questionnaire (satisfied or very satisfied).

- Has the OEB provided specific guidelines or methodology concerning customer satisfaction surveys? Are the formats for the customer satisfaction survey available?

  The OEB has provided no specific guidelines. However, Hydro One follows standard research practices and methodologies (e.g., sample size, statistical analysis, etc.).

2.6 Smart Meter Program

Rick Stevens (Director, Smart Meter Project) provided information on the Smart Meter Program. He described how the initiative is designed to work and the implementation plan to 2010; 1.3 million smart meters will be installed by the end of 2010. The meters are called “smart” because they collect time-of-use data and can transmit these data via an Advanced Metering Communication Device and a local area network (LAN) to an Advanced Metering Regional Collector, and then to the Meter Data Management/Repository Company (MDMR). As a result, manual meter reading will be eliminated. Rick provided a regulatory update and program implementation status report on Hydro One’s smart meter program. He also described the 2008 deliverables. He described some of the numerous challenges that are unique to Hydro One’s implementation program (e.g., the need to use enhanced technologies in rural areas because of the distances and limited availability of communications infrastructure, and the resulting higher cost).

Rick also described various elements of the program: Capital expenditures, OM&A expenditures, and anticipated savings. Expenditures to May 2008 will be handled through three proposed variance accounts that would be settled as part of the 2008 application. Capital and operating costs are to be included in the 2008 revenue requirement.

The following questions were asked/points were clarified in ensuing discussion:

- Do you have any concerns about whether your meter data management system will meet your needs from an operational perspective, as opposed to the billing and customer information aspects (slide 2)?

The focus is on time-of-use billing but there will be potential operational benefits to having all that data. It will be archived and contracts will be developed with the Independent Electricity System Operator (IESO) and the MDMR provider. Another option is that the data stored in the Advanced Metering Communications Device can be streamed off for Hydro One use, if a business case shows merit.

- When will the first time-of-use bills go out?

  This will happen in the second and third quarters of 2008. By then we will have 500,000 to 600,000 customers on- line. Rather than doing them all at once, we may have to stage the billing implementation to make sure that all the bills are accurate.

- The MDMR will involve costs and it appears that the OEB currently has no plans to regulate the MDMR. How will Hydro One deal with these costs in its submission (slide 3)?

  We expect there will be more direction on this from the OEB, and quite possibly another variance account to track costs that cannot be forecasted.

- Perhaps Hydro One should proactively suggest this to the OEB (slide 3).

  That is a good idea. Hydro One could ask the OEB for an MDMR variance account. The proposed incremental functionality variance account (last slide) may cover this item.

- What are the anticipated total smart meter Capital costs and annual OM&A costs to 2010?

  We have not evaluated that yet. There are regulatory standards on minimum meter functionality for the residential and small commercial sectors (i.e., less than 50 KW). Standards for the greater than 50 KW segments, in which we have a much smaller number of customers, have not yet been developed.

  We are currently implementing smart meters in urban and semi urban areas where we have a good understanding of costs. When we get to more rural and remote areas, there may be technology limitations and issues around the economics. Implementing in these areas will be a sizable program. Rural territory requires use of enhanced equipment and multiple technologies that would increase costs. Deployment costs increase with expansion into lower density areas. We are running a rural pilot north of Peterborough this summer to get a better handle on costs.

- What does the outage detection capability plug into?

  There are two super capacitors in the collector (slide 5) that allow four to six minutes to clear the network. The collector communicates with the meter and has backup battery power. The modems also have backup battery power. So as long as the cellular tower does not go down, information about an outage occurrence will be transmitted.

  No data is lost in the event of an outage. The data are stored in both the meter and in the collector.

2.7 Major Investment Programs and Key Drivers (OM&A and Capital)

George Juhn (Manager, Distribution Development & Lines Sustainment) described the investment programs required by Hydro One. These programs are determined by business drivers (e.g., meeting company objectives, public and employee safety, meeting regulatory requirements, etc.), as well as the need to improve performance, as described by metrics for reliability (e.g., SAIDI, SAIFI) and customer satisfaction. George outlined the key customer base segments of the Distribution business and the principal assets used to service these segments. He described the asset categories, actual 2006 expenditures, and associated programs for OM&A program and Capital program elements. Information on expenditures was also provided for OM&A sustaining programs, and Capital sustaining and development programs.

Additional funds are required to address various challenges associated with OM&A and Capital programs:

OM&A Programs

- Demand Sustaining OM&A – projected increases in trouble calls resulting from storm damage, expect more cable locate and disconnect/reconnect requests based on recent experience (there is a greater public awareness of "call before you dig"), and increased economic activity;
- Vegetation management – increased vegetation management is required to improve reliability and reduce storm-related damage costs (55% of unreliability is associated with trees); and,
- Development – more generation connections, more stringent safety standards and additional Long Term Load Transfer assessments.

Capital Programs

- Asset replacement – cost escalation for equipment and material such as wood poles, transformers, and conductors;
- Trouble call & storm damage – 2006 storm damage is considered a worst-year scenario for expenditure planning purposes;
- New connections and system reinforcement; and,
- Generation connections.

The following questions were asked/points were clarified in ensuing discussion:

- How did the OM&A Sustaining 2006 actual spending ($253M) track against the OEB-approved spending, and what caused the differential (slides 4 and 5)?

  The OEB-approved spending was about $230M. The differential was caused primarily by the unusually high level of trouble calls and storm restoration we experienced in 2006. This information will be provided in the filing.

- Assuming that 2006 was an aberration and that in future years trouble calls will track closer to the historical average, is the 2006 $253M actual spending number too high to base your forecast on?

There is no doubt that the 2006 storm damage was unusually high, and this has been appropriately factored into the calculation of our forecast for future years.

- Are you segregating the cost of low voltage (LV) facilities into OM&A and Capital costs in order to come up with the revenue requirement? In other words, are you tracking LV charges separately in order to come up with a rate or are LV costs simply consolidated with all the other costs? At the end of the day, how do I know that $0.63/KW for LV assets is the rate I should be paying based on your projected Capital and OM&A costs for LVs?

  It would be a very onerous task to track costs at this level of detail. We run an integrated operation with one total revenue requirement. In accordance with the Board's requirements, we use cost allocation to tie costs to the various rate groups.[2] *The September stakeholder session will focus on cost allocation. The rates were originally set using cost allocation and they will be set the same way again.*

- Did increased trouble calls and storm damage in 2006 impact net income?

  Yes, and the impact was significant, as indicated in our Annual Report.

- Were some programs (e.g., asset replacement) negatively impacted because you had to transfer staff/resources from other activities to respond to trouble calls and storm damage in 2006?

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[2] Hydro One uses the Cost Allocation Methodology issued by the Board on September 29, 2006 to separate Capital and OM&A Sub-transmission, Primary and Secondary costs (Section 6.3.1), and to allocate those costs to the various rate classes (Section 6.3.2). The methodology states:

6.3.1 Direction – Identifying Bulk, Primary and Secondary Costs
Once the bulk, primary and secondary assets have been identified based on the above tests and guidance, it is necessary to break out the associated costs. As the accounting granularity is presently not available to do such a breakout, the distributor must provide an estimate of the percentage of costs of the assets in each of the bulk, primary and secondary buckets. This percentage will be applied to the total cost in the asset account. For contributed capital see below.
The Filing Summary must explain how the distributor broke out its costs between bulk, primary and secondary assets. The following approach is to be used:

> The distributor should determine the unit cost of installing bulk, primary and secondary assets and then apply the kilometres of line for the bulk, primary and secondary assets to these unit costs. The result from each type of asset should be divided by the total for all assets and this percentage should be used to determine costs by asset type.

6.3.2 Direction - Breakout of Bulk, Primary and Secondary Sub-accounts
The bulk, primary and secondary sub-accounts should be broken out to the corresponding rate classifications that use those assets. In particular:

- Secondary costs will only be allocated to those rate classifications that use secondary assets.
- Primary costs will only be allocated to those rate classifications that use primary assets.
- Bulk costs will be allocated to those rate classifications that use bulk assets. For many distributors, bulk costs will be allocated to all classifications since the bulk assets deliver power to the primary and secondary assets.

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There is some flexibility. Additional resources were recruited through the Hiring Hall and via overtime. However, some programs were negatively affected. Some LDCs also offered assistance but at a cost.

- With respect to your benchmarking, Hydro One appears to do it one way while other utilities applied for a Z-factor to compensate for storm damage. In your rate application, are you trying to recover the costs for potential storms, rather than requesting a Z-factor?

  Other LDCs requested a Z-factor because of the force majeure *events. Hydro One also had* force majeure *events but does not believe they triggered a Z-factor. So for 2007, Hydro One asked for no additional money for storms even though other LDCs did so. We will not try to recover the incremental costs we spent in 2006 on damage resulting from higher than usual storm activity. We have a normal budget allocated for dealing with storms. We will continue to budget for storms in the future; however, the large amount of storm activity in 2006 does not mean a lot more resources will be allocated for storms in the next filing. We use a four-year history to project future budgets for storm damage, and discount abnormal years such as 2006. It is not our objective to inflate the budget, as can be seen in our last rate filing.*

- With respect to asset replacement, how much of your capital is planned versus unplanned (i.e. "assumed reactive" related to storms) in a normal year?

  Replacement of assets is funded primarily by Sustaining Capital, but some assets are also replaced under Development. Development Capital funds additions and changes to the system and, during the course of this work, some assets may be replaced. The breakdown for 2006 was as follows:

Capital Program		***2006 Demand***	***2006 Planned***
***Sustaining**:*	*Trouble Calls, Storm Damage, Joint Use and Relocations*	*68%*	*32%*
***Development**:*	*New Customer Connections and Upgrades*	*71%*	*29%*

- With respect to new customer connections, do your numbers include capital contributions from developers or are they net (slide 8)?

  The numbers are net.

- The storms of 2006 are going to contribute to reliability in 2007 and 2008 because many of the dangerous trees have fallen, been cut, or been removed. This will be a future benefit. Why is more forestry and vegetation management required?

  We cannot assume that the 2006 storms have taken out all of the danger trees. About 1,500 km of lines have been rebuilt. This is a small amount when compared to the 119,000 circuit km in the Hydro One Distribution system. Also, some trees may have been weakened by the storms but not fallen, and we don't know which ones they are. Therefore, we cannot assume a future benefit as a result of the 2006 expenditures.

- The Federation of Ontario Cottagers' Associations believes that vegetation management should be a priority. We would also like to see improved communication with townships, local community organizations and individual customers and notification before work begins, especially if herbicides are going to be used. The public is more likely to accept the judicious use of herbicides if they understand there are no serious environmental consequences.

  Agreed and noted. There is always room for improvement, especially better information and education regarding herbicide use.

- Hydro One has spent a lot of money since 2004 to improve reliability and you will be asking for more in this filing. We need to see some evidence in the filing that this money was well spent, given that reliability since 2004 has, in fact, not increased.

  Agreed and noted. Reliability is significantly influenced by weather. The increased storm activity in 2006 skewed our reliability results. Major system changes would be required to make significant reliability improvements if such storms were to become routine events. Excluding force majeure *events, Hydro One's reliability has remained consistent. If we had not received the rate adjustment in 2005, we would be in a worse position now.*

- Where does the capital come from to offset load transfers (slide 14)?

  This capital comes from the new customer connections budget. However, the amounts involved are not large.

- There seems to be a discrepancy between the 8,000 poles referred to in slide 18 and the 6,000-7,000 poles in slide 17. What is the timeframe to replace 8,000 poles and in which years will this take place? Is pole replacement accounted for under Capital or in OM&A?

  Some poles will be replaced this year and some next year. There is always a 2,000 to 3,000-pole carryover from the previous year because we coordinate pole replacement with line refurbishment when this is most cost effective. Some poles may be replaced on a "one for one" basis (i.e. the 6,000-7,000 poles in slide 17), while others may be replaced when a line is being refurbished i.e. the 2,000 to 3,000-pole carryover which is not included in the slide 17 figure. Pole replacement therefore takes place under several work programs. Pole replacement is captured in our Capital budget.[3]

- How will the new rules concerning ground voltage in the agricultural community impact Hydro One? You will be more affected than any other utility and this will be a very technically complex area involving significant amounts of analysis time.

  This is very new. The government has directed the OEB to examine this issue. To date no new standards have been announced so it is difficult to gauge the impact on us or be precise about how we should modify existing programs. Hydro One is working closely with the Ontario Federation of

[3] George Juhn provided further detail to this stakeholder after the session was adjourned.

Agriculture on this, and we both expect to work with the OEB and Electrical Safety Authority (ESA) on this issue.

- We have seen quartile benchmarking on reliability. Can you benchmark reliability spending in the same way, so that we could compare money spent against results achieved with respect to reliability?

  Some high level cost studies have been done but inconsistencies (e.g., in cost accounting and reliability definitions) make it difficult to draw conclusions about the relationship between spending and reliability across the industry.

2.8 Shared Services and Other (OM&A and Capital)

Ian Innis (Acting Director, Corporate Planning and Regulatory Finance) provided an overview of OM&A and Capital expenditures associated with the Shared Services and Other category of Hydro One's business. These are common costs that relate to the asset management function and shared services (Common Corporate and Information Management) that support both Transmission and Distribution. There are economies of scale and efficiencies associated with the sharing of expertise and resources by both Transmission and Distribution. Three key factors will drive the Shared Services OM&A and Capital requirements. These include the cascading effect of increased work programs as outlined earlier by George Juhn, new policy-based processes (such as Bill 198 and Regulatory Compliance) and the end-of-life of common infrastructure. Ian provided a cost breakdown using actual 2006 expenditures. Increases needed in the Common and Other Capital category are due to end-of-life common infrastructure replacement, in particular the Cornerstone project which is required to address the replacement of core business systems.

The following questions were asked/points were clarified in ensuing discussion:

- Make clear in your filing exactly which and how the increased standards, codes and compliance requirements referred to in slides 2, 4 and 5 affect Distribution.

  Agreed. Hydro One will identify standards that affect Distribution.

- The IESO has just sent out a regulatory compliance notification to all transmission and distribution companies in the province. The majority of these requirements impact Transmission, but the IESO also identifies the compliance standards it believes Distribution companies are accountable for and asks for feedback.

2.9 Rate Change Overview

Ian Innis (Acting Director, Corporate Planning and Regulatory Finance) provided a summary of the 2008 Distribution Revenue Requirement. Hydro One is not conducting new "special" studies for the filing; rather the methodologies from studies previously accepted by the OEB are being applied with current data. While specific financial data are not yet available, the structure and information to be provided will be consistent with the previous Distribution filing. Ian discussed the financial parameters and assumptions in the 2008 filing, and compared their values to the 2006 approved values. Finally, he identified the factors that will contribute to an increase or provide an offset to the Distribution rate change.

The following questions were asked/points were clarified in ensuing discussion:

- With respect to the common corporate costs methodology (slide 2), will you be updating the cost drivers that actually do the allocation?

  Some drivers will be updated where relevant and appropriate, but for the most part they will be the same.

- Was it the OEB or the government that told you to get rid of the preferred equity (slide 3)?

  Our actual capital structure still contains a preferred equity component. However, for the purpose of determining our revenue requirement, we apply the deemed regulatory capital structure that is approved by the OEB, which no longer includes return on preferred equity.

2.10 Final Comments

A final discussion period followed the conclusion of the presentations. The following questions were asked:

- With respect to the capital program and work prioritization, please provide a justification in the Distribution filing for the programs that you are proposing to undertake. In the Transmission submission, there were a few large projects, which were undertaken because the IESO or the OPA said they were needed. On the distribution side, if a project is demand-driven (e.g., a subdivision or other new connects) the need is understandable. But there will likely be many more potential projects that you will have to prioritize. Explain why you chose one portfolio of projects over another.

  The pre-filed evidence will provide individual Investment Justification documentation for capital projects equal to or greater than $1M, which include summaries of project needs and results.

- How do you decide whether a generation connection point goes into the distribution or transmission system?

  There are many variables but size is the key determinant. Typically, if above 20 MW it will be connected directly to the Transmission system.

- It would be helpful for us to know if Hydro One did the work, which was approved as part of the last Distribution filing.

  Hydro One will provide actual 2006 expenditures within its pre-filed evidence thereby enabling comparisons to the OEB approved 2006 revenue requirement.

3. NEXT STEPS

The following next steps were agreed to at the conclusion of the session.

- The report on this stakeholder consultation session will be posted on Hydro One's 2008 Distribution rate application website. There is a web consultation that parallels the stakeholder sessions. Stakeholders can go to the website to download the notes and the presentations, and to submit feedback.
- Hydro One requested any additional comments be forwarded by email to Enza Cancilla (Manager, Public Affairs) at enza.cancilla@HydroOne.com. Stakeholders may also forward comments to other Hydro One staff present at the stakeholder sessions, or provide comments via the website.
- There will be two more stakeholder sessions:
  - Stakeholder Session 2 will be a one or two-day session planned for early September 2007. At the session, the principles of Cost Allocation and Rate Design will be discussed, but the specific rates will not be available. However, stakeholders will have the Revenue Requirement numbers submitted to the OEB on August 15, 2007; and,
  - Stakeholder Session 3 will be the final 1-day session planned for mid-October 2007. The meeting topics will include the numbers on Cost Allocation and Rate Design.

Susan Frank thanked all participants for attending the session and providing their input. Hydro One has received many good comments that will help it submit a better filing. She invited all participants to attend Stakeholder Session 2 in September and reminded them that Hydro One would like their help with incentive regulation through participation in the stakeholder Incentive Regulation Working Group over the next few months.

Chris Haussmann then adjourned Stakeholder Session 1.

Stakeholder Consultation

2008 Distribution Rate Application

Stakeholder Session #1
Metropolitan Hotel
Mandarin Ballroom, Lower Level
108 Chestnut Street, Toronto
July 18, 2007

Registration and Continental Breakfast start at 8:00 a.m.

AGENDA

8:30 a.m.	Introductions and Process Overview	Chris Haussmann, Facilitator, Haussmann Consulting Inc.
8:45	Welcome	Susan Frank, Vice President & Chief Regulatory Officer
9:00	Hydro One Business Strategy / Q&A	Laura Formusa, President & CEO (Acting)
9:45	Application Overview	Joe Toneguzzo, Director, Distribution Rate Filing
10:15	**BREAK**	
10:30	Benchmarking, Reliability and Service Quality	Carm Altomare, Manager, Performance Analysis
11:30	Hydro One Distribution Incentive Regulation Proposal for 2009/2010	Andy Poray, Director, Regulatory Policy AND John Todd, President, Elenchus Research Associates
12:00 p.m.	**LUNCH**	
1:00 p.m.	Major Investment Programs and Key Drivers (OM&A and Capital)	George Juhn, Manager, Distribution Development & Lines Sustainment AND Rick Stevens, Director, Smart Meter Project
2:30 p.m.	Shared Services 2008 Revenue Requirement Summary	Ian Innis, Director, Corporate Planning & Regulatory Finance
3:00	Discussion	All
3:30	Next Steps and Wrap-up	Chris Haussmann
3:45	Thank you & Adjourn	Susan Frank

ATTACHMENT #1

Stakeholder Consultation

2008 Distribution Rate Application

Stakeholder Consultation 2006 Distribution Rate Application Metropolitan Hotel – Jul 18, 2008 PARTICIPANT LIST	
Stakeholder Organization	**Name**
City of Timmins	Peter Scully
Energy Probe	Tom Adams
Essex Power	Ray Tracey
Federation of Ontario Cottage Association	John McGee
Grimsby Power Inc.	Brian Weber
Innisfil Hydro Distribution Systems Ltd.	Laurie Ann Cooledge
Ontario Power Generation Inc	Tony Petrella
Power Workers' Union	Bayu Kidane
Pollution Probe	Jack Gibbons
Society of Energy Professionals	Richard Long
Union of Ontario Indians	Al Dokis
Vulnerable Energy Consumers Coalition	Bill Harper
Vulnerable Energy Consumers Coalition	Michael Buonigur o
Hydro One Networks Inc.	**Name**
Acting President & CEO	Laura Formusa
Vice President & Chief Regulatory Officer	Susan Frank
Director, Distribution Rate Filing	Joe Toneguzzo
Manager, Performance Analysis	Carm Altomare
Director, Regulatory Policy	Andy Poray
Manager, Customer Care	Barb Allen
Director, Smart Meter Project	Rick Stevens
Manager, Distribution Development & Lines Sustainment	George Juhn
Director, Corporate Accounting, Policies & Systems	Ian Innis
Senior Advisor, Distribution Regulation	Bohdan Dumka
Manager, Public Affairs	Enza Cancilla
Manager, Transmission Rates	Henry Andre
Manager, Customer Support	Jim Patterson
Director, Supply Connections	Mark Graham
Hydro One Networks Inc. Consultants	**Name**
President, Elenchus Research Associates	John Todd
Facilitator, Haussmann Consulting Inc.	Chris Haussmann
Rapporteur, Haussmann Consulting Inc.	Glynn Gomes
Rapporteur, Haussmann Consulting Inc.	Peter Mueller

SUMMARY OF BOARD DIRECTIVES AND UNDERTAKINGS FROM PREVIOUS PROCEEDINGS

This exhibit identifies Board directives to Hydro One Distribution from its previous rates proceedings. Table 1 lists the directives and indicates the Exhibit number in this application in which the evidence responds to the Board directives, or provides the response itself.

Table 1
Directives from Proceeding RP-2005-0020/EB-2005-0378 (2006 Distribution Rates)

Item #	Issue	Summary of Directive	Reference Exhibit
(i)	CDM	The Board expects Hydro One to provide a more sound analysis of CDM program details and reduction objectives in future applications. (2.3.9) **Response Note - Hydro One will take guidance on planned reductions and funding from OPA based programs.**	Exhibit A, Tab 14, Schedule 3, Section 2.6
		The Board expects Hydro One to present future CDM load reduction forecasts with a bottom-up analysis estimating the expected results of their CDM activities and those of others that affect their loads. The Board expects Hydro One's next CDM load reduction forecast, of this order of magnitude, to include a proposal for an LRAM. (2.3.13) **Response Note - Hydro One has concerns with the practical difficulties and related accuracy of determining the actual amount of CDM savings achieved by its customers in a given year, through the implementation of CDM initiatives from various sources such as the Ontario Power Authority, Provincial Government and Federal Government. Hydro One believes it is prudent to wait for the OPA to develop Measurement and Verification programs for determining actual CDM achievements and as such is not proposing or requesting an LRAM at this time.**	Exhibit A, Tab 14, Schedule 3, Section 4.0

Item #	Issue	Summary of Directive	Reference Exhibit
(ii)	Compensation	The Board has noted in this proceeding that since the de-merger on Ontario Hydro, Hydro One has taken a number of steps to control its overall compensation costs …. These are positive steps and the Board expects the company to continue and enhance such efforts in the future and report to the Board at the next main rates case. The Board is particularly concerned about the apparently high labour rates. In this respect, the Board expects Hydro One to identify what steps the company has taken or will take to reduce labour rates. (3.4.3)	Exhibit C1, Tab 3, Schedule 2
		The Board will not make an adjustment to the proposed OM&A costs based on compensation levels at this time but expects the utility to demonstrate in the future that lower compensation costs per employee have been achieved or demonstrate concrete initiatives whereby compensation costs will be brought more in line with other utilities. (3.4.5)	Exhibit C1, Tab 3, Schedule 2
		The Board expects Hydro One to file appropriate evidence in the next main rates case to establish that none of the incentive compensation should be charged to the shareholder. (3.4.6)	Exhibit C1, Tab 3, Schedule 2
(iii)	Benchmarking	While the Board is not prepared to order a comprehensive benchmarking study, the Board sees value in a high level benchmarking study for initial review at the next rate proceeding. The Board directs Hydro One to engage an independent party to develop a list of comparable North American companies with similar business models (transmission and/or distribution) and to report on high level comparative performance and cost information for Hydro One and these companies. In future rate cases, this information may assist with determination of areas for a more comprehensive benchmarking review. The Board does not anticipate that the high level benchmarking study will be overly costly. Hydro One will want to consult with intervenors regarding the scope of the study. The independent study should be submitted as part of Hydro One's next main application for distribution rates. (3.5.6)	Exhibit A, Tab 15, Schedule 2 Exhibit A, Tab 16, Schedule 1
		In addition, the Board directs Hydro One to engage an independent party to develop a comparison of labour rates and overtime policies amongst Hydro One, other comparative Ontario electricity distributors and other Canadian utilities as identified in the high level benchmarking study. This independent study should also be submitted as part of Hydro One's next main applications for distribution and transmission rates. (3.5.7)	Exhibit A, Tab 15, Schedule 2

(iv)	Spending on Line Losses	The Board does accept the submissions of intervenors regarding the expected benefits of the $4.75 million expenditure and directs Hydro One to include in its next main rates case filing a budget and a work plan to implement all the cost-effective line-loss reduction suggestions contained within the Kinetrics study. If Hydro One concludes that any of the recommendations in the Kinetrics study should not be implemented, it must clearly demonstrate the reasons for that position, and an accompanying budget and work plan for its preferred implementation plan. (4.3.10)	Exhibit A, Tab 15, Schedule 3
(v)	AFUDC	The Board therefore directs Hydro One to recalculate the AFUDC using a rate of 6.2%, which is the Company's blended long-term debt rate. (4.4.4) ***The AFUDC rate to be used by LDCs is currently prescribed under the Board-approved interest rate methodology (EB-2006-0117)***	Exhibit D1, Tab 4, Schedule 1
(vi)	Deferral Accounts – Pension Costs, MEU Rate Mitigation	The Board directs Hydro One to recalculate the interest using 3.88% instead of 7.71%. (6.2.3) The Board directs Hydro One to recalculate the interest using 5.75% instead of 7.71%. (6.2.7) ***Deferral Account interest rates now prescribed under the Board-approved interest rate methodology (EB-2006-0117)***	Exhibit F1, Tab 1, Schedule 1
(vii)	Line Loss Factors	The Board is of the view that either a less expensive metering program, or a second effort to evaluate line losses using current load data and local experience, may provide loss factor estimates that are more acceptable and credible to stakeholders. (7.3.10)	Exhibit A, Tab 15, Schedule 3
		The Board expects Hydro One to continue its efforts to refine line loss factors as they affect the bills of individual LV customers. (7.3.12)	Exhibit G1, Tab 10, Schedule 1, Section 1.1

Board Directives from Proceeding EB-2005-0528 (Rates for Distributed Generation)

Item #	Issue	Summary of Directive	Reference Exhibit
(i)	Rates for Distributed Generation	The Board therefore directs the Company as part of its upcoming cost allocation review filing to properly identify the costs for serving the proposed new rate classification (s), Following this, the Board will expect the Company to come forward with an updated rate design proposal for distributed generators that also considers the benefits that these customers provide.	Exhibit G2, Tab 1, Schedule 1 Section 4.0

Board Directives from Proceeding EB-2006-0501 (2007 and 2008 Electricity Transmission Revenue Requirements)

Item #	Issue	Summary of Directive	Reference Exhibit
(i)	Benchmarking	The PA study filed in this Application suffered from various deficiencies and shortcomings, as noted by the authors of the study, the Applicant and the intervenors. The Board expects the new study to be comprehensive and reliable, with none of the limitations of the PA study. If Hydro One cannot correct all of these deficiencies in time for the Company's 2008 Distribution rate filing, the Board expects them to be corrected in the 2009 transmission filing. (Page 33 of Decision with Reasons)	Exhibit A, Tab 15, Schedule 2 Attachments A and B.
(ii)	Reduction in CDM Forecast	The Board finds that Hydro One should reduce the expected impact of CDM on total Ontario peak demand by 350 MW. (Page 92 of Decision with Reasons)	Exhibit A, Tab 14, Schedule 3, Section 2.6

Directive in Letter from the Board dated October 29, 2007 Re: Ontario Uniform Transmission Rate Order, EB-2007-0759

Item #	Issue	Summary of Directive	Reference Exhibit
(i)	Retail Transmission Rates and Associated Variance Accounts	The Board directs each distributor to propose an adjustment to their retail transmission rates and disposition of the associated variance account balances in its 2008 Cost of Service or Incentive Rate Mechanism application, as applicable. The Board notes that resetting these rates should take into consideration the reduction in the wholesale transmission rates and the pattern of variance in the accounts.	Exhibit G1, Tab 6, Schedule 1 and Exhibit F1, Tab 1, Schedule 1.

Board Directives from Proceeding EB-2007-0063 (Combined Smart Meter Proceeding)

Item #	Issue	Summary of Directive	Reference Exhibit
(i)	Recovery of Smart Meter Costs Incurred to Date	The Board will allow each utility to recover its costs as set out Appendix "A" by including those costs in rate base for the 2006 and 2007 rate years and calculating a revenue requirement on that investment in the manner set out in Appendix "E". Before calculating a rate increase from this revenue requirement, however, the utility must first deduct the amount of money previously collected in rate adders pursuant to the Orders of March 21, 2006. (Page 18 of Decision with Reasons)	Exhibit F1, Tab 1, Schedule 1, Section 2.3
(ii)	Recovery of Project Management Costs Incurred to Date	The Board will allow half of Hydro One's project management costs incurred to date with an invitation to Hydro One to apply for the remaining amount with further and better evidence to justify the prudence of this cost at the time of its 2008 rate application.	Exhibit F1, Tab 1, Schedule 1, Section 2.5

PROCEDURAL ORDERS, CORRESPONDENCE, NOTICES

To be filed behind this tab as and when Procedural Orders, correspondence, Notices are filed.

LIST OF WITNESSES

PANEL ONE (tentative hearing dates - July 7, 8 & 10, 2008) **Application Overview,** **OM&A and Capital: Shared Services,** **Customer Care Programs, Rate Base, Revenue Requirement**
Witnesses: Ian Innis**,** Mark Fukuzawa, Sandy Struthers, Greg Van Dusen
Issues 3.3 Is the proposed level of 2008 Shared Services and Other O&M spending appropriate? 3.4 Are the methodologies used to allocate Shared Services and Other O&M costs to the distribution business for 2008 appropriate? 4.1 Are the amounts proposed for Rate Base appropriate? 4.6 Is the proposed level of 2008 Shared Services and Other Capital expenditures appropriate? 4.7 Are the methodologies used to allocate Shared Services and Other Capital expenditures to the distribution business consistent with the methodology approved by the Board in previous Hydro One rate applications?
Pre-filed Evidence A-1-1 Application A-2-1 Summary of Application A-2-2 Financial Summary C1-2-5 Customer Care OM&A C1-2-6 Shared Services and Other OM&A C1-5-1 Common Corporate Costs C1-5-3 Common Asset Allocation D1-1-1 Rate Base D1-1-4 Materials and Supply Inventory D1-3-5 Shared Service and Other Capital D2-1-1 Statement of Utility Rate Base D2-3-1 Continuity of Property , Plant and Equipment D2-3-3 Continuity of Construction Work In Progress E1-1-1 Revenue Requirement
Interrogatory Responses H-1-1, H-1-2, H-1-3, H-1-4, H-1-5, H-1-6, H-1-9, H-1-10, H-1-11, H-1-12, H-1-13, H-1-16, H-1-19, H-1-29, H-1-30, H-1-31, H-1-32, H-1-33, H-1-37, H-1-39, H-1-41, H-1-42, H-1-56, H-1-65, H-1-66, H-1-67, H-1-68, H-1-78, H-1-81, H-1-82, H-1-83, H-1-84, H-1-85, H-1-86, H-1-87, H-1-89, H-1-90, H-1-91, H-7-12, H-7-13, H-7-14, H-7-25, H-7-26, H-10-13, H-10-14, H-10-15, H-11-16, H-11-19, H-11-20, H-11-21, H-11-29, H-12-17, H-12-18, H-12-19, H-12-23, H-13-14, H-13-15, H-13-16, H-13-17, H-13-18, H-13-20, H-13-21, H-13-22, H-13-23, H-13-24, H-13-25, H-13-26, H-13-27

Filed: June 25, 2008
EB-2007-0681
Exhibit A
Tab 19
Schedule 1

PANEL TWO (tentative hearing dates - July 11, 14 & 15, 2008) **OM&A and Capital: Sustainment, Development and Operations, Smart Meters**
Witnesses: Mark Graham, Jack Coulis, George Juhn, Rick Stevens
Issues 3.1 Are the overall levels of the 2008 Operation, Maintenance and Administration budgets appropriate? 3.2 Is the 2008 vegetation management budget appropriate? 4.2 Are the amounts proposed for 2008 Capital Expenditures appropriate? 4.3 Are the 2008 sustaining capital expenditures proposed for Asset Replacement appropriate? 4.4 Are the 2008 amounts proposed for Development capital appropriate? 4.5 Is the 2008 budget for storm related capital expenditures appropriate? 8.1 Is the 2008 smart meter O&M budget appropriate? 8.2 Is the proposed 2008 capital spending for the Smart Meter program appropriate?
Pre-filed Evidence A-3-1 Summary of Distribution Business A14-4 Project and Program Approval and Control A-14-5 Work Program Prioritization C1-1-1 Cost of Service Summary C1-2-1 Summary of OM&A Expenses C1-2-2 Sustaining OM&A C1-2-3 Development OM&A C1-2-4 Operations OM&A C2-1-1 Cost of Service C2-2-1 Comparison of OM&A Expense by Major Category D1-1-2 Distributions Assets D1-3-1 Summary of Capital Expenditures D1-3-2 Sustaining Capital D1-3-3 Development Capital D1-3-4 Operations Capital D2-2-1 Comparison of Capital Expenditures – Historic, Bridge Year and Test Year D2-2-2 List of Capital Expenditure Programs/Projects in excess of $1M D2-2-3 Justification for Programs/Projects in excess of $1M

PANEL TWO (tentative hearing dates - July 11, 14 & 15, 2008) **OM&A and Capital: Sustainment, Development and Operations, Smart Meters**
Witnesses: Mark Graham, Jack Coulis, George Juhn, Rick Stevens
Interrogatory Responses H-1-7, H-1-8, H-1-14, H-1-15, H-1-18, H-1-19, H-1-20, H-1-21, H-1-22, H-1-23, H-1-24, H-1-25, H-1-26, H-1-27, H-1-28, H-1-34, H-1-35, H-1-36, H-1-40, H-1-49, H-1-50, H-1-51, H-1-52, H-1-55, H-1-56, H-1-57, H-1-59, H-1-60, H-1-61, H-1-62, H-1-63, H-1-64, H-1-80, H-1-126, H-1-127, H-3-3, H-6-2, H-6-3, H-6-4, H-7-1, H-7-2, H-7-4, H-7-5, H-7-6, H-7-7, H-7-8, H-7-9, H-7-10, H-7-11, H-7-15, H-7-16, H-7-24, H-7-32, H-10-10, H-10-11, H-10-12, H-10-16, H-10-17, H-10-21, H-10-22, H-10-27, H-10-28, H-10-29, H-10-31, H-10-32, H-11-15, H-11-17, H-11-18, H-11-22, H-11-23, H-11-24, H-11-25, H-11-26, H-11-27, H-12-15, H-12-16, H-12-26, H-12-27, H-12-28, H-12-29, H-12-30, H-12-35, H-12-36, H-13-2, H-13-3, H-13-4, H-13-5, H-13-6, H-13-7, H-13-8, H-13-9, H-13-10, H-13-11, H-13-12, H-13-13, H-13-17, H-13-43, H-13-44, H-13-45, H-13-46, H-13-47, H-13-48

PANEL THREE (tentative hearing dates - July 17, 18 & 21, 2008)
Cost Efficiency, Compensation, Staff Resourcing, Cornerstone

Witnesses: Greg Van Dusen, David Curtis, Judy McKellar

Issues
1.1 Has Hydro One responded appropriately to all relevant Board directions from previous proceedings with respect to CDM and compensation?[1]
3.6 Are the 2008 Human Resources related costs (wages, salaries, benefits, incentive payments, labour productivity and pension costs) including employee levels, appropriate?

Note 1: With respect to Issue 1.1, Panel 3 is responsible for Board directives pertaining to compensation.

Pre-filed Evidence
A-15-2 Distribution Benchmarking Study (Attachment A – Comparison of Labour Rates and Overtime Policy Study)
A-17-1 Summary of OEB Directives and Undertakings from Previous Proceedings (limited to items in Table 1 pertaining to compensation)
C1-3-1 Corporate Staffing
C1-3-2 Compensation, Wages, Benefits
C1-4-1 Costing of Work
C1-4-2 Cost Efficiency
C2-3-1 Comparison of Wages and Salaries
D1-3-5 Shared Service and Other Capital (Sect. 2.4.1 - Cornerstone)
D2-2-3 Justification for Programs/Projects in excess of $1M (IT1 - Cornerstone)

Interrogatory Responses
H-1-37, H-1-38, H-1-69, H-1-70, H-1-71, H-1-72, H-1-73, H-1-74, H-1-75, H-1-76, H-1-77, H-1-78, H-1-79, H-1-88, H-7-3, H-7-27, H-10-18, H-10-23, H-10-24, H-11-28, H-12-20, H-12-21, H-12-22, H-12-31, H-13-1, H-13-26, H-13-31, H-13-33, H-13-34, H-13-35, H-13-32, H-13-36

PANEL FOUR (tentative hearing dates - July 22, 24, 25, 28 & 29, 2008) **Cost Allocation, Rate Design, Load Forecast and CDM, Regulatory Assets**
Witnesses: Mike Roger, Stanley But, Ian Innis
Issues 1.1 Has Hydro One responded appropriately to all relevant Board directions from previous proceedings with respect to CDM and compensation?[2] 1.5 Have the impact of Conservation and Demand Management initiatives been suitably reflected in the load forecast? Is Hydro One's load forecast compatible with OPA's load forecast? Is an LRAM appropriate at this time? 3.10 Is the level of Hydro One initiated and or delivered CDM activity and budget appropriate and should it be funded by OPA or in rates? 5.3 Is the proposed accounting treatment of non utility revenue and expenditures associated with OPA funded CDM appropriate? 6.1 Is the proposal for the amounts, disposition and continuance of Hydro One's existing Deferral and Variance Accounts (Regulatory Assets) appropriate? 6.2 Is the proposal to establish new Deferral and Variance Accounts appropriate? 7.1 Are Hydro One's proposed new Customer Rate Classes appropriate? 7.2 Is Hydro One's cost allocation appropriate? 7.3 Are Hydro One's proposed rates appropriate? 7.4 Are the proposed revenue to cost ratios appropriate? 7.5 Are the fixed-variable splits for each class appropriate? 7.6 Is Hydro One's proposal to have both fixed and variable service charges for sub-transmission customers, appropriate? 7.7 Is the proposal for harmonization of rates appropriate? 7.8 Are the customer bill impacts resulting from the proposed rate impact mitigation plan reasonable? 7.10 Is the proposal for regulatory asset rate rider #3 appropriate? 8.3 Are the amounts for Smart Meter related variance accounts appropriate? 8.5 Is Hydro One's regulatory treatment of Smart Meter costs appropriate? *Note 2: With respect to Issue 1.1, Panel 4 is responsible for Board directives pertaining to CDM.*
Pre-filed Evidence A-13-1 Summary of Initiatives Based on Legislative Changes A-14-3 Distribution Business Load Forecast and Methodology (limited to incorporation of CDM in the load forecast, load forecast methodology has been settled) A-16-1 Stakeholder Consultation Report A-17-1 Summary of OEB Directives and Undertakings from Previous Proceedings (limited to items in Table 1 pertaining to CDM) F1-1-1 Regulatory Assets F1-2-1 Planned Deposition of Regulatory Assets F1-3-1 Variance Account Requested

PANEL FOUR (tentative hearing dates - July 22, 24, 25, 28 & 29, 2008) **Cost Allocation, Rate Design, Load Forecast and CDM, Regulatory Assets**
Witnesses: Mike Roger, Stanley But, Ian Innis
F2-1-1 Regulatory Assets for Approval F2-2-1 Schedule of Annual Recoveries G1-1-1 to G2-95-1 excluding exhibits related to settled Issues; G1-6-1 Retail Transmission Service Rates, G1-10-1 Total Loss Factors and G2-4-1 Retail Transmission Service Rates Details
Interrogatory Responses H-1-101, H-1-102, H-1-104, H-1-105, H-1-106, H-1-113, H-1-114, H-1-115, H-1-116, H-1-117, H-1-118, H-1-119, H-1-120, H-1-121, H-1-122, H-1-123, H-1-124, H-1-125, H-1-128, H-1-129, H-1-130, H-1-131, H-1-132, H-1-133, H-1-134, H-1-135, H-1-136, H-1-137, H-1-138, H-1-139, H-1-140, H-1-141, H-1-142, H-1-143, H-1-144, H-1-145, H-1-146, H-1-147, H-1-148, H-1-149, H-1-150, H-1-151, H-1-152, H-1-153, H-1-154, H-1-155, H-1-156, H-1-157, H-1-158, H-2-1, H-2-2, H-2-5, H-2-6, H-2-7, H-2-8, H-2-9, H-2-10, H-2-11, H-2-12, H-2-13, H-2-14, H-2-15, H-2-16, H-2-17, H-2-18, H-2-19, H-2-20, H-2-21, H-2-22, H-2-23, H-2-24, H-2-25, H-3-1, H-3-2, H-3-4, H-4-1, H-4-2, H-4-3, H-4-4, H-4-5, H-4-6, H-4-7, H-4-8, H-4-9, H-4-10, H-5-2, H-7-20, H-7-28, H-7-29, H-7-30, H-7-31, H-8-1, H-8-2, H-8-3, H-8-4, H-8-5, H-8-6, H-8-7, H-8-8, H-8-9, H-8-10, H-8-11, H-8-12, H-9-1, H-9-2, H-9-3, H-9-4, H-9-5, H-9-6, H-9-7, H-9-8, H-9-9, H-9-10, H-9-11, H-9-12, H-9-13, H-9-14, H-9-15, H-10-1, H-10-4, H-10-5, H-10-6, H-10-20, H-10-28, H-10-30, H-10-33, H-10-34, H-10-35, H-10-36, H-10-37, H-10-38, H-10-39, H-10-40, H-10-41, H-10-42, H-10-43, H-10-44, H-10-45, H-11-5, H-11-6, H-11-7, H-11-30, H-11-31, H-11-32, H-11-33, H-11-34, H-11-35, H-11-36, H-11-37, H-11-38, H-11-39, H-11-40, H-11-41, H-12-4, H-12-5, H-12-7, H-12-37, H-12-38, H-12-39, H-12-40, H-12-41, H-12-42, H-12-43, H-12-44, H-12-45, H-12-46, H-12-47, H-12-48, H-12-49, H-12-50, H-12-51, H-12-52, H-12-53, H-12-54, H-12-55, H-12-56, H-12-57, H-12-58, H-12-59, H-12-60, H-12-61, H-12-62, H-12-63, H-12-64, H-12-66, H-12-67, H-12-68, H-12-69, H-12-70, H-12-71, H-12-72, H-12-73, H-12-74, H-12-75, H-12-76, H-12-77, H-12-78, H-12-79, H-12-80, H-12-81, H-12-82, H-12-83, H-13-38, H-13-41, H-13-49, H-13-52, H-13-53, H-13-54, H-13-55, H-13-56, H-13-57, H-13-58, H-13-59, H-13-60, H-13-61, H-13-62, H-13-63, H-13-64, H-13-65, H-13-66

CURRICULUM VITAE OF STANLEY BUT

EDUCATION:

York University, Toronto, Ontario (1981-1983)
Completed course requirements for Master of Arts in Economics

York University, Toronto, Ontario (1980)
Master of Business Administration

York University, Toronto, Ontario (1979)
Honours Bachelor of Arts in Economics

INDUSTRY EXPERIENCE:

1999 – Present:	Hydro One Networks Inc. / Ontario Hydro Services Company
1986 – 1999:	Ontario Hydro
1980 – 1986:	Ontario Government

2002-Present	Manager, Economics & Load Forecasting
1999-2002	Senior Advisor, Load Forecasts
1993-1999	Team Lead/Senior Energy Economist, Corporate Finance
1989-1993	Senior Economist, Economics & Forecasts Division
1986- 1989	Economist, Economics & Forecasts Division
1985- 1986	Senior Economist, Ontario Manpower Commission, Ontario Ministry of Skills Development
1984- 1985	Senior Economist, Ontario Task Force on Employment and New Technology, Ontario Ministry of Labour
1980-1984	Research Economist, Ontario Manpower Commission, Ontario Ministry of Labour

APPEARANCE(S) BEFORE THE ONTARIO ENERGY BOARD:

EB-2005-0378:	Hydro One Networks Inc. Distribution 2006 Rate Application
EB-2006-0501:	Hydro One Networks Inc. 2007-2008 Electricity Transmission Revenue Requirement Application

CURRICULUM VITAE OF
CLIFFORD JOHN (Jack) COULIS

EDUCATION:

Secondary Diploma

BUSINESS EXPERIENCE:

2001 – Present:	Hydro One Networks Inc.
1999 – 2001:	Ontario Hydro Services Company
1974 – 1999:	Ontario Hydro

2005 – Present:	Director, Forestry Services
2000 – 2005:	Director, Hydro One Remote Communities
1999 – 2000:	Manager, Customer Service - Northern Territory
1997 – 1999:	Manager, Operations – Kenora & Fort Frances Operations Centers
1996 – 1997:	Manager, Operations – Kenora Operations Center
1994 – 1996:	Supervisor, Customer Operations – Kenora Operations Center
1990 – 1994:	Area Distribution Technician – Kenora Operations Center
1978 – 1990:	Powerline Maintainer, Journeyperson
1974 – 1978:	Powerline Maintainer, Apprentice

**CURRICULUM VITAE OF
DAVID B. CURTIS**

EDUCATION:

McMaster University, Hamilton, Ontario (1978)
Masters of Business Administration (Co-operative) - Operations Research and Finance

State University of New York, Stony Brook, New York (1974)
Masters (Nuclear Physics)

McMaster University, Hamilton, Ontario (1972)
Bachelor of Science (Physics)

BUSINESS EXPERIENCE:

2001 – Present:	Hydro One Networks Inc.
1999 – 2001:	Ontario Hydro Services Company
1978 – 1999:	Ontario Hydro

2005 – Present:	Director, Business Transformation
2001 – 2005:	Director, Transmission Regulation
1998 – 2001:	Manager, Transmission Regulation
1997 – 1998:	Manager, Strategic Planning and Programming
1996 – 1997:	Section Head, Strategy & Regulatory Affairs
1994 – 1996:	Section Head, Grid System Strategies and Plans
1993 – 1994:	Supervising Resource Planner, Grid System Strategies and Plans
1992 – 1993:	Senior Advisor, Executive Office
1988 – 1992:	Senior Planner, Power System Planning Division
1984 - 1988:	Supervising Engineer, Power System Operations Division
1980 – 1984:	Technical Officer, Power System Operations Division
1978 – 1980:	Assistant Technical Supervisor, Nuclear Generation Division

APPEARANCES BEFORE THE ONTARIO ENERGY BOARD:

RP-1998-0001	Transmission and Distribution Transitional Rates
RP-1999-0044	Transmission Cost Allocation Rate Design

APPEARANCE BEFORE THE ONTARIO LABOUR RELATIONS BOARD:

File # 2954-05-R	Labours International Union of North America

CURRICULUM VITAE OF
MARK FUKUZAWA

EDUCATION:

Schulich School of Business, York University, Toronto, Ontario (1999)
Masters of Business Administration

University of Western Ontario, London, Ontario (1988)
Honours Bachelor of Science (Geo-Physics)

BUSINESS EXPERIENCE:

1999 – Present:	Hydro One Networks
1988 – 1999:	Ontario Hydro

2005 – Present:	Director, Customer Care
2001 – 2004:	Manager, Strategy and Business Planning
1999 – 2001:	Manager, Business Operations
1996 – 1998:	Manager, Integrated Technology Management Centre
1993 – 1995:	IT Customer Service Centre Administrator
1989 – 1992:	Network Analyst
1988 – 1989:	Assistant Business Systems Supervisor

APPEARANCE(S) BEFORE THE ONTARIO ENERGY BOARD:

EB-2005-0378:	Hydro One Networks Inc. Distribution Rate Application for 2006

CURRICULUM VITAE OF
MARK C. GRAHAM

EDUCATION:

University of Waterloo, Waterloo, Ontario
Bachelor of Mathematics (Honours Co-operative, Computer Science and Statistics)

INDUSTRY EXPERIENCE:

April 1999 – Present:	Hydro One Networks Inc. / Ontario Hydro Services Company
1981 – 1999:	Ontario Hydro
1978 – 1981:	Bell Northern Research

2004 – Present:	Director, Supply Connections and Director, Investment Policy and Agreements, Asset Management
2004:	On secondment to Government of Ontario, Ministry of Energy
1999 – 2003:	Director, Transmission Business Development
1995 – 1999:	Director, Financial Planning and Performance (Acting) and Director, Policies and Standards, Transmission Network Asset Management
1993-1995:	Senior Adviser, Corporate Business Planning
1993:	Seconded to Task Force on Change
1991 – 1992:	Region Controller, Georgian Bay Region (Acting)
1984 – 1991:	Regions Branch Controller (various positions, ending as Section Head, Business Planning and Budgeting)
1981 – 1984:	Budget and Cost Analyst, Corporate Budgets Department
1978 – 1981:	Analyst, Bell Northern Research

CURRICULUM VITAE OF
IAN R. INNIS

EDUCATION

McMaster University, Hamilton, Ontario (1980)
Bachelor of Commerce (Finance and Accounting)

PROFESSIONAL REGISTRATION

Society of Management Accountants (1983) - Certified Management Accountant

INDUSTRY EXPERIENCE

April 1999 – Present:	Hydro One Networks Inc. / Ontario Hydro Services Company
1980 – April 1999:	Ontario Hydro

2007 – Present:	Director, Corporate Planning and Regulatory Finance (Acting), Corporate Finance
2001 – 2007:	Manager, Regulatory Finance, Corporate Finance
1998 – 2001:	Manager, Finance, Network Management
1997 – 1998:	Manager, Planning and Reporting, Transmission
1993 – 1997:	Financial Services Manager, Hydroelectric
1991 – 1993:	Senior Comptrollership Advisor, Procurement and Power System Planning
1989 – 1991:	Senior Internal Control Analyst, Corporate Comptrollers Division
1984 – 1989:	Senior Business Analyst, Comptrollers Department, Production Branch
1981 – 1984:	Asset Control Analyst, Corporate Accounting Division
1980 – 1981:	Finance Trainee, Corporate Accounting Division

APPEARANCE(S) BEFORE THE ONTARIO ENERGY BOARD

RP-2005-0020/ EB-2005-0378	Hydro One Networks Inc., 2006 Distribution Rate Application
EB-2006-0501:	Hydro One Networks Inc., 2007-2008 Transmission Revenue Requirement and Rate Application
EB-2007-0063:	Hydro One Networks Inc., Smart Meter Hearing

CURRICULUM VITAE OF GEORGE JUHN

EDUCATION:

University of Waterloo, Waterloo, Ontario (1982)
Bachelor of Science (Civil Engineering)

PROFESSIONAL REGISTRATION:

Professional Engineers Ontario, Toronto, Ontario (1990)

INDUSTRY EXPERIENCE:

1999 – Present:	Hydro One Networks
1990 – 1999:	Ontario Hydro
1989 – 1990:	LeBlanc & Royle Telecom Inc., Oakville, Ontario
1982 – 1989:	SaskPower, Regina, Saskatchewan

2007 – Present:	Manager, Distribution Development & Lines Sustainment System Investment Division, Asset Management
2004 – 2006:	Manager, Lines & ROW Programs System Investment Division, Asset Management
2000 – 2004:	Manager, Lines & ROW Sustainment Programs Investment Planning Division, Network Management
1998 – 2000:	Senior Analyst, Transmission Lines Sustainment Asset Sustainment Division Transmission Network Asset Management
1994 – 1998:	Transmission Lines Specialist Northeastern District, Sudbury
1990 – 1993:	Technical Services Engineer Transmission Lines Department HG&TO Division
1989 – 1990:	Design Engineer, LeBlanc & Royle Telecom Inc.
1983 – 1989:	Design Engineer, Transmission Line Design SaskPower
1982 – 1983:	Assistant Engineer, Power Production SaskPower

APPEARANCE(S) BEFORE THE ONTARIO ENERGY BOARD

RP-2005-0020/ EB-2005-0378:	Hydro One Networks Inc. Distribution 2006 Rate Application

CURRICULUM VITAE OF
JUDITH L. MCKELLAR

EDUCATION:

University of Toronto (Victoria College), Toronto, Ontario (1978)
Honours Bachelor Degree in Political Science

INDUSTRY EXPERIENCE:

1999 – Present:	Hydro One Networks Inc. / Ontario Hydro Services Company
1986 – 1999:	Ontario Hydro

2001 – Present:	Director, Human Resources
1997 – 2001:	Manager, Human Resources
1995 – 1997:	Divisional Human Resources Manager
1989 – 1995:	Branch Human Resources Officer
1987 – 1989:	Human Resources Officer
1984 – 1987:	Assistant Human Resources Officer
1982 – 1984:	Management and Professional Trainee

APPEARANCE(S) BEFORE THE ONTARIO ENERGY BOARD:

RP-2005-0020/ EB-2005-0378:	Hydro One Networks Inc. Distribution Rate Application for 2006
EB-2006-0501:	Hydro One Networks Inc. 2007-2008 Electricity Transmission Revenue requirement Application

CURRICULUM VITAE OF MICHAEL ROGER

EDUCATION:

Technion, Israel Institute of Technology, Haifa, Israel, (1975)
Bachelor of Science in Industrial and Management Engineering

University of Toronto, (1977)
Master of Business Administration, Specialized in Management Science, Data Processing and Finance.

INDUSTRY EXPERIENCE:

2002 – Present:	Hydro One Networks
1999 –2002:	Ontario Power Generation
1978 – 1999:	Ontario Hydro

2002 – Present:	Manager, Distribution Pricing
1999 – 2002:	Manager, Management Reporting and Decision Support
1998 – 1999:	Director, (acting), Financial Planning and Reporting
1997 – 1997:	Financial Advisor, Financial Planning and Reporting
1994 – 1995:	Section Head, Power Costing, Financial Planning and Reporting
1986 – 1997:	Section Head Pricing Implementation, Pricing
1983 – 1986:	Rate Economist, Rates
1980 – 1983:	Forecasting Analyst, Financial Forecasts
1979 – 1980:	Project Development Analyst, Financial Forecast
1978 – 1979:	Assistant Engineer Reliability Statistics, Hydroelectric Generation Services

APPEARANCE(S) BEFORE THE ONTARIO ENERGY BOARD:

HR 23:	1996 Ontario Hydro Rates
HR 24:	1997 Ontario Hydro Rates
RP-2004-0117/ RP-2004-0118:	Regulatory Asset Review
RP-2005-0020/ EB-2005-0378:	2006 Distribution Rates

CURRICULUM VITAE OF
RICHARD D. STEVENS

EDUCATION:

York University, Toronto, Ontario (on going)
Bachelor Degree (Business Administrative Studies)

Schulich School of Business, York University (2002)
Facilitative Leadership

Princeton, Risk Assessment and Trading in Electricity and Gas Industry (2001)
Risk Management

Schulich School of Business, York University (1999)
Acquisitions and Divestitures

Centennial College, Toronto, Ontario (1984)
Business Administration Programmer/ Analyst

Centennial College, Toronto, Ontario (1983)
General Business Data Processing

INDUSTRY EXPERIENCE:

1999 – Present:	Hydro One Networks Inc. / Ontario Hydro Services Company
1984 –1999:	Ontario Hydro

2005 – Present:	Project Director Smart/ Smart Network
2003 – 2004:	Project Director AMS / WEP
2001 – 2007:	Director Distribution Business Development
1998 – 2001:	Director Development Strategy
1998:	Senior Advisor, Business Strategy
1993 – 1997:	Marketing Supervisor, Customer Service (Retail Utilities)
1991 – 1993:	Customer Account Supervisor (Penetanguishene Area)
1989 – 1991:	Senior Business Analyst, Retail Service Department
1987 – 1989:	Financial Planning Analyst, Financial Planning Department
1984 – 1987:	Development Projects Analyst, Forecast Systems Development Department

APPEARANCE(S) BEFORE THE ONTARIO ENERGY BOARD:

EB-2007-0063: Combined Proceeding regarding Smart Meters

CURRICULUM VITAE OF
ALEXANDER (Sandy) STRUTHERS

EDUCATION:

Canadian Institute of Chartered Business Valuators, Toronto, Ontario (1995)
Chartered Business Valuator

Ontario Institute of Chartered Accountants, Toronto, Ontario (1985)
Chartered Accountant

York University, Toronto, Ontario (1985)
Masters of Business Administration

Queen's University, Kingston, Ontario (1981)
Bachelor of Commerce

INDUSTRY EXPERIENCE:

2000 – Present:	Hydro One Networks Inc. / Ontario Hydro Services Company
2005 – Present:	Chief Information Officer
2002 – 2004:	Director, Financial Strategy
2000 – 2001:	Director, Mergers & Acquisitions, Finance
1998 – 1999:	Partner, BDO Dunwoody LLP, Chartered Accountants Corporate Finance
1989 – 1997:	Price Waterhouse, Chartered Accountants Financial Advisory Services
1983 – 1988:	Cross & Bradbury, Chartered Accountants Accounting Services
1981 – 1982:	Thorne Riddell, Chartered Accountants Accounting Services

APPEARANCE(S) BEFORE THE ONTARIO ENERGY BOARD:

RP-2005-0020/ EB-2005-0378:	Hydro One Networks Inc. Distribution Rate Application for 2006
EB-2006-0501:	Hydro One Networks Inc. 2007-2008 Electricity Transmission Revenue requirement Application

CURRICULUM VITAE OF
GREGORY J. VAN DUSEN

EDUCATION:

York University, Toronto, Ontario (1981)
Masters of Business Administration – Management Sciences and Finance

York University, Toronto, Ontario (1978)
Honours B.A. – Mathematics Major and History Minor

INDUSTRY EXPERIENCE:

April, 1999 – Present: Hydro One Networks Inc. /Ontario Hydro Services Company
1981 – 1999: Ontario Hydro

2007 – Present:	Director, Business Integration
2006 – 2007:	Director, Corporate Planning and Regulatory Finance
2005 – 2006:	Acting Director, Regulatory Finance
2002 – 2006:	Director, Corporate Accounting Policies and Systems
2001 – 2002:	Director, Special Projects (Asset Mgmt Project)
1998 – 2000:	Manager, Regulation Finance
1997 – 1998:	Manager, Control / Financial Systems
1997 – 1997:	Team Leader, Planning & Reporting – Finance Div.
1996 – 1997:	Team Leader, Financial Planning – GRID System
1994 – 1996:	Senior Corporate Financial Analyst
1989 – 1994:	Senior Public Hearings Analyst
1986 – 1988:	Fuel Resources Officer
1985 – 1986:	Financial Forecasting Analyst
1982 – 1984:	Financial Projections Analyst
1981 – 1982:	Finance Branch Trainee

APPEARANCE(S) BEFORE THE ONTARIO ENERGY BOARD:

RP-1998-0001:	Transmission Performance Based Regulation Proposal
RP-2005-0020/ EB-2005-0378:	Hydro One Networks Inc. Distribution Rate Application for 2006
EB-2006-0501:	Hydro One Networks Inc. 2007-2008 Electricity Transmission Revenue requirement Application

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COST OF CAPITAL

1.0 INTRODUCTION

The purpose of this evidence is to summarize the method and cost of financing Hydro One Distribution's capital requirements for the 2008 test year.

2.0 CAPITAL STRUCTURE

Hydro One Distribution's deemed capital structure for rate making purposes is 60% debt and 40% common equity. This capital structure was determined by the Ontario Energy Board as being appropriate for all distributors in its December 20, 2006 Cost of Capital report.[1] Consistent with the Board's report, there is no adjustment for a preferred share component in rates as determined by the Board. The 60% debt component is comprised of 4% deemed short term debt and 56% long term debt.

3.0 RETURN ON COMMON EQUITY

Hydro One Distribution is requesting an equity return for the 2008 test year of 8.64% per the Board's formulaic approach in Appendix B of the Cost of Capital report. The return of 8.64% is based on the Long Canada Bond Forecast for 2008 using the May 2007 Consensus Forecast. In accordance with the Cost of Capital report, upon the final decision in this case, Hydro One assumes that the ROE will be adjusted using the January, 2008 Consensus Forecast.

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[1] *Report of the Board on Cost of Capital and 2nd Generation Incentive Regulation for Ontario's Electricity Distributors*, Ontario Energy Board (December 20th, 2006) [EB-2006-0088/EB-2006-0089]

4.0 DEEMED SHORT TERM DEBT

The Board has determined that the deemed amount of short-term debt that should be factored into rate setting be fixed at 4% of rate base, and that the deemed short-term debt rate be based on the forecast 3-month bankers' acceptance rate plus a fixed spread of 25 basis points. For 2008 the deemed short term rate is 4.74%, using the May 2007 Consensus Forecast. In accordance with the Cost of Capital report, upon the final decision in this case, Hydro One assumes that the deemed short term debt rate will be adjusted using the January, 2008 Consensus Forecast.

5.0 THIRD PARTY LONG TERM DEBT

The Distribution business' third party long term debt is $2,326 million for 2008. The effective cost of third party long term debt is calculated as the weighted average cost of embedded third party debt, new third party debt and forecast third party debt planned to be issued in 2007 and 2008. The weighted average cost of third party long term debt rate for 2008 is 5.71%. Details of Hydro One Distribution's long term debt portfolio for the 2008 test year are identified at Exhibit B2, Tab 1, Schedule 2, Page 5. A detailed discussion of the Hydro One Distribution's debt and forecast interest rate support is provided at Exhibit B1, Tab 2, Schedule 1. Historical long term debt cost information is filed at Exhibit B2, Tab 1, Schedule 2, pages 1 – 3, for the 2004 – 2006 period.

6.0 DEEMED LONG TERM DEBT

Deemed long term debt consists of the amount of any variable rate debt or affiliate debt callable on demand, as well as any remaining amount required to balance the total financing with the rate base. Consistent with the Board's Cost of Capital report, the deemed long term debt rate is to be applied to any variable rate debt and for any affiliate debt callable upon demand. The deemed long-term debt rate for 2008 is 5.69% based on the approach in Appendix A of the Cost of Capital report, using the May 2007 Consensus Forecast. In accordance with the Cost of Capital report, upon the final decision in this case, Hydro One assumes that the deemed long term debt rate will be adjusted using the January, 2008 Consensus Forecast.

7.0 COST OF CAPITAL SUMMARY

The overall capital incorporated in Hydro One Distribution's 2008 revenue is $4,382 million which results in an after tax required return on rate base of 6.84%.

2008 Cost of Capital

Particulars	$ Millions	%	Cost Rate (%)	Return ($M)
Third Party long-term debt	2,326	53.1	5.71	133
Deemed long-term debt	128	2.9	5.69	7
Deemed short-term debt	175	4.0	4.74	8
Common equity	1,753	40.0	8.64	151
Total	4,382	100.0	6.84	300

Historical, bridge and test year debt and equity summary schedules have been provided at Exhibit B2, Tab 1, Schedule 1.

COST OF THIRD PARTY LONG TERM DEBT

1.0 HYDRO ONE DISTRIBUTION LONG TERM DEBT

The debt portfolio for Hydro One Distribution, as set out in Exhibit B2, Tab 1, Schedule 2, is based on debt issued by Hydro One Networks Inc. to Hydro One Inc., of which the Distribution business is mapped a portion. Hydro One Networks Inc. has issued debt to Hydro One Inc., reflecting debt issued by Hydro One Inc. to third party public debt investors.

Third party public debt investors hold all of the long term debt issued by Hydro One Inc. Hydro One Inc.'s debt financing strategy takes into consideration the objectives of cost effectiveness, distributing debt maturities evenly over time, and ensuring the term of the debt portfolio is compatible with the long life of the Company's assets.

Hydro One Inc. has a Medium Term Note program that provides ready access to issue debt with a term greater than one year into the Canadian debt capital markets. The short form base shelf prospectus for the current $2.5 billion Medium Term Note program is provided in Exhibit A, Tab 11, Schedule 2. The standard maturity terms of 5, 10 and 30-years are preferred by investors and represent the main financing Hydro One utilizes to execute its financing strategy and raise the required funds.

2.0 CREDIT RATINGS

Hydro One Inc. issues medium term notes in the Canadian public debt markets, hence credit ratings are a requirement. The credit ratings of Hydro One Inc.'s debt obligations by Dominion Bond Rating Service, Moody's Investors Service and Standard & Poor's Rating Services are as follows:

Rating Agency	**Short-term Debt**	**Long-term Debt**
Standard & Poor's Rating Services (S&P)	A-1	A
Dominion Bond Rating Service (DBRS)	R-1(middle)	A(high)
Moody's Investors Service (Moody's)	Prime-1	Aa3

The most recent rating agency reports are provided in Exhibit A, Tab 11, Schedule 1.

3.0 COST OF THIRD PARTY LONG TERM DEBT

The Distribution business' third party long term debt is $2,326 million for 2008. The effective cost of third party long term debt is calculated as the weighted average cost of embedded third party debt, new third party debt and forecast third party debt planned to be issued in 2007 and 2008. This cost includes the amortization of issuance costs. The weighted average cost of third party long term debt rate for 2008 is 5.71%. Details of Hydro One Distribution's third party long term debt portfolio for the 2007 bridge year and 2008 test year are identified at Exhibit B2, Tab 1, Schedule 2, Pages 4 and 5.

The amount of each Hydro One Networks Inc. debt issue that is mapped to the Distribution business is based on its most recent forecast of borrowing requirements. Borrowing requirements are mainly driven by debt retirement, capital expenditures net of internally generated funds, and the maintenance of its capital structure. For example, in March 2007 Hydro One Inc. issued $400 million of 30 year notes with a coupon rate of 4.89%, of which $160 million was mapped to Hydro One Distribution as shown on line 21 of Exhibit B2, Tab 1, Schedule 2, Page 5. The interest rates of debt issues mapped to the Distribution business as shown in Exhibit B2, Tab 1, Schedule 2 are equal to the actual interest rates on debt issued by Hydro One Networks to Hydro One Inc., and by Hydro One Inc. to third party public debt investors.

3.1 Embedded Third Party Debt

The Board has determined in its Cost of Capital Report that for embedded debt, the rate approved in prior Board decisions shall be maintained for the life of each active instrument, unless a new rate is negotiated, in which case it will be treated as new debt. Hydro One Distribution's embedded third party long term debt, which was issued during the period from 2000 to 2005, is shown on lines 1 to 16 of Exhibit B2, Tab 1, Schedule 2, Page 5. The rates on these embedded debt issues were approved by the Board as part of RP-2005-0020.

3.2 New Third Party Debt

The Board has determined in its Cost of Capital Report that the rate for new debt that is held by a third party will be the prudently negotiated contract rate. This would include recognition of premiums and discounts. The following discusses new third party debt issued during 2006 and 2007, which are shown on lines 17 to 21 of Exhibit B2, Tab 1, Schedule 2, Page 5.

In March of 2006, Hydro One issued $300 million of 10-year notes with a 4.64% coupon rate of which $90 million was mapped to Hydro One Distribution as shown on line 17 of Exhibit B2, Tab 1, Schedule 2, Page 5.

In April of 2006, Hydro One Inc. issued $250 million of 30-year notes, of which $62.5 million was mapped to Hydro One Distribution as shown on line 18 of Exhibit B2, Tab 1, Schedule 2, Page 5. The offering was a re-opening of the 5.36% coupon bond originally issued in May 2005 bringing the total outstanding in that series to $600 million.

In August of 2006, Hydro One Inc. issued $150 million of 10-year notes with a 4.64% coupon rate, of which $90 million was mapped to Hydro One Distribution as shown on line 19 of Exhibit B2, Tab 1, Schedule 2, Page 5.

In October of 2006, Hydro One Inc. issued $75 million of 40-year notes with a 5.00% coupon rate, of which $45 million was mapped to Hydro One Distribution as shown on line 20 of Exhibit B2, Tab 1, Schedule 2, Page 5.

In March of 2007, Hydro One Inc. issued $400 million of 30-year notes with a 4.89% coupon rate, of which $160 million was mapped to Hydro One Distribution as shown on line 21 of Exhibit B2, Tab 1, Schedule 2, Page 5.

3.3 Forecast Third Party Debt

The issuance of 5, 10 and 30 year debt will be the main financing to meet Hydro One Distribution's forecast borrowing requirement of $205 million remaining for 2007 and $434 million for 2008. For planning purposes it is assumed that debt issuance will be evenly distributed over the standard 5, 10 and 30 year terms which are preferred by investors.

The following table lists the fixed rate medium term notes Hydro One Distribution plans to issue in 2007, as shown in lines 22 and 23 of Exhibit B2, Tab 1, Schedule 2, Page 5. The remainder of the third party debt to be issued during 2007 is assumed to be issued as 5 and 10 year debt, as a 30 year issue was completed during March 2007.

2007		
Principal Amount ($Millions)	**Term (Years)**	**Coupon**
102.5	5.5	4.47%
102.5	10	4.71%

The following table lists the fixed rate medium term notes Hydro One Distribution plans to issue in 2008, as shown on lines 24 to 26 of Exhibit B2, Tab 1, Schedule 2, Page 5.

2008		
Principal Amount ($Millions)	**Term (Years)**	**Coupon**
144.7	5.5	4.77%
144.7	10	5.01%
144.7	30	5.37%

3.4 Interest Rates for 2007 and 2008 Forecast Debt Issues

Distribution business borrowing will be financed at market rates applicable to Hydro One Inc. The following table summarizes the derivation of the forecast Hydro One Inc. yield for each of the planned issuance terms for 2007 and 2008.

	2007		**2008**		
	5-year	**10-year**	**5-year**	**10-year**	**30-year**
Government of Canada	4.13%	4.20%	4.43%	4.50%	4.55%
Hydro One Spread	0.34%	0.51%	0.34%	0.51%	0.82%
Forecast Hydro One Yield	4.47%	4.71%	4.77%	5.01%	5.37%

Each rate is comprised of the forecast Canada bond yield plus the Hydro One Inc. credit spread applicable to that term. The 10-year Government of Canada bond yield forecast for 2007 and 2008 is based on the May 2007 Consensus Forecasts. The 5 and 30-year Government of Canada bond yield forecasts are derived by adding the April 2007 average spreads (5-year to 10-year for the 5 year forecast and 30-year to 10-year for the 30-year forecast) to the 10-year Government of Canada bond yield forecast. This derivation is consistent with the Board's methodology in establishing the forecast of the

30-year Government of Canada yield, in the formula based return on common equity approach for regulated utilities. Consistent with this methodology, Hydro One's credit spreads over the Government of Canada bonds are based on the average of indicative new issue spreads for April 2007 obtained from our MTN dealer group for each planned issuance term.

3.5 Treasury OM&A Costs

Treasury OM&A costs are incurred to:

- execute borrowing plans and issue commercial paper and long-term debt;
- ensure compliance with securities regulations, bank and debt covenants;
- manage the company's daily liquidity position, control cash and manage the company's bank accounts;
- settle all transactions and manage the relationship with creditors; and
- communicate with debt investors, banks and credit rating agencies.

These costs are $1.1 million for 2008 as shown on line 28 of Exhibit B2, Tab 1, Schedule 2, Page 5.

3.6 Other Financing-Related Fees

Column (e) of Exhibit B2, Tab1, Schedule 2 (ie. Premium, discount and expenses) represents the costs of issuing debt. These costs are specific to each debt issue and include commissions, legal fees, debt discounts / premiums on issues or re-openings of issues relative to par, and hedge gains / losses.

Other financing related fees, $0.4 million in 2008, identified on line 29 of Exhibit B2, Tab 1, Schedule 2, Page 5, include the Distribution allocation of Hydro One Inc.'s annual credit rating agency, letter of credit, banking, custodial and trustee fees.

HYDRO ONE NETWORKS INC.
DISTRIBUTION

Debt and Equity Summary
Historical Years (2004, 2005 and 2006) and Bridge (2007)
As at December 31

		Historical			Bridge
		2004	2005	2006	2007
		Amount Outstanding	Amount Outstanding	Amount Outstanding	Amount Outstanding
Line No.	**Particulars**	**($ Millions)**	**($ Millions)**	**($ Millions)**	**($ Millions)**
I	Debt *	1,886.0	1,983.0	2,091.0	2,305.1
2	Preference shares	99.0	137.0	137.0	137.0
3	Common equity	1,230.0	1,280.0	1,359.0	1,420.5

* Includes debt payable within one year; excludes unamortized debt discount and hedging losses.

HYDRO ONE NETWORKS INC.
DISTRIBUTION

Debt and Equity Summary
Test Year (2008)
As at December 31

Line No.	Particulars	Test 2008 Amount Outstanding ($ Millions)
I	Debt *	2,629.2
2	Preference shares	0.0
3	Common equity	1,752.8

* Includes debt payable within one year; excludes unamortized debt discount and hedging losses.

HYDRO ONE NETWORKS INC.
DISTRIBUTION

Cost of Long-Term Debt
Historical Year (2004)
Year ending December 31

Line No.	Offering Date	Coupon Rate	Maturity Date	Principal Amount Offered ($Millions)	Premium Discount and Expenses ($Millions)	Net Capital Employed: Total Amount ($Millions)	Net Capital Employed: Per $100 Principal Amount (Dollars)	Effective Cost Rate	Total Amount Outstanding: at 12/31/03 ($Millions)	Total Amount Outstanding: at 12/31/04 ($Millions)	Avg. Monthly Averages ($Millions)	Carrying Cost ($Millions)	Projected Average Embedded Cost Rates
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
1	1-Apr-99	6.778%	28-Mar-04	69.0	-	69.0	100.0	6.78%	69.0	-	15.9	1.1	
2	1-Apr-99	6.778%	31-May-04	69.0	-	69.0	100.0	6.78%	69.0	-	31.8	2.2	
3	1-Apr-99	8.875%	25-Oct-05	30.4	-	30.4	100.0	8.88%	30.4	30.4	30.4	2.7	
4	1-Apr-99	8.875%	25-Oct-05	9.1	-	9.1	100.0	8.88%	9.1	9.1	9.1	0.8	
5	1-Apr-99	7.750%	3-Nov-05	43.6	-	43.6	100.0	7.75%	43.6	43.6	43.6	3.4	
6	1-Apr-99	7.200%	30-Jan-06	30.4	-	30.4	100.0	7.20%	30.4	30.4	30.4	2.2	
7	1-Apr-99	14.250%	21-Apr-06	65.7	-	65.7	100.0	14.25%	65.7	65.7	65.7	9.4	
8	1-Apr-99	7.200%	1-Jun-06	46.9	-	46.9	100.0	7.20%	46.9	46.9	46.9	3.4	
9	1-Apr-99	9.640%	10-Nov-06	36.2	-	36.2	100.0	9.64%	36.2	36.2	36.2	3.5	
10	1-Apr-99	9.130%	1-May-07	12.0	-	12.0	100.0	9.13%	12.0	12.0	12.0	1.1	
11	1-Apr-99	9.130%	4-May-07	15.2	-	15.2	100.0	9.13%	15.2	15.2	15.2	1.4	
12	1-Apr-99	9.130%	5-May-07	15.2	-	15.2	100.0	9.13%	15.2	15.2	15.2	1.4	
13	1-Apr-99	9.130%	6-May-07	15.2	-	15.2	100.0	9.13%	15.2	15.2	15.2	1.4	
14	1-Apr-99	9.130%	7-May-07	15.2	-	15.2	100.0	9.13%	15.2	15.2	15.2	1.4	
15	1-Apr-99	9.720%	10-Aug-07	18.4	-	18.4	100.0	9.72%	18.4	18.4	18.4	1.8	
16	1-Apr-99	6.990%	9-May-05	48.2	-	48.2	100.0	6.99%	48.2	48.2	48.2	3.4	
17	3-Jun-00	6.940%	3-Jun-05	60.8	0.7	60.1	98.9	7.22%	60.8	60.8	60.8	4.4	
18	3-Jun-00	7.150%	3-Jun-10	121.6	1.6	120.0	98.7	7.34%	121.6	121.6	121.6	8.9	
19	3-Jun-00	7.350%	3-Jun-30	121.6	2.0	119.6	98.3	7.49%	121.6	121.6	121.6	9.1	
20	22-Jun-01	6.400%	1-Dec-11	76.0	(0.3)	76.3	100.4	6.34%	76.0	76.0	76.0	4.8	
21	22-Jun-01	6.930%	1-Jun-32	47.7	0.6	47.2	98.8	7.02%	47.7	47.7	47.7	3.4	
22	17-Sep-02	5.770%	15-Nov-12	213.0	1.0	212.0	99.5	5.83%	213.0	213.0	213.0	12.4	
23	17-Sep-02	6.930%	1-Jun-32	142.0	(5.3)	147.3	103.8	6.64%	142.0	142.0	142.0	9.4	
24	31-Jan-03	5.770%	15-Nov-12	111.0	(0.5)	111.5	100.5	5.70%	111.0	111.0	111.0	6.3	
25	31-Jan-03	6.350%	31-Jan-34	74.0	0.6	73.4	99.2	6.41%	74.0	74.0	74.0	4.7	
26	22-Apr-03	6.590%	22-Apr-43	105.0	0.7	104.3	99.3	6.64%	105.0	105.0	105.0	7.0	
27	23-Jun-03	4.000%	23-Jun-08	210.0	6.1	203.9	97.1	4.66%	210.0	210.0	210.0	9.8	
28	24-Feb-04	3.950%	24-Feb-09	87.5	0.4	87.1	99.6	4.05%	-	87.5	74.0	3.0	
29	25-Jun-04	6.350%	31-Jan-34	48.0	(0.1)	48.1	100.2	6.33%	-	48.0	25.8	1.6	
30	20-Aug-04	6.590%	22-Apr-43	26.0	(2.1)	28.1	107.9	6.06%	-	26.0	10.0	0.6	
31	24-Aug-04	6.350%	31-Jan-34	26.0	(0.9)	26.9	103.5	6.09%	-	26.0	10.0	0.6	
32	15-Nov-04	2.534%	15-May-07	14.0	0.1	13.9	99.1	2.91%	-	14.0	2.2	0.1	
33		**Subtotal**							1,822.5	1,886.0	1,854.3	126.5	
34		Treasury OM&A costs										0.6	
35		Other financing-related fees										0.8	
36		**Total**							1,822.5	1,886.0	1,854.3	127.9	6.90%

HYDRO ONE NETWORKS INC.

DISTRIBUTION

Cost of Long-Term Debt
Historical Year (2005)
Year ending December 31

Line No.	Offering Date	Coupon Rate	Maturity Date	Principal Amount Offered ($Millions)	Premium Discount and Expenses ($Millions)	Net Capital Employed Total Amount ($Millions)	Net Capital Employed Per $100 Principal Amount (Dollars)	Effective Cost Rate	Total Amount Outstanding at 12/31/04 ($Millions)	Total Amount Outstanding at 12/31/05 ($Millions)	Avg. Monthly Averages ($Millions)	Carrying Cost ($Millions)	Projected Average Embedded Cost Rates
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
3	1-Apr-99	8.875%	25-Oct-05	30.4	-	30.4	100.0	8.88%	30.4	-	23.4	2.1	
4	1-Apr-99	8.875%	25-Oct-05	9.1	-	9.1	100.0	8.88%	9.1	-	7.0	0.6	
5	1-Apr-99	7.750%	3-Nov-05	43.6	-	43.6	100.0	7.75%	43.6	-	36.9	2.9	
6	1-Apr-99	7.200%	30-Jan-06	30.4	-	30.4	100.0	7.20%	30.4	30.4	30.4	2.2	
7	1-Apr-99	14.250%	21-Apr-06	65.7	-	65.7	100.0	14.25%	65.7	65.7	65.7	9.4	
8	1-Apr-99	7.200%	1-Jun-06	46.9	-	46.9	100.0	7.20%	46.9	46.9	46.9	3.4	
9	1-Apr-99	9.640%	10-Nov-06	36.2	-	36.2	100.0	9.64%	36.2	36.2	36.2	3.5	
10	1-Apr-99	9.130%	1-May-07	12.0	-	12.0	100.0	9.13%	12.0	12.0	12.0	1.1	
11	1-Apr-99	9.130%	4-May-07	15.2	-	15.2	100.0	9.13%	15.2	15.2	15.2	1.4	
12	1-Apr-99	9.130%	5-May-07	15.2	-	15.2	100.0	9.13%	15.2	15.2	15.2	1.4	
13	1-Apr-99	9.130%	6-May-07	15.2	-	15.2	100.0	9.13%	15.2	15.2	15.2	1.4	
14	1-Apr-99	9.130%	7-May-07	15.2	-	15.2	100.0	9.13%	15.2	15.2	15.2	1.4	
15	1-Apr-99	9.720%	10-Aug-07	18.4	-	18.4	100.0	9.72%	18.4	18.4	18.4	1.8	
16	1-Apr-99	6.990%	9-May-05	48.2	-	48.2	100.0	6.99%	48.2	-	18.5	1.3	
17	3-Jun-00	6.940%	3-Jun-05	60.8	0.7	60.1	98.9	7.22%	60.8	-	28.1	2.0	
18	3-Jun-00	7.150%	3-Jun-10	121.6	1.6	120.0	98.7	7.34%	121.6	121.6	121.6	8.9	
19	3-Jun-00	7.350%	3-Jun-30	121.6	2.0	119.6	98.3	7.49%	121.6	121.6	121.6	9.1	
20	22-Jun-01	6.400%	1-Dec-11	76.0	(0.3)	76.3	100.4	6.34%	76.0	76.0	76.0	4.8	
21	22-Jun-01	6.930%	1-Jun-32	47.7	0.6	47.2	98.8	7.02%	47.7	47.7	47.7	3.4	
22	17-Sep-02	5.770%	15-Nov-12	213.0	1.0	212.0	99.5	5.83%	213.0	213.0	213.0	12.4	
23	17-Sep-02	6.930%	1-Jun-32	142.0	(5.3)	147.3	103.8	6.64%	142.0	142.0	142.0	9.4	
24	31-Jan-03	5.770%	15-Nov-12	111.0	(0.5)	111.5	100.5	5.70%	111.0	111.0	111.0	6.3	
25	31-Jan-03	6.350%	31-Jan-34	74.0	0.6	73.4	99.2	6.41%	74.0	74.0	74.0	4.7	
26	22-Apr-03	6.590%	22-Apr-43	105.0	0.7	104.3	99.3	6.64%	105.0	105.0	105.0	7.0	
27	23-Jun-03	4.000%	23-Jun-08	210.0	6.1	203.9	97.1	4.66%	210.0	210.0	210.0	9.8	
28	24-Feb-04	3.950%	24-Feb-09	87.5	0.4	87.1	99.6	4.05%	87.5	87.5	87.5	3.5	
29	25-Jun-04	6.350%	31-Jan-34	48.0	(0.1)	48.1	100.2	6.33%	48.0	48.0	48.0	3.0	
30	20-Aug-04	6.590%	22-Apr-43	26.0	(2.1)	28.1	107.9	6.06%	26.0	26.0	26.0	1.6	
31	24-Aug-04	6.350%	31-Jan-34	26.0	(0.9)	26.9	103.5	6.09%	26.0	26.0	26.0	1.6	
32	15-Nov-04	2.764%	15-May-07	14.0	0.1	13.9	99.1	2.91%	14.0	14.0	14.0	0.4	
33	9-May-05	4.830%	9-May-15	48.0	-	48.0	100.0	4.83%	-	48.0	29.5	1.4	
34	9-May-05	4.830%	9-May-15	42.0	-	42.0	100.0	4.83%	-	42.0	25.8	1.2	
35	14-Dec-05	4.560%	14-Dec-15	56.0	-	56.0	100.0	4.56%	-	56.0	4.3	0.2	
36	19-May-05	3.950%	24-Feb-09	45.0	(0.4)	45.4	100.9	3.69%	-	45.0	27.7	1.0	
37	19-May-05	5.360%	20-May-36	98.1	3.5	94.6	96.4	5.60%	-	98.1	60.4	3.4	
38		**Subtotal**							1,886.0	1,982.9	1,955.4	129.0	
39		Treasury OM&A costs										0.8	
40		Other financing-related fees										0.7	
41		**Total**							1,886.0	1,982.9	1,955.4	130.5	6.68%

HYDRO ONE NETWORKS INC.
DISTRIBUTION
Cost of Long-Term Debt
Historical Year (2006)
Year ending December 31

Line No.	Offering Date	Coupon Rate	Maturity Date	Principal Amount Offered ($Millions)	Premium Discount and Expenses ($Millions)	Net Capital Employed Total Amount ($Millions)	Net Capital Employed Per $100 Principal Amount (Dollars)	Effective Cost Rate	Total Amount Outstanding at 12/31/05 ($Millions)	Total Amount Outstanding at 12/31/06 ($Millions)	Avg. Monthly Averages ($Millions)	Carrying Cost ($Millions)	Projected Average Embedded Cost Rates
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
6	1-Apr-99	7.200%	30-Jan-06	30.4	-	30.4	100.0	7.20%	30.4	-	2.3	0.2	
7	1-Apr-99	14.250%	21-Apr-06	65.7	-	65.7	100.0	14.25%	65.7	-	20.2	2.9	
8	1-Apr-99	7.200%	1-Jun-06	46.9	-	46.9	100.0	7.20%	46.9	-	21.7	1.6	
9	1-Apr-99	9.640%	10-Nov-06	36.2	-	36.2	100.0	9.64%	36.2	-	30.6	2.9	
10	1-Apr-99	9.130%	1-May-07	12.0	-	12.0	100.0	9.13%	12.0	12.0	12.0	1.1	
11	1-Apr-99	9.130%	4-May-07	15.2	-	15.2	100.0	9.13%	15.2	15.2	15.2	1.4	
12	1-Apr-99	9.130%	5-May-07	15.2	-	15.2	100.0	9.13%	15.2	15.2	15.2	1.4	
13	1-Apr-99	9.130%	6-May-07	15.2	-	15.2	100.0	9.13%	15.2	15.2	15.2	1.4	
14	1-Apr-99	9.130%	7-May-07	15.2	-	15.2	100.0	9.13%	15.2	15.2	15.2	1.4	
15	1-Apr-99	9.720%	10-Aug-07	18.4	-	18.4	100.0	9.72%	18.4	18.4	18.4	1.8	
18	3-Jun-00	7.150%	3-Jun-10	121.6	1.6	120.0	98.7	7.34%	121.6	121.6	121.6	8.9	
19	3-Jun-00	7.350%	3-Jun-30	121.6	2.0	119.6	98.3	7.49%	121.6	121.6	121.6	9.1	
20	22-Jun-01	6.400%	1-Dec-11	76.0	(0.3)	76.3	100.4	6.34%	76.0	76.0	76.0	4.8	
21	22-Jun-01	6.930%	1-Jun-32	47.7	0.6	47.2	98.8	7.02%	47.7	47.7	47.7	3.4	
22	17-Sep-02	5.770%	15-Nov-12	213.0	1.0	212.0	99.5	5.83%	213.0	213.0	213.0	12.4	
23	17-Sep-02	6.930%	1-Jun-32	142.0	(5.3)	147.3	103.8	6.64%	142.0	142.0	142.0	9.4	
24	31-Jan-03	5.770%	15-Nov-12	111.0	(0.5)	111.5	100.5	5.70%	111.0	111.0	111.0	6.3	
25	31-Jan-03	6.350%	31-Jan-34	74.0	0.6	73.4	99.2	6.41%	74.0	74.0	74.0	4.7	
26	22-Apr-03	6.590%	22-Apr-43	105.0	0.7	104.3	99.3	6.64%	105.0	105.0	105.0	7.0	
27	23-Jun-03	4.000%	23-Jun-08	210.0	6.1	203.9	97.1	4.66%	210.0	210.0	210.0	9.8	
28	24-Feb-04	3.950%	24-Feb-09	87.5	0.4	87.1	99.6	4.05%	87.5	87.5	87.5	3.5	
29	25-Jun-04	6.350%	31-Jan-34	48.0	(0.1)	48.1	100.2	6.33%	48.0	48.0	48.0	3.0	
30	20-Aug-04	6.590%	22-Apr-43	26.0	(2.1)	28.1	107.9	6.06%	26.0	26.0	26.0	1.6	
31	24-Aug-04	6.350%	31-Jan-34	26.0	(0.9)	26.9	103.5	6.09%	26.0	26.0	26.0	1.6	
32	15-Nov-04	4.030%	15-May-07	14.0	0.1	13.9	99.1	2.91%	14.0	14.0	14.0	0.4	
33	9-May-05	4.830%	29-Jun-07	48.0	-	48.0	100.0	4.83%	48.0	48.0	48.0	2.3	
34	9-May-05	4.830%	29-Jun-07	42.0	-	42.0	100.0	4.83%	42.0	42.0	42.0	2.0	
35	14-Dec-05	4.560%	29-Jun-07	56.0	-	56.0	100.0	4.56%	56.0	56.0	56.0	2.6	
36	19-May-05	5.360%	20-May-36	98.1	3.5	94.6	96.4	5.60%	98.1	98.1	98.1	5.5	
37	19-May-05	3.950%	24-Feb-09	45.0	(0.4)	45.4	100.9	3.69%	45.0	45.0	45.0	1.7	
38	3-Mar-06	4.640%	3-Mar-16	90.0	0.4	89.6	99.5	4.70%	-	90.0	69.2	3.3	
39	24-Apr-06	5.360%	20-May-36	62.5	0.8	61.7	98.7	5.45%	-	62.5	43.3	2.4	
40	22-Aug-06	4.640%	3-Mar-16	90.0	1.1	88.9	98.8	4.80%	-	90.0	25.5	1.2	
41	19-Oct-06	5.000%	19-Oct-46	45.0	0.3	44.7	99.3	5.04%	-	45.0	5.6	0.3	
42		**Subtotal**							1,982.9	2,091.2	2,022.2	123.2	
43		Treasury OM&A costs										0.8	
44		Other financing-related fees										0.7	
45		**Total**							1,982.9	2,091.2	2,022.2	124.7	6.17%

HYDRO ONE NETWORKS INC.
DISTRIBUTION
Cost of Long-Term Debt Capital
Bridge Year (2007)
Year ending December 31

Line No.	Offering Date	Coupon Rate	Maturity Date	Principal Amount Offered ($Millions)	Premium Discount and Expenses ($Millions)	Net Capital Employed: Total Amount ($Millions)	Net Capital Employed: Per $100 Principal Amount (Dollars)	Effective Cost Rate	Total Amount Outstanding at 12/31/06 ($Millions)	Total Amount Outstanding at 12/31/07 ($Millions)	Avg. Monthly Averages ($Millions)	Carrying Cost ($Millions)	Projected Average Embedded Cost Rates
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
1	1-Apr-99	9.130%	1-May-07	12.0	0.0	12.0	100.00	9.13%	12.0	0.0	4.6	0.4	
2	1-Apr-99	9.130%	4-May-07	15.2	0.0	15.2	100.00	9.13%	15.2	0.0	5.8	0.5	
3	1-Apr-99	9.130%	5-May-07	15.2	0.0	15.2	100.00	9.13%	15.2	0.0	5.8	0.5	
4	1-Apr-99	9.130%	6-May-07	15.2	0.0	15.2	100.00	9.13%	15.2	0.0	5.8	0.5	
5	1-Apr-99	9.130%	7-May-07	15.2	0.0	15.2	100.00	9.13%	15.2	0.0	5.8	0.5	
6	1-Apr-99	9.720%	10-Aug-07	18.4	0.0	18.4	100.00	9.72%	18.4	0.0	11.3	1.1	
7	9-May-05	4.830%	29-Jun-07	48.0	0.0	48.0	100.00	4.83%	48.0	0.0	22.2	1.1	
8	9-May-05	4.830%	29-Jun-07	42.0	0.0	42.0	100.00	4.83%	42.0	0.0	19.4	0.9	
9	14-Dec-05	4.560%	29-Jun-07	56.0	0.0	56.0	100.00	4.56%	56.0	0.0	25.8	1.2	
10	3-Jun-00	7.150%	3-Jun-10	121.6	1.6	120.0	98.70	7.34%	121.6	121.6	121.6	8.9	
11	3-Jun-00	7.350%	3-Jun-30	121.6	1.9	119.7	98.43	7.48%	121.6	121.6	121.6	9.1	
12	22-Jun-01	6.400%	1-Dec-11	76.0	(0.2)	76.2	100.28	6.36%	76.0	76.0	76.0	4.8	
13	22-Jun-01	6.930%	1-Jun-32	47.7	0.5	47.3	99.05	7.01%	47.7	47.7	47.7	3.3	
14	17-Sep-02	5.770%	15-Nov-12	213.0	1.0	212.0	99.55	5.83%	213.0	213.0	213.0	12.4	
15	17-Sep-02	6.930%	1-Jun-32	142.0	(5.1)	147.1	103.60	6.65%	142.0	142.0	142.0	9.4	
16	31-Jan-03	5.770%	15-Nov-12	111.0	(0.5)	111.5	100.48	5.70%	111.0	111.0	111.0	6.3	
17	31-Jan-03	6.350%	31-Jan-34	74.0	0.6	73.4	99.21	6.41%	74.0	74.0	74.0	4.7	
18	22-Apr-03	6.590%	22-Apr-43	105.0	0.8	104.2	99.26	6.64%	105.0	105.0	105.0	7.0	
19	23-Jun-03	4.000%	23-Jun-08	210.0	6.1	203.9	97.08	4.66%	210.0	210.0	210.0	9.8	
20	24-Feb-04	3.950%	24-Feb-09	87.5	0.4	87.1	99.55	4.05%	87.5	87.5	87.5	3.5	
21	25-Jun-04	6.350%	31-Jan-34	48.0	(0.1)	48.1	100.22	6.33%	48.0	48.0	48.0	3.0	
22	20-Aug-04	6.590%	22-Apr-43	26.0	(2.1)	28.1	107.89	6.06%	26.0	26.0	26.0	1.6	
23	24-Aug-04	6.350%	31-Jan-34	26.0	(0.9)	26.9	103.48	6.09%	26.0	26.0	26.0	1.6	
24	15-Nov-04	4.173%	15-May-07	14.0	0.1	13.9	99.08	4.57%	14.0	0.0	5.4	0.2	
25	19-May-05	5.360%	20-May-36	98.1	3.5	94.6	96.44	5.60%	98.1	98.1	98.1	5.5	
26	19-May-05	3.950%	24-Feb-09	45.0	(0.4)	45.4	100.90	3.69%	45.0	45.0	45.0	1.7	
27	3-Mar-06	4.640%	3-Mar-16	90.0	0.4	89.6	99.51	4.70%	90.0	90.0	90.0	4.2	
28	24-Apr-06	5.360%	20-May-36	62.5	0.8	61.7	98.68	5.45%	62.5	62.5	62.5	3.4	
29	22-Aug-06	4.640%	3-Mar-16	90.0	1.1	88.9	98.77	4.80%	90.0	90.0	90.0	4.3	
30	19-Oct-06	5.000%	19-Oct-46	45.0	0.3	44.7	99.29	5.04%	45.0	45.0	45.0	2.3	
31	13-Mar-07	4.890%	13-Mar-37	160.0	0.8	159.2	99.48	4.92%	0.0	160.0	123.1	6.1	
32	15-May-07	4.100%	15-Nov-07	14.0	0.0	14.0	100.00	4.10%	0.0	0.0	8.6	0.4	
33	15-Sep-07	4.710%	15-Sep-17	102.5	0.5	102.0	99.50	4.77%	0.0	102.5	31.6	1.5	
34	15-Nov-07	4.470%	16-May-13	102.5	0.5	102.0	99.50	4.57%	0.0	102.5	15.8	0.7	
35		**Subtotal**							2091.2	2205.1	2131.1	122.7	
36		Treasury OM&A costs										1.1	
37		Other financing-related fees										0.7	
38		**Total**							2091.2	2205.1	2131.1	124.5	5.84%

HYDRO ONE NETWORKS INC.
DISTRIBUTION
Cost of Long-Term Debt Capital
Test Year (2008)
Year ending December 31

Line No.	Offering Date	Coupon Rate	Maturity Date	Principal Amount Offered ($Millions)	Premium Discount and Expenses ($Millions)	Net Capital Employed: Total Amount ($Millions)	Net Capital Employed: Per $100 Principal Amount (Dollars)	Effective Cost Rate	Total Amount Outstanding: at 12/31/07 ($Millions)	Total Amount Outstanding: at 12/31/08 ($Millions)	Avg. Monthly Averages ($Millions)	Carrying Cost ($Millions)	Projected Average Embedded Cost Rates
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
1	3-Jun-00	7.150%	3-Jun-10	121.6	1.6	120.0	98.70	7.34%	121.6	121.6	121.6	8.9	
2	3-Jun-00	7.350%	3-Jun-30	121.6	1.9	119.7	98.43	7.48%	121.6	121.6	121.6	9.1	
3	22-Jun-01	6.400%	1-Dec-11	76.0	(0.2)	76.2	100.28	6.36%	76.0	76.0	76.0	4.8	
4	22-Jun-01	6.930%	1-Jun-32	47.7	0.5	47.3	99.05	7.01%	47.7	47.7	47.7	3.3	
5	17-Sep-02	5.770%	15-Nov-12	213.0	1.0	212.0	99.55	5.83%	213.0	213.0	213.0	12.4	
6	17-Sep-02	6.930%	1-Jun-32	142.0	(5.1)	147.1	103.60	6.65%	142.0	142.0	142.0	9.4	
7	31-Jan-03	5.770%	15-Nov-12	111.0	(0.5)	111.5	100.48	5.70%	111.0	111.0	111.0	6.3	
8	31-Jan-03	6.350%	31-Jan-34	74.0	0.6	73.4	99.21	6.41%	74.0	74.0	74.0	4.7	
9	22-Apr-03	6.590%	22-Apr-43	105.0	0.8	104.2	99.26	6.64%	105.0	105.0	105.0	7.0	
10	23-Jun-03	4.000%	23-Jun-08	210.0	6.1	203.9	97.08	4.66%	210.0	0.0	96.9	4.5	
11	24-Feb-04	3.950%	24-Feb-09	87.5	0.4	87.1	99.55	4.05%	87.5	87.5	87.5	3.5	
12	25-Jun-04	6.350%	31-Jan-34	48.0	(0.1)	48.1	100.22	6.33%	48.0	48.0	48.0	3.0	
13	20-Aug-04	6.590%	22-Apr-43	26.0	(2.1)	28.1	107.89	6.06%	26.0	26.0	26.0	1.6	
14	24-Aug-04	6.350%	31-Jan-34	26.0	(0.9)	26.9	103.48	6.09%	26.0	26.0	26.0	1.6	
15	19-May-05	5.360%	20-May-36	98.1	3.5	94.6	96.44	5.60%	98.1	98.1	98.1	5.5	
16	19-May-05	3.950%	24-Feb-09	45.0	(0.4)	45.4	100.90	3.69%	45.0	45.0	45.0	1.7	
17	3-Mar-06	4.640%	3-Mar-16	90.0	0.4	89.6	99.51	4.70%	90.0	90.0	90.0	4.2	
18	24-Apr-06	5.360%	20-May-36	62.5	0.8	61.7	98.68	5.45%	62.5	62.5	62.5	3.4	
19	22-Aug-06	4.640%	3-Mar-16	90.0	1.1	88.9	98.77	4.80%	90.0	90.0	90.0	4.3	
20	19-Oct-06	5.000%	19-Oct-46	45.0	0.3	44.7	99.29	5.04%	45.0	45.0	45.0	2.3	
21	13-Mar-07	4.890%	13-Mar-37	160.0	0.8	159.2	99.48	4.92%	160.0	160.0	160.0	7.9	
22	15-Sep-07	4.710%	15-Sep-17	102.5	0.5	102.0	99.50	4.77%	102.5	102.5	102.5	4.9	
23	15-Nov-07	4.470%	16-May-13	102.5	0.5	102.0	99.50	4.57%	102.5	102.5	102.5	4.7	
24	15-Mar-08	5.370%	15-Mar-38	144.7	0.7	144.0	99.50	5.40%	0.0	144.7	111.3	6.0	
25	15-Jun-08	5.010%	15-Jun-18	144.7	0.7	144.0	99.50	5.07%	0.0	144.7	77.9	4.0	
26	15-Sep-08	4.770%	16-Mar-14	144.7	0.7	144.0	99.50	4.87%	0.0	144.7	44.5	2.2	
27		**Subtotal**							2205.1	2429.3	2325.8	131.4	
28		Treasury OM&A costs										1.1	
29		Other financing-related fees										0.4	
30		**Total**							2205.1	2429.3	2325.8	132.9	5.71%

COST OF SERVICE SUMMARY

1.0 INTRODUCTION

This evidence presents an overview of Hydro One Distribution's Cost of Service evidence. The Cost of Service submissions include the following components:

- Operation, Maintenance and Administration ("OM&A") expenses
- Resourcing
- Costing of Work
- Corporate Cost Allocation
- Depreciation and Amortization Expense
- Payments in Lieu of Corporate Income Taxes
- Taxes Other Than Income Taxes

Each of these components is separately addressed within the company's evidence. Exhibit reference numbers are provided below.

Hydro One Distribution's forecast cost of service has been developed consistent with corporate objectives. The Company's planning process is described in detail at Exhibit A, Tab 14, Schedule 1.

1.1 Operation, Maintenance and Administration Expenses (OM&A)

Total OM&A expenses for the 2008 test year are $477.7 million.

Hydro One Distribution plans and organizes its OM&A expenses on the basis of the various work programs and functions performed by the company. Exhibits in support of

OM&A costs have been prepared by program area, and appear within the submitted evidence as follows:

Program Areas	2008 Total Cost ($ million)	Reference
Summary of OM&A Expenses	$477.7	Exhibit C1, Tab 2, Sch 1
Sustaining	$280.0	Exhibit C1, Tab 2, Sch 2
Development	$9.1	Exhibit C1, Tab 2, Sch 3
Operations	$13.4	Exhibit C1, Tab 2, Sch 4
Customer Care	$103.8	Exhibit C1, Tab 2, Sch 5
Shared Services, and other Costs	$66.9	Exhibit C1, Tab 2, Sch 6
Taxes other than Income Taxes	$4.5	Exhibit C1, Tab 2, Sch 7

In order to satisfy the requirements of the *2006 Electricity Distribution Rate Handbook* and the *Filing Requirements for Transmission and Distribution Applications* (November 14, 2006), Exhibit C2, Tab 2, Schedule 2 identifies OM&A costs by grouped USofA accounts.

1.2 Resourcing

Labour costs are charged to OM&A and Capital work programs. The evidence contained at Exhibit C1, Tab 3 presents total staff levels and costs incurred by the company as follows:

- Corporate Staff Levels — Exhibit C1, Tab 3, Schedule 1
- Compensation, Wages, Benefits, Bonus — Exhibit C1, Tab 3, Schedule 2
- Pension Costs (Appendix A) — Exhibit C1, Tab 3, Schedule 2

1.3 Costing of Work

OM&A and Capital work programs are comprised primarily of costs relating to labour, materials and equipment. Exhibit C1, Tab 4, Schedule 1 provides exhibits that explain how costs flow to work programs and also discusses cost efficiencies that have been achieved.

Throughout its operations, Hydro One Distribution has been successful in containing costs and undertaking productivity initiatives, as described in Exhibit C1, Tab 4, Schedule 2.

1.4 Corporate Cost Allocation

Hydro One Networks Inc. provides common services to Distribution and Transmission and other subsidiaries on a centralized basis. The costs of these services and assets are assigned to business units on the basis of cost causation. These costs and assets are directly assigned where it is possible to do so. All other costs are allocated based on cost drivers, direct benefits or other appropriate methods. Exhibit C1, Tab 5 describes these allocation methods, as well as the derivation of the overhead capitalization rate, which determines the assignment of overhead costs to capital expenditures.

In RP-2005-0020/EB-2005-0378, Hydro One Distribution commissioned R.J. Rudden Associates to establish a cost allocation approach for Common Costs, which would be in accordance with accepted industry standards. The Common Corporate Cost Allocation Study determined the appropriate allocation of these shared costs between the business units. The study and its methodologies were accepted by the OEB in its Decision with Reasons dated April 12, 2006. The company's evidence on shared services uses this methodology and is shown in Exhibit C1, Tab 5, Schedule 1.

Exhibit C1, Tab 5, Schedule 2 provides evidence regarding the derivation of Overhead Capitalization Rates.

Exhibit C1, Tab 5, Schedule 3 provides evidence regarding shared assets and their allocation to business units.

1.5 Depreciation and Amortization Expense

In RP-2005-0020/EB-2005-0378, the Company filed the Foster Associates Inc. depreciation study which methodologies and associated costs flows were accepted by the OEB in its subsequent Decision with Reasons. The results of this study form the basis of the depreciation submission in this application. The company is proposing to recover $238.9 million in depreciation and amortization expense. Hydro One Distribution's evidence on depreciation expense is filed at Exhibit C1, Tab 6, Schedule 1.

1.6 Payments in Lieu of Corporate Income Taxes

As a result of *the Electricity Act, 1998*, Hydro One Distribution has been required to pay proxy taxes since 1999. Evidence outlining the calculation of Payments in Lieu of Income Taxes of $38.8 million appears at Exhibit C2, Tab 6, Schedule 1.

SUMMARY OF OM&A EXPENDITURES

1.0 SUMMARY OF OM&A EXPENDITURES

The requested OM&A expenditures result from a rigorous business planning and work prioritization process that reflects risk-based decision making to ensure that the most appropriate, cost effective solutions are put in place. This process is described in detail at Exhibit A, Tab 14, Schedules 1 through 5.

The proposed OM&A programs represent Hydro One Distribution's integrated set of asset maintenance and customer activity needs to meet public and employee safety objectives, to comply with the Distribution System Code, environmental requirements and Government direction, maintain distribution business service quality and reliability at targeted performance levels, and ensure public confidence as stewards of provincial assets.

The development of asset maintenance programs is based on equipment specifications coupled with comprehensive asset condition information and good utility practice, as discussed in Exhibit D1, Tab 2, Schedule 1.

Work planning and implementation of programs is based on Hydro One Distribution's long-term planning cycle and prioritization approach described in "Work Planning and System Operations" within section 4 of Exhibit A, Tab 3, Schedule 1

Hydro One Distribution's OM&A budget is grouped into different investment categories: Sustaining, Development, Operations, Customer Care, Shared Services and Other OM&A and Taxes Other than Income Taxes. Table 1 provides a summary of Hydro One Distribution's OM&A expenditures for the historical, bridge and test years.

Table 1
Summary of Distribution OM&A Budget ($ Million)

Description	Historic (Actual)			Bridge	Test
	2004	2005	2006	2007	2008
Sustaining	207.9	222.0	255.6	278.8	280.0
Development	5.5	4.8	4.2	8.0	9.1
Operations	16.3	11.2	14.9	12.6	13.4
Customer Care	103.0	96.3	103.7	97.1	103.8
Shared Services and Other OM&A	9.3	23.3	21.2	91.9	66.9
Taxes Other Than Income Tax	4.0	4.6	4.5	4.2	4.5
TOTAL	346.0	362.1	404.1	492.6	477.7

Total OM&A expenditures have increased by 38% or $132 million over the 2004 to 2008 period. Contributing to the increase over this period is escalation of about 24% in OM&A costs, as noted on page 2 of Exhibit A, Tab 14, Schedule 2, as well as an additional $37 million in pension related costs.

In particular, expenditures have grown by $74 million from 2006 to 2008 driven primarily by increases in Sustainment expenditures to ensure the safe and reliable operation of the distribution system, including increased vegetation management costs, increased maintenance costs associated with aging assets, and an increase in costs associated with smart meters. Also contributing to the total increase in OM&A expenditures is an increasing shared services workload associated with supporting increased core work programs as well as required compliance and regulatory activities; higher than planned overheads capitalized credit in 2006, which, consistent with the Rudden overhead capitalization rate methodology, is subsequently trued up as outlined in Exhibit C1, Tab 5, Schedule 2; and, recognition of pension costs (which were deferred during the 2004 to April 2006 period).

Detailed descriptions of the work activities in each area of Distribution OM&A expense and the reasons for the changes in costs over the 2004 – 2008 period are discussed in the schedules that make up Exhibit C1, Tab 2.

2.0 SUSTAINING

The Sustaining OM&A budget represents investments required to maintain existing distribution lines and stations facilities so that they will continue to function as originally designed to support a typically rural based system. The proposed investments are intended to ensure that the overall reliability of the system is improved, that customer commitments are achieved, and that all legislative, regulatory, environmental and safety requirements are met. Details of the expenditures under this program are provided at Exhibit C1, Tab 2, Schedule 2.

3.0 DEVELOPMENT

The Development OM&A program, through system data collection, system studies and generation connection studies, enables the analyses needed for economical operation, development and expansion of the distribution system to meet existing and anticipated load and generation demands, while maintaining delivery system reliability. This program also ensures appropriate standards are maintained as required to meet construction, legal and regulatory requirements, as well as funding Research & Development that will enhance the long- and short-term effectiveness of the distribution system. Details of the expenditures under this program are described in detail at Exhibit C1, Tab 2, Schedule 3.

4.0 OPERATIONS

The Operations OM&A program represents the annual expenditures required for the Central Distribution Operations function, operated out of Hydro One's Ontario Grid Control Centre. The Distribution Operations function is concerned with the real time operations of the Hydro One Distribution system, including the dispatch of field crews to distribution system problems received by the Customer Call Centre. Details of the expenditures under this program are filed at Exhibit C1, Tab 2, Schedule 4.

5.0 CUSTOMER CARE

The Customer Care OM&A work program represents the set of work activities that are required to provide services to customers connected to the Hydro One Distribution system, and to meet the service levels stipulated in the Electricity Distribution Rate Handbook. The work program includes service to customers receiving electricity under Standard Supply Service and to customers under retailer contracts. Details of the expenditures under this program are filed at Exhibit C1, Tab 2, Schedule 5.

6.0 SHARED SERVICES AND OTHER OM&A

The Shared Services and other OM&A program includes the provision of Common Corporate Functions and Services and Asset Management programs to support the Distribution business, as well as the maintenance of existing infrastructure, including business systems, facilities, and information technology. The Common Corporate functions and services include the provision of financial, human resource, legal, information technology and strategic planning services. Asset Management programs include developing Distribution asset strategies, policies and standards; identifying, planning and prioritizing specific OM&A and Capital work on the distribution network;

facility services; and monitoring the execution of the annual work program. Other OM&A programs include the credits for overheads capitalized and the cost of goods sold in support of external revenues. Details of the expenditures under this program are filed at Exhibit C1, Tab 2, Schedule 6.

7.0 TAXES OTHER THAN INCOME TAXES

This program consists of property and proxy taxes, and indemnity payments to the Province. Details of the expenditures under this program are filed at Exhibit C1, Tab 2, Schedule 7.

SUSTAINING OM&A

1.0 INTRODUCTION

Distribution Sustaining OM&A represents expenditures required to maintain existing distribution lines and stations facilities so that they will continue to function as originally designed. Hydro One Distribution manages its Sustaining OM&A program by dividing the program into four categories: stations, lines, vegetation management, and meters.

The expenditures covered under the Sustaining OM&A program are intended to ensure that the reliability of the system is improved where it is cost effective to do so, customer commitments are achieved, and that all legislative, regulatory, environmental and safety requirements are met. Hydro One Distribution sustaining OM&A programs and proposed spending levels for 2008 are described below.

2.0 DISCUSSION

Distribution assets and their components are subject to deterioration and failure over time. Appropriate maintenance practices ensure that the life of assets is optimized and will help protect against major equipment failures and associated reliability problems. Maintenance programs are designed with recognition that asset integrity is influenced by factors such as condition, design, environment, deterioration with age, and equipment utilization. As assets deteriorate, equipment performance usually suffers resulting in increased environmental risks and an increase in potential safety hazards to both the public and employees, and a decrease in system reliability. Ultimately, assets will deteriorate to the point that they are no longer able to perform their function(s) effectively or where current year or longer term costs of maintaining the asset exceed the costs of replacement. At this point, it becomes more cost-effective to replace an asset rather than to continue to repair or maintain. Replacement of capital assets is discussed in Exhibit D1, Tab 3, Schedule 2.

Sustaining OM&A programs fund both planned and unplanned work. The planned programs represent the work required to preserve the functionality of the distribution system by maintaining or replacing defective components and managing rights-of-way to ensure vegetation growth does not adversely affect system reliability. The determination of which specific facilities need to be maintained is in part based on the comprehensive Asset Condition Assessment (ACA) process described in Exhibit D1, Tab 2, Schedule 1. The condition of assets is one consideration in determining the need to schedule maintenance. Other factors include historical performance, asset criticality, asset demographics, availability of spare equipment and material, local customer impacts and the business drivers as detailed in the work program prioritization process discussed at Exhibit A, Tab 14, Schedule 5. The prioritization process allows all distribution programs to be ranked and compared to one another so that investments can be directed to where they provide the maximum business value.

Sustaining OM&A includes demand work, also referred to as unplanned work. Demand work involves responding to customer outages and restoring power on a twenty-four hour basis, responding to safety issues, managing billing meters to ensure they are replaced upon failure, responding to customer requests to remove hazardous trees, responding to requests to locate underground power cables, and replacing or repairing failed equipment. The variable nature of this work requires Hydro One Distribution to forecast costs based on historical averages of cost and volume of work, with adjustments made to reflect anticipated changes in expenditure patterns and work requirements.

Demand work requires an immediate or timely response to customer, safety and system needs, and is initiated by interruptions to service, line and station inspection findings, and customer and property owner requests. Hydro One Distribution maintains infrastructure, equipment and resources to respond to these issues within the appropriate time frame as they arise. Some demand work does not pose the same degree of urgency, and in these instances, the work is scheduled over time based on knowledge of the condition of the assets and coordinated in a cost effective manner with other work.

The spending for 2008, along with the spending levels for the bridge and historic years are provided in Table 1 below.

Table 1
Sustaining OM&A
($ Millions)

Description	**Historic**			**Bridge**	**Test**
	2004	**2005**	**2006**	**2007**	**2008**
Stations	18.4	19.9	26.0	25.0	24.9
Lines	92.4	105.3	126.5	123.1	118.1
Meters	8.2	10.3	14.0	15.7	17.6
Vegetation Management	88.9	86.4	89.1	115.0	119.4
Total	**207.9**	**222.0**	**255.6**	**278.8**	**280.0**

The change in overall spending for 2008 relative to historic expenditures is attributed to the following reasons:

- Increased vegetation management line clearing and brush control to manage and improve reliability.
- Increased maintenance on distribution station transformers to restore the condition of these aging assets.
- Maintenance and other OM&A spending for Smart Meters.
- Continuing efforts on lines data collection and increased emphasis in defect corrections to manage reliability and safety

These increases are discussed in more detail below.

2.1 Stations

Hydro One Distribution owns and operates 1,006 distribution and regulating stations province-wide. Stations are used for the delivery of power, voltage transformation, and switching. Station facilities typically contain the following components: power transformers, instrument devices, fuses, reclosers, disconnect switches, bus, insulators, support structures, power cables, cable terminators, surge arresters, station service supplies, grounding systems, fences, mobile substation facilities and buildings.

Stations sustaining OM&A covers investments required to maintain existing assets located within distributing stations, regulating stations, as well as Hydro One Distribution's 28 mobile substations. The work is divided among three programs as noted in Table 2 below. Funding for 2008 along with the spending levels for the bridge and historic years are provided in Table 2 below.

Table 2
Stations Sustaining OM&A
($ Millions)

Description	Historic			Bridge	Test
	2004	2005	2006	2007	2008
Stations Demand and Corrective Maintenance (d)	6.2	6.7	7.0	6.9	6.1
Planned Station Maintenance	6.6	8.9	12.1	13.1	12.9
Land Assessment and Remediation	5.6	4.3	6.9	5.1	5.9
Total	**18.4**	**19.9**	**26.0**	**25.0**	**24.9**

(d) – indicates this is a demand program

2.1.1 Stations Demand and Corrective Maintenance

This program covers emergency work required to respond to component failures at distributing and regulating stations, correct situations where there is a likelihood of failure that could cause a power interruption or present a safety hazard, and to complete unplanned corrective work discovered during planned maintenance activities that cannot be deferred until the next planned maintenance. When station components fail, the consequence is typically a service interruption to customers. Station interruptions can impact a large number of customers, typically from 1,000 to 10,000 customers per interruption. Emergency and corrective maintenance work must be carried out in a timely manner in order to minimize the risks to customer reliability and safety.

In most cases, smaller components such as reclosers, insulators, connectors, switches, etc. will be repaired, temporarily bypassed, or replaced on site. The failure of a large component, such as a transformer, may require moving the equipment off site and repairing it at a central location. If a prolonged service interruption is anticipated, service is typically restored through the temporary use of a mobile substation.

The 2008 spending requirement for this program is $6.1 million and is within 10% of historic expenditures except for 2006. During 2006 copper theft and a number of site security and safety problems were identified that required corrective action.

2.1.2 Planned Station Maintenance

The planned station maintenance work program includes station inspections, power equipment maintenance, asset condition assessments, grounds and site maintenance, and maintenance of mobile substations. A planned maintenance program is required to reduce the risk of equipment failure, which can impact reliability of service to the large number of customers typically supplied from a station. Planned maintenance also ensures equipment reaches its maximum economic life potential and limits the amount of unplanned maintenance in future years.

Appendix C of the Distribution System Code requires all LDCs to inspect their stations on a regular basis to identify obvious structural problems, hazards and signs of vandalism. Hydro One Distribution's stations are inspected two times per year in rural areas and monthly in urban areas as stipulated in the Distribution System Code. The 2008 spending for this activity is $2.0 million. Inspections identify obvious problems and safety hazards prior to initiating the planned maintenance work. The planned maintenance of stations is required to preserve operational integrity and to correct equipment defects before they cause outages and reduce the reliability of service to customers, or impact employee safety.

A preventive maintenance optimization (PMO) approach has been adopted, where appropriate, for the planned maintenance of station assets. PMO is a structured program that best utilizes a company's resources to efficiently and effectively execute its maintenance requirements. Using a PMO process, detailed analysis of failure modes, causal impacts, and asset criticality are all considered in evaluating preventative measures. The end result of PMO will be a listing of routine maintenance tasks that are the most technically correct and cost-effective to address the causes of critical modes of failure, as opposed to the more traditional standardized time based maintenance approach.

The 6,000 station reclosers are maintained on a 6 year interval, and airbreak switches, circuit switchers, high voltage fuses, and transformer underload tap changers are maintained on a similar interval. These activities, in addition to mid-life maintenance overhaul on major equipment, management of station PCBs, transformer diagnostics and technical services account for a 2008 spending of $8.6 million.

Station grounds and site maintenance includes weed control, snow removal, fence repair, access road maintenance, site drainage and foundation repairs, and accounts for a 2008 spending of $1.6 million.

Hydro One Distribution’s 28 mobile substations play a key role in providing reliable service to customers. They provide emergency backup, should a distributing station fail, and facilitate planned maintenance programs at distributing stations, as well as providing load relief during heavy load periods in the summer or winter. As such, planned maintenance of mobile substations is required to ensure these critical units are available and in good working condition when required. The cost to maintain the mobile substations during 2008 is estimated to be $0.7 million.

The total 2008 spending requirement for Planned Station Maintenance is $12.9 million to maintain 1,006 station sites and associated equipment including infrastructure. The 2008 spending is about the same as the bridge year spending and a 7% increase over 2006 expenditures. The increase in spending is attributed to a need for added transformer maintenance and mid-life overhauls as identified through inspections and diagnostic activities.

Maintenance plans initiated during 2005 are showing benefits. Increased use of transformer diagnostics (dissolved gas analysis), and the removal of suspect transformers from service in a proactive manner based on the results of the diagnostic tests, have enabled a reduction of forced outages (i.e. failures). A reduction in failures has benefits to customer reliability and avoids environmental contamination from spilled or burning insulating oil. It is important that the coordinated maintenance strategy (i.e., ACA, proactive removal of suspect transformers and mid-life overhauls) adopted for this aging class of key assets be maintained in order to increase the life of these assets and to keep failures in check over the longer term.

2.1.3 Land Assessment and Remediation

Hydro One Distribution owns 1,006 distribution and regulating station properties across Ontario. Soil contamination has occurred over time within some of the properties as a result of the following: application of certain long lasting chemicals, such as wood preservatives and arsenic-based herbicides; storage and use of mineral insulating oil, fuel, PCBs, and miscellaneous other materials. The historical use and storage of these materials and chemicals met all applicable environment regulations and guidelines at the time that they were first used. Approximately 45% of these properties have some level of on-site soil contamination, exceeding applicable Ministry of Environment land-use criterion. Because contaminated properties have the potential to cause adverse effects on people and the environment, Hydro One Distribution has undertaken to assess their properties and carry out remedial work where environmental risks are significant. The ACA process described in Exhibit D1, Tab 2, Schedule 1 provides additional details concerning Land Assessment and Remediation.

The Land Assessment and Remediation program's primary focus is to reduce the human and ecological risk of off-property impacts, through the implementation of remedial measures to treat, remove or otherwise manage the contamination found off-site and/or the implementation of on-site management controls to mitigate future off-property impacts.

The 2008 spending requirement for this program is $5.9 million. This level of funding is required to complete assessments and required remedial work on 8 priority sites. This volume of work aligns with a managed remediation schedule that would address all high to medium risk sites within the next 5 years. Historic costs have varied year over year due to the complexity and volume of work needed to address the particular sites during any given year.

2.2 Lines

Distribution lines total 119,900 circuit km province-wide and are used to deliver power to Hydro One Distribution customers. Lines are constructed on road allowances where possible, or on rights-of-way for which Hydro One Distribution has legal rights to occupy. Line components include poles, conductor, transformers, switches, fuses, surge arresters, voltage regulators, capacitors, insulators, guy anchors and reclosers.

Funding under lines sustaining OM&A provides for investments required to maintain the integrity of the distribution lines system. The work is divided among four categories, Trouble Call/Cable Locates/Reconnect and Disconnects, Line Maintenance, Waste Management and Other Services. Funding for 2008, along with the spending levels for the bridge and historic years, are provided in Table 3 below.

Table 3
Lines Sustaining OM&A
($ Millions)

Description	**Historic**			**Bridge**	**Test**
	2004	**2005**	**2006**	**2007**	**2008**
Trouble Call Response, Cable Locates and Disconnects/Reconnects (d)	67.2	73.8	89.2	78.6	76.9
Line Maintenance	15.2	19.3	26.7	30.2	28.8
Waste Management	2.7	2.8	3.2	3.1	3.0
Other Services	7.3	9.4	7.4	12.7	9.4
Total	**92.4**	**105.3**	**126.5**	**124.6**	**118.1**

(d) – indicates this is a demand program

2.2.1 Trouble Calls, Underground Cable Locates, Disconnects/Reconnects

These demand programs provide funding for responding to customer service interruptions and power quality concerns and for customer-driven service response activity. The externally driven nature of this work requires Hydro One Distribution to forecast costs based on historical averages with adjustments made to reflect anticipated changes in expenditure patterns or work requirements. The funding is divided into three programs as shown in Table 4.

Table 4
Trouble Calls, Locates, Disconnects/Reconnects
($ Millions)

Description	**Historic**			**Bridge**	**Test**
	2004	**2005**	**2006**	**2007**	**2008**
Trouble Calls (d)	51.5	56.8	70.9	57.6	58.9
Underground Cable Locates(d)	9.1	10.2	10.7	12.4	10.5
Disconnects/Reconnects (d)	6.6	6.8	7.6	8.6	7.5
Total	**67.2**	**73.8**	**89.2**	**78.6**	**76.9**

(d) – indicates this is a demand program

Trouble Calls

The Trouble Call program is required to address unplanned power interruptions to customers, customer power quality related complaints, and the emergency repair of equipment and component defects found on the distribution system.

Unplanned power interruptions on the distribution system are largely due to line component failures and/or contact with right-of-way vegetation (trees). Line component failures can be caused by severe weather conditions (e.g. snow/ice, wind, lightning), right-of-way vegetation falling into lines and system component deterioration. Tree related interruptions are largely due to trees falling onto lines or branches contacting the lines, and in many cases are due to adverse weather conditions.

Service quality complaints from customers can include concern with momentary outages (flickering lights), radio and television interference and high neutral voltage (also known as 'tingle voltage' in the farming community).

The Trouble Call program also addresses assets that are in immediate need of repair or replacement, or encroachment of vegetation that has the potential to cause an outage within a short period of time. If not attended to, these types of defects may ultimately result in a power interruption to customers or create a safety hazard to the public or employees.

The majority of trouble calls result in an interruption to customers and/or power quality degradation. Service interruptions can impact from one customer to thousands of customers depending on the severity of the incident and system configuration. Service restoration requires that the defective component be repaired, temporarily bypassed, or replaced by crews dispatched to the site at any time, day or night. Defective equipment, if categorized as a capital component would be replaced under Sustaining Capital as discussed in Exhibit D1, Tab 3, Schedule 2.

This program is reactive in nature and will vary due to external factors such as weather severity (e.g. storms), variability in equipment deterioration, random equipment failures, and the volume of customer power quality complaints. Historically, there are approximately 50,000 trouble calls responded to annually, of which roughly one-third are incidents that do not cause a service interruption, but pose a high risk to the reliability of supply or safety, and need to be addressed in an expedient manner.

Hydro One Distribution must address trouble calls in order to comply with legal and regulatory requirements to correct known hazardous problems and to maintain safe and reliable electric service in accordance with good utility practice. Performance on this program will impact the system reliability service quality indicators specified by the OEB in the Electricity Distribution Rate Handbook, Sections 15.2.1 and 15.2.3.

The 2008 spending requirement for this program is $58.9 million based on a forecast volume of 49,100 Trouble Calls and an allowance for storm related costs that are not capitalized, i.e., vegetation management and overtime accumulated during storm events. The 2008 allowance for OM&A storm related costs is $6 million. The proposed spending takes into account observed historic volumes and historic expenditures for storm response. Trouble Call volumes have remained relatively steady but increasing expenditures associated with storm activity since 2004 have placed greater demands on program expenditures.

Spending for 2008 is projected to be 17% lower than 2006 actual costs. During 2006 there were an unusually high number of damaging storms resulting in much higher storm related costs than normal. It is expected that spending of this magnitude will be not required during 2008.

Underground Cable Locates

This program provides a service of locating and marking Hydro One Distribution underground plant for customers and contractors who require this information prior to excavating. This service is provided in accordance with the Electrical Safety Authority's (ESA) "Guidelines for Excavating in the Vicinity of Distribution Lines". The program costs are not recovered through end-user charges in order to encourage property owners and contractors to make use of this service and avoid hazardous situations that can cause serious injury. This approach is consistent with the practice followed by other regulated utilities, including telephone service and natural gas utilities.

Program funding is driven by external demand and varies based on the amount of public and economic development activity in any given year. Hydro One Distribution has seen an approximate 12% increase in volume since 2004 from 73,001 to 81,975 locates during 2006, due mainly to an increased number of locates generated by increased public awareness of the "call before you dig" message.

Performance on this program is tracked by the "Underground Cable Locates" service quality indicator specified by the OEB in the Electricity Distribution Rate Handbook, Section 15.1.2. Refer to Exhibit A, Tab 15, Schedule 1 for additional details.

The 2008 spending requirement for this program is $10.5 million and is based on a projected volume of 75,800 cable locate requests The volume forecast is derived using a 4 year average with adjustments made to incorporate recent trending in volumes. The projected spending maintains recent historic expenditures.

Service Disconnects and Reconnects

This program funds the provision of service to customers, or their contractors, who require isolation from the distribution system to facilitate working safely around the customer-owned portion of a distribution line (e.g., clearing trees and vegetation or working on customer-owned equipment). When customers complete their work, the service is reconnected and returned to normal conditions. There is no cost to the customer for providing this service once per calendar year during normal working hours in order to encourage customers to maintain their facilities and to work safely.

Performance on this program contributes to the "Appointments" service quality indicator specified by the OEB in the Electricity Distribution Rate Handbook, Section 15.1.4.

The 2008 spending requirement for this program is $7.5 million to complete a forecast 10,600 disconnect/reconnect requests. The volume forecast is derived using a 4 year average with adjustments made to incorporate recent trending in volumes

2.2.2 Line Maintenance

The line maintenance program includes funding to gather information needed to effectively manage the line assets and to carry out ongoing equipment maintenance to maximize the life of these assets and to ensure performance and operability of equipment. As well, defective equipment or components at end of life are replaced or repaired under the corrective programs within line maintenance.

Line maintenance is divided into 3 program categories: Line Patrols/Wood Pole Assessment and Asset Data Collection; Preventative and Corrective Maintenance; and Sentinel Lights. Funding for 2008, along with spending levels for the bridge and historic years, are provided in Table 5 below.

Table 5
Line Maintenance
($ Millions)

Description	**Historic**			**Bridge**	**Test**
	2004	**2005**	**2006**	**2007**	**2008**
Line Patrols, Wood Pole Assessment & Asset Data Collection	8.1	8.1	13.1	15.4	13.4
Preventative & Corrective Maintenance	7.2	9.7	12.3	13.6	13.7
Sentinel Lights (d)	*	1.5	1.4	1.3	1.6
Total	**15.2**	**19.3**	**26.7**	**30.2**	**28.8**

(d) – indicates this is a demand program
* During 2004 sentinel lights were treated as a non-utility expense and as such were not included in the revenue requirement. The cost during 2004 was $2.0 million.

2.2.2.1 Line Patrols, Wood Pole Assessment and Data Collection

Appendix C of the Distribution System Code requires that all local distribution companies patrol their distribution lines to identify structural problems, damaged equipment and components that may cause a power interruption, as well as any hazards such as leaning poles, damaged equipment enclosures, and vandalism. Hydro One Distribution is required to patrol one-sixth of all rural distribution feeders and one-third of urban feeders each year to identify defects for corrective action. Those defects requiring immediate attention are corrected under the trouble call programs as discussed in section 2.2.1 of this Schedule and Exhibit D1, Tab 2, Schedule 2 for capital expenditures. The less serious defects are addressed on a planned basis in the appropriate time frame. The approach adopted by Hydro One Distribution for line patrols meets the requirements of the Distribution System Code, and combines patrol activities with asset condition assessment required to effectively plan future corrective work, and data collection on assets needed to improve the future management of these assets. Using an integrated approach that combines line patrols, asset condition assessment and data collection to acquire information during one site visit is the most cost effective means of acquiring the information needed to effectively manage the distribution lines system.

As part of the patrols, each pole is assessed visually and sounded to identify voids in a pole that may jeopardize its structural integrity. During the assessment, a pole may be identified to be at end-of-life, in need of follow-up testing if there is uncertainty concerning end-of-life, or given an acceptable rating. Follow-up testing, if needed, will involve a measurement of the remaining sound wood and the degree of wood decay, internal and external. The pole assessment and test results are used to plan future pole replacements as well as supporting the need for line refurbishment and line upgrades.

About 18,000 km of rural and urban patrols are completed annually, with about 300,000 poles assessed out of a total of 1,650,000. The findings are recorded in a database where the nature of a deficiency and suggested follow-up actions are highlighted.

When a pole is assessed, the geographic coordinates of the pole are captured, equipment and line components on the pole identified, condition assessed and all information is recorded in electronic format and entered into Hydro One Distribution’s Asset Condition Assessment Database. The line data capture was started in 2005 and will be complete by 2010, at which time all lines will have been patrolled and poles assessed. This scope of work was recognized during the 2006 Rates proceeding as an implementation of good utility practice.

This program helps ensure that reliability and safety problems are identified and corrected, provides information needed to plan replacement of defective poles and equipment, and ensures valuable asset information is obtained that will improve the management of the line assets in the future.

The 2008 spending requirement for this program is $13.4 million. These expenditures are required to complete line inspections as required by the OEB, remain on schedule to complete the data collection by 2010, and assess poles during inspections.

The 2008 spending is similar to 2006 expenditures.

Reduced funding for this work will prevent Hydro One Distribution from realizing the benefits that can be achieved by having more detailed information on its asset base.

The lines data collection is in the early stages, however the Company is starting to see the benefits from a planning and work execution perspective. The line data collected to date has provided benefits in a number of areas, including; allowing more accurate identification of the number of wood poles requiring replacement; providing a centralized repository of line defects that enables more efficient scheduling and bundling of work for field crews; and reducing the time for job planning and site visits, and easier identification of the work location through the availability of geographic coordinates.

2.2.2.2 Preventative and Corrective Maintenance

Hydro One Distribution's lines preventative maintenance program includes equipment maintenance that is carried out primarily on a time based schedule and adjusted based on the Preventative Maintenance Optimization (PMO) approach.

The equipment maintained includes line reclosers, line regulators, three-phase airbreak switches, underground and submarine cable and insulator washing to remove salt accumulation at locations where there has been a history of problems. There are approximately 17,000 reclosers, 3,000 line regulators, 1,500 three phase switches. The

2008 plan is to maintain 1,850 reclosers, 150 line regulators, 150 three-phase switches, 500 pad mounted transformers at underground cable locations and wash insulators on about 8,000 structures. The projected 2008 spending requirement for these activities is $3.8 million.

Distribution line defects such as broken guy wires, damaged insulators, and defective lightning arresters are identified and logged during line patrols as described in Section 2.2.2.1 under this Schedule. The defects identified are categorized based on the requirements of the Distribution System Code and corrected in an appropriate time frame.

As well as the normal deterioration that is addressed through the end of life component replacement programs and ongoing defect corrections, Hydro One Distribution has identified several system wide problems that need to be addressed in the near term. One such system wide problem is a type of polymeric insulator known as EPAC that has a history of failing prematurely due to a design flaw that allows moisture ingress under the polymeric cover that protects the fiberglass rod. This situation has resulted in insulator failures well before the expected end of life and has required the implementation of work restrictions to address safety risks. These insulators as well as other defective line components are identified during the patrols and scheduled for corrective action. The 2008 spending requirement for defect corrections is $9.9 million and includes the replacement of 6,500 EPAC insulators 3,850 other insulators and about 9,000 other defects that need to be addressed to ensure the reliability and safety of the distribution system.

The 2008 spending requirement for the preventative and corrective maintenance programs is $13.7 million which maintains the spending for the bridge year. The increase in expenditures over historic amounts is attributed to the need for addressing an increase in defects identified during line patrols and a greater emphasis on equipment maintenance with a goal of improving reliability.

Reduced funding in the preventative maintenance program will reduce the performance of line protective and isolating equipment needed to minimize customer impacts during power interruptions. Reductions in the corrective program will increase the failure rate of equipment and line components, resulting in more frequent and longer duration outages to customers and increased safety risks. Reductions will lead to a deteriorating trend in reliability over time.

2.2.2.3 Sentinel Lights

The sentinel light program provides outdoors dusk-to-dawn lighting for rural customers and has been in existence in Ontario for over 20 years. Hydro One Distribution has a contractual obligation to honour commitments made by the former Ontario Hydro for present installations, but no longer accepts requests for new sentinel light installations.

The current inventory of sentinel lights totals about 41,100 and drives an annual maintenance program between 4,000 and 5,000 maintenance responses.

The 2008 spending requirement for this program is $1.6 million. The forecast is based on historic volumes with adjustments made to incorporate recent trending in volumes and cost. The projected spending maintains historic averages.

Hydro One Distribution is required to honour agreements currently in place, as such, there is no alternative other than to respond to the maintenance requests.

2.2.3 Waste Management and PCB Lines Transformer Oil

This program ensures that wastes generated during the course of maintaining distribution assets are managed in an environmentally responsible manner and in compliance with Federal, Provincial and Municipal regulations. Oils are used in a number of equipment types and may enter the environment should equipment fail. In such instances, Hydro One Distribution must respond to minimize impacts to the environment.

The 2008 funding, along with spending levels for the bridge and historic years, are provided in Table 6 below.

Table 6
Waste Management
($ Millions)

Description	Historic			Bridge	Test
	2004	2005	2006	2007	2008
Waste Management	2.7	2.8	3.2	3.1	3.0

2.2.3.1 Waste Management

Once transformers and other distribution equipment are removed from service, there is a requirement to manage the solid and liquid waste materials, which includes reporting of PCB inventories to regulatory authorities, disposal and destruction of these inventories, disposal of non-contaminated oils, and management and disposal of other wastes. Waste and PCB management will be an ongoing activity as Hydro One Distribution has 475,000 distribution line transformers and a number of other equipment types that will generate wastes as they are removed from service. These wastes will need to be managed in an environmentally approved manner

.

The 2008 spending requirement for this program is $3.0 million, which maintains the amount being projected for the bridge year and is slightly less than the 2006 expenditures.

Reduced funding in this program would impact Hydro One Distribution's environmental stewardship commitment for responsible waste management and hamper the ability to comply with waste management regulations.

2.2.3.2 PCB Lines Transformer Oil

Distribution pole-mount and pad-mounted transformers manufactured prior to 1980 contain insulating oil that may contain polychlorinated biphenyl (PCB) compounds. Regulations at this time place strict due diligence requirements on situations where PCB's have potential to enter the environment or have entered the environment as a result of transformer failure or oil leakage, but there are no regulations mandating the elimination of PCB contaminated oil. Environment Canada is proposing to change regulations to eliminate PCB contaminated oil above 50 ppm by 2014 in pad-mount transformers and by 2025 in pole-mount transformers. Hydro One Distribution has elected to wait until regulations are enacted before a plan is implemented to test and inspect transformers, and as such the 2008 program does not include any funding for proactive PCB testing and inspections of line transformers. Should Environment Canada regulations be enacted as currently proposed, it is estimated that Hydro One Distribution will be required to test about 200,000 transformers prior to 2025 at an annual cost of about $8 million. It is emphasized that this application does not contain any allowance to fund transformer oil sampling and testing should Environment Canada proceed with the regulations as proposed.

The proposed Environment Canada regulations, if enacted, will not only increase OM&A spending, but will also require the replacement of transformers with PCB levels above the 50 ppm threshold. Based on previous testing results for PCB content, about 10% of those transformers tested (pre 1982) will require replacement at an average capital cost of about $4 million per year. These costs are not included in any 2008 capital programs.

2.2.4 Other Services

Lines sustaining OM&A also covers a number of other miscellaneous services listed in Table 7.

Table 7
Sustaining OM&A – Other Services
($ Millions)

Description	**Historic**			**Bridge**	**Test**
	2004	**2005**	**2006**	**2007**	**2008**
Customer Inquiries (d)	2.8	3.8	3.2	3.8	3.5
Investigations & Data Collection (d)	1.6	2.4	1.0	1.2	1.0
Miscellaneous Services	2.9	3.2	3.2	6.2	4.9
Total	**7.3**	**9.4**	**7.4**	**11.2**	**9.4**

(d) – indicates this is a demand program

Customer Inquiries provides for the work required to respond to inquiries concerning customer services, bills, location of Hydro One Distribution assets on customer properties, planned and unplanned outages, power quality complaints, clarifications on policies, etc. Approximately 9,000 customer inquiries are processed annually.

Investigations and Data Collection captures the work required to respond to requests for detailed information on distributing station and line assets. This program addresses information requirements related to the condition of the assets, public and employee safety hazards, unacceptable system performance, audit of joint use facilities and data required to support response to customer reliability concerns.

Miscellaneous Services covers a number of activities including: payments to other LDCs for pole rental where Hydro One Distribution wires are supported by other LDC's poles; LDC switching requests; funds to collect and report data for a number of service quality indicators to the Ontario Energy Board on an annual basis; miscellaneous engineering and environmental support; Corporate Environmental Health and Safety activities. Environmental Health and Safety includes activities required to meet legal obligations, ensure a level of due diligence that is appropriate for Hydro One Distribution and assist in meeting safety targets. Included in Environmental Health and Safety are costs for technical and safety training, work method support, incident management, compliance reviews, work place inspections, and public safety awareness.

Work on these programs requiring an appointment at a customer's residence or requiring a written response to a customer inquiry contributes to Hydro One Distribution's performance on the "Appointments" and "Written Response to Inquiries" service quality indicators specified by the OEB in the Electricity Distribution Rate Handbook, Sections 15.1.4 and 15.1.5, respectively.

The 2008 spending requirement for this program is $9.4 million, and is based on historic customer demand and forecasted workload. The 2008 spending is 17% greater than the historic average. The increase over average historic expenditures is primarily attributed to an increasing focus on Health and Safety consistent with the company's strategic goals.

2.3 Metering

Hydro One Distribution currently owns and maintains revenue meters of three main types as follows:

- Retail Meters
  - About 1.2 million meters measuring energy consumption for residential and other customers whose average monthly demand is 50 kW or less.
  - About 7,300 electronic demand meters for smaller business customers with an average monthly electricity demand of greater than 50 kW.
  - About 1,300 interval meters for existing business customers whose demand exceeds 1,000 kW, recently connected customers whose demand exceeds 200 kW and customers below the threshold who have requested interval meters.
- Smart Meters – Advanced metering devices and components of a metering system with functionality to bill customers on the basis of Time of Use (TOU) pricing. These will replace the existing 1.2 million energy meters by 2010.
- Wholesale revenue meters used to settle the purchase of energy where the point of supply is directly connected to the IESO-controlled grid. A number of these meters are transitioning from Transmission to Distribution as noted below.

OM&A expenditures are required to ensure that all metering installations are maintained properly, replaced when needed and verified in accordance with requirements of the Electricity and Gas Inspection Act (E&GIA), Measurement Canada and the market rules. In 2007 and 2008, metering sustaining OM&A expenditures are significantly affected by the full deployment of the Smart Meter Program.

The funding for distribution revenue metering for 2008, and spending levels for the bridge and historic years, is provided in Table 8 below.

Table 8
Metering OM&A
($ Millions)

Description	Historic			Bridge	Test
	2004	**2005**	**2006**	**2007**	**2008**
Customer Retail Meters	8.0	7.2	8.1	8.5	6.0
Smart Meters	-	2.4	4.9	6.2	9.7
Wholesale Revenue Meters	0.2	0.7	1.0	1.0	1.9
Total	**8.2**	**10.3**	**14.0**	**15.7**	**17.6**

2.3.1 Customer Retail Revenue Meters

Of Hydro One's existing 1.2 million retail meters, about 500 must be removed and replaced each year due to random failures, damage or obsolescence. In addition, under the E&GIA and regulations, all revenue meters must be routinely inspected, maintained and their accuracy verified by an accredited meter verifier. A statistically derived sample group of about 2,000 meters is tested annually, according to a sampling program monitored and regulated by Measurement Canada. Normally the samples pass, but a failure of a sample group entails replacement of all meters in that group which could require the replacement of 10,000 meters.

Meters that do not qualify to be sampled, such as commercial or industrial meters, require all seal meters to be verified. These verification averages between 8,000 to 12,000 meters per year.

To avoid inefficiencies which would result from the testing and verification of installed meters, followed by their near term replacement by smart meters, Hydro One Distribution received a dispensation in 2006 from Measurement Canada which allows meters coming due for verification from 2008 through 2010 to remain in place without verification. This dispensation applies only to meters that have been demonstrated to retain a high level of accuracy, comprising about 75% of the sample group population. The remainder will continue to be tested and re-verified annually as planned.

For its demand and interval-metered customers, Hydro One Distribution is currently examining smart meter options with appropriate communication platforms and once these are determined, will develop and implement smart metering plans. The current meters, however, will continue to need expenditures focused on routine maintenance, re-sealing, verification, trouble calls and other sustaining activities.

The 2008 spending for this program is $6.0 million, $2.5 million less than for 2007. This funding level is based on an assessment of historic costs and projected meter verifications, while accounting for estimated savings of $2.8 million from reduced meter testing and replacement due to the Measurement Canada dispensation. The 2008 spending is 22% less when compared to average historic expenditures. The reduction is again attributed to the Measurement Canada dispensation.

2.3.2 Smart Meters

This section of the evidence describes the OM&A expenditures related to Hydro One Distribution's Smart Meter Program. Capital requirements are described at Exhibit D1, Tab 3, Schedule 2 and at Exhibit D2, Tab2, Schedule 3, S19. Distribution Regulatory Asset account information associated with the Smart Meter Program is filed at Exhibit F1, Tab 1, Schedule 1

In 2007, in line with legislative and regulatory requirements, Hydro One Distribution began full implementation of its Smart Metering Program, including smart meter deployment, communication network "build-out," and customer information system

(CIS) and associated process re-engineering, to enable it to support TOU and Regulated Price Plan (RPP) implementation.

These installations require on-going sustaining investments, with expenditures of $9.7 million in 2008. This spending requirement reflects the continuing deployment of smart meters through Hydro One Distribution's service territory, toward its target of about 1.2 million meter installations by 2010. The related sustaining activities and costs encompass both minimum and incremental functionality work:

- Activities associated with the government's regulations concerning minimum functionality, which account for $6.2 and $5.8 million in 2007 and 2008 respectively, include the following work:

    - maintaining and operating hardware, software and software licenses associated with the advanced metering control computer (AMCC);
    - telecommunication charges associated with operating the local area networks (LANs) and wide area network (WAN); and,
    - maintaining and operating smart meters and the network devices that have been placed into service.

- Incremental functionality activities associated with effective use of the smart meters to provide time-differentiated billing to customers and provide Hydro One the ability to leverage its Advanced Metering Infrastructure (AMI) system for other business benefits, which account for $0.0 and $3.9 million in 2007 and 2008 respectively, include the following work:

    - managing, developing and implementing business process re-design (e.g. manual to automated meter reading for on-cycle and off-cycle reads), change management (including staff training) and customer communication related work;

- responding to a higher number of customer inquiries as a result of pre- and post-installation of smart meters on customer premises; and,
- Maintaining the changes required to the CIS system (new processes, workflow and tariffs) and the systems and interfaces necessary to integrate to the AMCC and the IESO's meter data management and meter data repository (MDM/R).

The 2008 expenditure level of $9.7 million is about $3.5 million higher than for 2007, reflecting higher costs for on-going IT-related and meter maintenance. Spending on smart meter program contributes to lower costs in other program areas. In addition to the estimated savings of $2.8 million in customer retail meter maintenance costs resulting from reduced meter testing and replacement due to the Measurement Canada dispensation, as discussed in Section 2.3.1 of this exhibit, there are also estimated savings of $1.4 million in 2008 as a result of reduction in the number of manual meter reads related to the smart meter program, as discussed in Section 2.1.2 of Exhibit C1, Tab 2, Schedule 5.

A fuller description of the Smart Meter Program is provided in Exhibit D1, Tab 3, Schedule 2 and in the IJD in Exhibit D2, Tab 2, Schedule 3.

2.3.3 Wholesale Revenue Meters

Since 2003, in accordance with market rules, accountability for legacy wholesale revenue meters (WRMs) owned by Hydro One Transmission, but used to settle Hydro One Distribution purchases from the IESO-administered market, have been transitioning to

Hydro One Distribution. By the end of 2008, Hydro One Distribution will have assumed accountability for a projected 375 WRMs.

As Hydro One Distribution is an IESO-registered meter service provider it will provide all servicing for its WRMs, i.e. preventative maintenance, meter re-sealing and verification, response to problems, corrective services and IESO registration. Funding for this program includes these services and is required to ensure accurate wholesale billing by the IESO, and to comply with the market rules and Measurement Canada regulations.

The 2008 spending for this program is $1.9 million and is based on known costs and volumes. The 2008 spending is greater than the bridge year and greater than historic expenditures as the number of meters to maintain has gradually increased due to the transition of the WRMs from Hydro One Transmission to distribution as required by the market rules.

2.4 Vegetation Management

The Vegetation Management program manages clearances to energized equipment to maintain an acceptable and sustainable level of reliability; manage safety hazards that trees in proximity to energized lines pose, manage plant species on the right of way floor to permit worker access for maintenance and restoration of power, and minimize environmental, ecological and social impacts.

There are approximately 101,000 km of lines on rights-of-way, with most requiring tree trimming or removal, and brush (undergrowth) control. Tree growing conditions vary throughout Ontario, which contains three forestry zones. The predominate region is the temperate hardwood forests which includes areas of the south, east and as far north as Wawa & New Liskeard. The other two regions include the deciduous forests of southwestern Ontario and the boreal forests of parts of northern Ontario. Tree species indigenous to the southern part of the province, and better growing conditions usually results in more frequent maintenance cycles in the south than in the north.

Vegetation management activities include line clearing comprising of tree removal and trimming, brush control, customer notification, vegetation asset condition assessment, and unplanned maintenance in response to reliability and customer issues as required. The annual program is compiled using the following inputs: vegetation condition data, tree clearances to energized facilities, and recent reliability data and customer issues.

Vegetation Management work is divided into 5 programs with proposed funding for 2008 along with spending levels for the bridge and historic years provided in Table 9 below.

Table 9
Vegetation Management
($ Millions)

Description	**Historic**			**Bridge**	**Test**
	2004	**2005**	**2006**	**2007**	**2008**
Unplanned Maintenance (d)	6.2	5.3	6.1	6.9	6.0
Customer Notification	6.9	6.8	6.8	6.5	7.9
Asset Condition Assessment	0.5	0.2	0.5	0.5	0.5
Line Clearing	55.6	52.9	50.6	74.1	76.8
Brush Control	19.6	21.1	25.2	26.9	28.2
Total	**88.9**	**86.4**	**89.1**	**115.0**	**119.4**

(d) – indicates this is a demand program

The 2008 spending on the vegetation management program is $119.4 million, which is about 35% greater than average historic expenditures. The reason for the increase is primarily attributed to increase levels of accomplishment in line clearing (accomplishment increased by 35%) and brush control (accomplishment increased by 25%), for the reasons discussed below.

Vegetation management is the largest program managed by Hydro One Distribution and has the greatest impact on system reliability. As noted in Section 6 of Exhibit A, Tab 3, Schedule 1, tree-related contacts accounted for 57% of SAIDI and 28% of SAIFI between 2003 and 2006, and the negative impact of trees during storm events were especially acute. As such, vegetation management presents the greatest opportunity to improve reliability.

Hydro One Distribution proposes to increase spending in a prudent and gradual manner for maintaining vegetation on its rights-of-way, taking into account the availability of resources.

The need for increasing the accomplishments in line clearing was highlighted on page 31 of Exhibit C1, Tab 2, Schedule 2 of the 2006 Distribution Rates application under proceeding RP-2005-0020/EB-2005-0378, and is repeated below:

"Hydro One Distribution's goal is to continue to increase accomplishments for line clearing with an objective to reach an optimum cycle from a reliability perspective of eight years by 2008. Annual accomplishment would have to increase from the current 10,360 km to 12,500 km."

The proposed 2008 accomplishments for vegetation management is 12,500 km of rights-of-way line clearing and 12,500 km for brush control, which maintains Hydro One Distribution's strategy to gradually improve the condition of its rights-of-way, as articulated in 2006.

Accomplishments over the 2004-2006 period have averaged 9,300 km for line clearing and about 10,000 km for brush control. The accomplishments during this period were below plan because the 2005 program was impacted by a labour disruption and the 2006 program was affected by the redirection of resources to respond to the unusually high number of storms in that year. Accomplishments in 2007 were 12,211 km for line clearing, which is above historic values and partially offsets the shortfalls during the previous two years.

Details concerning each of the components that make up the vegetation management program are discussed in the sections below and additional information on vegetation management is also provided as part of the ACA discussion in Exhibit D1, Tab 2, Schedule 1.

2.4.1 Unplanned Vegetation Management

All of the 101,000 km of rights of way is situated in the public domain and the management of vegetation on and adjacent to the rights of way is of interest to many of the 1.2 million Hydro One Distribution customers, property owners, municipalities, and government ministries. Each year these groups identify vegetation issues that need to be addressed during the current year in order to ensure customer reliability and public safety. Unplanned work initiated by the public includes the removal of hazard trees that may fall into a line and restoring clearances to energized equipment at locations that are not within the current years planned program.

A number of the reliability issues that develop each year need to be addressed during the current year in an off-cycle manner. A portion of the unplanned funding is allocated to address unforeseen system reliability problems cause by tree or underbrush growth.

The 2008 spending requirement for this program is $6 million which is similar to historic expenditures. This is a demand program that is needed to respond to customer and reliability issues during the current year, as well as responding to and managing safety risks to the public.

2.4.2 Customer Notification

Prior to commencement of line clearing and brush control, customer approval is acquired to gain access onto private property and to resolve issues concerning tree removal, trimming and control of brush, as well as obtain input from customers concerning any property restrictions and environment concerns. During this phase of the work, job planning and project layouts are completed, a detail scope of work is prepared and approvals are obtained from property owners, Municipalities, Ministry of Natural Resources, etc. These planning and project management activities are essential for Hydro One Distribution to complete its annual vegetation management work programs, (i.e., line clearing and brush control) with minimum disruptions, and to manage customer and property owner concerns in a responsible and proactive manner.

The 2008 spending requirement for this program is $7.9 million. The amount is approximately 15% above historic expenditures. The primary reason for the increase is higher volume of notification associated with increases in line clearing and brush control program for 2008.

Reductions in this program will see an increase in customer complaints, incomplete approvals to enter properties to carry out work, and expected disruptions to planed work as a result of property owner intervention. As well, with disruptions in the flow of planned work, one can expect unit costs to increase with the larger line clearing and brush control programs.

2.4.3 Asset Condition Assessment

Asset condition assessment is an integral aspect of the asset management approach and is generally completed about 2 years prior to the time projected for line clearing. Information obtained includes vegetation height, tree and brush densities and clearances to conductors, and this information is then used to prioritize and schedule work. For further details concerning the condition of vegetation on Hydro One Distribution's rights of way refer to Exhibit D1, Tab 2, Schedule 1.

The 2008 spending requirement for this program is $0.5 million, and is consistent with historic expenditures.

Reductions in this program will result in planning inefficiencies that will seriously reduce the effectiveness of the larger brush control and line clearing programs.

2.4.4 Line Clearing.

Line clearing includes: removal of damaged or diseased trees along the edge and on the rights-of-way that pose a threat of falling into a line; and tree trimming required to maintain clearances to energized facilities, thereby reducing the likelihood of power interruptions. On average there are slightly more than 50 trees per kilometer that need to be removed or trimmed on the distribution system, and during 2006 Hydro One Distribution removed and trimmed about 480,000 trees in total. This program maintains tree clearances and reduces risks of danger trees, and as such has a great potential to improve reliability.

For 2008, Hydro One Distribution is proposing an accomplishment of 12,500 km. This volume of work is needed to reduce the high negative impacts vegetation have on reliability of the distribution system under more normal conditions and during storm events. The impact that vegetation has on reliability can be seen in Table 10 below.

Table 10: Total SAIDI and Vegetation Contribution

Year	All Interruptions (hrs)			Force Majeure Events (hrs)		
	Total	Tree Contribution	Tree %	Total	Tree Contribution	Tree %
2003	15.1	8.9	59%	7.1	6.0	84%
2004	6.9	2.0	29%	0.4	0.2	39%
2005	14.5	7.9	54%	6.5	5.4	83%
2006	28.4	18.1	64%	21.3	16.2	76%
Total	**65.0**	**36.9**	**57%**	**35.3**	**27.8**	**78%**

The impacts of trees on Hydro One Distribution's system is significant. Considering all interruptions, trees on average account for about 57% of SAIDI and during *force majeure* events the impacts increase to an average of 78% with a high of 84%. The planned 35% increase in the volume of work will target the rights-of-way contributing most to unreliability on Hydro One Distribution's system, and should make appreciable improvements over time to the benefit of our customers. Hydro One believes its plan demonstrates good utility practice and addresses customer reliability. Hydro One Distribution monitors the performance of its distribution system on a continual basis and once the 12,500 km accomplishment is achieved, the need for further improvements will be re-assessed. This topic is further discussed as part of the ACA in Exhibit D1, Tab 2, Schedule 1.

The 2008 spending requirement for this program is $76.8 million. The increase over historic years is about 45%, primarily attributed to an increase in volume of about 35%.

Reduced funding in this program will allow the current tenuous situation to persist resulting in a highly variable reliability performance, as can be seen above, and an increase in safety hazards associated with vegetation in proximity to energized line facilities. Reductions in this program also increase the life cycle costs for vegetation management and thereby create future inefficiencies.

Evidence of the effectiveness of line clearing can be seen in the performance improvements achieved with feeders cleared during 2005. Table 11 below highlights the aggregate percentage improvements when comparing reliability in 2003 and 2004 (i.e. years prior to clearing) to that experienced in 2006 (year after clearing in 2005).

Table 11
2006 Reliability Improvements Attributed to Line Clearing in 2005

Measure	Improvement *
Average Customer Interruptions	33%
Average Customer Hours of Interruption	41%

* Excludes impact of force majeure events

As can be seen from the results in Table 11, customers connected to the lines cleared during 2005 received significant benefits, as their average outage durations were reduced by 41% and the number of customer interruptions were reduced by 33%. These results highlight the large improvements that can be achieved with more frequent line clearing.

2.4.5 Brush Control

Brush control involves the management of specific plant types on the right-of-way floor to minimize the presence of trees that can grow tall enough to contact the overhead lines. This program also provides a right-of-way that will facilitate access of equipment, inspection and maintenance activities, and emergency response.

Costs to control brush increases significantly once the height exceeds 3 meters and can more than double in cost if the brush is allowed to grow within the electrical limits of approach. Mechanical brush control methods and the requirement to use work procedures to ensure worker safety are the primary reason for the increase in cost. These methods are increasingly required as a result of community resistance to herbicide use. The level of accomplishment proposed for 2008 is the same as for line clearing and involves clearing brush on 12,500 km of rights-of-way.

The 2008 spending requirement for this program is $28.2 million which is about 28% greater than historic expenditures. This increase is primarily attributed to an increase in volume of about 25%.

Reduced funding in this program will increase unit cost for brush control and the overall life cycle cost. Reduced brush control also makes it more difficult to access the rights-of-way, which hampers emergency restoration and consequently increases outage durations.

DEVELOPMENT OM&A

1.0 INTRODUCTION

Development OM&A provides funds for the analysis needed to economically operate and develop the distribution system as necessary to meet existing and anticipated load and generation demands, while maintaining delivery system reliability. As well, Development OM&A ensures that standards are in place to meet distribution construction and planning needs, and legal and regulatory requirements.

2.0 DISCUSSION

Development OM&A provides funding for the collection of feeder voltage and current (loading) data and the analysis required to support system expansions, reinforcement and protection requirements. As well, generation connection studies are undertaken to evaluate the impact of connecting new or modified generation projects to the Hydro One distribution system as per the requirements of the Distribution System Code.

The Standards and Technology OM&A program covers the development of new, and the review of existing technical distribution standards. Some revisions to existing standards or the development of new standards, are made in response to compliance requirements set by authorities outside Hydro One Distribution, such as the Electrical Safety Authority (ESA). The Technology portion of the program encompasses Research and Development projects.

The funding for 2008, along with the spending levels for the bridge and historic years are provided in Table 1 below.

Table 1
Summary of Development OM&A
($ Million)

Description	Historic			Bridge	Test
	2004	**2005**	**2006**	**2007**	**2008**
Data Collection, Engineering and Technical Studies	2.7	2.0	2.8	5.2	5.2
Standards and Technology	2.8	2.8	1.3	2.8	3.9
TOTAL	**5.5**	**4.8**	**4.2**	**8.0**	**9.1**

The increase in overall spending for 2008 relative to historic expenditures is attributed to a need to assess Long Term Load Transfers, added costs to prepare for the increase in generation connections and an increased business need for technical standards and specifications. Additional details are provided further on in this Schedule.

2.1 Data Collection, Engineering and Technical Studies

To ensure that up to date and accurate information is available on the operating characteristics of the distribution system, data is collected on an annual basis for use in assessing the adequacy of equipment and supply lines to meet system and customer needs. A portion of the OM&A Development program funds the collection of this data during high load conditions on a sampling basis, using electronic recording ammeters.

Investments in System Capability Reinforcement for lines and stations (Exhibit D1, Tab 3, Schedule 3) are based on system utilization, i.e., voltage and current, and reliability performance information. Distribution Development OM&A also funds studies to determine system capability and reinforcement needs, and thereby, investment levels required to ensure reliable operation of the electrical system. Other studies are needed to ensure compliance with the Distribution System Code and associated supply standards (e.g., voltages maintained within acceptable limits). The program also provides funding for high-end technical support needed to address customer specific issues in areas such as power quality investigations. This work is of a continuous and ongoing nature and is required to avoid deterioration of service.

The required number of studies is based on operational and customer issues, and system performance issues identified through ongoing analysis of the system, equipment and feeder operating characteristics.

An example of activity under this program would be the collection of feeder loading data with further analysis to identify a distribution feeder that has experienced steady load growth due to the addition of many small services over time. The feeder loading survey and analysis of data would identify the issue of a feeder nearing its rated capacity, so that alternative solutions can be studied with eventual implementation of a preferred plan.

The 2008 spending requirement for this program is $ 5.2 million, and represents a 100% increase from average historic expenditures. The increase is primarily attributed to three factors:

- Evaluation of Long Term Load Transfers (LTLTs) to comply with the Distribution System Code requirement that Local Distribution Companies eliminate all LTLTs by January, 2009.
- The need for increased electrical system modeling to prepare for the anticipated increase in generation connections. Locations selected for modeling are identified by interested parties as likely locations for wind and other small generation.
- Increased analysis of the distribution system to ensure protections function as intended and are synchronized, to ensure operating conditions remain within equipment ratings and to address phase imbalance thereby reducing line losses.

Reduced funding of this program would result in a lack of data available on which to base distribution system investment decisions, inability to properly analyze the needs of the system to meet existing customer and new connection requirements. More specifically, there would be an inability to meet expected time lines for processing and connecting new generators. Direct impacts of reduced funding include an increased risk of electrically overloading system assets and allowing the delivery system performance to deteriorate, leading to declining reliability for customers and service quality degradation, e.g., equipment damage, voltage degradation, increased frequency of outages, and increased outage duration.

2.2 Standards and Technology

Technical standards form a collection of comprehensive references used as templates and productivity tools to efficiently and effectively carry out operating, maintenance, and capital programs. Standards also incorporate company policies and requirements to ensure compliance with regulations such as the Electrical Safety Code. The collection includes over 350 planning, design and maintenance specifications, 500 material specifications and 800 drawings.

This program covers the development and maintenance of distribution standards, which are driven by public and worker safety, equipment obsolescence, evolving regulatory requirements, technological advancements and changes in work methods. Hydro One Distribution monitors and influences emerging industry standards and requirements for new standards mainly through its participation in Canadian Standards Association working groups.

The Technology program provides the funding to monitor, assess the benefits, and evaluate the feasibility, of emerging technologies, and enable the implementation of new tools and methods. Hydro One Distribution monitors emerging technologies mainly through its participation in industry interest groups that include CEA Technologies Inc. (CEATI) and Electric Power Research Institute (EPRI). Where possible, the Technology program expenditures are leveraged through those interest groups by jointly funding projects with other utilities that have similar interests or challenges.

The 2008 spending requirement for this program is $3.9 million, which is 39% greater than 2004, 2005 and 2007 expenditures. The increases are primarily attributed to the following:

- Added due diligence to document and approve standards and provide technical review to manage field modifications in order to comply with new ESA requirements.
- Added research and development to understand and address the complexities associated with generation connections and the development of new standards for generation connections.

The lower spending during 2006 was primarily attributed to delays in research and development work until formal agreements could be reached with the primary vendor. The delay has also deferred spending for 2007 research and development. As well, 2006 was a transition year for ESA compliance, as such plans were under development but not implemented and resources had not been fully assigned to the required tasks.

Reduced funding would result in the unavailability of sufficient standards to meet regulatory requirements, construction and planning needs and to effectively deal with technical issues associated with generation connections. Opportunities to utilize emerging technologies would be missed with increased longer term costs as a result.

OPERATIONS OM&A

1.0 INTRODUCTION

Operations OM&A investments are required to manage the day to day flow of electricity within Hydro One Distribution's system. The Operations function coordinates and dispatches crews to restore power as required, schedules and coordinates planned outages and provides customer notifications, and monitors and reports on the performance of the distribution electricity system.

2.0 DISCUSSION

Distribution System Operations activities are carried out centrally at the Ontario Grid Control Centre (OGCC) using modern technology and systems. OGCC is a shared facility which allows central operations of the distribution and transmission systems and is backed up by facilities located at a separate site.

The cost assigned to Hydro One Distribution for Distribution Operations at OGCC is based on the "Rudden" cost allocation study discussed in Exhibit C1, Tab 5, Schedule 1.

Operating control of the distribution and transmission systems was consolidated at the OGCC during 2003 and 2004 through the combination of Hydro One Distribution's Central Operations with Hydro One Transmission's real-time operation of the transmission system. This consolidation enabled several ongoing efficiency and effectiveness benefits:

- Reduced staffing costs through allocation of staff between transmission and distribution operations, taking advantage of the general non-coincidence of workload between these two functions.
- Improved effectiveness through real-time communication and coordination of priorities between transmission restoration and distribution restoration.
- Reduced staff development costs through sharing of training programs and facilities.
- Reduced support and systems costs through sharing of common infrastructure.

A suite of systems and tools is used to aid in the monitoring, planning, and maintenance of the distribution system. Hydro One Distribution has been proactive in assessing and implementing technologies to improve the operation of the distribution system and the consolidation to one centre further facilitates assessment and implementation of these systems.

The primary systems in place are as follows:

- The ***Distribution Operating Maps and Distribution Station Diagrams*** are the legacy tools that continue to be used by field crews and, to a lesser extent, by OGCC to provide the picture and detailed information showing the configuration of the distribution system, and to ensure the safe isolation of equipment.
- The ***Network Management System (NMS)*** is the supervisory control and data acquisition (SCADA) tool. It provides the real-time voltage and loading on the sub-transmission circuits at the transformer station as well as monitoring and control of the status of the breakers feeding those circuits.
- The ***Outage Response Management System (ORMS)*** is the distribution outage management tool that automatically analyses no-power calls received at the customer call centre and pinpoints the location of outages, identifies all affected customers and facilitates optimal dispatch of field crews.

- The ***Interactive Voice Response (IVR)*** system is the tool used to advise customers of the status of an outage affecting them. The IVR is set automatically by the ORMS after it has determined all affected customers for an outage location. This significantly reduces the call volumes that agents need to handle at the Customer Call Centre.
- The ***Provincial Mobile Radio System*** is the means by which both the OGCC and the field operations centres maintain continuous contact with field crews. It is designed to be reliable in the event of a widespread blackout and at all remote locations where field crews would be dispatched.
- The ***OGCC Integrated Voice System*** which allows Central Operations to effectively manage voice communications using multiple paths of communication, such as the public telephone network, public cell phone network, Hydro One's Distribution's provincial mobile radio system and mobile satellite telephone system.
- ***The OGCC Emergency Response Services Information System*** which provides verified up-to-date contact numbers for all emergency response services (e.g. police, fire, ambulance, ministry of environment, gas utilities, etc.) across the province keyed in a Geographical Information System to their service territories.

The OGCC is the operating authority for Hydro One Distribution's 44/27/13 kV systems (i.e., from the transformer supply station to the distribution supply station). During real-time operations, the OGCC monitors the distribution system at the transformer supply stations for correct voltage levels, power quality, equipment loading, and equipment alarms.

Distribution Operations is divided into two programs, Operations and Operating Support, with the funding for 2008 and the spending levels for the bridge and historic years provided in Table 1 below.

Table 1
Operations OM&A
($ Millions)

Description	**Historic**			**Bridge**	**Test**
	2004	**2005**	**2006**	**2007**	**2008**
Operations	13.0	8.1	10.8	8.5	9.5
Operating Support	3.3	3.2	4.1	4.1	3.9
Total	**16.3**	**11.2**	**14.9**	**12.6**	**13.4**

2.1 Operations

The Operations program funds the real time distribution operating functions, training of staff, and ensuring that the various systems and tools are kept current and functioning as required.

Specific functions include managing planned and unplanned outages, coordinating emergency response and monitoring system performance. These activities are described in greater detail below.

2.1.1 Managing and implementing planned outages: all outages on the distribution system are managed at the OGCC. Planned outages are about 10% to 15% of all Hydro One Distribution customer outage durations. Applications for planned outages are coordinated to capture efficiencies and mitigate impacts on customers. This involves:

- Assessing all equipment involved in the outage to determine appropriate limits and control actions.
- Identifying and notifying customers of upcoming outages using means such as auto-dialer, phone, fax, newspapers, flyers, radio, and door to door visits.

- Addressing customer concerns regarding outages by moving, where possible, the outage times/date, transferring customers to other distribution sources, or providing a back up source.
- Applying the Utility Work Protection Code to all outages to ensure all safety barriers are established.

2.1.2 Responding to and managing unplanned outages: equipment failures, tree/vegetation contact, road accidents, severe weather, and lightning result in interruptions to the distribution system and cause unplanned outages. Unplanned outages account for about 85% of Hydro One Distribution total customer outage durations. The cost of wide-area rural telecommunication and monitoring and control equipment has prohibited the use of real-time monitoring and remote controls on Hydro One Distribution's system. Hydro One Distribution accordingly relies on "no-power" phone calls from customers to detect and locate distribution system outages. All restoration measures depend on field crews responding to the location of the outage. Once the location of the faulted equipment is determined, the OGCC dispatches repair crews. The OGCC tracks all crews that have been dispatched to effect repairs and is able to manage response times by following repair status. Affected customers are kept advised of the interruption status through the use of an interactive voice response (IVR) system, which informs callers that the problem is known and that crews have been dispatched, as well as providing an estimated time of power restoration if known.

2.1.3 Emergency response coordination: when the Hydro One Distribution system experiences widespread interruptions due to weather impacts, an emergency response system is implemented. The level of response varies according to the area(s) and number of customers affected and the expected duration of the problem. The OGCC will dispatch crews normally until a decision is made, based on volume of power-off calls, to move to "Field Operations Center Dispatch" mode. In this mode, customer power-off calls are spread out over the field operations centers to allow supervisors to dispatch crews at a more local level and manage their resources efficiently. If the emergency is significantly widespread, incident command centers (ICCs) and forward command posts (FCPs) are established to centralize a command structure to address resources, equipment needs, and restoration activities. The OGCC provides media notifications to keep Hydro One Distribution customers advised and it provides municipalities and agencies with outage progress updates.

Following the 1998 Ice Storm and in preparation for Y2K, Hydro One Distribution developed a formal Emergency Preparedness Program (EPP). The EPP consists of emergency response plans, procedures, designated facilities and a trained and tested emergency response organization. Maintaining an effective and efficient Emergency Preparedness Program is a market rule requirement.

2.1.4 <u>Acquire system performance information, internal reporting and performance monitoring:</u> Reliability information is needed to support sustainment and development decisions, respond to emerging problems, and report on system performance to the Ontario Energy Board, customers and other stakeholders. Data required to calculate the standard reliability indices such as SAIDI (System Average Interruption Duration Index), SAIFI (System Average Interruption Frequency Index), and CAIDI (Customer Average Interruption Duration Index) is acquired at the OGCC. Outage inquiries from customers are reviewed and the data extracted from the various systems to advise customers what has been done as well as establish additional plans.

2.1.5 <u>Summary:</u> The 2008 spending requirement for this program is $9.5 million which is within the range of historic expenditures. These costs have fluctuated somewhat over the years, due to several factors. 2004 was the last year for higher expenditures relating to the consolidation of transmission and distribution operations at the OGCC. Lower demand in 2005 resulted in spending which was slightly lower than usual. Operations work and related costs were higher in 2006, as it was a higher than normal year for storm activity thereby requiring added efforts to manage restorations.

Distribution operations is an essential activity for the safe and reliable supply of power. Any funding reductions in this program would negatively impact customer reliability, efficiency of power restoration, and the safe operation of the distribution system.

2.2 Operating Support

As highlighted under the Discussion portion of this Schedule, Operations relies on a number of systems and tools to manage and operate the distribution system, as well as a Back-up Operating Facility.

Operating Support funds ongoing costs that include system configuration updates for ORMS, updates to the distribution operating maps and station diagrams, emergency preparedness, and the allocated portion of the maintenance and upkeep of operating facilities at the OGCC and the back-up operating facility. The historical fluctuation in funding for this program is due to variations in volume of updates to the distribution operating maps and station diagrams.

The OGCC came into service in 2004 and the Back-up Operating Centre came into full service in 2005. Funding needed for the Distribution allocation of the cost to sustain these facilities became part of this program in 2004.

The 2008 spending requirement for this program is $3.9M, which is within the range of historic expenditures with variations attributed to changes in volume of work associated with map and diagrams updates.

Reduced funding for this program would result in deterioration in the performance of ORMS and control room facilities to unacceptable levels, reduction in the accuracy of operating maps (which increases the safety risk to workers), and non-compliance with emergency preparedness obligations.

CUSTOMER CARE OM&A

1.0 INTRODUCTION

Customer Care OM&A represents the set of work activities required to provide customer care services to customers connected to the Hydro One Distribution system, to address the Company goal to improve customer satisfaction, and to meet or perform better than the relevant service levels stipulated in the Electricity Distribution Rate Handbook, Chapter 15, Service Quality Regulation.

The Customer Care Work Program includes service programs and projects. The main service programs are: meter reading, billing, settlements, customer contact handling and collections. Project work includes regulatory compliance initiatives and service enhancements.

The Customer Care services programs are provided to the approximately 1.2 million customers who are connected to the Hydro One Distribution system. These customers are in a variety of rate classifications, and include residential, seasonal, farm and general service customers, as well as local distribution companies, direct customers and generators with connection points embedded in the Hydro One Distribution system. The services are provided to customers purchasing electricity through Standard Supply Service or under Retailer contracts.

1.1 Customer Care Resources

The Customer Care services of billing, settlements, contact handling, and collections are delivered through the outsourcing contract with Inergi LP. The Inergi contract became effective on March 1, 2002 and the contract is described in Exhibit C1, Tab 2, Schedule 6.

Although these services are delivered by Inergi, Hydro One retains within the Company accountability for customer policy, planning, work program budgeting and service performance management. The focus of this work is to translate corporate customer objectives into Inergi service delivery results, and to build a healthy buyer-vendor relationship that allows Hydro One Distribution to benefit from the specialized expertise of the outsourcing partner. Hydro One resources also manage customer research and surveying, Customer Service System project management, and management of escalated customer complaints.

The meter reading service program and delivery of field support services are required for customer billing, settlements and collections, and these activities remain within Hydro One.

2.0 WORK PROGRAM FUNDING

The proposed Customer Care Work Program funding for the test year, and the spending levels for the bridge and historic years, are provided in Table 1 below.

Table 1
Customer Care Costs by Category ($ Million)

Description	Historic			Bridge	Test
	2004	**2005**	**2006**	**2007**	**2008**
Base Services	80.1	76.8	80.9	80.8	84.6
Bad Debt	11.8	9.7	17.3	13.5	13.0
Regulatory Compliance	7.1	6.6	4.1	0.7	3.6
Service Enhancements	4.0	3.1	1.4	2.1	2.6
TOTAL	103.0	96.3	103.7	97.1	103.8

The Base Services represent the largest cost component of the Customer Care Work Program, and include the provision of meter reading, billing, settlements, contact handling and collection services to Hydro One Distribution customers. Bad Debt is shown as a separate cost category.

Regulatory compliance work is required to implement government and regulator policies which impact Customer Care, such as the Bill 100 legislation or Regulated Price Plan, and distribution customer rate changes. Costs related to smart meters are not currently part of this work program. All smart meter OM&A costs are included in Exhibit C1, Tab 2, Schedule 2. Service Enhancements represent investment in service or productivity improvements to our customer service programs, such as initiatives to automate processes or introduce self-serve options.

The Total Customer Care Work Program increases by under $1 million over the period 2004 to 2008. The largest change is in the Base Services costs, due primarily to annual cost-of-living-adjustment (COLA) added to Inergi fees, and to a change in customer care management costs. This is offset by a reduction in spending on regulatory compliance projects.

The sub-sections that follow provide a description of each of the Customer Care cost categories.

2.1 Base Services

Table 2 below shows the breakdown of Base Service program costs for the historic and bridge years and the planned expenditures for the test year.

Table 2
Customer Care Base Services Cost Breakdown

Description	Historic			Bridge	Test
	2004	2005	2006	2007	2008
Customer Service Operations	37.8	35.5	39.0	39.3	40.5
Meter Reading	23.3	23.6	22.2	19.9	19.6
Other Field support costs	6.8	6.8	6.8	6.5	7.6
Other Service Support costs	9.3	8.4	8.8	8.7	9.8
Customer care management	2.9	2.5	4.1	6.3	7.2
TOTAL	80.1	76.8	80.9	80.8	84.6

2.1.1 Customer Service Operations

Customer Service Operations costs include delivery of billing, contact handling, collections and settlements services, and the customer services included in the contract with Inergi LP. The change in costs year-over-year represents the annual cost decline in base service fees contained within Hydro One Distribution's contract with Inergi, offset by growth in annual volumes, annual COLA amounts, and changes in scope of services delivered.

2.1.1.1 Billing

This service program covers delivery of the billing process, including validation and editing of meter reading data, bill calculation, exception handling, accuracy management, bill creation, insertion and issuance, and validation of receivables processing.

The majority of customers are issued monthly bills, but approximately 160,000 seasonal customers are issued quarterly bills and about 140,000 customers are billed bi-monthly.

Hydro One Distribution has implemented a number of initiatives to improve billing services for customers and manage billing costs. An electronic billing presentment and payment option was launched for Hydro One customers in 2007. Ongoing changes to the method of estimating consumption between actual meter reads have been implemented to better align consumption amounts to bills issued and to smooth out variances between bills. In addition, Hydro One has expanded the ability to receive customer self-reads. In 2008, Hydro One plans to promote Summary Billing to more customer segments, and promote self-service options on the Hydro One website.

2.1.1.2 Contact Handling

Hydro One's Distribution customers contact the Company in many ways: by telephone, letters, faxes, email, via self-service features on the Interactive Voice Response (IVR) technology and the Company's Internet website. This service program covers the management of customer calls and other types of contacts at Hydro One Distribution's contact centres in Markham and London.

Regular business hours for call handling are from 7:30 a.m. to 8:00 p.m., Eastern Time, Monday through Friday, with seven days a week, 24-hour a day emergency and power outage call handling service. The contact centres handle more than two million calls a year from Hydro One Distribution customers.

The Hydro One Distribution contact centres manage all areas of customer call activity: Bill and account enquiries; collections; outages and emergencies; and service requests. In 2006, bill and account enquiries made up 34 per cent of total calls, collections calls were 12 per cent, and outages and emergency 27 per cent of calls. The balance cover service requests, including new service, upgrade, cable locates or forestry requests, and general topics such as questions on market changes, energy efficiency, electricity safety, and damage claims.

Bill and account enquiry call types include requests for information or questions on high bills, bill format, rates and charges appearing on bill (including commodity pricing, Good and Services Tax and debt retirement charge), exemptions and refunds, usage, meter readings, meter queries, payment options, payment confirmation, late payment charges, change to customer account details, security deposits, rate changes, rate classifications, and account balances. Move-in and move-out calls are triggered by a change of property ownership or tenancy. Move-in calls require opening an account. Move-out calls require a final account billing which depends on a field service order for a final meter reading. Calls relating to collections activity include negotiating payment arrangements, confirming payments made, processing overdue account payments via credit card, and responding to customer calls during disconnection.

An outage call can relate to either a planned or unplanned power outage. Emergency calls are those from emergency service agencies and personnel (fire, police, etc.) and the general public regarding damage caused to field-based equipment, or notification of unsafe conditions. A Business Customer Centre, located in Markham, manages the special needs of the large demand, distribution customers, as well as the contact relationship with Retailers, services for net billing customers, and Theft of Power activities.

In addition to responding to customer calls, the contact centres respond to inquiries received via other contact methods, including: customer letters; lawyers letters for move-in and move-out requests; customer and contractor faxes and customer email. These contacts numbered over 200,000 in 2006. In addition, the contact centres issue pamphlets or other information, such as duplicate bills, welcome packages, or a summary of Hydro One Distribution's Terms and Conditions of Service.

Since 2006, significant improvements have been made in the outage management area. These changes have increased the accuracy and availability of information for customers during an outage. As an example, processes to improve the accuracy of estimated restoration times were implemented and this information is now delivered to contact centre representatives and made available in our automated telephone system in a much more timely fashion. Improvements have been made to services provided within the Business Customer Centre to large Distribution customers, to provide dedicated points of contact and support for complicated billing explanations. In 2008, Hydro One is planning to improve first call resolution for customers and also review and upgrade the Interactive Voice Response menus and self-serve options.

As indicated in Exhibit A, Tab 15, Schedule 1, Hydro One Distribution has performed better than the OEB established target in the telephone accessibility measure, and the Company plans to maintain this higher level in 2007 and 2008.

2.1.1.3 Collections

This program includes the execution of collection processes associated with electricity revenues, for both active and final-billed accounts. This work includes issuing collection letters and notices, establishing payment arrangements, issuing payment confirmation letters and scheduling and issuing disconnection orders. The program also provides required information for power of sale, foreclosures, bankruptcies, debt reviews and consumer proposals and receiverships. More than 82,000 payment arrangements on overdue accounts were fulfilled in 2006.

Hydro One Distribution has added processes to manage collections costs and improve ease of making payments of past due amounts. In 2004, a credit card payment option was introduced for customers in collection arrears. Outbound calling has been added to the steps taken when an account falls into the collections process. Hydro One continues its policy of using load limiters during the winter months in place of full disconnection. In 2007, a second third-party collections agency was added to improve account recovery on final billed accounts. Additional outbound calling will be implemented later in 2007, and an end-to-end process review is underway to streamline the collection processes and identify areas of continual improvements. Relevant improvement items will be considered for 2008 implementation.

The billing, contact handling and collection service programs discussed above were part of the PA Consulting study of Inergi fees for Customer Service Operations, completed in 2005 and filed with RP-2005-0020/EB-2005-0378. The study found that Inergi fees in Customer Service Line of Business were within 1.0% of the fair market value range. The Inergi agreement established benchmarking at years three, six and nine of the 10-year agreement. The year six benchmarking is planned for 2008.

2.1.1.4 Settlements

The program ensures the integrity of financial transactions between Hydro One, the Independent Electricity System Operator (IESO), and applicable customers. The program includes: reconciling purchases of energy from the IESO; applying retail transmission service tariffs; updating data in totalization tables; and, implementing commodity and other charges, including appropriate distribution rates, to embedded LDCs, direct and generator customers as well as interval-metered, end-use customers. It also includes calculating and administering payments for energy produced by retail embedded generators, and settlements for short- and long-term load transfers. The Settlements program provides the appropriate level of due diligence to ensure that billing and payment transactions are reconciled accurately for parties involved, and to ensure that affected customers receive timely, accurate bills.

2.1.2 Meter Reading

This service program includes manual reading of conventional meters and remote reading of interval meters. Manual meter reads involve a visit by field staff to the customer premise to obtain the reading; interval meters are read remotely by the system via a telecommunications connection.

The manual meter reading activities include scheduled meter reads used for regular cycle billing of Hydro One Distribution's approximately 1.2 million customers. Meters are scheduled to be read on a monthly, bi-monthly, quarterly or annual basis, depending on the service territory and rate classification of the customer.

This program also includes unscheduled meter reads, which are taken on customer request and are typically used for check reads or final billing on move-out or property transfer. Program costs also include ancillary charges required for support activities, such as maintaining meter reading tools, reviewing demand charges annually and updating 911 customer addresses.

Time-of-use billing will be rolled out in a stepped fashion, with a target of having all feasible customers on time-of-use billing by the end of 2010. In 2008, time-of-use billing will be activated for customers who have received their smart meter, and also have the required communications infrastructure in place. All other meters will continue to be manually read. Manual meter reading costs are expected to decline in 2008 due to the reduction in the number of manual reads related to the Smart Meter Project.

The meter reading program also includes the cost of interval meter reading. In late 2004, Hydro One Distribution made a policy change to expand the installation of interval meters for new connections by lowering the size threshold from 500 kilowatts (as required by the Distribution System Code), to 200 kilowatts. The change was made to be directionally consistent with the Government's anticipated policy on smart metering greater than 50 kW. In 2006, Hydro One Distribution had approximately 1,500 interval remote meters. These meters are read and the data processed several times per week.

2.1.3 Other Field support costs

This category covers the field work required to support the billing, collections and settlements service programs. It includes execution of service orders to disconnect or load limit electricity services due to non-payment, to reconnect electricity services when payment issues are resolved, and, in certain situations, to follow up to ensure the integrity of a reconnect, a disconnect, or a load limiter. Field work is also requested to investigate high bill complaints and other miscellaneous customer issues. Also included in this cost category is work required to develop, review and revise the totalization tables that are required for settlements services.

2.1.4 Other Service support costs

These services include: Postage and courier service to issue bills, telephone expenses including costs for 1-800 numbers, third party contracts held by Hydro One Distribution for centralized payment processing, and collection agency costs related to final bill collection activity.

2.1.5 Customer Care Management

This program includes customer policy, planning, work program budgeting, service performance management, contract management, customer research and surveying, project preparation and coordination of implementation, and management of escalated customer complaints.

The 2008 costs represent Hydro One Distribution's assessment of the needs of this function to serve its distribution customers. The distribution-related costs have changed from $4.1 million in 2006 to a forecast value of $7.2 million in 2008. The increase is due to a number of factors including: supporting the corporate objective of improved customer satisfaction; refining management practices associated with the Inergi contract to assist in raising service quality to customers; preparing for time of use billing related to the incorporation of Smart Meters.

2.2 Bad Debt

This cost category reflects bad debt expenses, net of recoveries. Bad debt expense peaked in year 2006 and is expected to improve by 2008 to a value of $13 million. There are two reasons for the higher cost of bad debt in 2006. First, rising energy costs and worsening economic conditions have increased the number of customers in arrears and the average value of outstanding accounts in the collections process. The second reason was a change in the provision rates used to calculate the bad debt allowance. An allowance is calculated each year, estimating bad debt from uncollected accounts receivable. The allowance provision rates were updated in 2006 to better reflect actual write offs, and resulted in a one-time adjustment of $3.6 million to amounts that should have been allotted to the allowance since 2003.

To address bad debt costs, additional front-end collections methods have been introduced, aimed at reducing outstanding receivables before the final billing of an account. As well, Hydro One Distribution has added a second collections agency to help increase amounts recovered in final billed receivables. Examples of these and other collection tactics are noted in the description of the collection services program, Section 2.1.1 Customer Service Operations.

2.3 Regulatory Compliance

The cost of projects to implement legislative, regulatory and rate changes are included in this category. Hydro One Distribution has implemented the Regulated Price Plan (RPP) including the seasonal threshold changes, and is required to update commodity amounts twice a year, under direction from Ontario Energy Board. Among the regulatory projects included in 2007 and 2008 planning are the annual RPP commodity threshold and price changes, implementation of release 4.0 of electronic business transactions for retailer activity, and plans for rate changes to better align costs with rates, and to harmonize the rates of acquired utilities with the rates of legacy customers.

2.4 Service Enhancements

Service enhancements represent investment in service or productivity improvements to our customer service programs. The 2008 planning includes: promotion of Summary Billing and web self-serve options; process efficiencies for bill exception handling; a review and update to Call Centre Interactive Voice Response menus and self-serve options; improvements to first call resolution; introduction of new collections initiatives to enhance receivables recovery.

SHARED SERVICES AND OTHER OM&A

1.0 INTRODUCTION

Hydro One Shared Services are comprised of Common Corporate Function and Services (CCF&S), Common Asset Management Services, Information Management Services, and Cost of Sales to external parties. Other OM&A includes the capitalized overhead credit, the environmental provision credit, indirect depreciation and miscellaneous shared services/costs.

CCF&S services include finance, human resources, legal, corporate communications, risk management, internal audit, regulatory, corporate management, and strategic planning activities. Common Asset Management services include, asset strategy, system investment, business transformation, business integration, real estate facilities and contracts and business relations activities. Information management activities include providing and managing computer systems (for example, hardware and software) and IT infrastructure.

Hydro One utilizes a centralized shared services model to deliver its common services. The common services are delivered to the Distribution and Transmission businesses within Hydro One Networks Inc., and to the legal entities Hydro One Inc., Hydro One Telecom, Hydro One Brampton, and Hydro One Remote Communities. The centralized shared services model has allowed Hydro One to efficiently deliver key common services across the whole company in a cost-effective manner.

Many organizations have adopted a shared service model as an effective method of delivering common services to multiple subsidiaries and / or multiple business units. Hydro One adopted this model when it was established in 1999. Hydro One does not have any specific studies or reports that support the efficiencies of a shared services model for Hydro One, however the additional cost to establish the common functions in each of its subsidiaries would be cost prohibitive. In addition, the shared service model allows for the delivery of specialty services (i.e. Tax, IT systems and processes) without the need for having multiple experts in many areas.

This shared services model is a recognized business concept which has many benefits including:

- Minimization of the work force through commonly available specialist expertise and resources;
- Ensuring consistent policy and governance framework processes;
- Rationalizing and providing consistent levels of service across the organizations (for example, consolidation of office space, centralization of human resources, pay and financial services, infrastructure support);
- Using common technology systems and platforms and providing better access to information (for example, implementation of common financial and work material management systems);
- Synergies from economies of scale (for example, accounts payable processing, common procurement process and management of supplier relationships);
- Increased flexibility to pursue outsourcing of services where appropriate.

Shared services cost levels are fully reviewed as part of the annual business planning process (Exhibit A, Tab 14, Schedule 1).

Table 1 summarizes the Distribution portion of the Shared Services and Other OM&A Costs over the Historic, Bridge and Test years.

Table 1
Allocated Distribution Shared Services and Other Costs ($ Millions)

	Historic			Bridge	Test
Description	**2004**	**2005**	**2006**	**2007**	**2008**
Common Corporate Functions and Services	21.1	24.4	33.2	35.6	40.5
Asset Management *	26.0	20.7	40.9	38.1	46.3
Information Management Services	41.5	42.5	46.8	51.3	52.6
Cost of Sales	28.1	15.3	6.6	6.9	5.9
Other Shared Services	(107.5)	(79.5)	(106.3)	(40.1)	(78.3)
Total	**9.2**	**23.3**	**21.2**	**91.9**	**66.9**

* For the years 2004 and 2005, Asset Management costs were lower due to certain program costs, including facilities and work scheduling, being charged directly to work programs through standard labour rates.

The allocation methodology utilized in the 2004 - 2005 timeframe was developed internally for Hydro One and was customized to the business model being used by Hydro One at that time. The approach was based on the general principles of cost causality and benefits received. Cost drivers were utilized based on a high-level activity based costing approach.

For the 2006-2008 periods, Hydro One utilized the methodology developed by R.J.Rudden (as discussed in Exhibit C1, Tab 5, Schedule 1). The Rudden approach utilizes a further breakdown of activities and drivers.

The two approaches are similar in nature. They both use direct allocation where possible and the use of appropriate drivers where costs cannot be directly assigned. Hydro One's use of the Rudden approach has expanded the use of drivers, further refined the services / activities to be allocated and has updated data. The changes have lead to more precision and accuracy in the allocations.

Table 2 provides an overview of the various shared services cost categories for 2008 showing the total costs (where applicable) as well as the allocated Distribution costs.

Table 2
Shared Services and Other Costs ($ Millions)

Description	2008 Total	2008 Dx Allocation
Common Corporate Functions and Services	84.2	40.5
Asset Management *	118.9	46.3
Information Management Services	99.3	52.6
Cost of Sales	11.5	5.9
Other Shared Services	(165.3)	(78.3)
Total	**148.5**	**66.9**

As noted above, shared services costs are managed on an integrated or centralized basis, and then allocated to Transmission, Distribution and other businesses based on methodology developed through a cost allocation study.

In its transitional rate order RP-1998-0001, the Board directed Networks to provide more substantial support for its corporate services costs and allocation methodology. As a result, for the 2006 Distribution Rates Application (RP-2005-0020 / EB-2005-0378), Hydro One Networks engaged an independent expert, R.J. Rudden Associates (Rudden) to establish a cost allocation approach for Common Costs, which would be in accordance, with accepted industry standards. Hydro One submitted this study as part of its 2006 Distribution Rates Application and the subsequent Transmission Rates Application (EB-2006-0501).

In the 2006 Distribution Rates decision, the Board accepted the recommendations contained in the Rudden study and accepted the costs flowing to Hydro One Distribution for purposes of setting rates. The decision also stated that the Board “considers it reasonable for the Company to employ the Rudden methodology in the pending transmission case". Accordingly, Hydro One Networks has utilized the Rudden methodology to update their study for the purpose of the 2008 Distribution Rates Application, consistent with the OEB accepted allocation approach.

The following sections of this exhibit provide information for the years 2004-2008 on the following areas:

- Common Corporate Functions and Services (including Inergi sustainment costs);
- Asset Management Services;
- Information Management Services;
- Cost of Sales;
- Other Shared Services /Costs.

In addition, Hydro One Networks Inc. (Networks) entered into an outsourcing agreement with Inergi LP (Inergi) in December 2001 that extends to February 29, 2012 (the "Master Services Agreement" or "MSA"). Inergi is a wholly owned subsidiary of Capgemini and is not an affiliate of Hydro One Networks Inc. During the review of Hydro One's Distribution rates for 2006 (RP-2005-0020/EB-2005-0378), the Company provided evidence on the MSA, which the Board and intervenors assessed. The Board noted the "considerable scrutiny" given by intervenors to the agreement and concluded in its Decision, issued April 12, 2006, "that the Inergi contract represents a reasonable strategy by Hydro One to reduce costs, improve efficiencies and improve focus on the utility's primary operations. The Board is satisfied that the cost consequences flowing from the Inergi agreement for the test year are reasonable and therefore approved for ratemaking purposes." The terms of this agreement cover elements which are common to both Distribution and Transmission Businesses and accordingly are approved for application to the Distribution Business. For completeness of this Application, the agreement is addressed in summary form in Attachment A to this Exhibit.

2.0 COMMON CORPORATE FUNCTIONS AND SERVICES

The Corporation has identified certain functions that provide common services to all business units. It was determined that these functions could be shared effectively by all business units, avoiding costly and unnecessary duplication

Table 3 presents for comparison purposes the total CCF&S costs over the Historic, Bridge and Test years as well as the 2008 Distribution amounts.

Table 3
Total 2004 - 2008 CCF&S Costs and
2008 Allocation to Distribution ($ Millions)

	Historic			Bridge	Test	
Description	**2004**	**2005**	**2006**	**2007**	**2008**	**2008 DX**
Corporate Management	6.6	6.9	8.3	5.6	6.2	2.8
Finance	18.9	22.6	22.3	22.4	26.9	12.1
Human Resources	10.1	10.2	10.5	12.1	12.6	6.4
Corporate Communications	4.9	4.7	6.4	5.8	5.7	3.8
General Counsel and Secretariat	6.5	6.6	6.8	7.9	7.5	2.9
Regulatory Affairs	14.0	11.7	15.8	18.0	19.7	10.3
Corporate Security	1.2	5.4	1.8	1.7	2.5	1.2
Internal Audit	2.4	2.4	2.5	2.5	3.0	0.9
Total CCF&S Costs	**64.6**	**70.5**	**74.3**	**76.0**	**84.2**	**40.5**

The increase in CCF&S cost in 2005 is due to increased security costs associated with the Society labour disruption and new Bill 198 compliance work. The cost increase of approximately $3.8 million in 2006 as compared to 2005 is primarily due to Regulatory OEB costs, increased Corporate Communication Costs, and general cost escalation increases. The increase of approximately $1.7 million in 2007 over 2006 is mainly due to increased on-going regulatory obligations, the Theft of Power Program, and general escalation increases. The increase of approximately $8.2 million in 2008 over 2007 is primarily due to increased Regulatory compliance requirements, human resources support for increased staffing and new programs, and general escalation. Details of the cost changes for each of the CCF&S functions are described in the following sections.

2.1 Corporate Management

Table 4 provides a summary of Corporate Management costs:

Table 4
Corporate Management Function ($ Millions)

	Historic			Bridge	Test	
Description	2004	2005	2006	2007	2008	2008 DX
Corporate Management	6.6	6.9	8.3	5.6	6.2	2.8

Corporate Management represents those functions responsible to provide overall strategic direction to the corporation, including the Board of Directors, Treasurer's Office the Chief Executive Officer ("CEO"), Chief Financial Officer ("CFO"), the General Counsel and Secretary as well as the costs of certain supporting functions, Executive Office support and External Relations.

The President, CFO and General Counsel & Secretary are considered to be part of Hydro One Inc. and provide services to Hydro One Networks Inc.

The General Counsel and Secretary function in Hydro One consists of:

- Provision of advice and support to the Board of Directors and Corporate Officers.
- Provision of advice, training and reports on Code of Conduct and activities.
- Managing all donations, sponsorships and Community Citizenship programs.
- Managing and supporting all activities related to the Freedom of Information and Privacy Act and the Federal PIPEDA.
- Managing corporate archives.
- Carrying out the functions of Chief Ethics Officer.

The CFO functions in Hydro One Inc. consist of:

- Review and approval of financial and investment decisions.
- Provision of input to strategic and business plans.
- Oversight of Finance functions and provision of reporting information to Hydro One, subsidiaries, regulators, investors and the shareholder.
- Ensuring financial services are provided efficiently and reliably.
- Ensuring integrity of, and compliance with, internal controls over regulatory, financial, accounting activities.
- Monitoring of performance against operational, financial and regulatory targets.
- Ensuring sufficient revenue for operating, financial and regulatory needs.
- Supporting Hydro One's Board of Directors.
- Ensuring access to capital on reasonable terms.

The costs associated with the activities of the Treasurer's Office are charged to the company's costs of debt as discussed at Exhibit B1, Tab 2, Schedule 1.

The allocation of the costs associated with the activities of Corporate Management are governed by a Service Level Agreement between the Holding Company and the legal subsidiaries as outlined in Exhibit A, Tab 8, Schedule 3. This exhibit also describes the activities preformed by the Holding company and the amounts allocated to the various subsidiaries.

The cost changes over the 2004 to 2008 period are due to incorporation of improved IT systems and processes; an increased effort for the on-going Bill 198 requirement; and increased effort for streamlining regulation approvals to proceed with timely implementation of critical capital expansion programs. As a reporting issuer, Hydro One is required to comply with the Ontario Securities Commission (OSC) Multilateral

Instrument MI 52-109 and MI 52-111 concerning internal control and the related certifications, often referred to as Bill 198. As such, Hydro One management initiated the Financial Control Compliance Readiness Project and established a formal project governance structure in order to implement and comply with the underlying requirements on a continuing basis. The increase in 2006 is due to the CEO severance payout partially offset by lower audit fees and board costs. The decrease in 2008 includes a lower level of executive compensation, consistent with the Agency Review Panel (the "Arnett Panel") report (as discussed in Exhibit C1, Tab 3, Schedule 2).

Hydro One has not included any charitable donations in its 2007/2008 Distribution revenue requirement request, although Hydro One does make charitable donations to a number of organizations throughout the province. The primary beneficiaries of these donations are the annual United Way Campaign, energy awareness, local community causes, injury prevention programs, health care facilities, food banks, and employee volunteer grant programs.

2.2 Finance

Table 5 provides a summary of Finance costs:

Table 5
Finance Function ($Millions)

	Historic			Bridge	Test	
Description	2004	2005	2006	2007	2008	2008 DX
Finance	18.9	22.6	22.3	22.4	26.9	12.1

2.2.1 Overview

The Finance function consists of the Corporate Controllers, Corporate Tax, Treasury and Financial Strategy work programs.

Corporate Finance provides strategic advice and services related to the planning, processing, recording, reporting and monitoring of all financial transactions taking place within the organization. Clients include parties both internal and external to the organization, depending on the service provided. Services are provided through the following specialist functions:

- Corporate Controllers;
- Corporate Tax;
- Financial Strategy;
- Treasury.

The increase in costs in 2004 - 2008 are primarily attributed to the costs of complying with the requirements of Bill 198 on a continuing basis, as well as increased work requirements related to the Securities Commission and Provincial Audit issues.

2.2.2 Corporate Controllers

Corporate Controllers provide leadership and direction regarding all business planning, financial reporting, accounting and internal control policies; and procedures to ensure statutory and regulatory compliance and consistency with generally accepted accounting principles. The total cost of Corporate Controllers activities in 2008 is $18.1 million, of which $8.4 million is allocated to Distribution.

The function oversees the development of actual and forecast financial information and manages reporting processes to appropriate audiences or stakeholders. Clients receiving information and reports generated through Corporate Controllers may be internal to the organization, such as the executive team and board of directors, or may be external parties such as auditors, investors, regulatory and government agencies. Some examples of services provided include consolidated financial statements, annual and quarterly financial and regulatory reports and regular reports of internal OM&A and capital work program results.

Corporate Controllers are responsible for establishing and leading the annual business planning and budgeting processes, developing the instructions and assumptions used in the plan, finalizing the plan and budget documents, and leading the presentation of the plan to the Board of Directors and the Provincial Government.

The function develops and maintains financial models and provides analytical support for a variety of financial planning and reporting processes. In addition, this function is responsible for the financial management of revenues and associated costs of power.

Routine financial services, such as Accounts Payable, Accounts Receivable, Fixed Asset Accounting, General Accounting, Planning Budgeting and Reporting, Pension Support and a number of administrative procedures are outsourced to Inergi. These services are a major portion of the Corporate Controllers costs. The Inergi contract is discussed in more detail in Attachment A to this Exhibit.

Corporate Controllers are also responsible for managing and providing direction to the company with respect to matters of internal control, including Organization Authority Registers and financial policies and procedures providing leadership regarding compliance with Bill 198 and associated OSC-related rules.

2.2.3 Financial Strategy

Financial Strategy costs in 2008 are $3.1 million. Of this amount $1.5 million in 2008 is allocated to Distribution.

The function provides Financial Strategy services to the company through decision support as well as business case review and preparation, business valuation, transaction support, and other services as required. In addition, this function’s work includes the directing of the development and maintenance of all financial systems in the company.

The function is also responsible for the implementation and on-going management of the internal control compliance project within the company. Financial Strategy provides overall Inergi contract governance and support. Financial Strategy provides direction and analysis of the financial systems and of Enterprise Systems.

2.2.4 Corporate Tax

Corporate Tax manages the tax affairs of Hydro One Inc. and its subsidiaries. The costs associated with Corporate Tax activities in 2008 is $1.8 million. Of this amount $0.7 million is allocated to Distribution in 2008. Corporate Tax cost has been basically unchanged over the 2004 - 2008 periods.

Corporate Tax manages the tax obligations of each corporation within the Hydro One group including corporate income and capital taxes, the federal goods and services tax, the provincial retail sales tax, debt retirement charge, payroll and non-resident withholding tax and the employer health tax. Corporate Tax ensures that internal and external tax compliance requirements are met.

Tax compliance activities involve the preparation of income tax, goods and services tax ("GST"), Retail sales tax ("RST") and debt retirement charge ("DRC") returns for all corporate entities. Corporate Tax is also responsible for ensuring that the proper amount of tax is withheld from payments made to non-residents, particularly from payments for services performed in Canada by non-residents. The function calculates, manages and remits the corporate income and capital tax installments made by each entity in the group to ensure conservation of cash while eliminating any interest charges that would result from deficient installments. Other activities involve tax accounting and managing federal and provincial government tax audits.

Corporate Tax provides tax advice to the Human Resources department concerning employee taxable benefits; to Treasury concerning tax effective financing; to the Pension department concerning various plan issues; and to the operating lines of business to ensure tax effective acquisitions and dispositions. Tax planning strategies include a review of the tax classification of capital expenditures to ensure maximum allowable deductions are taken.

Corporate Tax also performs a monthly transactional analysis to ensure that the GST amounts charged to the Hydro One group and claimed as input tax credits are correct and that proper procedures are in place to ensure collection of GST, provincial RST, and DRC amounts.

2.2.5 Treasury

Treasury total costs are $6.1 million in 2008. Of this amount, $2.2 million for 2008 represents costs incurred to:

- execute borrowing plans and issue commercial paper and long-term debt;
- ensure compliance with securities regulations, bank and debt covenants;
- manage the company's daily liquidity position, control cash and manage the company's bank accounts;
- settle all transactions and manage the relationship with creditors; and
- communicate with debt investors, banks and credit rating agencies.

The Distribution portion charged to the company's cost of debt is $1.1 million in 2008, as shown in Exhibit B2, Tab 1, Schedule 2 Pages 5 Line 28.

Treasury is also responsible for the costs incurred in relation to assessment of risk, negotiation and purchase of insurance policies, claims management and settlement. These costs total $3.9 million for 2008, (of which $1.6 million is allocated to Distribution in 2008) and form the basis of the Treasury costs allocated as part of CCF&S. Included in the $3.9 million are the premiums paid for third party liability, fiduciary liability, and, directors and officers insurance. These costs do not include the premiums paid for insurance such as automobile, property, and other insurance. The premiums for these insurance policies are charged to work programs or included as an Asset Management cost as deemed appropriate.

Insurance and claims requirements are based on historical experience and are determined through consultation with management, as well as with insurance companies to ensure their understanding of the company's assets, operations, maintenance program and governance. This is followed by review and assessment of insurance policy options to ensure that appropriate statutory and discretionary coverage is in place at a cost-effective rate.

Hydro One also self-insures exposures that are either not covered by insurance policies or fall below the specified deductibles. Hydro One employs the services of a third party claims processing service provider to administer and settle claims against the company that are under $50,000. Claims against the company greater than $50,000 are managed by Treasury in consultation with internal and external legal counsel as appropriate.

All aspects of claims are managed through investigation, evaluation and negotiation, ensuring fair and cost effective settlement of claims for which the company is legally liable.

Table 6 shows the premium for Hydro One Inc.'s insurance policies for the 2004 to 2008 period and is a summary of the annual claims expense and associated administrative cost.

Table 6
Hydro One Inc. Insurance Program ($ Millions)

	2004	2005	2006	2007	2008
Hydro One Inc. Insurance Premiums	5.6	4.9	5.0	5.1	5.3
Insurance Expense – Self-Insured	1.4	1.1	0.7	1.0	2.4
Total	**7.0**	**6.0**	**5.7**	**6.1**	**7.7**

2.3 HUMAN RESOURCES

Table 7 provides a summary of Human Resources costs:

Table 7
Human Resources Function ($Millions)

	Historic			Bridge	Test	
Description	**2004**	**2005**	**2006**	**2007**	**2008**	**2008 DX**
Human Resources	**10.1**	**10.2**	**10.5**	**12.1**	**12.6**	**6.4**

2.3.1 Overview

The Human Resources (HR) function exists to enable the success of Hydro One. As a staff function, HR adds value by providing advice, guidance and services to managers (and on their behalf, to employees) which support and optimize the acquisition and management of the workforce, and the treatment of pensioners. HR provides consulting, staffing & training, compensation and benefits and labour relations' services. The total cost for 2008 is $12.6 with $6.4 million allocated to Distribution.

Total costs for the function remained relatively stable 2004-2006. The cost increases in 2007 and 2008 are due to general escalation increases, increased employee-related transactions associated with increased staff, and new programs.

2.3.2 Human Resources Purpose

In the last decade there has been an increase in awareness that human performance is the critical differentiating factor between success and failure for organizations, and that progressive management – supported by effective HR policies and services – can significantly enhance employee engagement, which in turn drives and sustains performance gains.

HR's main purpose is to support the organization's business strategy, so it must react and flex to meet the needs of that strategy. HR, like every other part of Hydro One, has been required to look for ways of increasing its efficiency by driving costs and redundancies out of its processes.

These reductions have been achieved by several means; in some areas Hydro One has leveraged new technologies such as PeopleSoft Employee Self Service, Intranet self service reports and training, Internet recruitment and pension inquires. In some cases Hydro One has chosen to outsource work completely, such as the Mercer Pension Administration System and Inergi LLP for payroll services, as the best way to achieve the required efficiencies.

One of the greatest challenges facing Hydro One is in an area where HR will be expected to play a significant role – the dramatic demographic "churn" that will occur in the Hydro One workforce in the next 3-5 years and beyond. Approximately 25 percent of the workforce (>1000 employees) become eligible to retire in the next 1 1/2 years. Hydro One must not only replace these people, but also find an additional 600 people over the next 5 years to meet the needs of the planned work programs. HR is also involved in promoting the development of the skill base and expertise required by Hydro One from graduates of high schools, trades schools, colleges and universities. New staff means extra training which will be provided by HR staff dedicated to this function. Hydro One is currently looking at ways by which to mitigate some of the impact of this "wave" of staffing work; by outsourcing or further automating (IT) some of the more labour intensive components of the hiring processes.

2.3.3 HR Consulting

HR Consultants provide advice and guidance to managers, supervisors, and employees on myriad of issues related to HR policies and procedures, collective agreement administration, staffing and other large initiatives that impact staff. HR consultants are assigned to specific "Client Groups" within the organization, but much of their day-to-day work, that at one time would have been done face to face with managers and employees, is now done via fax, telephone and email. However, given the nature of some of the issues, and Hydro One's geography, those consultants who serve field client groups around the province still spend a lot of time 'on the road'.

Certain elements of the HR Consultants' work are out-sourced to ensure they are still accorded the level of attention they require; one such area is that of the investigation of harassment or Human Rights complaints from employees. The law and Hydro One policy both treat these complaints very seriously, and because of the exhaustive and time-consuming information collection process demanded in relation to these complaints, Hydro One typically outsource this work, and the resulting mediation processes, to appropriately trained external professionals.

Technology changes have been implemented, so that employees can obtain HR information without the need for the assistance of an HR Consultant. The AskHR website, for example, provides managers and employees who use it with information on policies and procedures. The HR Hot-Line email and telephone service deals with the many daily inquiries that come from managers and employees (and pensioners).
Alongside the Generalist consulting group, Hydro One HR contains a number of smaller 'specialist' support/service activities.

2.3.4 <u>Staffing and Training</u>

This function recommends and administers policy in areas related to hiring and development; in addition it manages all of Hydro One's management/leadership development activities and Hydro One's principal[1] cyclical hiring processes - the New Graduate, the Co-Op Student and the Summer Student Hiring programs, plus miscellaneous specialized one-off hiring initiatives, as required.

The annual hiring processes are complex and labour-intensive and increasingly Hydro One is competing with other high profile employers. Hydro One offers Co-Op work terms to approximately 65 students three times a year. This provides Hydro One, and

[1] Trades staff are hired through the Power Workers' Union Hiring Hall processes.

200 young people with an opportunity to work with each other and as a result, if Hydro One is later able to hire a Co-Op student as a new Graduate, both parties will know what they are getting. Historically, the ‘Grad Hiring Program’ resulted in line managers being able annually to attract and hire Engineering and Business graduates from Universities across Ontario and beyond.

As part of the HR resourcing strategy, Hydro One offers a range of management/leadership development training programs related to identified management competencies for managers and supervisors. The costs reflect an increase in management training. While HR is active in developing the training strategy and identifying and specifying programming needs, most of the program design and delivery is outsourced to external training vendors. HR has found this a cost-effective way of keeping leadership development activities flexible and high quality.

The Human Resources function has always had a role in organizational succession planning, but in Hydro One in the last two years, HR’s role in this area has widened considerably. The demographic changes referenced above have added urgency to the situation and, as a priority HR has focused effort on identifying a number of mid-level staff who, based on internal recommendation and expert external assessment, are considered to have high potential to excel in due course in the most senior positions in the Company. As part of what is termed an “Acceleration Pool’, the development of these people is assigned a high priority which translates into exposure to high-profile projects and work assignments and special external educational opportunities as appropriate.

In addition, the Human Resources department manages the internal vacancy system. All PWU, Society and Management vacancies are posted internally, and employee applications are processed through the vacancy management office in Human Resources.

2.3.5 Compensation & Benefits

Payroll operations for a company of the size and complexity of Hydro One are both critical and extensive. The labour intensive transactional elements of payroll administration were largely outsourced to Inergi with contract administration within Hydro One to ensure compliance and cost containment. This same group also manages the Annual Performance Pay process for Society - represented staff and the Short Term Incentive ("STI") Plan for Management Compensation Plan ("MCP") staff.

As with pay, benefits administration in Hydro One is a complex area, since the plans offered to employees vary according to their jurisdiction, their date of first employment and, in some cases, their personal choices. The transactional administration of the main Benefit Plans is outsourced (currently to Great West Life). Compensation and Benefits is accountable for designing and implementing changes or new additions to the various compensation and benefits programs provided to Hydro One staff.

Minor status changes and inquiries can be handled by Hydro One's Hotline service, but substantive pension-related issues and events before and after retirement are dealt with by Compensation and Benefits. They are also accountable for managing any changes that are made to the provisions of the Pension Plan as a result of changes in the Law or in Hydro One Corporate policy. For the 7,140 pensioners (as at Dec 31, 2006), the Compensation & Benefits unit is their principal link with Hydro One. The cost levels are not changing significantly and those that do change are recoverable from the pension plan. Inergi Base contract price declines are offset by COLA and OPEB cost escalations.

Compensation & Benefits provides regular strategic reporting of HR and Pay data for Senior Management in such areas as retirement demographics, headcount, overtime reports, data for OEB submissions etc.

2.3.6 Labour Relations

Labour Relations exists to provide advice, guidance and training to Managers regarding collective agreements and labour legislation. There are 23 collective agreements plus midterm agreements and letters of understanding that bind the company. In addition, the company must comply with legislation such as the Ontario Labour Relations Act, the Employment Standards Act, the Human Rights Code, etc, all of which require interpretation and advice to Managers.

Labour Relations negotiates with 21 different bargaining agents to renew 23 collective agreements. Fifteen of the renewal agreements are negotiated in conjunction with the Electrical Power System Contractors Association ("EPSCA"), while the remaining eight are negotiated directly with the applicable unions.

The Labour Relations unit manages the grievance and arbitration processes and in addition, prepares and presents company briefs at grievance and arbitration hearings. It also participates in Ontario Labour Relations Board (OLRB) hearings involving various unions. Most of the construction unions (Buildings Trades Unions [BTU]) utilize the Ontario Labour Relations Board ("OLRB") instead of a grievance/arbitration process. Labour Relations prepares and presents company briefs at the OLRB.

2.4 Corporate Communications

Table 8 provides a summary of Corporate Communications costs:

Table 8
Corporate Communications Function ($ Millions)

	Historic			Bridge	Test	
Description	**2004**	**2005**	**2006**	**2007**	**2008**	**2008 DX**
Corporate Communications	**4.9**	**4.7**	**6.4**	**5.8**	**5.7**	**3.8**

2.4.1 Overview

Corporate Communications is responsible for managing all communications initiatives for the corporation, including communications strategy development; media and public relations, public affairs, community and government relations; customer communications; employee communications; and internet/intranet communications. Increased communication costs from 2004 to 2008 are associated with increased focus on proactive customer communications and consultation associated with transmission citing rate increases and billing activity as well as communications in support of government directed initiatives around safety and conservation and demand management activities, including smart meters.

The increase in costs in 2006 is due to increased work for initiatives such as the Smart Meter roll-out, and Hydro One and OPA's conservation programs as well as communication around storm restoration activities.

2.4.2 Corporate Communications Activities

2.4.2.1 Media Relations

Media relations is key to reducing overall operating costs by reducing reliance advertising and other paid forms of communications. Proactive media relations is seen as a important driver of customer satisfaction by providing timely communication and important third party endorsement of company activities.

- **Local investment**: Corporate Communications issues press releases concerning Distribution projects in order to promote the ongoing commitment of the company to investing in critical electricity infrastructure and improve reliability.

- **Conservation:** Working with the Conservation and Demand Management Group, Corporate Communications establishes marketing and media campaigns to promote customer enrollment/participation in a full range of conservation programs.
- **Electrical safety**: enables Hydro One to abide by various regulations and laws pertaining to public health and safety, mitigate risk and cost of potential liability by demonstrating due diligence, and protecting the Company's assets from damage (i.e. encouraging customers to "call before you dig.")
- **Power Outages and other significant events:** Local media and government officials can contact Hydro One's media relations desk 24/7 for immediate updates concerning expected duration of outages. Regular updates are provided to government officials allowing them to make informed decisions about emergency measures that may need to be taken in their communities and can help reduce calls to the Call Centre. This service also extends to other operational emergencies including, Health and Safety Events, contingencies on the distribution system, Load Shedding, Voltage Reductions

2.4.2.2 Stakeholder/Industry Relations

Many of the services provided by the Communications function involve educating and informing external parties such as customers and stakeholders regarding company and shareholder directed initiatives. Included among these activities would be stakeholder consultations (including consultation for First Nations) for rates changes and capital project related proceedings. These processes allow stakeholders the opportunity to understand the company's submissions and provide input, allowing them to influence the end results.

2.4.2.3 Community Outreach

Corporate Communications plays a key role in environmental assessment teams working to obtain approvals for Distribution lines and stations. As part of Hydro One's work program, Corporate Communications liaises with both elected and administrative staff in the affected municipality, coordinating briefings, participating in council presentations, and providing notification letters, and issues management, coordinating all activities associated with Public Information Centres, (PICs). Community outreach is another tactic used to disseminate the messages noted above. Activities include meetings and events with local government officials, service organizations and other community groups, participation in municipal conferences, local fairs and events.

Corporate Communications develops also liaises directly with customers and the community to keep them apprised of distribution related work taking place in their communities (maintenance, forestry and construction). An emphasis is placed on helping when controversial issues arise; this also includes managing community complaints either through telephone conversations, letters or community meetings.

Customer Communication: Customer communication activities involve informing customers of changes in their electricity and delivery rates using multiple communications channels. This includes explaining the impacts on their electricity bills and how to make wise use of electricity. Hydro One also communicates with customers on several other customer related issues/concerns including security deposit policies, and conditions of service, etc., as part of the Company's customer focus and as required by regulation.

2.4.2.4 Internal Communications

Internal communications efforts are equally important. The function provides managers/supervisors and employees with information related to corporate strategy, goals and specific operational initiatives to build awareness and buy-in. The employee communications function also facilitates the sharing of new ideas, approaches and suggestions among employees across the organization that can help to lower costs and improve productivity.

It should be noted that Corporate Communications costs do not include Customer Care Services or the Call Centre.

2.5 General Counsel and Secretary

Table 9 provides a summary of the costs of the General Counsel and Secretary function:

Table 9
General Counsel and Secretariat Function ($ Millions)

	Historic			Bridge	Test	
Description	**2004**	**2005**	**2006**	**2007**	**2008**	**2008 DX**
General Counsel and Secretariat	**6.5**	**6.6**	**6.8**	**7.9**	**7.5**	**2.9**

2.5.1 Overview

The office of the General Counsel and Secretary ("GC&S") provides legal advice and direction to Hydro One and its operating subsidiaries, as well as overall guidance in the areas of corporate structure, governance, business ethics and the business code of conduct. The GC&S function consists of two main functions: Law and the Corporate Secretariat.

The GC&S functions in Hydro One Networks Inc. consist of:

- Provision of legal services to all business units including the Company's major borrowing and financing initiatives, regulatory activities, transmission and distribution businesses (contracts, other commercial matters), employment, including pension and benefits, health, safety and environment and all Board-related activities. Arranging for the provision of legal services to the Corporation. The volume of these services is driven by capital and OM & A activities, as well as regulatory and legislative requirements.
- Overseeing the Regulatory, Law and Corporate Secretariat functions.
- Ensuring compliance with legal and regulatory requirements.

Hydro One does most of its legal work in-house, except when the in-house expertise is not available (for example, tax, labour) or when the workload exceeds the capacity of the internal legal group. The level of spending for external legal services has remained fairly constant. While the use of external legal resources has decreased, rates for those resources continue to climb. For most retainers, Hydro One undertakes an RFP process for retention of law firms.

Overall, GC&S expects its costs to remain relatively steady over the forecast period while continuing to manage increasing work loads. The nature of the Corporation's work programs, focused as they are on the core specialized business, can be more easily managed with internal resources, thereby minimizing the higher costs associated with external legal and other consulting resources. In 2008, there is an increase associated with increased work for rate applications, increased work programs and increased legislative and regulatory oversight.

2.5.2 Law

Law provides legal advice to all business units of the Corporation, acting as an internal "law firm" for the corporation. It advises on most aspects of law affecting the corporation, and relies on its experience and knowledge of the Company's business in providing economical and timely advice. The Law function maintains core knowledge of the law and the Company's business.

In particular, Law provides legal support to the Corporation's major borrowing and financing initiatives; regulatory activities, including approvals for major Distribution projects; approvals, land acquisitions, claims, Distribution businesses (contracts, other commercial matters); employment, including pension and benefits; and health, safety and environment. This support generally takes the form of reviewing legislation, giving general legal advice, drafting legal opinions, contracts and other legal documents, doing collections work, pursuing and defending litigation where claims have been made against the company.

2.5.3 Corporate Secretariat

The Corporate Secretariat provides support to the Office of the Chair, the Board of Directors and its Committees, including the administrative aspects of the Board and its meetings. It provides advice and analysis with regard to a variety of board-related matters, including corporate governance best practices and emerging trends and issues. It provides advice and direction with regard to the business Code of Conduct, ensuring appropriate actions to resolve known or suspected violations. This group also has responsibility for Community Citizenship initiatives and Freedom of Information and Privacy matters, advising the Corporation on compliance with privacy legislation, and administering requests for information under the Freedom of Information and Protection of Privacy Act.

The level of legal or corporate secretariat services required is not entirely dependent on the volume of work programs being undertaken by the Corporation but is also driven by the nature of the work programs and by changes in legislative and regulatory regimes.

2.6 Regulatory Affairs

Table 10 provides a summary of Regulatory Affairs Costs:

Table 10
Regulatory Affairs Function ($ Millions)

	Historic			Bridge	Test	
Description	**2004**	**2005**	**2006**	**2007**	**2008**	**2008 DX**
Regulatory Affairs	5.3	5.8	7.0	7.9	8.9	4.7
OEB Costs	8.7	5.9	8.8	10.1	10.8	5.6
Total Cost	**14.0**	**11.7**	**15.8**	**18.0**	**19.7**	**10.3**

2.6.1 Overview

Regulatory Affairs consists of Regulatory Affairs and the Pricing and Load Forecast Management functions. The costs of this function include Hydro One’s share of the OEB costs. OEB costs are approximately $10.8 million of total 2008 costs. The cost increases over the period are primarily related to increased regulatory compliance and major OEB proceedings.

2.6.2 Regulatory Affairs Activities

Regulatory Affairs is responsible for managing the Company's relationships with the regulatory bodies with which it interacts, including the Ontario Energy Board, the IESO and the OPA. Through this function, it is responsible for developing strategy and coordinating the Company's submissions to these bodies and participation in regulatory initiatives in areas such as the development of cost allocation and rate design.

Regulatory Affairs is involved in the coordination, preparation and processing of applications, as well as providing support to witnesses and business support staff. Such proceeding-specific services are provided for a wide range of applications, including distribution and transmission rates, transmission leaves–to-construct, merger/ acquisition/ divestiture applications and area and system supply planning.

In addition to proceeding-specific work, Regulatory Affairs is responsible for a variety of ongoing reporting and other activities. The function prepares quarterly and annual reports required under OEB Reporting and Record-keeping requirements; Regulatory Compliance manages the increased emphasis of the IESO and OEB on compliance matters and the OPA’s standard offer programs which have challenged Distribution connection assessment capability.

Pricing and Load Forecast management is responsible for Cost Allocation and Rate Design for the regulated businesses of Hydro One. The function develops rate structures and rate proposals for the regulated transmission and distribution tariffs applicable to the company and provides support in submitting and defending rate proposals. Load Forecasts are developed to enable system planning and financial planning which underlie the company's financial forecasts. In addition, provision of metering information for revenue reconciliation purposes is also provided. The increase in Regulatory Affairs costs in 2007 and 2008 is related to increased work associated with regulatory compliance and major OEB proceedings, Section 92 applications, and load forecasting for rate design activities.

2.6.3 Ontario Energy Board Costs

Under the *Ontario Energy Board Act, 1988*, the Ontario Energy Board is required to recover all of its annual operating costs. Almost all of its costs are recovered from gas and electricity distributors and electricity transmitters. A small fraction of OEB costs are recovered through licensing fees and penalties. OEB costs that are subject to recovery include its staff costs, office space costs, administration costs and overheads. These costs are allocated to one of three categories – electricity distribution, electricity transmission and gas distribution. Hydro One Networks' then receives an allocation of each for electricity distribution and electricity transmission related OEB costs.
In 2005 the Board implemented a new cost allocation methodology which resulted in a significant year over year reduction in overall OEB costs for Hydro One Networks.

In a letter dated December 20, 2004 the Board announced an amendment to the Accounting Procedures Handbook and the Uniform System of Accounts to establish a deferral account to record Ontario Energy Board Costs Assessments. The intent of this account is to record Ontario Energy Board cost assessments for the Board's fiscal year 2004 and subsequent fiscal year(s) determined in accordance with the Board requirements.

The OEB costs shown in Table 10 for 2005 and 2006 are net of amounts deferred. The increased OEB costs from 2006 to 2007 reflect a shift of recoverable Board costs into the electricity sector as well as higher overall OEB costs. The decrease in 2008 reflects lower OEB invoice assessments based on updated information received from the OEB.

2.7 Corporate Security

Table 11 provides a summary of Corporate Security costs:

Table 11
Corporate Security Function ($ Millions)

	Historic			Bridge	Test	
Description	**2004**	**2005**	**2006**	**2007**	**2008**	**2008 DX**
Corporate Security	**1.2**	**5.4**	**1.8**	**1.7**	**2.5**	**1.2**

2.7.1 Overview

The Corporate Security Services (CSS) function exists to enable the success of Hydro One primarily in the protection of assets (assets include people, property and information) and assisting in the reliable delivery of electricity. CSS adds value by providing advice, guidance, investigative and intelligence gathering expertise and services to managers (and on their behalf, to employees) which support and optimize the reliable delivery of electricity and the protection of Hydro One assets.

The total costs in 2008 are $2.5 million of which $1.2 million is allocated to Distribution. In the last decade there has been a dramatic increase in the focus on the protection of critical infrastructure and the industries that comprise these key social, safety and security functions due to the recognition of the criticality for electricity delivery assets and global terrorist activities (9/11). Cost increases in 2008 are primarily related to implementation of the new Theft of Electricity security program, and assuming the investigative and security monitoring role related to Information Technology.

2.7.2 Corporate Security Activities

Effective asset protection and recovery can be the primary differentiating factor between success and failure for critical infrastructure organizations such as Hydro One. This is achieved by effective corporate security policies, directives, guidelines and services, which can significantly enhance employee and business productivity. Hydro One places emphasis on providing safe reliable power supply in the Province of Ontario, and in large part is influenced by events such as terrorism, domestic extremism, sabotage, theft of copper conductors and other metals, and pandemic threats. The events of September 11th, the August 2003 Blackout, and the Caledonia substation sabotage and the subsequent blockade against the continuation of Hydro One work have underlined the importance and critical role CSS plays within Hydro One.

The CSS work program concentrates on providing physical security advice and co-ordination, IT investigation and system use monitoring, as well as assuming the security response role within the emergency preparedness program.

CSS also provides other security services such as criminal investigations and security advocacy roles to influence the electricity industry and intelligence agencies regarding the protection of the power supply in the Province of Ontario. Security services that directly impact Hydro One employees range from undertaking investigations regarding employee or contractor wrongdoing, security threats intelligence gathering and assessment, security clearances, employee safety and protection initiatives, workplace violence prevention, as well as corporate ID card processing.

The leveraging of new technologies and information gathering systems to retain security incidents and threats has promoted a more mobile and visible CSS function and has increased CSS's ability to identify security and threat trends. CSS has introduced an external email address for the general public to solicit tips for information and increased critical infrastructure protection information sharing strategies regarding the protection of Hydro One assets.

Efforts are made to identify potential security risks that could interrupt the reliable transmission and delivery of electricity. These risks include preventing asset threats, pandemic infections that can deplete available staff, criminal acts such as thefts, mischief or sabotage and hacking attempts into critical IT systems. CSS personnel have developed key relationships with various agencies that gather and disseminate information that can be used to reduce or eliminate these threats. CSS staff are able to gather and use this information to assess the risk impact to Hydro One operations. Greater emphasis can therefore be given to those actual risks that threaten Hydro One's business operations.

Emergency preparedness support activities include acting as the primary source of threat and corporate intelligence assessment for the OGCC, the Emergency Preparedness Program and maintenance of the Corporate Security Response Plan. Industry advocacy roles include participation in the Canadian Electrical Association's ("CEA") "Critical Infrastructure Protection Working Group", Provincial and Federal intelligence liaison committees and security industry standards development.

Continued vigilance is required to ensure protection against terrorist threats. Although there are no industry standards in place to guard against such threats, CSS follows general industry accepted approaches at gathering and analyzing information and trends. Current efforts in this area involve continued membership in CEA Critical Infrastructure Protection Working Group and the CISO (Criminal Intelligence Service of Ontario). The company plans to increase access to intelligence information through the Federal Government and expand information-sharing protocols with Natural Resources Canada ("NRCan"), Canadian Security Intelligence Service ("CSIS"), Electrical Sector Information Analysis Canada ("ESISAC"), CEA, and Public Safety Canada ("PSC").
Security costs increased substantially in 2005 due to security services associated with the Society Labor disruption.

The 2008 cost increases are due to the implementation of several security initiatives that the industry has developed for infrastructure and information protection as well as a new Theft of Electricity pilot program and the IT investigative function. The goal of this pilot program is to detect electricity theft through proactive investigation; therefore reducing the overall costs associated with electricity theft.

2.8 Internal Audit and Risk Management

Table 12 provides a summary of Internal Audit and Risk Management costs:

Table 12
Internal Audit Function ($ Millions)

	Historic			Bridge	Test	
Description	**2004**	**2005**	**2006**	**2007**	**2008**	**2008 DX**
Internal Audit	**2.4**	**2.4**	**2.5**	**2.5**	**3.0**	**0.9**

2.8.1 Overview

Internal Audit reports to the CEO and the Audit and Finance Committee of the Board of Directors. It is an independent, objective, assurance and consulting activity designed to add value to and improve Hydro One's operations. The mandate for Internal Audit is to provide independent assurance to the CEO and Board that internal controls are adequate in areas of high-risk and to follow-up and report on management actions to address findings from past audits. It helps the Company accomplish its objectives by bringing a systematic and disciplined approach to evaluating and improving the effectiveness of risk management, internal control and governance processes. The total cost for this function in 2008 is $3.0 million of which $0.9 million is allocated to Distribution. Costs over the 2004 - 2008 periods have changed because of normal salary increases, upgrading of staff in areas of electricity operations and information technology auditing in an escalating period of hiring auditors due to Bill 198 and improved emphasis on governance.

2.8.2 Internal Audit and Risk Management Activities

The Corporate Business Risk Management function supports the CEO by:

- developing business risk management policies, frameworks and processes;
- introducing and promoting new techniques for assisting management to identify and evaluate risks within their operations;
- preparing corporate risk assessments; and,
- maintaining a framework of key business risks.

The annual internal audit work program is determined based on an assessment of risks and a prioritization process involving input from audit staff, senior management, the CFO, the CEO, the external auditors and the Audit and Finance Committee of the Board of Directors. Internal Audit and Risk Management's contribution to achieving corporate strategic goals includes: providing assurance that management systems and internal controls will continue to operate effectively; identification of and recommendation for areas where controls can break down or need improvement to meet corporate objectives; and, finding opportunities to improve the efficiency and effectiveness of operations. The types of audit conducted vary from year to year but generally consist of internal control reviews of processes such as Information Technology, Finance, Safety & Environment, and Operational audits.

Generally, audits focus on assessing the adequacy of the various corporate systems of internal control to ensure: the reliability and integrity of information; compliance with laws, regulations and corporate policies and procedures; safeguarding of assets; economical and efficient use of resources; and, effectiveness of management systems in achieving stated objectives. In addition, audits focus on assessing the adequacy of management systems to ensure efficiency, effectiveness and economy.

Audit recommendations are well received and often acted upon during the course of the audit. External auditors rely on the work of the internal audit function when conducting their examination of the financial statements.

3.0 ASSET MANAGEMENT

3.1 Overview

The Distribution and Transmission businesses are operated using the Asset Management model, which the company adopted in 1998 and is described in Exhibit A, Tab 3, Schedule 1. The model separates the planning, decision-making and approvals associated with customer and asset needs from the engineering design, estimating and asset service functions required to expand and maintain the assets. This separation of functions is a common industry practice in today's utilities and reflects the different skills required for these functions. By applying this model and centralizing the decision-making, Hydro One Networks Inc. can ensure that management decisions involving customer and asset requirements are made on a consistent basis across the service territory.

The costs associated with the operation of the Asset Management function are outlined below while the various activities that are performed as part of this function are discussed in the following sections.

Table 13
Asset Management Function ($ Millions)

Function/Service	Historic			Bridge	Test	
	2004	2005	2006	2007	2008	2008 Dx
Strategy & Business Development	6.4	6.3	6.4	5.9	9.6	5.1
System Investment	17.2	14.0	22.0	22.7	32.2	7.7
Business Transformation	1.8	2.3	2.7	3.4	3.2	1.7
Business Integration	13.1	12.1	16.5	15.5	20.3	8.7
Facilities and Real Estate	38.7	35.4	38.7	37.5	44.0	21.6
Contracts & Business Relations	3.2	2.6	4.9	5.1	4.9	0.7
Work Program Optimization	2.5	2.5	3.6	3.8	4.7	0.7
Total Costs	82.9	75.2	94.8	93.8	118.9	46.3

Asset Management remains focused on ensuring, and being able to demonstrate, that the necessary distribution and transmission assets are planned, acquired, constructed and maintained to deliver the required function and level of performance expected by customers in a sustainable manner. The Asset Management function balances the needs of customers, the regulator, employees, and the shareholder by delivering on the following accountabilities:

- Development of an investment plan that ensures maintenance of critical distribution and transmission infrastructure, in order to meet the needs of customers in the short and long term and to ensure regulatory compliance.
- Ensure the effective delivery of the programs and projects within the plan, by working with other business units to optimize the bundling and sequencing of the work;

- Implementation of effective processes and support for the bundling, release, monitoring and redirection of investment projects, and assurance that expected results are being delivered;
- Ensuring that Hydro One Networks Inc. meets the transmission development challenge presented by the Province's supply situation, including identifying and undertaking system augmentation, load connections, generation connections, and interconnections with neighbouring systems;
- Development, integration, and implementation of Corporate strategies and support or lead, appropriate key initiatives such as Conservation & Demand Management, smart networks, business development opportunities, and productivity improvement initiatives;
- Influencing the business and regulatory environment to ensure customer needs and business objectives (safety, regulatory compliance, environmental performance, etc.) are met in an effective and efficient manner;
- Coordinating and managing an integrated approach to emergency preparedness and business continuity, including liaison with other industry organizations and various levels of government; and
- Managing property rights and maintain facilities.

Effective delivery of these accountabilities is key to the Company to meet public and employee safety objective, to comply with the Distribution System Code, environmental requirements and Government direction, maintain distribution business service quality and reliability at targeted performance levels, and ensure public confidence as stewards of provincial assets. In particular, Asset Management plays a key role in the development of asset strategies and investment plans to move the distribution and transmission businesses to first quartile reliability on a like-for-like basis; in undertaking initiatives to increase customer satisfaction to 90%; and through transformation initiatives to improve the efficiency of Hydro One's business environment.

As shown in Table 13, the 2008 cost of doing this work is $118.9 million with $46.3 million allocated to Distribution. Please refer to Exhibit C1, Tab 5, Schedule 1 for further details on the percentages used to allocate costs into Distribution and Transmission components.

Over the period 2004 through 2008, total costs increased in Asset Management by 43% mainly due to:

- The large increase in the corporate OM&A and Capital work programs resulting in the need for more planning engineers and finance support staff.
- Increased regulatory support including OEB rate hearing, Environmental Assessment Board (EAB) and OEB leave-to-construct (Section 92) support,
- Support for the compliance activities including Bill 198 programs
- Succession planning / demographics planning (i.e. dealing with staff attrition)

3.2 Strategy and Business Development

Table 14 provides a summary of Strategy and Business Development costs***:***

Table 14
Strategy and Business Development Function ($ Millions)

	Historic			**Bridge**	**Test**	
	2004	**2005**	**2006**	**2007**	**2008**	**2008 Dx**
Total Costs	**6.4**	**6.3**	**6.4**	**5.9**	**9.6**	**5.1**

3.2.1 Overview

The Strategy and Business Development function provides leadership to ensure the Asset Management function fulfills its role in managing the distribution and transmission businesses, meeting all legislative, regulatory and corporate requirements. The 2008 total cost for this activity is $9.6 million, with $5.1 million being allocated to Distribution.

The increases in costs in 2008 over 2006 are due to increased requirements related to Distribution Business Development for Distribution Rationalization ($1.5 million), increased insurance costs due to escalation ($1.2 million) and additional staffing requirement ($0.6 million). Distribution Rationalization was launched together by Ministries of Finance and Energy to promote further rationalization of the electric distribution sector in Ontario.

3.2.2 Strategy and Business Development Activities

Strategy & Business Development will continue to lead and support the development and integration of strategies that respond to corporate direction, and to changes in the industry environment and/or government policy; as well as opportunities to optimize leveraging of Hydro One's assets and improving efficiencies within the utility sector such as utility rationalization.

The Strategy and Business Development function provides the following key work activities:

- continuing to lead and support the development and integration of strategies that respond to corporate direction, and to changes in the industry environment or

- government policy (for example, Distribution Rationalization, and the Conservation and Demand Management initiative);
- supporting opportunities to optimize leveraging of Hydro One Networks Inc.'s assets (for example, secondary land use);
- develop strategies and implementation plans for business improvement initiatives (for example, smart networks);
- developing business initiatives that support corporate goals related to the transmission and distribution functions;
- assisting with improving efficiencies within the utility sector (for example, utility rationalization).

Included in the cost of this function is the funding for Property and Boiler and Machinery insurance (approximately $3.5 million for both 2007 and 2008).

3.3 System Investment

Table 15 provides a summary of System Investment costs:

Table 15
System Investment Function ($ Millions)

	Historic			Bridge	Test	
	2004	2005	2006	2007	2008	2008 Dx
Total Costs	17.2	14.0	22.0	22.7	32.2	7.7

3.3.1 Overview

System Investment focuses on developing an effective distribution and transmission integrated system investment plan that delivers on the planned business objectives. As shown in Table 15, the 2008 cost for this activity is $32.2 million with $7.7 million being allocated to Distribution. The increase in cost since 2004 is due to the need to address staff demographics and to accomplish additional work activities related to the growth of the Distribution and Transmission work programs (62% increases) managed by System Investment. Specifically,

- the management of an aging asset base requiring higher levels of maintenance refurbishment and replacement;
- the unprecedented number of new proposed generation connections;
- the impact of the Government's policy decisions (e.g. Smart meters) and OPA programs (e.g. Standard offer program);
- the need to plan, consult and obtain approval for new facilities to accommodate load growth, address reliability issues or improve operational flexibility;
- the emergence of new industry standards and codes; and
- the need to address customers' concerns regarding service quality including reliability and power quality (e.g. Tingle voltage).

3.3.2 System Investment Activities

System Investments activities include:

- setting overall policy, strategy and standards for managing the regulated asset base;
- providing the framework to develop, scope and establish priorities for work programs to manage the risk to Hydro One's business values;
- evaluating and recommending an integrated OM&A and Capital investment plan, through an integrated assessment and prioritization process;
- developing programs and plans to manage the performance of existing assets;
- developing plans to connect new loads and generators to address network constraints;

- preparing and obtaining approval for system investment business cases;
- developing, in consultation with customers, OPA and IESO, economic, cost efficient and practical investments that are consistent with customers needs or government policy
- supporting regulatory filings and applications;
- conducting technical evaluations (including system performance studies and asset condition analysis), developing and scoping alternatives, conducting economic studies to establish preferred plan, supporting industry transformation and compliance through representation in industry organizations to influence reliability or equipment requirements; and
- identifying and testing new technologies, such as the Geographic Information System ("GIS") to provide a digitized spatial representation of the physical assets to improve Hydro One Inc.'s knowledge of its assets and use this knowledge to improve investment decision making.

There will continue to be an increased focus on connecting new generation and providing increased transmission and distribution capacity to allow new supply to be delivered to load centers. Initiatives to improve the performance of the distribution and transmission systems are ongoing. Station and line assets and rights of ways have been assessed performance outliers and end-of-life equipment have been identified and corrective actions have been prioritized within the investment plan. Actions required to ensure assets are planned, designed and operated in compliant with industry standards, are also included in the investment plan.

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3.4 Business Transformation

Table 16 provides a summary of Business Transformation costs:

Table 16
Business Transformation Function ($ Millions)

	Historic			Bridge	Test	
	2004	2005	2006	2007	2008	2008 Dx
Total Costs	**1.8**	**2.3**	**2.7**	**3.4**	**3.2**	**1.7**

3.4.1 Overview

The Corporate Projects / Business Transformation function identifies emerging issues, develops appropriate responses, fulfills the needs set by corporate strategic direction, and implements selected time-limited initiatives that are critical to the future of Hydro One Networks Inc. Opportunities for improvement and especially projects that require a focused, integrated approach across Hydro One Networks Inc. are a focus of the function.

Investments are required to effect more efficient, industry standard business practices, oversee replacement of the end-of-life Enterprise business systems to meet business needs and maintaining and ongoing sustainment function, develop governance of shared business data, provide project delivery services for major corporate initiatives and mitigate risks in certain critical areas of Corporate infrastructure and business functions.

The total 2008 cost for this function is $3.2 million with $1.7 million being allocated to Distribution. The increase in cost since 2004 is due to increased work activities and scope in areas such as, project management for cross functional initiatives, enhancing data and systems, and providing a sustainment organization over this period.

3.4.2 Business Transformation Activities

Corporate Projects / Business Transformation Activities include:

- participating in the preliminary definition and scoping of cross-functional priority projects, or directly managing and mobilizing resources for large projects;
- managing cross-corporate initiatives to ensure an integrated approach to data, systems, and processes within Hydro One. The current priority is planning the replacement of a corporate core system, the first phase of which is the replacement of the existing purchasing module, inventory module, work management module, labour time entry module, and Accounts Payable module (refer to Section 4.0 of this exhibit and to Exhibit D1, Tab 3, Schedule 5, Section 2.4 for more information);
- managing the Data Management Program providing a single coordinating agency for optimizing Hydro One's data systems and processes; and
- providing appropriate physical security and monitoring, response security services, police awareness and adequate backup facilities for critical infrastructure; and managing Hydro One's integrated approach to Emergency Preparedness and Business Continuity, including liaison with other industry organizations and various levels of government.
- providing a sustainment organization for the corporate strategic direction in assisting the development of corporate strategy, ensuring ongoing sustainment of critical corporate initiatives once developed, and supporting for maintaining ongoing strategic relationships and other strategic projects.

3.5 Business Integration

Table 17 provides a summary of Business Integration costs:

Table 17
Business Integration Function ($ Millions)

	Historic			Bridge	Test	
	2004	**2005**	**2006**	**2007**	**2008**	**2008 Dx**
Total Costs	**13.1**	**12.1**	**16.5**	**15.5**	**20.3**	**8.7**

3.5.1 Overview

The Business Integration function provides effective support across the organization through its role in planning, budgeting, releasing, monitoring, reporting, and control of the Capital and OM&A work programs and related processes. As shown in Table 17, the 2008 cost for this activity is $20.3 million, with $8.7 million allocated to Distribution. The increase in cost since 2004 is mainly due to support for an increased work program and labour escalation increases.

3.5.2 Business Integration Activities

Business Integration Activities include:

- Development of specific business plan requirements, support for the development of plans, and consolidation of the plan;
- Development of work program standard costing rates;
- Management of integration processes for releasing and monitoring program results through common systems;

- Reporting and analysis of work program costs and results, and managing necessary program redirection;
- Reporting and analysis of system and component reliability;
- Development and maintenance of field business processes;
- Management of field processes for data capture, reporting and internal controls; and
- Management of Inergi contract governance including official contract notice, joint operating committees, internal governance.

3.6 Facilities and Real Estate

Table 18 provides a summary of Facilities and Real Estate function costs:

Table 18
Facilities and Real Estate Function ($ Millions)

	Historic			Bridge	Test	
	2004	**2005**	**2006**	**2007**	**2008**	**2008 Dx**
Total Costs	**38.7**	**35.4**	**38.7**	**37.5**	**44.0**	**21.6**

3.6.1 Overview

The total cost for the Facilities and Real Estate function in 2008 is $44.0 million with $21.6 million allocated to Distribution.

3.6.2 Real Estate Services ("RES")

Real Estate Services manages Hydro One's land rights portfolio across the Province. This involves ensuring that rights across over 200,000 acres of owned transmission corridor, easement and "statutory right" properties are maintained and new rights are acquired as necessary to ensure the safe and reliable operation of the transmission systems. In addition, Real Estate oversees the management of Hydro One's rights associated with distribution and transmission lands, stations and other property. Key work activities include:

- managing acquisition of real estate and new real estate rights (this includes Company Transmission Development Project Initiatives across the Province);
- managing the Provincial secondary land use program on behalf of the shareholder / Province, for example leasing transmission corridor lands to external parties;
- managing easement, other rights agreements on public/private sector, railway and other lands;
- managing First Nations settlements and First Nations;
- managing about 500,000 unregistered, low-voltage, real estate rights agreements;
- providing specialized real estate service activities, including managing property tax payments to municipalities, appealing property tax assessments, and providing employee relocation services.
- maintenance of Geographic Information System (GIS) – property record database.

More specific support is provided on a selected project basis. This includes provision of land ownership information, damage claim settlement, road access and other rights acquisitions.

Specialized real estate services are provided as necessary. This includes assessment appeals, payment of property taxes on distribution lands/buildings, as well as Employee Relocation Services as appropriate.

3.6.3 Facilities

Facility costs contribute $33.0 million, or approximately 75% of the total Real Estate costs. The Facilities function manages all of the building and site facilities across the

Corporation. This includes leasing costs and contract management for Head Office. In addition, it also includes costs for administrative & service centers, transmission site facilities and infrastructure and other work locations (for example, London Call Centre and the Ontario Grid Control Centre).

The Facilities Program focuses on providing employee workspace at sites across the province including Head Office, administrative and service centers, including the OGCC and other work locations, such as the London Call Centre, and Network Services field centre facilities.

Providing adequate workspace, storage and garage facilities for employees and trades is critical to the effective undertaking of organizational work programs. Equally important is ensuring that new or existing employee workspaces are consistently maintained to a standard that meets current work requirements and complies with all corporate, legislative and other related health, safety and environmental standards.

This Program includes:

- Administration of 42 contract lease agreements for workspace rented from other parties, including contractual obligations undertaken regarding payment of rent, operating expenses and taxes;
- Coordination of activities related to the ongoing management, operation, maintenance and inspection of 92 administrative/service Centers;
- Provision of support services for Head Office space, such as provision of office supplies and equipment, coordination of office moves, records management and tenant services.
- Providing accommodation strategies and acquiring new employee / trades workspace in line with operational requirements is also undertaken.

The Facilities work program is extensively driven by fixed cost contractual obligations as well as by the current regulatory environment (including Health & Safety and Corporate Standards) and corporate staff levels.

Fixed cost contractual obligations arise primarily through relationships with external landlords. For example, rent, operating and tax costs are specified in formal lease agreements and opportunities to significantly amend these set costs typically do not materialize until the agreement expires. Other fixed costs are represented by negotiated contracts with internal and external service providers for base level facility maintenance (for example, Administrative/Service Centre building maintenance, janitorial and snow removal, minor repairs, building component inspections) and similar activities. These contracts focus on maintaining facilities in a condition that meets current employee work requirements and corporate/legislative requirements.

The 2008 funding level primarily reflects the new Company accommodation and space requirements. In addition, fixed facility cost components (for example, utilities, property taxes, operational costs) are expected to continue to rise. This is due to the anticipated escalation of electricity and natural gas prices in Ontario.

3.7 Contracts & Business Relations

Table 19 provides a summary of Contract & Business Relations function costs:

Table 19
Contracts & Business Relations Function
($ Millions)

	Historic			Bridge	Test	
	2004	**2005**	**2006**	**2007**	**2008**	**2008 Dx**
Total Costs	**3.2**	**2.6**	**4.9**	**5.1**	**4.9**	**0.7**

3.7.1 Overview

Improving customers' view of Hydro One Inc. is one of the company's strategic objectives, this strategy targets achieving a 90% customer satisfaction rating by the end of 2010. Within Hydro One Inc., it is the role of each employee to ensure that they work towards improving customer satisfaction in all of their dealings. The Contracts and Business Relations function focuses its efforts on large distribution and transmission customers.

3.7.2 Contract & Business Relations Activities

Contracts & Business Relations activities include:

- Maintaining and enhancing customer service and customer loyalty while working within regulatory boundaries in a manner that optimizes shareholder value;
- Enhancing relationships with large distribution and transmission customers; Implementation of the "Large Customer" strategy has resulted in an increase in effort to better manage customer expectations, reflect their concerns in Hydro One Inc.'s plans, and demonstrate accountability on the part of Hydro One Inc. Although there has been great improvement in these activities, there is a need to spend more time and include more customers in order to achieve planned customer satisfaction initiatives;

- Facilitating of new connection agreements;
- The wholesale meter exit program and the SCADA data provision program.

3.8 Work Program Optimization

Table 20 provides a summary of Work Program Optimization costs:

Table 20
Work Program Optimization Function ($ Millions)

	Historic			Bridge	Test	
	2004	**2005**	**2006**	**2007**	**2008**	**2008 Dx**
Total Costs	**2.5**	**2.5**	**3.6**	**3.8**	**4.7**	**0.7**

3.8.1 Overview

Work Program Optimization focuses on planning, integrating and bundling awarded transmission and distribution work across Hydro One Networks. As shown in Table 20, the 2008 cost for this activity is $4.7 million with $0.7 million allocated to Distribution. The year over year changes since 2006 are due to increased work activities that are a direct consequence of an increasing distribution work program plus the addition of long term work modeling as well as resource management to improve overall work execution effectiveness.

3.8.2 Work Program Optimization Activities

Activities of the function can be split into four major categories:

- Work Planning, Bundling & Integration - Work closely with functions across the organization to bundle and schedule work utilizing a corporate planning and scheduling system, to minimize outages, costs and resources used.
- Scheduling Operations - Provide administration of the corporate planning and scheduling system including the management of any required upgrades, training and operating requirements and the development of planning standards and templates for the efficient scheduling of work.
- Regulatory Compliance Monitoring – Manage the regulatory compliance program which includes the communication and coordination of requirements to ensure corporate compliance targets are met. Create a data set that demonstrates regulatory compliance has been achieved; and coordinate activities taken by other business units in completing the work.
- Knowledge Management - Manage a knowledge management system for key Engineering & Construction Services documents. The system includes standard document templates and a structured workflow for document creation. Provide a storage and management system to enable searching and retrieval of historic documents.

4.0 INFORMATION TECHNOLOGY

4.1 Overview

Information Technology (IT) refers to computer systems (hardware, software and applications) that support business processes through which employees perform work activities. IT infrastructure includes the voice and data telecommunication networks and computer equipment that connect employees to customers, IT systems and facilities for the distribution and transmission of electricity.

The mission of Information Technology is:

- To act in the role of custodian of the technology assets and infrastructure.
- To ensure a robust, resilient, secure and flexible information, technology and business telecom infrastructure
- To develop information and technology strategies and plans consistent with the lines of business needs to enable them to meet their operational objectives
- To be client-focused by delivering knowledgeable, expert advice and service to the lines of business
- To oversee, manage and deliver IT projects.

Broad industry-wide principles govern the strategies employed at Hydro One in the formulation of foundation principles, such as:

- Implementing a governance structure that involves the lines of business to meet the Company’s objectives by prioritizing required tools and funding
- IT tools supporting the business should be generic and “off the shelf”, and outsourced services should be readily available through leading providers

- Applications and hardware should be managed in accordance with their lifecycle parameters
- Disaster recovery should allow for the resumption of essential business processes in a reasonable time frame
- The IT custodian is accountable for maintaining a secure and robust technology infrastructure.

Table 21
Information Technology Summary of OM&A Expenditures
($ Millions)

	Historic			Bridge	Test	
Description	**2004**	**2005**	**2006**	**2007**	**2008**	**2008 DX**
Sustainment	**62.6**	**57.6**	**60.2**	**63.9**	**59.6**	**34.2**
Development	**7.5**	**7.0**	**12.5**	**10.9**	**14.4**	**5.8**
Business Telecom	**17.2**	**15.7**	**18.6**	**17.2**	**17.1**	**8.7**
IT Management & Project Control	**5.4**	**5.6**	**5.0**	**6.7**	**8.2**	**3.9**
TOTAL	**92.7**	**85.8**	**96.2**	**98.7**	**99.3**	**52.6**

Sustainment costs in 2006, which were paid to Inergi pursuant to the Outsourcing Contract, include an additional $1.2M attributable to COLA. In 2007, sustainment costs increased to $63.9 million as a result of the purchase of additional Inergi support services for field side and helpdesk support, storage services, and IT vendor management. Support costs included in sustainment increased with the delivery of new applications such as the Work Execution Project (WEP) and the “lock in” of support for the Arc FM application.

Development OM&A includes the impact of capital projects, which increases going forward as a reflection of the Cornerstone project. Business Telecom costs fluctuate when major initiatives to enhance Hydro One’s telecom network are required, such as extensive work and materials to refresh and realign Local Area Networks throughout the company, part of a three year program from 2006 through 2008.

IT work programs include both OM&A and capital items and includes the maintenance and sustainment of existing and newly commissioned applications and technologies; the development and implementation of new technology processes; the provision of Business Telecom services; and the overall management and control of information technology capital projects. IT capital investments are made in accordance with approved business strategies and are described in Exhibit D1, Tab 3, Schedule 5.

IT Sustainment and Business Telecom services represent approximately 77% of total IT OM&A expenditures in the Test year and are work programs provided by third parties. This work is obtained through competitive contracts or at costs representing fair market prices.
Work management and project control costs relate to, IT administration, project oversight and reporting, program and spend coordination, and QA/QC processes. These functions comprise approximately 8% of the annual expenditure. The development, enhancement and upgrading of IT applications approximates 15% of the IT OM&A expenditure. The provision of these small non-Capital applications and/or added incremental functionality enables Hydro One to more efficiently perform work and to enhance the business value of existing applications.

Since January, 2005, Hydro One has evolved its IT governance structure to address IT control requirements contemplated by Bill 198, the financial control structure to which the company adheres.

IT governance has evolved from a project centric model to a more structured corporate enterprise wide model which looks proactively at IT strategy, project expenditures and service delivery as integral to allowing the lines of business to meet their objectives.

The IT governance model involves the senior business managers who provide guidance, direction and support to the decision-making for corporate technology decisions. These executives act as an IT Steering Committee to which the CIO reports at regular intervals. The CIO also reports to the CFO and CEO and the Executive Committee on IT matters. The Steering Committee's mandate is to review and prioritize the IT investments on a corporate enterprise basis.

The integrated governance structure generates a close working relationship among IT and the lines of business, and the outsource provider Inergi, to ensure that information technology provides the IT solutions required by business operations.

IT infrastructure is composed of three major categories which are described in Table 22.

Table 22
Overview of IT and Business Telecom Infrastructure

Item	**Description**
IT Hardware Infrastructure	Hardware infrastructure includes processors, data storage, data backup and disaster recovery systems located at data centers and which are required to run business applications. As of January 2007, it included IBM mainframe computers (used by Customer Information System), 55 Unix servers (used by major business applications) and 357 Windows servers (used by small business applications, web servers, Email, and file/print services), 66 terabytes of data storage, and employee workstations. There are approximately 6700 desktop, laptops and other portable devices used by Hydro One staff to carry out their work assignments.
IT Software Infrastructure	Software infrastructure includes applications, utilities, and tools required to operate and maintain Hydro One work functions. There are approximately 700 software applications used by various groups throughout Hydro One. Of these there are a small number of critical and broadly used applications as noted below in Table 25 of this section. Infrastructure software includes items such as: desktop office programs; data base applications; operating systems; geographic information systems ("GIS"); programming language compilers; database design tools; web design tools; data extraction and analysis tools; report writing tools; and application integration tools. Enterprise software are applications those that enable the linking of several applications and/or several work efforts to a single business process.
Business Telecom Infrastructure	Voice and data telecommunication infrastructure links staff and business applications at major Hydro One sites (Trinity, Richview TS, Markham and London Call Centres, Mississauga Data Centre), at over 120 field office locations and at additional work sites located throughout Ontario. Hydro One's 1.2 million customers can connect with the company's two Call Centres by telephone, facsimile, letter and email as can access customer information and notices electronically on the Web-site. Business Telecom infrastructure includes voice and data lines leased from common carriers, leased equipment, as well as company owned data circuits and internal wiring for local and wide area data networks ("LAN" and "WAN"). There are over 5300 desktop handsets for telephone and voice mail service, over 790 routers and switches for the data network, and approximately 22 network security devices (for example, firewalls, intrusion detection, anti-virus appliances, and proxy servers).

4.2 IT Sustainment OM&A

Table 23 shows the expenditures for IT sustainment of the Information Technology infrastructure.

Table 23
OM&A Sustainment of Information Technology
($ Millions)

	Historic			Bridge	Test	
Description	**2004**	**2005**	**2006**	**2007**	**2008**	**2008 DX**
Base IT Sustainment Services	48.4	41.3	45.9	43.5	42.8	24.5
OMS Incremental Sustainment	7.9	7.1	6.8	6.5	6.6	3.8
Other Incremental Sustainment	6.3	9.2	7.5	13.9	10.2	5.8
Total	62.6	57.6	60.2	63.9	59.6	34.2

IT OM&A Sustainment represents expenditures for work programs required to operate IT services for Hydro One and is provided through the outsourced service contract with Inergi. Sustainment charges for enterprise information technology systems and applications includes work performed on the data centre server systems, on desktop office applications, on customer service applications and contact centre systems, financial and material management systems, work management applications, administration and communications systems, engineering and planning applications as well as on field operations systems. Sustainment work includes help desk support; implementing system patches; applying fixes for application troubles; decommissioning or installing software applications or equipment; maintaining and operating Hydro One equipment located at offices and the data centre. Sustainment OM&A costs also include amounts paid to third parties for software licenses and equipment operating leases.

IT sustainment work is broken down into the three categories discussed below. These categories are Base IT Services, Open Market Systems ("OMS") Incremental

Sustainment (which comprises those applications introduced in response to Government open market policy initiatives) and Other Incremental Sustainment representing new services or technology support obtained after March 2002.

4.2.1 Base IT Sustainment Services

The term "Base" IT Sustainment Services refers to those IT services, including the sustainment services discussed above, that were part of the original scope of work outsourced in March, 2002.

Base IT services are provided by Inergi LLP (Inergi) pursuant to a 10-year competitively bid outsourcing agreement entered into in 2002. The cost to Hydro One for base IT services from Inergi will decline over the term of the agreement. Service levels are contractually maintained throughout the contract period.

The amount of the base IT cost is predicated on the assumption that the level of service for the number of applications supported at the time of the contract would continue while costs associated with those services charged to Hydro One would decline over the life of the agreement. Inergi is responsible for managing its business operations to obtain the guaranteed savings being provided to Hydro One without affecting the contracted service levels.

Base IT Sustainment services are required each year to support corporate computer applications including Microsoft Windows, Microsoft Office, PassPort, PeopleSoft and Customer-1, the corporate LAN and the corporate data centre systems that existed in March, 2002. Base IT services are discussed under the five categories below.

Hardware Maintenance/Software License Fees

Hydro One maintains a careful watch over application software licenses and versions, and hardware equipment and warranty programs to ensure interoperability among various applications and hardware and to honour licensing agreements. Inergi and IT staff work with application and hardware vendors to undertake maintenance work or upgrades as required.

Application software license costs are fees paid to third party vendors. Application usage is reviewed on an ongoing basis jointly by Inergi and Hydro One personnel.

At the inception of the outsourcing agreement $13.4 million of application costs were transferred to Inergi to administer on a pass through basis. Over time many of these contracts have migrated back to Hydro One, and are now administered by Hydro One. In 2008 the remaining administered contract cost reflected in the base fee is $5.3 million. Contract costs which are now being managed by Hydro One, and administered by Inergi, are reflected in Other Incremental Sustainment costs.

Application Support

Application support includes the work to maintain and to address matters associated with the approximately 730 Hydro One business applications used by the various business units across the Province. Within these applications there are strategic or business critical software applications used in major functional areas, such as those shown in Table 24. These critical programs affect many work processes and are enterprise wide serving many employees across multiple work and business groups.

Based on support levels established by IT and the respective business operations, applications are managed in a problem management framework. Application problems and user inquiries are logged, prioritized, and managed through to resolution.

Table 24
Strategic Information Technology Systems

IT Systems	Description
Desktop Applications	These include Microsoft Office XP/2003 (for example, Word, Excel, Access, and PowerPoint) email, Internet browser, and various others such as anti-virus and directory functions.
PassPort™	This is an integrated enterprise asset management (EAM) application suite that provides Asset and Work Management, Purchasing and Supply Chain functions as well as Inventory Management functions. This application is currently being replaced with an SAP solution as part of the Cornerstone Program as described in Exhibit D1, Tab 3, Schedule 5.
PeopleSoft™	This Financial and HR application suite provides General Ledger, Accounts Receivable, Fixed Assets, Project Accounting, Payroll, and Pension functions. These applications are planned to be replaced or upgraded as part of the Cornerstone Program. Work has commenced to replace these systems as part of the Cornerstone project
Customer Information System	The CIS is an application suite providing billing and services support through sub-systems of Customer Service System (CSS) and Open Market Systems that interface with each other. The CIS application is also scheduled for replacement under the Cornerstone Program.
Contact Centre Technology	This suite of applications enables contact centre operators to respond to customers (service requests, billing inquiries, information), and provide operator scheduling and service quality-monitoring functions.
Open Market Systems (“OMS”)	These are a set of applications that provide for meter data collection, sending/receiving of electronic business transactions with market participants, bill calculations, and settlement functions with the Independent Electricity System Operator.
Field Design Tool (ArcFM)	This is a geographic application that is used to design and modify customer connections to the electrical distribution system.

Outage Response Management System (ORMS)	ORMS is used for the reporting of distribution outages and managing the service restoration, which includes outage repair scheduling and dispatching of field crews
Work Execution Project (WEP)	WEP consists of 3 applications (Pragmacad, P3e,e-time) which are used to plan, schedule, dispatch and report on work completion. The applications are used for work planning, crew scheduling and for both planned and unplanned field work. The applications are "out of the box" and are cross linked to ArcFM, Passport and to Customer One through the use of the enterprise bus or enterprise middleware.
Asset Data Mart	This application provides the storage of information on distribution asset condition and maintenance history, and is used in planning asset/work management. It extracts and aggregates data from a variety of applications, including Passport and PeopleSoft.
Work Planning and Reporting System (WPRS)	The WPRS is an application that provides work planning, crew scheduling, dispatching and time recording functions to the LOB users such as Customer Operations, Grid Operations and E&CS and as such interfaces with PassPort, PeopleSoft and other critical systems

Data Centre Services

Data centre services include operating, maintaining, and repairing hardware (servers, mainframe, and data storage devices) plus associated applications located at the data centre facilities. This hardware is used to run key business applications, noted above, such as Passport, PeopleSoft, Market Ready OMS and the Customer Information Systems that are critical to operating the business.

Data Centre service levels have been established to ensure the reliable operation of business applications and are based on system criticality. The system hardware is located at data centres, which have the required system redundancies including 24/7 monitoring. In addition to the primary site, there is a back up data centre facility for development and testing and which would be used in the event of a disaster recovery scenario to recover critical business systems.

Distributed Server Sustainment

Distributed server sustainment includes the support services that maintain and operate the application and file servers that are located at various Hydro One facilities across the province. The servers are used to run business applications and administration systems such as file sharing, e-mail exchange, web hosting and security monitoring systems. This work is required to maintain the reliability of the servers and the business applications used to operate the business.

Help-Desk & Desktop Support

Help-Desk & Desktop Support includes daily and emergency IT maintenance services delivered to employees across the Province.

The support function is provided through two key service areas: the Help Desk which provides centralized call handling through a 1-800 number, problem resolution and escalation or referral for all IT and telecom service areas; and Desktop Workstation Support which provides physical desk side support to fix hardware and software problems for laptops, desktops and rugged tablet computers. Desktop Workstation Support includes the support for IT peripherals such as printers, plotters, scanners and other equipment. Help Desk support includes work comprising a number of functions including handling trouble calls, providing application support and resetting or enabling application or system passwords.

Desktop and Help Desk support is available to all users across the province and assistance can be provided by telephone, remotely through the data network, or if necessary through the use of field technicians. On a monthly basis, approximately 5,000 help desk calls are logged, dealt with and cleared. Effective response to these calls ensures the efficient operation of infrastructure that enables staff to perform their work unimpeded.

4.2.2 OMS (Open Market Systems) Incremental Sustainment

This category is incremental to the base sustainment identified and sourced to Inergi in 2002. Specifically, the work addresses OMS and consists of the support functions performed to sustain the OMS hardware and software applications. The OMS is comprised of a suite of software applications that have been bundled together to provide the required functionality. The support for the OMS was "locked in" and is supported by Inergi at an annual cost of $6.6 million in 2008. The OMS suite is used to enable wholesale and retail settlement processes. The processes provide interaction with the IESO and other market participants and are required for the business to operate under the Province's open market policies, driven in part by the *Electricity Act, 1998* and related legislative policies.

4.2.3 Other Incremental Sustainment

Other Incremental Sustainment includes additional sustainment services provided in order to support and manage hardware and business applications, commissioned since March, 2002 and includes license and software costs. The work and the associated costs which are shown are incremental.

New applications are being continually commissioned or added to meet new business requirements. Since 2002, therefore, the incremental sustainment cost has increased as additional hardware and applications have been added annually through capital projects and also through development projects.

As noted above, included in the Incremental Sustainment charges are costs related to additional application software licences, hardware maintenance costs for new equipment, as well as contracts which when they expired were transferred back to Hydro One for direct payment.

While the overall trend of “incremental sustainment” is upward as more applications are being added, savings from decommissioned applications are netted against these new costs.

A list of planned incremental capital projects, which in turn will create incremental sustainment needs when these projects are commissioned, is found in Exhibit D1, Tab 3, Schedule 5.

Cost increases in 2007 reflected the introduction into production of the WEP applications, a “lock in” of the support costs for Arc FM, consolidation of servers (partially offset by a reduction in server volume based costs) and the increases in database volume requirements. In addition, help desk and support costs services were increased to meet demands for improved support for field business processes and to adjust for increasing ongoing support volumes.

4.3 IT Development OM&A

Table 25 lists the expenditures driven by non-Capital small IT projects and the OM&A portions of capital projects.

Table 25

OM&A Development Expenditures

($ Millions)

	Historic			Bridge	Test	
Description	**2004**	**2005**	**2006**	**2007**	**2008**	**2008 DX**
Small Projects	**5.2**	**5.6**	**9.1**	**5.6**	**6.5**	**2.4**
Data Management Program	**0.0**	**0.0**	**0.0**	**0.1**	**0.0**	**0.0**
Impact of Capital Projects	**2.3**	**1.4**	**3.4**	**5.1**	**7.9**	**3.4**
Total	**7.5**	**7.0**	**12.5**	**10.9**	**14.4**	**5.8**

4.3.1 Small Projects

Small Projects include those individual projects that are valued at less than $2 million each and according to the Hydro One accounting rules are not capitalized. Small Projects include enhancements made to existing applications or new software for minor process automation improvements, software (version) upgrades or task defined software replacements.

Hardware costs for smaller items such as desktop computers, tablets, and printers are not included in this category and are considered minor fixed assets and are capitalized.
The number of small projects and the associated small project costs varies each year depending on the work projects requested by the lines of business to meet their needs and programs. Small projects costs and programs are reviewed with the IT steering committee on a regular basis.

Small project costs for 2007 include upgrades to the learning management system, the real estate GIS system, and the purchase of a customer call virtual hold functional application which operates in conjunction with the call center IVR. In 2008, there are a number of smaller enhancement projects which include upgrades to the ArcFM GIS application, Hazardous Waste application and some additional work flow improvements for the customer system.

Small projects typically fall into two categories:

1. Software version upgrades which are undertaken to ensure reliability and to maintain warranty status by securing continued vendor support for applications that may otherwise be outdated, unsupported or may present an undue risk of failure given their age. Therefore, these investments are critical to maintain existing functionality.
2. Enhancements or improvements which are made to existing applications, or to enhance business processes to add improved functionality or usability.

4.3.2 Data Management Program

The Data Management Program provides the single coordinating agency accountable for optimizing Hydro One's data systems and processes. Data issues are addressed by Data Management in consultation with stakeholders in the lines of business and Business Information Technology. Program expenses are forecast to take place in 2007, with data efforts being focused in the Cornerstone Project in 2008. .

4.3.3 Impact of Capital Projects

The item “Impact of Capital Projects” includes business process re-engineering costs such as training and change management work efforts that are required to implement and train the line of business personnel when new or revised IT applications are introduced. These costs are associated with the IT capital projects discussed under Exhibit D1, Tab 3, Schedule 5, and typically reflect an OM&A cost equal to 10% of the Capital project.

Increases in annual costs in 2006, 2007 and 2008 relate to projected work primarily associated with the implementation of the Cornerstone project.

In accordance with Hydro One's accounting practices, the cost associated with this implementation work (training and business process change) is not capitalized. The implementation work ensures each new business application or upgrade is properly introduced and has the necessary user understanding and support.

4.4 Business Telecom

The work involved in ensuring adequate Business Telecom services also includes the Field Services work involved in the Local Area Network (LAN) upgrades. The charges assigned to Voice Services reflect voice components from combined Data/Voice telecom bills rendered by Bell Canada and by other 3rd party providers.

Data Services reflects the LAN equipment materials as well as carrier charges (Bell, Allstream etc) for increased network bandwidth capacity, required to support business field applications, and network changes to add or delete locations.

Business Telecom provides the data and voice telecommunications services, network operations management and field service repairs which are required for the company to operate from its province wide locations. The business telecommunications data network is comprised of a mixture of company owned and leased facilities and equipment.

The costs shown in Table 26 reflect the lower supplier costs now available from common carriers while still responding to the generally increasing demands of all forms of communications. Growth in data network points served and circuit capacity bandwidth have generally been offset by pricing concessions obtained by Hydro One Telecom from common carriers on behalf of Hydro One.

Cost increases in 2006 reflect additional charges for bills in dispute between Hydro One and a large carrier. These invoices were resolved and resulted in a one time increase in costs for data and voice services.

Table 26
Business Telecom OM&A Expenditures
($ Millions)

	Historic			Bridge	Test	
Description	**2004**	**2005**	**2006**	**2007**	**2008**	**2008 DX**
Operations and Carrier Management	**2.9**	**3.0**	**3.2**	**4.2**	**4.4**	**2.2**
Field Services	**3.9**	**3.3**	**4.1**	**3.8**	**4.9**	**2.5**
Voice Services	**5.3**	**3.7**	**5.4**	**4.1**	**3.4**	**1.7**
Data Network	**5.1**	**5.6**	**6.0**	**5.1**	**4.4**	**2.3**
TOTAL	**17.2**	**15.7**	**18.6**	**17.2**	**17.1**	**8.7**

A 2005 independent industry review concluded that the service level agreement for the Hydro One Telecom operation centre, and for the services provided by it, reflects market conditions and that Hydro One Telecom has provided an advantage to Hydro One in respect of telecom administration and the resultant costs.

In 2006, an updated review was undertaken. The report considered the revised services which will be performed in the contract and the increase in costs charged by Hydro One Telecom. The report concluded the proposed contracted costs for 2007 and 2008 are indicative of fair market value. The 2006 review considered the negotiated service level agreement between Hydro One and Hydro One Telecom for services to be provided in 2007 through 2008.

4.4.1 Operations and Carrier Management

Operations and Carrier Management costs relate to telecommunications management services provided by Hydro One Telecom. Increases in 2007 and 2008 relate to additional security monitoring and infrastructure management services, an increase in the growth of the business telecom network, and reflects the new contract for Telecom services.

Work performed by Hydro One Telecom includes operating and monitoring the business telecom and data networks; management of security firewalls, managing data and voice system problems, obtaining and managing fibre services from third party vendors, and directing other telecom service providers and vendors to change, maintain, and restore the networks as required. On an ongoing basis, this function includes managing contracts as well as analyzing and processing bill payments to third party common carriers and other telecom service providers.

Telecom service firms who provide fibre and network access include common carriers such as Bell Canada, Telus and MTS/Allstream. These companies lease telecom data and voice circuits to Hydro One at competitive market rates. The management of these services requires the contracted services of Hydro One Telecom to proactively liaise with the many common carriers in Ontario and other service suppliers.

Operations and Carrier Management also provides oversight of the Bell Field Services contract as described below.

4.4.2 Field Services

Field Services includes the maintenance and repair of voice and data telecom equipment. Field Services also includes the handling of connection changes for moves, additions, changes, and deletions (MACDs). In 2004 this work was outsourced to Bell Canada after a competitive process.

The Bell Canada maintenance agreement evolved from a time and materials arrangement into a three-year contract that can be extended for another two years to August of 2009. After a review of the options available to it the Company intends to extend this agreement until August 2009.
The MACD agreement was based on a competitive bid process that was undertaken earlier in 2004. The agreement came into operation in September 2004 with the first full year of operations under the agreement being 2005. This agreement calls for Bell Canada technicians to be dispatched to resolve any telecommunications issues. These include MACDs and preventive maintenance at any of the Hydro One sites across the entire Province. Selected Bell Canada staff have been specifically trained to work at the Hydro One sites and facilities.

Included in the 2004 cost is $1.8 million related to one-time fees required to put the Bell agreement into operational effect, including establishing inventories, network testing and coverage verification.

4.4.3 <u>Voice Services</u>

Voice Services investments consist of payments made to common carriers and vendors to use and lease voice circuits and equipment. Rates charged by common carriers are competitive. Voice Services include monthly charges, usage fees and equipment rentals for voice grade business telecom (local and long distance). Total Voice Service costs have varied over time as a result of contract renewals and renegotiations. Hydro One obtains discounted market level services and rates as part of the effective management of telecom services.

Hydro One has obtained voice long distance rate reductions from common carriers which are based on volume. The effect is to lower the forecasted long distance costs in 2007 through 2008.

4.4.4 Data Network Services

Data Network Services investments consist of payments made to third party common carriers such as Bell, MTS/Allstream, and Telus to lease data network circuits and equipment at market rates. The data network is used to connect servers and computers across the province for software applications.

In 2005, Hydro One completed a bandwidth upgrade to all office site locations, increasing the wide area network connectivity bandwidth across the Province. Hydro One continues to monitor and upgrade band width as applications are deployed to field offices in order to support business processes and business requirements. In 2007 and 2008 work is being undertaken to increase bandwidth to the various Hydro One offices to meet business performance requirements for the WEP applications and in advance of the Cornerstone Phase 1 application go live.

While network capacity grows each year to accommodate sharing more data among more functions, the Company has maintained strong cost control on data network components. Downward cost pressure is maintained through investments in efficient up-to-date IT hardware and negotiated network leases, even while network capacities grow and extend to new locations.

4.5 IT Management & Project Control

Table 27 lists the associated costs for IT Management and for Project Support and Control.

Table 27
OM&A IT Management & Project Control
($ Millions)

	Historic			Bridge	Test	
Description	**2004**	**2005**	**2006**	**2007**	**2008**	**2008 DX**
IT Management	**3.0**	**5.3**	**4.2**	**5.6**	**6.1**	**3.1**
Project Support and Control	**2.5**	**0.3**	**0.8**	**1.1**	**2.1**	**0.8**
IT Management & Project Control	**5.4**	**5.6**	**5.0**	**6.7**	**8.2**	**3.9**

IT Management oversees the delivery of information technology and telecommunication services used by all employees across all lines of business. IT Management includes the cost to coordinate, manage and plan the extensive IT infrastructure, to manage the daily issues around IT outsourced services, and to oversee projects. IT Management performs work covered through needs assessment, business case preparation, planning, development, and service delivery to the lines of business.

Increases in the costs in 2008 relate to the need hire additional architecture staff who have SAP experience as a result of the implementation of the Cornerstone project and additional security staff to ensure compliance with Bill 198 and NERC cyber security requirements. It had originally been contemplated these roles might have been filled by contract staff, however the roles are currently assessed as being required on an ongoing basis.

As the enabler and project controller, IT Management develops and implements IT strategies, policies and processes along with IT architectural standards for application interoperability, infrastructure capacity, network security, regulatory compliance and IT governance, and telecom capabilities and communications security. IT Management includes work associated with hardware procurement, training, detailing vendor responsibilities, architecture development, and research services that are required to match IT solutions to known business needs and opportunities. Work performed also includes keeping current on industry trends, product innovations, technology changes in infrastructure and applications, research, as well as planning for future investments.

Project Support and Control comprises the work required to monitor and control the delivery and cost of projects, including the services of external service providers. The Project Management function is focused on managing overall project delivery costs and ensuring efficient implementation through coordination among Hydro One, Inergi and various other service providers.

In 2007, Project Management work which was included in small project costs were moved to this category to better reflect the general nature of the work done. This transfer accounts for the cost increase in 2007 and 2008 as compared to 2006.

Cost variations are primarily attributable to architecture and infrastructure control costs driven by the number and scope of major capital programs underway in a given year. Staff will be needed to enhance the continuity of project oversight and regulatory requirements, consistent with IT and Corporate strategy. The increases in the test years are particularly driven by the Cornerstone project described in Exhibit D1, Tab 3, Schedule 5 Section 2.4.1 and by the Smart Metering project.

5.0 COST OF SALES – EXTERNAL WORK

5.1 Overview

Hydro One tracks and reports Cost of Sales for the competitive work segment of its unregulated revenues which includes the following external work: new customer connections and customer upgrades; emergency work for other Canadian and U.S. utilities; minor forestry work; and health, safety & environment training (refer to Exhibit E3, Tab 1, Schedule 1 and Exhibit E3, Tab 2, Schedule 1 for the categories of external business and associated revenues over the 2004 – 2008 period). These are one time competitive services requested by customers and are individually priced. The cost of sales for the 2004 to 2008 period is provided below.

Table 28
Cost of Sales – Distribution External Work
($ Millions)

	Historical			Bridge	Test
	2004	**2005**	**2006**	**2007**	**2008**
New Connects & Upgrades	4.9	4.8	3.9	4.4	3.8
Lines Other	22.6	9.9	2.0	1.9	1.3
Forestry	0	0.0	0.1	0.0	0.1
Health, Safety & Environment Training	0.6	0.6	0.6	0.7	0.7
Total	**28.1**	**15.3**	**6.6**	**6.9**	**5.9**

The overall 2004 to 2008 trend is downward due to a shift in customer responsibility for costs associated with new connections and system reinforcements as per OEB directives. The Lines Other costs in 2004 was significantly high because it includes $19.2 million of Hydro One Distribution support provided to Florida Power during two hurricanes.

Hydro One does not track and report cost of sales associated with revenues from regulated services. The rates and associated costs for these services in 2008 are based on the methodologies as per the 2006 Electricity Distribution Rate Handbook.

The Cost of Sales identified in Table 28 relate to unregulated services for New Connects and Upgrades and for Other External Work only. Hydro One does not track costs for all its unregulated service revenues identified in Exhibit E3, Tab 1, Schedule 1. In particular, costs related to Joint Use and Miscellaneous Revenues as described below are not included:

- royalty payments from Inergi,
- under-density agreement payments from Bell Canada and other customers in Northwest Ontario for maintenance of line sections Hydro One agrees to look after,
- specific negotiated joint use agreement with Bell Canada where Hydro One and Bell Canada share each others poles,
- specific negotiated joint use agreement with municipalities for streetlight attachments and land access rights.

The costing of external work is calculated the same way as for internal work as described in Exhibit C1, Tab 4, Schedule 1.

5.2 New Connections/Upgrades

Hydro One Distribution connects approximately 17,500 new customers to its distribution system each year, and approximately 6,500 upgrade services are also completed each year to meet customers’ increased electricity requirements as described in Exhibit D1, Tab 3, Schedule 3.

Both the new connection service and the upgrade service have elements of work that must be done by Hydro One Distribution under its Distribution License. This includes: working within Limits of Approach (pre-determined boundaries for live equipment, which is voltage level dependent but nominally for distribution equipment is 3 meters or 10 feet) of the distribution equipment to install any required equipment; connect the customer to Hydro One Inc.'s distribution system; and connect the meter at the customer site.

The remainder of the new connection/upgrade work may be performed by a qualified contractor of the customer's choice. Hydro One Distribution competes for this work since crews are usually on-site and set up. The above ground services include the installation of poles, conductor, and related equipment to run from the distribution line to the meter at the customer site. The underground services include digging the trench and laying the cable and related equipment. This type of project is known as contestable or competitive work and is what primarily contributes to the external revenues for this segment.

5.3 Lines Other

The Lines Other component consists of approximately $1 million to $3 million per year of costs, excluding the support to Florida in 2004 and 2005, and consists of the following categories.

5.3.1 Emergency Support

Emergency support to other North American utilities to get their business systems back up and running.

5.3.2 Subdivision Redesign

Hydro One Distribution will provide an initial subdivision design and will recover this cost through the staking fee charged to the developer. When the developer revises the subdivision plan, a redesign of the subdivision is needed. The cost of the redesign is borne by the developer.

If a subdivision design has been completed but construction has not commenced for a period of 12 months or more, a review of the subdivision design is necessary. This review includes a field visit and is necessary to determine if the original design is still viable or if a revised design is needed to supply the subdivision. The cost to do this additional work is also covered by the developer.

5.3.3 Distribution Generation Studies

The costs in Distribution Generation Studies are for undertaking connection impact assessments in response to requests from generation proponents. Hydro One Inc. does assessments based on a customer request that includes the proposed size of the generator and where it will be located. Connection impact assessments are technical studies that determine the impact of the new generation facility on the Distribution System and ensure the generator will comply with the technical requirements. The technical requirements generators must meet to connect to Hydro One Inc.'s distribution system are outlined in “Technical Requirements for Generators Connecting to Hydro One's Distribution

System". These requirements are in place to ensure public and employee safety, protect the integrity of Hydro One Inc. 's system and guarantee reliable and quality service to our customers. For more information about these studies, refer to Exhibit C1, Tab 2, Schedule 3.

5.4 Forestry

Forestry costs include trimming of trees on customer property that are interfering with the secondary i.e. the line running from our pole to customer's residence/building.

5.5 Health, Safety and Environment Training

External training covers a wide range of practical and classroom delivered courses. These include courses like Electrical Safety Awareness, a mandatory course for anyone working in the proximity of live electrical apparatus regardless of trade or occupation. Packaged delivery of technical courses for numerous trade and professional types are delivered for Lines, Forestry, Power Electricians, Metering technicians, Protection engineers and technicians. Customers include large (Toronto Hydro) and small utilities (Peninsula West Utilities Limited), large (INCO) and small (Wardrop Engineering) companies including Non Utility Generators (Trans Alta, Brighton Beach) that send trainees to a cross section of courses in various trades/disciplines.

6.0 OTHER SHARED SERVICES

Table 29
Total Distribution Other Shared Services ($ Millions)

	Historic			Bridge	Test
Description	**2004**	**2005**	**2006**	**2007**	**2008**
Corporate Overhead	(45.0)	(46.2)	(59.8)	(46.6)	(47.7)
Environmental Provision	(9.5)	(7.1)	(11.6)	(6.3)	(7.9)
Indirect Depreciation	(9.0)	(9.9)	(11.6)	(10.5)	(10.3)
Deferred Pension Credit	(33.2)	(30.6)	(10.7)	0.0	0.0
Other	(10.8)	14.4	(12.6)	23.3	(12.4)
Total	**(107.5)**	**(79.5)**	**(106.3)**	**(40.1)**	**(78.3)**

6.1 Capitalized Overhead Credit

Table 30
Distribution Corporate Overhead Credit ($ Millions)

	Historic			Bridge	Test
Description	**2004**	**2005**	**2006**	**2007**	**2008**
Corporate Overhead	(45.0)	(46.2)	(59.8)	(46.6)	(47.7)

Capitalized overheads represent that portion of allocated shared corporate and/or business unit functions and services that are deemed, through the capital overhead rate, to be supportive of Capital projects as opposed to OM&A projects. OM&A expense is thus reduced by the capitalized amounts. The overhead credit has increased from the 2004 level primarily due to the higher level of Capital spending.

The capitalized OM&A costs are distributed to Capital projects based on the allocation methodology accepted by the Board as discussed in Exhibit C1, Tab 5, Schedule 2. The capital works program is further detailed in Exhibit D1, Tab 3, Schedule 1. The total amount allocated to Distribution Capital in 2008 is $47.7 million.

6.2 Environmental Provision

Table 31
Distribution Environmental Provision ($ Millions)

	Historic			Bridge	Test
Description	**2004**	**2005**	**2006**	**2007**	**2008**
Environmental Provision	(9.5)	(7.1)	(11.6)	(6.3)	(7.9)

In 2001, Networks business recognized a liability on its balance sheet for the present value of future estimated environmental expenditures necessary to deal with legacy contamination. The change in accounting policy from the previous as-incurred basis was adopted to align with the theoretically stronger U.S. generally accepted accounting principle that was expected to be imminent in Canada. Environmental work is initially recognized in the sustaining work program. The amount is then removed from OM&A and the liability / provision is amortized by the amount of the expenditures incurred. The resultant impact on OM&A expense of this environmental work is nil, since the amortization expense is grouped with 'Depreciation and Amortization' on the operating statement and the balance is transferred from OM&A to Depreciation expense.

6.3 Indirect Depreciation

Table 32
Distribution Indirect Depreciation ($ Millions)

	Historic			Bridge	Test
Description	**2004**	**2005**	**2006**	**2007**	**2008**
Indirect Depreciation	(9.0)	(9.9)	(11.6)	(10.5)	(10.3)

Transportation and Work Equipment ("TWE") charges in the OM&A work programs include depreciation expense associated with the asset being used. For accounting classification purposes it is necessary to remove this depreciation amount from OM&A and appropriately charge it to Depreciation Expense.

The total amounts of indirect depreciation removed from OM&A and charged to Depreciation Expense in 2008 is $10.3 million.

6.4 Deferred Pension Costs

Table 33
Distribution Deferred Pension Costs ($ Millions)

	Historic			Bridge	Test
Description	**2004**	**2005**	**2006**	**2007**	**2008**
Deferred Pension Costs	(33.2)	(30.6)	(10.7)	0.0	0.0

Since Hydro One Networks commenced operations, employer pension contributions have been paid from the Hydro One Pension Plan surplus. These notional contributions were not recorded as a cost of the Distribution business, nor were they recovered in rates. Commencing on January 1, 2004, Hydro One was legally required to make cash contributions for current and past funding costs related to staff who worked for, or retired from, Hydro One Networks. As a result, Networks commenced recognizing cash pension costs as a part of the cost of Networks' labour. A pension credit has been applied to recognize a deferral account on the balance sheet to record cash pension cost included in operating and maintenance costs associated with the Distribution business. This deferral account, plus interest, is in keeping with the July 2004 Board Decision and Order RP-2004-0180.

6.5 Other

Table 34
Distribution Other Costs ($ Millions)

	Historic			Bridge	Test
Description	**2004**	**2005**	**2006**	**2007**	**2008**
Other Costs	(10.8)	14.4	(12.6)	23.3	(12.4)

These costs represent material unexpected or non-recurring expenses. For example they include items such as insurance rebates, adjustments to provisions, vacation reserves, Gregorian or fiscal adjustments and inventory adjustments.

The 2007 and 2008 costs primarily include the Inergi Pension true-up and the Distribution rate hearing preparation costs and other miscellaneous adjustments.

HYDRO ONE - INERGI OUTSOURCING AGREEMENT

1.0 SUMMARY OF TERMS

- Hydro One Networks Inc. (Networks) entered into an outsourcing agreement with Inergi LP ("Inergi") in December, 2001 (the "Master Services Agreement" or "MSA").
- Inergi is a wholly owned subsidiary of Capgemini and is not an affiliate of Hydro One Networks Inc.
- "Base services" refers to the services of which Inergi assumed provision as of the commencement date of the agreement. Inergi provides base services at historical service levels and volumes at a fixed price that declines by 30% in real terms over the term of the agreement.
- Base services commenced under the MSA on March 1, 2002 ("commencement date") and include Customer Service Operations, Supply Management Services, Finance and Accounting, Information Technology, HR Payroll, and Settlements.
- In addition to base services and ongoing services added to the arrangement from time to time, Inergi also provides short term "project" services at predetermined rates.
- Inergi fees for base services actually payable in any year vary according to agreed changes in volume and scope along with adjustments for Cost of Living adjustments as defined in the agreement.
- In 2008, Networks expects to pay a fee of $115.9 million for base services.
- The arrangement involved the transfer of over 900 Networks' employees to Inergi.
- Networks owns substantially all assets involved in Inergi's delivery of base services.
- Inergi has subcontracted the call centre operations to Vertex Canada (Vertex). Vertex is not an affiliate of Hydro One Networks Inc.
- The MSA provides for benchmarking of fees in contract years 3, 6 and 9 and downward adjustment of pricing in the event the benchmarking exercise determines the bundled pricing of base services is not competitive.

- The 10-year term of the MSA expires on February 29, 2012.

During the review of Hydro One's Distribution rates for 2006 (RP-2005-0020/EB-2005-0378), the Board and intervenors assessed Hydro One's MSA with Inergi. The Board noted the "considerable scrutiny" given by intervenors to the agreement and concluded in its Decision, issued April 12, 2006, "that the Inergi contract represents a reasonable strategy by Hydro One to reduce costs, improve efficiencies and improve focus on the utility's primary operations. The Board is satisfied that the cost consequences flowing from the Inergi agreement for the test year are reasonable and therefore approved for ratemaking purposes."

2.0 STATEMENT OF WORK SUMMARY

The contract includes the MSA, associated Schedules and Statement of Work (SOW) for each line-of-business which provides details of the base services provided. The following table summarizes the current SOW for each line of business ("LOB").

Line of Business	Domain	Service Description
Information Technology	Infrastructure Operations	Services that facilitate the operation of shared devices and servers on a corporate level and services required to engineer and manage the computing network infrastructure
	End User Support	Help Desk and Desktop Support
	Application Maintenance and Sustainment	Services to maintain technology platform, operational quality assurance and application support customised to the service requirements and needs of the business applications
	Projects	Provides problem definition; requirement definition; business case development; design, development, configuration and testing; and commissioning, (including system enhancements) to meet specific line of business or enterprise needs.
	Cross Functional	Provides Service Management, Account Management, Vendor and Asset Management, and Resource Management to all other IT domains

Line of Business	**Domain**	**Service Description**
	Mainframe Operations and Services	Services that facilitate the use of the mainframe computer and associated infrastructure
Customer Service Operations	Inbound Call contact Handling	Provides customer call handling services for billing, customer services, collections, outages and emergencies for Residential and small business segment. Includes corporate switchboard, maintain the day to day operational configuration of the IVR system, and responding to other contacts such as letters and email.
	Bill Production	Issue electricity bills, including bill print, insert delivery to Canada Post and remittance, managing exceptions, accuracy and timely delivery. Maintain accuracy of customer billing records to enable timely and accurate billing and print, envelope and dispatch bills to Canada Post.
	Collections	Manage the collection of outstanding customer debts and negotiate and collect deposits.
	Data Services	Administration and data input of timesheets, work order task packages and service and work orders for field personnel and transmission operations.
	Business Customer Centre	Selection of services for business customers, including inbound call and contact handling, retail settlements, billing exceptions and manual bills.
	Application support	Provide direction and work management for variety of billing systems. ▪ Perform systems/business analysis to define system changes to address bug fixes & enhancements. ▪ User acceptance testing for all code changes
Settlements		Wholesale Settlements - Provide settlement and reconciliation services for power procured from the Independent Electricity System Operator and embedded Retail Generators with due consideration to legislative initiatives for fixed energy prices for low volume customers, transmission revenues and inter-utility load transfers, and cost of power reporting, and Retail Settlements - Provide complex billing for interval meter accounts.
Supply Management Services	Demand Planning	Preparing Material Requests and capital demand forecasts
	Demand Management	Maintaining market intelligence of applicable commodities, processing purchase transactions and inspecting and

Line of Business	Domain	Service Description
	and Procurement	expediting services to ensure delivery to contract commitments
	Sourcing, Vendor Management and Inventory Management	Services to support sourcing all commodities and services which include: managing and developing supply strategies (strategic sourcing), monitoring spend on all commodities and services, managing the size and composition of vendor base, resolving vendor issues, managing inventory levels, and negotiating vendor stocking arrangement.
	Process Development and Data Management	Services supporting the execution of daily transactions including ensuring the operation of automated systems and maintaining catalogue schema
	Transportation	Negotiating and managing transportation contract with logistics providers
	Asset Disposal	Managing the selling and disposal of surplus materials.
Human Resources Payroll	Pay Operations	Services necessary to calculate all pay cycles
	Payroll Accounting	Services necessary for the distribution of pay and production of back up information for all pay cycles
	Inquiries and Application Support	Services necessary to support the performance of other payroll domains, including technology support and issue resolution
Finance and Accounting Services	Accounts Payable (AP)	Services required for processing disbursements which include: maintaining Vendor Master Data and CCC Master Data, invoice processing, payments management, AP inquiries support, period end and reconciliations, management reporting and special projects.
	Billing and Accounts Receivable (AR)	Services required for processing non-energy miscellaneous billings and AR which include: maintaining AR Master Data, customer billing information, customer invoicing, customer collections support, applying AR payments and adjustments, AR inquiries support, period end and reconciliation, management reporting and special projects
	Fixed Asset and Project Cost Accounting	Provides fixed assets and project costing transaction processing, reconciliation of sub-ledger balances to general ledger accounts, reconciliation of the fixed assets and project costing suspense accounts, transfer of projects to fixed assets and recording sales and retirement of assets

Line of Business	Domain	Service Description
	General Accounting and Planning, Budgeting and Reporting	General Accounting – ensuring financial recognition consistent with corporate requirements, accounting adjustments, processing of transactions and maintenance of the general ledger system account blocks, support of financial systems and modules and interface and support for pay services and management reporting Planning, budgeting and reporting – provide advice, guidance, consultation and project support on routine operating processes and business support initiatives.

3.0 BENEFITS OF OUTSOURCING

The successful implementation of the outsourcing arrangements has resulted in significant cost savings to Networks as the price of services has declined since the Commencement date. The outsourcing arrangements have resulted in lower than historical costs at consistent and stable service quality. Networks has retained proper management control and decision making authority over the outsourcing arrangement to continue the safe, secure and reliable delivery of electricity in the Province of Ontario.

Networks has realized other positive business results that have enhanced the value of this business arrangement to the benefit of Networks' ratepayers. These benefits include the development of defined service levels, access to change management and intellectual knowledge that understands Networks business and can provide benefit to Networks operations, improved career opportunities for transferred Networks employees, and increased management attention to operation and maintenance of the core Transmission and Distribution business.

4.0 COST OF OUTSOURCING

Table 1 below contains the contracted price for base services over the planning period. This section explains the various inputs to fees shown in Table 1.

Table 1

Summary of Inergi Fees

$ millions

Description	Historic				Test
	2004	2005	2006	2007	2008
Contracted Fees for Base Services	97.9	94.4	92.3	90.8	88.4
Managed Contract Reimbursement	(6.8)	(6.2)	(5.9)	(5.6)	(5.3)
COLA	4.1	3.1	8.3	11.5	14.9
Pension & Benefits Fees	6.8	6.3	6.0	5.8	5.5
Volume, Scope & Other	8.0	4.0	10.7	19.1	12.5
Base Services Subtotal	110.0	101.5	111.3	121.5	115.9
Royalties	(2.0)	(2.0)	(2.0)	(1.5)	(1.5)
Pension Top-up	-	8.4	8.4	8.4	-
Supplier Initiatives	0.8	-	-	-	-
Total Contract Payments	108.8	107.9	117.7	128.5	114.4

4.1 Base Service Fees

The contracted fees for base services paid by Networks under the outsource services agreements will decline over time so long as service is maintained at then prevailing service levels and activity volume levels are within the normal range of those for historical periods. The declining price reflects Networks and Inergi's negotiated agreement that assumes Inergi will achieve cost savings over time through improved labour costs, reduced overheads, increased efficiencies, process re-engineering and technology improvements and that such savings are passed onto Networks as a guaranteed reduction in the fee for base services.

4.2 Managed Contract Reimbursement

Prior to the commencement date, Networks purchased certain IT products and services under contracts with third parties. It was contemplated that Inergi would assume the majority of these contracts and provide the related products or services directly as part of the fees for base services. The balance of the third party contracts would continue to be held by Networks, and simply 'managed' by Inergi. As of the commencement date, a final determination as to which contracts were to be assumed had not been made. The costs which Networks would otherwise have incurred under all third party IT contracts were included in Base Service fees as of the commencement date, to be adjusted later. However, payments to the third party vendors are made directly by Networks and Inergi reimburses Networks for those payments. Once certain contracts were identified for assumption by Inergi (mostly hardware and software contracts), Networks stopped paying these third party contractors. The actual assumption of these contracts over the first three years is reflected in a reduction of reimbursements and Networks' termination of the data centre agreement with IBM.

4.3 Cost of Living Adjustments (COLA)

Base Fees and most other fees are subject to COLA. The COLA formula is based upon the Statistics Canada Indices of total wages, salaries, and supplementary labour income in Ontario, and total number of employees in Ontario.

4.4 Pension and Benefit Fees

The employment of 913 Networks employees was transferred to the outsource service provider. Of these 913 employees, 569 were represented by the Power Workers Union (the "PWU") and a further 277 were represented by the Society of Energy Professionals (the "Society"). The remaining 67 managers were not represented by a bargaining unit.

Agreement for the transfer of collective bargaining rights to Inergi respecting the outsourced work was obtained from the PWU directly on December 14, 2001 and from the Society by way of arbitration award in December 2001.

In order to simplify bid evaluation, Networks requested pricing net of pension, supplementary pension and post retirement benefit costs. During the due diligence and contract negotiation phase of the contracting process with Inergi, it was agreed that Networks would fund these costs on the following terms:

- Inergi would be held harmless for pension (funding) costs and for the Other Post Retirement Benefits ("OPRB") accruing due to transferred staff prior to the deal, and
- Inergi would provide benefit plans to transferred employees which would be no less favourable than the Networks' plans in place prior to the transfer.

4.5 Volume, Scope & Other

The parties have adjusted the contract to reflect permanent changes in the volume of transactions or scope of services purchased which has resulted in adjustments to the fees for base services for the remainder of the agreement. Inergi's price of base services has increased from 2006 to 2007 by about $8 million primarily due to

1. increased volume of supply chain transactions
2. supply chain transformation services
3. late payment of 2006 supply inspection services
4. improvement of IT help desk and deskside services
5. late payment of 2005 and 2006 IT application sustainment services

Adjustments to the fees for base services for changes in scope and volume of services decline over the test years 2008, 2009 and 2010 and reflect anticipated improvements to efficiency of delivery of these services as contracted with Inergi.

4.6 Royalty Payments - Business Development

Inergi agreed to make royalty payments to Networks concerning new business to be delivered by TSDC, which Networks assists, Inergi or Capgemini in attracting. The reduction in Royalty payments in 2007 from $2.0M per year to $1.5M per year was negotiated in the original outsourcing agreement.

Marketing support includes:

- conference and sales support programs as agreed to by both parties,
- hosting site visits and participating in occasional promotional meetings, and
- acting as a reference when required.

Networks' out-of-pocket costs to support Inergi marketing efforts are more than offset by the minimum royalty payments shown in Table 1.

In addition to the forgoing, the contract requires Inergi to pay royalties as agreed upon to Networks where Networks permits Inergi to use Networks assets for the benefit of third parties. With the minor exception of the use of 8-10 laptops by Inergi management staff for multiple clients, no such usage has occurred.

4.7 Pension Top-up

Networks is obliged to fund over three years, the difference between the solvency liabilities for the transferred employees on the Commencement date and the end of 2004 and a 4% funding cushion, to the extent such amounts are not offset by pension fund performance during the same period. This shortfall has been determined by Networks' actuary to be $23.6 million and 1/36th of this amount was added to the monthly outsourcing fee commencing in January 2005. This adjustment is described as "Pension Top-up" in Table 1.

4.8 Expenditures Supporting Productivity Improvements (Supplier Initiatives)

The MSA required Networks to provide $15 million per year during the first three contract years to partially fund "Supplier Initiatives" in return for the promised declining fee schedule. The $15 million expenditure is aligned with expenditures Networks estimated it would have made to achieve its business plan savings had it not outsourced base services. Although the contract identifies specific initiatives that Inergi planned to undertake, Inergi was unconstrained as to how, or if, the initiatives were implemented as the price reductions were guaranteed.

An example of a Supplier Initiative was the Speech Recognition Initiative – Customer Service Operations. This initiative was designed to reduce the number of calls handled by agents through the implementation of self-serve telephony applications using Interactive Voice Response (IVR) and Speech recognition technology. The goal was to understand 85% of customer speech on the first pass in both Canadian English and French. By integrating Speech Recognition software in the existing IVR and Customer Service System platform, several of the high volume call types were automated freeing the agent to handle more complex and non-automated functions. In addition, Speech Recognition allowed all-speech user experiences for selected services. Speech Recognition technology is expected to improve customer satisfaction and experience.

4.9 Allocation of Inergi Fees to Distribution

Networks collects estimated total spend on the Inergi contract as part of its business planning process. This process captures all the costs associated with each area and includes all adjustments for inflation, change orders, re-basing and OPEB adjustments.

Rudden Report - Exhibit B describes the allocation of Networks estimates of the 2008 Inergi costs to Transmission and Distribution business. The table below shows the service activity, the estimated activity cost, the cost driver, the rationale for selection of the cost driver and the percentage allocation to the Distribution business.

Hydro One Inergi CCF&S 2008 Costs

CCF&S	Activity	2008 Cost ($M) Forecast	Cost Driver	Selection of Cost Driver	2008 % to Dx
Customer Support Operations	Inbound Calls / Correspondence	$21.6	Direct to Dx	Dx function per OEB	100%
	Bill Production	$9.3	Direct to Dx, Remotes	Activity analysis	100%
	Data Services- Timesheets for field personnel	$3.0	Direct to Dx, Tx	Activity analysis	85%
	CSO Support	$4.5	Direct to Dx, Remotes	Analysis- other activities supported	100%
	Total CSO	**$38.3**			**99%**
Supply Management Services	Purchasing	$6.6	Oper Maint Cap xB	Related to O&M and Capital costs incurred	48%
	Transportation	$0.2	Oper Maint Cap xB	Related to transport of items purchased	48%
	Asset disposal; Investment recovery	$0.5	Gross utility plant xBxTxR	Related to asset disposal	37%
	Strategic Sourcing Initiative	$1.1	Oper Maint Cap xBxT	Opportunities to save in Purchasing	49%
	Support management of warehouse	$0.8	Total Assets xBxTxR	Related to assets	40%
	Other departmental activities	$0.9	Inergi SMS (Internal)	Roughly proportional to other activities	48%
	Less: To Materials Surcharge	($10.2)			**49%**
	Total SMS	**$0.0**			**0%**
Finance	Accounts Payable processing	$1.7	Invoices To Vendors	Physical units (c)	50%
	Accounts Receivable processing	$1.3	Other Bills To Customers	Physical units (c)	43%
	Fixed Assets processing	$0.6	Gross utility plant xB	Related to Fixed Assets	37%
	Corporate accounting, Budgeting, Analysis	$5.1	Non-energy Rev_Assets Blend xB	Related to both non-energy revenue and assets	41%
	Pension support	$0.1	FTEs	Related to number of employees	51%
	Inergi Corp. Finance	$1.0	Inergi Total (Internal)	Management of Inergi costs	68%
	Total Finance	**$9.8**			**49%**
Human Resources	Payroll Services and Recordkeepping	$3.7	FTEs	Related to number of employees	51%
Settlements	Wholesale and Retail Settlements	$3.1	Direct to Dx, Tx	Activity analysis	85%
Customer Support Operations Applications	Support Inergi CSO CCF&S	$6.8	Inergi CSO costs	Related to Inergi CSO CCF&S	99%
Finance Applications	Support Inergi Finance CCF&S	$4.5	Inergi Finance costs (excludes Inergi Corp. Finance)	Related to Inergi Finance CCF&S	43%
Human Resources Applications	Support Inergi HR CCF&S	$3.6	Inergi HR costs	Related to Inergi HR CCF&S	51%
Passport Applications	Support Passport Applications	$3.2	ProgramProject	Passport is related to Program Project Costs	53%
Market Ready Applications	Support Market Ready activities	$5.6	Market Ready	Planned costs to modify systems and business practices to meet several market opening requirements from Docket	80%
Telecom Support	Support Tele-communications infrastructure	$1.4	Telephones	Physical units (a)	51%
Infra-structure Svc. / Misc. Apps	Supply Management Services	$3.1	Inergi SMS (Internal)	Activity Analysis	43%
	Direct Assignments	$0.9	All Direct	Activity Analysis	100%
	General Infrastructure Support	$21.7	Non-energy Rev_Workstations Blend xB	Related to both non-energy revenue and assets	47%
	Total IIT	**$50.8**			**60%**
Grand Total		**$105.8**			

PROPERTY TAXES

1.0 SUMMAY OF TAXES OTHER THAN INCOME TAX

Table 1
($ Millions)

	Historic 2004	Historic 2005	Historic 2006	Bridge 2007	Test 2008
Property	3.2	3.6	3.6	3.4	3.7
Indemnity Payment	0.5	0.5	0.5	0.5	0.5
Rights Payment	0.3	0.5	0.4	0.3	0.4
Total	**4.0**	**4.6**	**4.5**	**4.2**	**4.5**

2.0 PROPERTY TAX

Hydro One is responsible for the payment of property taxes similar to every other land owner within the province of Ontario. Property taxes for Hydro One are regulated under the Electricity Act 1998, the Municipal Act 2001, and the Assessment Act 1990. Property taxes are paid on Hydro One owned distribution lands and buildings including Service Centre sites, Distribution Transformer Stations, and distribution lines. Property tax payments are made to over 400 municipalities each year by Hydro One.

A summary of annual distribution property taxes (including property proxy taxes) is presented in Table 2, below:

Table 2
($ Millions)

	Historic 2004	Historic 2005	Historic 2006	Bridge 2007	Test 2008
Property Tax	3.2	3.6	3.6	3.4	3.7

Total assessed value is assigned by the Municipal Property Assessment Corporation, and is updated utilizing the same schedule as the rest of the province. All Hydro One distribution owned properties, except distribution transformer station buildings, are assessed using Current Value Assessment – the valuation method used for other property owners within the province. Distribution transformer stations buildings are assessed at a statutory rate of $86.11 per square meter, per the Assessment Act R.S.O. 1990, chapter A31, Section 19.

Notices of Assessment are received and reviewed for accurate valuation and tax classification each year. Any incorrect classes and overvaluations are appealed through the Municipal Property Assessment Corporation, and/or the Assessment Review Board.

Additional property tax payments, called property proxy taxes, for owned distribution transformer station buildings are levied, payable to the Minister of Finance. The details of this additional assessment are contained within Ontario regulation 224/00 under the Electricity Act. Property proxy taxes are calculated for each distribution transformer station building owned by Hydro One and total $0.2 million per year and are included in the property tax amount.

Property taxes are increasing on an annual basis due to financial pressures on municipalities and school boards.

3.0 INDEMNITY PAYMENT TO PROVINCE

The Ontario Electricity Financial Corporation (OEFC) has indemnified Hydro One with respect to the failure of the transfer orders (orders used to establish the company as one of the successor companies to the former Ontario Hydro) in 1999.

The OEFC indemnification covers any defects in the transfer orders encompassing the following areas:

1) the transfer of any asset, right, thing, or any interest related to the business;

2) some adverse claims or interests of third parties or based on property title deficiencies arising from the transfer orders, except for some claims and rights of the Crown, and

3) claims related to any equity account previously referred to in the financial statements of Ontario Hydro including amounts relating to any judgement, settlement or payment in connection with litigation initiated by certain utilities commissions.

The Province has unconditionally and irrevocably guaranteed to Hydro One the payment of all amounts owing by OEFC under its' indemnity.

Hydro One Networks pays an annual fee of $5.0 million to the OEFC for the aforementioned indemnification. As the transfer order primarily relates to land assets, the amount allocated to Hydro One Distribution is based on the proportion of Hydro One Distribution land assets in relation to the total land assets of Hydro One. This results in $0.5 million of the $5.0 million total being allocated to Hydro One Distribution.

4.0 RIGHTS PAYMENT TO OTHER ENTITIES

Through agreements or permits (950 in total), Hydro One Distribution line facilities cross and/or occupy properties owned by railway companies and/or governmental bodies. Per the terms of the individual agreements, Hydro One pays an annual fee to the railway companies and the government entities for the right to cross and/or occupy their properties.

A financial summary of the annual right payment fees is presented in Table 3, below:

Table 3
($ Millions)

	Historic 2004	Historic 2005	Historic 2006	Bridge 2007	Test 2008
Rights Payment	0.3	0.5	0.4	0.3	0.4

CORPORATE STAFFING

1.0 OVERVIEW

Hydro One submitted its corporate staffing profile and strategy to the Board during two recent proceedings – EB-2005-0378, Hydro One Networks Inc.'s application for 2006 Distribution rates and EB-2006-0501, its application respecting its Transmission business' 2007 and 2008 revenue requirement. During these proceedings, Hydro One detailed its efforts to maintain the right mix of resources while implementing a more favourable cost structure, within the constraints of a heavily unionized company.

Hydro One's greatest corporate risk with respect to its human resources continues to be an aging workforce and, with a world-wide scarcity of core skills in the industry, a highly competitive labour market. By December 31, 2008, approximately 1,000 Networks staff, representing 24% of the current population, are eligible for an undiscounted retirement. This is a trend which is expected to continue through the next decade and is consistent with challenges faced by other utilities in the electricity sector throughout the world. Recent studies suggest that up to half the workforce in the North American electricity industry will be eligible for retirement in the next five years[1].

2.0 STAFFING STRATEGY

Hydro One utilizes a work-based approach to staffing, whereby the Company resources according to work programs rather than plans the work around the number of internal resources available. To address the fluctuating and seasonal nature of work programs, the Company maintains as much flexibility as possible by not hiring all regular staff. Instead, it utilizes a variety of labour resources, including regular, temporary, hiring hall and contract staff, which provides the needed flexibility to manage in a cost-effective manner.

Matching staff to dynamic work programs requires a rigorous approach to staff planning. The company must consider the amount of work to be done, the nature of the work and the skills required, as well as the most cost effective means of acquiring those skills, within the constraints of the collective agreements. Demographic and skills analyses are conducted annually to ensure that Hydro One retains the appropriate talent in the present and is positioned properly in the market to attract the talent we need in the future.

Progress has been made in attaining the optimal number and mix of staff required to complete the Company's increasing work programs. However, the increases in some of Hydro One's Distribution programs will add additional challenges, given the tight competition for labour and power system professionals. It is essential because of the long learning curves required for competent performance of our highly skilled jobs that we hire well in advance of expected retirements.

3.0 HYDRO ONE'S LABOUR PROFILE

As part of Hydro One's strategy to efficiently and economically manage its fluctuating work requirements, Hydro One utilizes four broad groups of staff – regular employees, temporary employees, casual workers (the Building Trade Unions -BTU's under agreements with the Electrical Power Sector Construction Association – EPSCA, the Labourers' International Union of North America - LIUNA, the Canadian Union of Skilled Workers - CUSW, and Power Workers Union - PWU Hiring Hall employees) and contract staff, discussed below.

[1] Lester B Lave et al, The Aging Workforce: Electricity Industry Challenges and Solutions, Electr J. (2007), doi: 10.1016/j.tej.2006.12.007

1) <u>Regular Employees</u> of Hydro One can be placed in three categories:

(i) PWU represented staff: The PWU is an industrial union that represents the trades, operators, technicians and clerical workers. They perform line work, forestry, electrical, mechanical, protection and control, meter reading, stock keeping, system operation, technical and clerical/administrative work. The majority of the PWU-represented employees in Hydro One have post-secondary education, predominately at the community college level. These include Hydro One electrical maintainers, line maintainers, mechanical maintainers, operators, technicians and administrative employees.

(ii) Society represented staff: The Society is a professional union that represents engineers, technical, administrative and supervisory staff. They perform engineering, high level technical and administrative work as well as supervisory functions. The majority of the Society-represented employees in Hydro One have either post-secondary education (university degrees) and/or post-graduate education. These include graduate engineers, finance and telecommunication specialists.

(iii) Management staff, who are excluded from representation because they carry out managerial duties or work on confidential labour relations matters or legal matters.

2) <u>Temporary Employees</u> are employees in any of the three categories set out above, engaged in work that is not of a continuing nature.

3) <u>Casual Workers</u>

Although the PWU does perform some construction work, the majority is performed by the PWU Hiring Hall, the Building Trades Unions (under agreements with EPSCA), the Labourers, and members of the Canadian Union of Skilled Workers

(i) Hiring Hall Employees (PWU) are utilized to meet fluctuating work demands, performing primarily supplemental construction and maintenance work on the distribution system. Non-recurring work peaks and special projects are resourced through the hiring hall.

(ii) Fifteen construction BTU's supply a contingent workforce through their hiring halls, negotiating their collective agreements with EPSCA. These represent the construction trades employed by Hydro One, with the exception of those represented by the CUSW and the Labourers.

(iii) The Labourers' International Union of North America (LIUNA) is a construction union that Hydro One negotiates with directly as opposed to via EPSCA.

(iv) The CUSW represents lines and electrical tradespersons who work on transmission construction, including the construction of lines over 50kV, transmission stations, switchyards, substations, system control centres, and associated telecommunications systems. Their members are contingent workers, accessed through the CUSW hiring hall to perform specific work programs and then laid off. They are paid a total wage package (including benefits and pension payments) for each hour worked. This relationship ensures that workers with the required skill set are hired in the right location for only the exact duration of the work assignment and that Hydro One has no on-going obligations with respect to benefits or pension for them.

4) Contract Staff are individuals engaged as independent contractors, not on the Corporation's payroll. Contract staff are retained for their particular skill sets on

projects, or to perform other work that is not of an ongoing nature. They are engaged at Hydro One for varying amounts of time and paid varying amounts commensurate with their skill sets and the market rate for that skill. Contract staff are tracked by work programs or activities and not by headcount. Where applicable, the procurement of contract staff is governed by the terms of the collective agreements between the Corporation and its respective unions where applicable.

4.0 RECRUITMENT

To help address the expected significant wave of retirements in its critical trades, technical and engineering groups, Hydro One continues to hire into its Graduate Training Program. Training and development is identified in consultation with the line organization and each graduate trainee takes part in an extensive program that involves rotations through various parts of the company as well as in-house and external workshops, seminars and courses. Since January 1, 2004, 59 graduate trainees have been hired through the Company's on-campus recruitment program, with the hiring of a further 40 to 50 graduate trainees anticipated in the Fall of 2007. New Graduates bring not only much needed skills but also new perspectives and fresh energy to the work of Hydro One.

Hydro One also continues its recruitment into trades apprenticeship and technical training programs and has partnered with universities and colleges to develop curricula that educate students in areas where we face a shortage of skilled professionals and trades people. Hydro One has taken a leadership role in support for power system engineering programs, assisting in developing on-line power system engineering programs, and providing scholarships to encourage enrolment in key areas where we face a labour shortage. Hydro One holds the Chair of the Electricity Sector Council, a Canada-wide organization composed of employers, bargaining agents, educators, associations and government representatives designed to deal with the skills shortage in the industry. The Council's primary goal is to increase the number of qualified individuals for employment within the industry. Hydro One also holds the Chair of the Canadian Electrical Association's Human Resources Committee. Its mandate is to assist the CEA Board in its oversight of HR support and development for the industry, monitor and report on emerging HR issues and share best practices and work collaboratively in development of mutually beneficial initiatives.

The Corporation is also partnering with the PWU in an initiative called "Trade Up for Success", which educates Grade 9 and 10 students and their parents in the benefits of choosing skilled trades careers and the educational requirements needed to enter applicable college programs.

In addition, Hydro One, with the clear support of the PWU and the Society, has become a corporate participant in Career Bridge – a national, private-sector, non-profit initiative, which aims to provide internationally qualified professionals with Canadian work experience in their field of expertise.

Hydro One will also continue its support of the University and College Co-Op Education Program, hiring approximately 200 co-ops a year. This is a mutually beneficial process in that Hydro One gains bright, skilled workers trained in the latest theories and practices to work for four- or eight-month work-terms, while the students gain "real world" work experience that can be used to develop their future careers We have also found that the Co-op programs have proven a rich source of talented candidates for Graduate Trainee positions by offering us an opportunity to assess the student's "fit" and long-term potential with the company. Once hired our experience shows that these former co-op students have a shorter learning curve than other new hires with no previous Hydro One experience.

5.0 TRAINING

In addition to the Graduate Training Program outlined above, Hydro One offers considerable training and development opportunities that are critical to the retention and motivation of staff.

5.1 Trades and Technical Training

Hydro One provides a comprehensive selection of trades and technical training, designed to target the specific needs of field staff in relation to the work requirements of the asset base.

5.2 Leadership and Senior Management Development

The primary objective of this program is to ensure that Hydro One has a systematic management development framework. This helps ensure we retain a competitive advantage by developing, maintaining, and enhancing those management competencies deemed to be essential.

Hydro One has established a Management Development Steering Committee to oversee the identification of Management Development needs in the Company. The committee includes senior managers from both line and support functions, and is also responsible for the succession planning process. Each year a Management Development Program Schedule is created based on the developmental needs of management staff.

5.3 Succession Planning

A Succession Planning Process has been developed for all senior management staff within the Company. The program's goal is to ensure that for each of the senior management positions, at least two successor candidates have been identified, and that a developmental plan for each of the candidates is developed and implemented.

6.0 SUMMARY

Attracting, motivating and retaining the right people is key to Hydro One's success. Despite the Company's efforts to date to ensure that we have an adequate supply of labour, it continues to face staffing challenges. In addition to the potential retirement of up to 1,000 employees in the next couple of years, there is a increasing distribution work program. Hydro One will continue to utilize a mix of regular, non-regular and contract staff in order to maintain the necessary flexibility to react to a changing environment.

In an industry with aging demographics and a highly competitive labour market, the Corporation needs to be positioned as an attractive employer if it is to succeed in recruiting and retaining staff with the requisite skills. To do so, it must provide a competitive compensation package and challenging and rewarding job opportunities. Hydro One believes its staffing stategy will allow us the flexibility to respond effectively and efficiently to any scenario that will arise over our business planning period.

COMPENSATION, WAGES, BENEFITS

1.0 OVERVIEW

Hydro One has experienced rapidly increasing transmission and distribution work programs since 2004. Resourcing of these work programs must occur on the most cost-effective basis possible within a highly competitive labour market.

Table 1 below outlines the compensation costs for Hydro One Networks employees from 2004 to 2008. The Company believes that the upward trend in these costs is reasonable in light of the steadily increasing transmission and distribution work programs since 2004, as well as the negotiated increases in labour rates.

The actual breakdown of compensation by employee category follows in Exhibit C2, Tab 3, Schedule 1.

Hydro One Networks Inc. Payroll* (M$)

Year	Total Wages	Base	Overtime	Incentive	Other**
2004	404.2	323.7	53.2	12.3	15.0
2005	397.9	321.1	50.6	8.4	17.7
2006	459.3	368.0	66.5	4.4	20.5
2007	495.5	414.7	60.9	6.6	13.2
2008	580.7	475.5	72.1	8.5	24.6

* This payroll reflects compensation costs associated with year-end headcounts for all EPSCA, PWU, Society and MCP staff.
** "Other" includes travel time, vacation bonus, unused vacation days paid out, standby allowance, shift allowance, vacation pay on termination.

2.0 COMPENSATION STRATEGY

Operating within an increasingly competitive labour market, Hydro One has faced, and continues to face, a number of challenges with respect to establishing and maintaining a more favourable cost structure. Most notably, more than 90% of the workforce is unionized, and came to Hydro One with pre-existing collective agreements. The collective agreements are complex and comprehensive and incorporate by reference the pension and benefit plans. Because 70% of the workforce is represented by a single union, the Power Workers' Union ("PWU"), the Corporation would be unable to continue operations for a sustained period in the event of a work stoppage by that union. Consequently, the primary focus in collective bargaining with the PWU has been on increasing productivity and on increasing management flexibility to run the operations rather than on seeking compensation concessions.

With respect to the Society, the corporation has substantially altered pension entitlements for new hires and recently negotiated a five year agreement which will provide labour stability and cost predictability. Highlights are provided in section 3.2 of this exhibit.

In terms of Management compensation, Hydro One has endeavoured to strike a balance between the need to attract and retain competent staff and the need to constrain costs. To this end it has increased hours of work for all Management staff and substantially altered pension and benefit provisions for new hires.

Hydro One has undertaken an independent benchmarking study on labour rates and overtime in response to the Board's directive EB-2005-0378. Hydro One issued a Request for Proposal for this study and ultimately engaged Hay Management Consultants. The study will benchmark sample Management, PWU and Society positions.

3.0 LABOUR AGREEMENTS

Hydro One has direct collective agreements with the Power Workers Union (PWU), the Society of Energy Professionals, the Canadian Union of Skilled Workers (CUSW) and the Labourers' International Union of North America (LIUNA) as well as collective agreements with each of the 15 Building Trade Unions (BTU's) through membership in the Electrical Power Systems Construction Association (EPSCA). The key agreements are with the PWU and the Society.

PWU – This industrial collective agreement covers wages, pensions, benefits and working conditions. The contract has been reduced in size and complexity since it was inherited from Ontario Hydro in 1999, in order to provide Management with the flexibility to direct and effectively utilize the workforce. However, wage rates, pension entitlements, and benefit coverage are prescribed and can be changed only through negotiations.

Society – This collective agreement covers wages, pensions, benefits and working conditions for professional staff. The Society had mandatory mediation/arbitration since the formation of Hydro One until 2005. Through arbitrated awards, Management attained some increases in flexibility and cost reduction in return for market rate wage increases. In 2005, mediation/arbitration did not apply and traditional bargaining took place. The resultant settlement, although obtained via arbitration was more responsive to Management's needs in that it established a two tier pension plan for new Society employees. As noted earlier, a renewal collective agreement was negotiated during the second quarter of 2007 and ratified on June 29, 2007.

3.1 PWU

Compensation of PWU-represented employees is negotiated through the collective bargaining process. An aging workforce in technical and trades positions in the utility industry is likely to limit the supply of skilled staff in the future, putting upward pressure on wages.

The key focus with respect to the PWU has been to achieve increased management flexibility to run the operations, as opposed to wide scale reductions in wages, benefits and pensions.

The gains made to date with respect to PWU negotiations include:

- PWU Incentive Plan non-renewal
- Lower meter reader B rate negotiated
- Modified duty hours
- Switching agents for stations
- Winter meal reduction
- Temporary headquarters established

The bulk of the gains were the result of 2005 contract negotiations with the PWU and total about $12 million between 2004 and 2008. Hydro One will be entering into new negotiations with the PWU in January 2008 in advance of expiry of the current contract on March 31, 2008.

It is likely an attempt by Hydro One to achieve significant cost reductions in wages, benefits and pension would result in a strike. The last PWU strike was in 1985 and lasted 12 days. It was handled by placing management and Society-represented staff in key functions to maintain operations/service to the extent possible. However, as a result of numerous downsizing programs, and re-organization of work, there are far fewer management staff available today with the requisite skills and experience to occupy key PWU positions during a strike. As a result, the Company would be unable to continue operations during a prolonged PWU strike.

3.2 Society

Compensation of Society-represented employees is negotiated through the collective bargaining process. Hydro One's goal is to compensate Society-represented staff at levels competitive in the market place in order to maintain the ability to attract, motivate and retain competent staff. For the utility industry, an aging workforce within operations management and specialist engineering positions is likely to limit the supply of skilled employees in the coming years, putting upward pressure on compensation. Further, utility hiring practices from the mid-1980's until recently have resulted in fewer engineers with requisite education and experience being available in the workforce.

In establishing rates for Society-represented staff, Hydro One considers the average industrial wage settlements, Consumer Price Index, and survey results from the Ontario Society of Professional Engineers. This survey is used as a major data source since engineers are the single biggest classification within the Society. As an employer, Hydro One focuses on the marketplace more than on inflation. Hydro One's goal is to occupy a certain position in that marketplace in order to attract, motivate and retain the kind of talent required.

With respect to the Society, the strategy prior to 2005 had been to achieve increased management flexibility to run the operations. Until then, the Society had mandatory mediation/arbitration as the method of dispute resolution, so there had been no strikes. Following the elimination of this approach in 2005, the Society conducted a 15-week strike. Subsequent arbitration resulted in a salary increase of 3% on April 1, 2005, and on April 1, 2006 and April 1, 2007. The expiration of that agreement was originally scheduled to occur on March 31, 2008. However, on April 5, 2007 both parties announced an early start to negotiations, having successfully concluded several months of co-operative work to resolve a variety of issues and disputes remaining between the parties. A new agreement was ratified on June 29, 2007 and, the Ontario Labour

Relations Board has granted permission to make the new collective agreement July 1, 2007.

Highlights of the agreement are below:

- The term is for five years, from April 1, 2008 to March 31, 2013. This has administrative savings since there is no need for bargaining for the next 5 years. It also ensures stability and predictability around a portion of the labour costs.
- Salaries will rise by 3% on April 1 2008, 2009 and 2010, and by 2.5% on April 1, 2011 and 2012, with cost of living adjustments provided in the last three years.
- Effective October 1, 2007, a new automatic step progression plan will replace the current performance pay plan (which had a mandatory 1% of base payroll payout per year).
- The salary range for all bands will be equivalent to 70-100% of current bands, with established progression steps. (replacing the existing 80-115% ranges).
- Unfair labour practice complaint and over 100 related grievances are resolved or withdrawn.
- Effective April 1, 2008, Hydro One will no longer subsidize the cost of optional life insurance.
- Hydro One will no longer add new spouses and children of re-married pensioners, surviving spouses of pensioners and surviving spouses of employees to the Health and Dental Plan.
- As a result of the change to the Society Purchased Services Agreement, Hydro One has no parameters or processes that restrict or inhibit its ability to contract out, other than the company can not lay off a Society represented employee as a direct result of contracting out his/her work.

In addition to the gains achieved during the recent round of negotiations, earlier notable gains have included:

- Cancellation of the annual incentive plan that had a maximum payment of 4% of base salary with a potential savings of $2.7M per year.
- Implementation of a two-tier pension plan for Society-represented employees hired after November 16, 2005 which is approximately 25% less costly than the existing plan for Society-represented staff hired prior to that date.
- Elimination of mandatory mediation/arbitration.

Hydro One believes these gains are consistent with the direction provided by the Board to continue its efforts to manage its overall compensation costs.

3.3 Management Compensation Plan ("MCP")

Following the Ontario Hydro demerger, Hydro One introduced a new Management Compensation Plan (MCP), which included base salary, benefits and variable pay. The MCP is designed around a structure comprised of 10 broad band levels.

The advantage of such a system is that it reduces the number of pay layers, simplifies administration, and provides increased opportunity for employees to progress as they gain skills and experience, without the frequent need to change positions. This plan is built around compensation goals and principles reflecting the need:

- To attract and retain competent executives.
- To achieve ongoing performance improvement.
- To align the interests of management and shareholder.
- To link compensation to the achievement of corporate objectives and individual performance.
- To provide flexible salary ranges, enabling executives to move up the ranges based on annual performance.

- To provide incentive pay on an annual basis and based on a rigorous performance management system.

Each management position is assigned to a salary band according to the accountabilities, size and complexity of the job. An employee's base salary within the pay band depends upon their expertise relative to the requirements of the job and is reviewed annually. Hydro One establishes reference positions using the Hay Methodology. All Hydro One MCP jobs are rated against these reference positions for scope and complexity.

Base salary adjustments for MCP staff are tightly managed and have never been applied as "across-the-board" economic increases, but rather to reflect improved competency in a job. In 2004, 2005 and 2006, 2.5%, 3% and 4% respectively were made available as base salary increases, by the Human Resource and Public Policy Committee of the Company's Board of Directors.

The variable pay concept is another key component of the management compensation strategy. Each of the 10 broad base salary bands has a maximum variable pay range associated with it. These maximums are percentages of the individual's base salary, and have been determined through an assessment of compensation practices in the target market. As noted earlier, two of the Hydro One management compensation principles are:

- Linking compensation to the achievement of corporate goals and individual performance.
- Providing incentive pay on an annual basis and based on a rigorous performance management system.

Hydro One believes that its short-term incentive program meets both of these principles in a cost-effective manner. The program provides an incentive payment, based on an employee’s performance against a specific set of annual performance criteria and factors in corporate performance. The incentive is re-earnable every year, so it is not built into the employee’s ongoing compensation. In years where performance is not strong, a reduced incentive, or no incentive pay, will be provided. Even in a year in which Net Income is achieved but other performance measures are not, there may not be an incentive payout. The re-earnable aspect of the program reflects a best practice approach since it minimizes the long-term compensation costs and allocates pay based solely on performance. Furthermore, the link between the performance factors and the Company's strategic goals (described in Exhibit A, Tab 3, Schedule 1) ensures that management performance is driven by a balance of considerations – the need for a safe workplace, customer focus, reliability, financial performance and employee and shareholder relations. These together, help create a high-performance, more efficient work environment. Achievement of these goals directly benefits the ratepayer and therefore it is appropriate that any incentive paid related to achievement of these goals, including net income, should be included in the revenue requirement.

Hydro One utilizes Hay Consulting to evaluate its positions relative to the market. Compensation adjustments are made as deemed necessary to attract, motivate and retain competent staff.

In May, 2007, the Agency Review Panel (the "Arnett Panel") submitted its report on Phase I of its review of Ontario’s provincially-owned electricity agencies. The Arnett Panel has provided the Government with a report on executive compensation. The Government supports the report and has indicated it will provide a directive to the Hydro One Board of Directors with respect to implementing the report’s recommendations.

Currently, the compensation strategy for MCP is that Hydro One targets total cash compensation at the 75th percentile of the target market comparator group, which is the Hay All Industrial Component. The organizations in this study represent corporations which are in the electricity sector or related fields and with which Hydro One competes for talent.

Hydro One's best performers are highly marketable, and several key management staff have left the company in recent years. The Hydro One succession plan has facilitated internal promotion and a smooth transition in most cases, but our internal replacement capacity is now significantly diminished in key areas. External recruitment has proved challenging as our compensation levels and structures have fallen below the market for top people. The Human Resources and Public Policy Committee mandate requires a review of the Management Compensation Structure every year. Hay Management is utilized to assist in the review. Recommendations are ultimately presented to the Board of Directors for approval. (Following a 2006 review, Hay recommended that the minimum and maximums of the majority of bands be increased in order to maintain market relativity)

In terms of Management compensation, Hydro One has endeavoured to strike a balance between the need to attract and retain competent staff and the need to constrain costs. To this end it has increased hours of work for all Management staff and substantially altered pension and benefit provisions for new hires.

4.0 PENSION AND BENEFITS

Hydro One Networks is a participant in the Hydro One Pension Plan ("Plan"). The Plan is a contributory, defined benefit pension plan whose members comprise represented employees of the Power Workers Union ("PWU"), Society of Professional Engineers ("Society"), non represented management employees, employee pensioners and beneficiary pensioners.

In an effort to contain escalating benefit and pension costs, in January 2004 the Corporation introduced revised pension and benefits plans for MCP hired after January 1, 2004. These new plans are approximately 25% less costly than the previous plans. As noted previously, the revised pension plan is also applicable to Society staff hired after November 16, 2005. Additional detail on pension costs is contained in Appendix A of this Schedule.

5.0 SUMMARY

As noted previously, in a heavily unionized environment, there are significant constraints on an employer’s ability to reduce compensation costs per employee. However, despite these constraints, the Corporation has made significant gains in the reduction of pension and benefits costs for MCP staff and pension costs for Society-represented staff. The elimination of the incentive plans for PWU and Society has reduced potential cash payouts to the PWU and Society by 6% and 4% respectively. Hydro One will also continue its focus on increasing productivity and management flexibility to run the business.

PENSION COSTS

1.0 PENSION COSTS

Hydro One Networks is a participant in the Hydro One Pension Plan ("the Plan"). The Plan is a contributory, defined-benefit pension plan whose members comprise represented employees of the Power Workers Union ("PWU"), the Society of Energy Professionals ("Society"), MCP employees, pensioners who were employees, and pensioners who are beneficiaries of employees or pensioners.

The Board has previously allowed cash payments related to pension obligations to be recorded in rates (RP-1998-0001). As well, in April 2006, the OEB in its Decision with Reasons, approved full recovery of Distribution pension costs included in OM&A (RP--2005-0020/EB-2005-0378).

Pursuant to the Inergi outsourcing agreement (see Exhibit C1, Tab 2, Schedule 6), Hydro One Networks is also required to pay, directly to Inergi, a predetermined estimate of Inergi's annual current service pension cost in each year for each of the ten years of the outsourcing.

The Hydro One pension cost allocated to Hydro One Networks is based on the ratio of base pensionable earnings for Hydro One Networks' staff, as compared to the total base pensionable earnings for all of Hydro One employees. The method of allocation of the pension cost and the Inergi annual pension charge is consistent among all shared services costs, for operating and capital costs, and is consistent with the methodology reviewed during RP-2005-0020/EB-2005-0378 and EB-2006-05-01.

For the Distribution business, the annual charge to be recovered through rates is estimated as follows:

Annual cash pension cost (millions)
(*may not add due to rounding*)

2008								
Corporate Pension Costs	Transmission		Distribution		Other		Total	
OM&A	$	27	$	33	$	3	$	63
Capital	$	18	$	23	$	-	$	41
	$	45	$	56	$	3	$	104
Inergi Annual Pension Charge								
OM&A	$	2	$	4	$	-	$	6

2.0 ACTUARIAL CALCULATION

The most recent actuarial valuation for the Hydro One Plan was as at December 31, 2003. In September 2004, Hydro One filed this actuarial valuation with the Financial Services Commission of Ontario (FSCO), which was reviewed during RP-2005-0020/EB-2005-0378. The valuation showed that the Plan had a deficit of $167 million, on a going-concern basis. The required contribution for the Hydro One companies was set at $81 million starting in 2004, variable based on the level of base pensionable earnings. Of this amount, about $60 million represented annual current service costs, and the remaining portion represented special payments over 15 years required toward the going-concern deficiency, and commuted value top-ups.

In accordance with applicable regulations, Hydro One has made all required contributions since January 1, 2004.

Hydro One's next actuarial valuation will be prepared as at December 31, 2006 and will be filed with FSCO in September 2007. The valuation will depend on investment returns, changes in benefits, and actuarial assumptions.

Pension costs for 2008 are estimated at $104 million respectively. These pension costs were derived from estimates prepared by Mercer Human Resource Consulting LCC (“Mercer”), the Plan’s actuary. The December 31, 2003 membership data and September 30, 2005 assets were extrapolated to December 31, 2006.

The estimated $104 million contribution in 2008 is comprised of $74 million in current service cost and $30 million in unfunded liability payment. The change from the $81 million contribution estimate in the 2003 actuarial valuation, or $23 million, is due to:

Impact of liability and service cost increase due to assumption changes	$20 million
Increase in current service cost reflecting staff growth	$ 8 million
Impact of asset gains	($5) million
	$ 23 million

Going concerns assumption in the 2003 actuarial valuation and in Mercer’s estimate for 2007 are the same except inflation was raised from 2.25% to 2.50%, consistent with market conditions. The inflation estimate is based on the spread between the yield on long-term Government of Canada Bonds and Government of Canada Real Return Bonds. This spread increased by 0.25% between December 31, 2003 and October 31, 2005 (the latest available yields at the time the estimate was prepared). The yield spread at July 31, 2006 is consistent with the yield spread at October 31, 2005.

The staff growth reflected in the increase in current service cost supports the requirements of the work program.

The short-term investment experience in 2004, 2005, and 2006 exceeded the long-term discount rate used to calculate pension plan liabilities at December 31, 2003. This investment experience in 2004, 2005 and 2006 is expected to contribute to a reduction in projected contribution requirements, starting in 2007, from the costs shown in this evidence. However, updated costs, and all other relevant assumptions, have not been finalized at the time this evidence has been prepared.

During 2007, actual contributions have commenced based on an estimated $100 million contribution level, consistent with estimates provided in RP-2005-0020/EB-2005-0378. Actual contribution requirements in 2007 and 2008 may differ that will depend on final membership data, plan assets and economic assumptions used in the actuarial report filed as at December 31, 2006. The difference between the estimated and actual pension costs will be tracked in a variance account (see Exhibit F1, Tab 3, Schedule 1).

3.0 PENSION PLAN GOVERNANCE AND PERFORMANCE

Hydro One is the Plan sponsor and administers the pension assets and obligations of the Plan. As of December 31, 2006, the Plan had a reported net asset value of $5,199 million and about 11,680 members. One-third of the Plan's members are active. The remaining Plan members are inactive, either retired or beneficiaries of retirees. The Plan governance was reviewed during RP-2005-0020/EB-2005-0378.

The Fund has consistently outperformed market indices. In the period from June 29, 2001 (the Fund's inception) to December 31, 2006, the Fund return was 9.54% and the Fund outperformed its target return number by 0.71%.

In addition, Fund performance has been favourable relative to that of other pension funds. Specifically, the Fund has a 20th percentile rank since inception.

COSTING OF WORK

1.0 OVERVIEW

Hydro One Distribution's work program is bundled into packages of work identified as programs or projects. Program and project costs are comprised primarily of activities associated with labour, equipment and material acquisition. Consistent with common industry practice, trade labour and equipment hours are distributed directly to benefiting programs and projects by using weekly-prepared timesheets. Standard hourly labour and equipment rates are then used to convert the reported hours into costs. Both labour and equipment rates are "fully loaded" to ensure that all associated support costs required to deploy resources and equipment are accurately and cost effectively distributed to the benefiting work. By creating predetermined standard rates, Hydro One Distribution sets cost targets to measure actual performance and to identify opportunities where, over time, cost efficiencies can be gained.

In terms of material costs, a standard material surcharge is included in this cost category to capture material procurement costs benefiting the particular program or project.

The cost compositions of these standard rates are explained in more detail in the Section 2 of this Exhibit.

Depending on the nature of the work, Hydro One Distribution's program or project costs also include additional costs beyond the major contributors identified above. These additional costs may include the costs of external contractors and/or miscellaneous job specific consumables such as travel expenses or the purchase of low value material. As well, certain programs (primarily customer demand work) benefit from staff support hours that are not distributed using weekly timesheets. These functions deal with a high volume of short duration customer demand requests and therefore it is neither practical nor cost effective to complete weekly timesheets. The costs of these activities are assigned monthly to the benefiting programs based on workload reviews and an assessment of the upcoming annual work program.

In terms of estimating and costing capital work, there may be circumstances when removal costs or customer contributions need to be separately identified. The cost of removal work is accounted for as OM&A and customer contributions are netted against our gross capital costs. Capital work also receives a monthly charge for its share of corporate and overhead costs and capitalized interest. The composition of these two cost categories and the annual calculation are explained in Exhibit C1, Tab 5, Schedule 2 and Exhibit D1, Tab 4, Schedule 1.

2.0 PROJECT / PROGRAM MAJOR COST CATEGORIES

2.1 Labour Rate

On an annual basis, the standard labour rates are derived based on information gathered through the annual budgeting process. Resource budgets for each major resource category are calculated and categorized into three basic cost components; forecast billable (direct charged) hours, forecast non-billable hours and forecast non-billable expenses. Total payroll and expense costs along with an assignment of support activity costs, divided by the forecast billable hours, create the standard labour rate. The cost elements embedded in the standard rate are illustrated in Table 1 and explained in the pages following, using the Regional Line Maintainer as an example.

Table 1

Regional Line Maintainer - Regular Staff 2008 Labour Rate	Billable $ per Hr.
Composition of the Standard Labour Rate	**$105.50**
Payroll Obligations	**$72.08**
Contractual time away from work	**$8.48**
Time not directly benefiting a specific Program or Project	**$4.84**
Support Activities	**$20.10**

2.1.1 Payroll Obligations ($72.08)

A brief description of the cost elements included in this category is provided below. Our compensation, wages and benefits are more fully explained in Exhibit C1, Tab 3, Schedule 2.

Base Labour and Payroll Allowances (54% of Payroll Obligations)

- Base Pay: Contractually negotiated and reflected in our wage schedules.
- Payroll Allowances: Allowances are also contractually negotiated and stated in our collective agreements. Regular staff (PWU) are entitled to travel, footwear and on-call allowances. Casual trades are entitled to travel and subsistence allowances where circumstances permit.

Company Benefits (42% of Payroll Obligations)

- Regular Staff: Comprised of Pension (28.9% of base pensionable earnings) and current and post employment benefits; health, dental, etc. (40.6 % of base pensionable earnings).

- Non-Regular Staff (eg: Lines Hiring Hall): Pension and Welfare contributions that are 40% lower in comparison to the company benefit contributions made on behalf of the regular employee.

Government Obligations (4% of Payroll Obligations)

- Consists of Canada Pension Plan (CPP), Employment Insurance (EI), Employee Health Tax (EHT) and Workplace Safety and Insurance Board (WSIB);
- In 2008, 6.3 percent is applied against total earnings (includes base pay, bonus, overtime, benefits and taxable allowances) to recover these costs.

2.1.2 Contractual Time Away from Work ($8.48)

This category consists primarily of employee vacation and statutory holidays, all established and identified in our collective agreements. Sickness and accident costs are also included and are based on historical trends and consider current company initiatives.

2.1.3 Time not directly benefiting a specific Program or Project ($4.84)

This category includes time for attendance at safety meetings, housekeeping and downtime often resulting from inclement weather. These estimates are based on historical trends and current initiatives.

2.1.4 Support Activities ($20.10)

Administrative Expenses and Centralized Support (39% of Support Activities)

- These costs include administrative expenses such as travel costs, cell-phones and other miscellaneous expenses that cannot be specifically attributed to a particular program or project. Also included, is an assignment of costs for centralized clerical support activities and other centralized support for maintaining mobile radios and supporting work management system requirements.

Field Support Staff (46% of Support Activities)

- These costs include management and technical staff providing support services to manage and monitor the status of the assigned programs and projects.

Networks Work Methods & Training (9% of Support Activities)

- Costs to design, develop and deliver work methods and training programs. Costs are assigned based on the forecasted consumption of these services as agreed to by the Work Methods & Training function and service recipient.

Networks Safety & Environmental Support (6% of Support Activities)

- Costs to design, develop and deliver safety and environmental practices primarily for staff working in field locations. Costs are assigned based on the forecasted consumption of these services as agreed to by the Safety & Environment function and the service recipient.

2.2 Fleet Rate

Hydro One owned fleet assets are categorized into 65 classes of equipment. For each equipment class a standard equipment rate is calculated by dividing the annual forecast cost to maintain each class of equipment by the annual forecast hours the class of equipment is required to work (utilization hours). Utilization hours are derived based on a review of historical trends and an annual review of the upcoming Work Program. Utilization hours are defined as the hours the equipment is being used "on the job". As illustrated in Table 2, the rate is fully loaded to ensure we attribute all associated costs to the benefiting work.

Table 2

Lines Maintenance Vehicle 2008 Fleet Rate	Billable $ per Hr
Composition of the Standard Fleet Rate	**$63.00**
Operations & Repairs	**$37.05**
Depreciation	**$19.94**
Fuel Costs	**$6.01**

Below is a brief description of each category. In addition, fleet rates for historical, bridge and test years are illustrated in Attachment A. A discussion on Fleet Management may be found in Attachment A of this exhibit.

2.2.1 Operations & Repair Costs (59% of Fleet Rate)

- This cost category consists primarily of repair costs (labour and parts) which are derived based on a forecast of the annual maintenance schedules for each piece of equipment. The age and the history of the vehicles are considered in the calculation. Throughout the year, all repair costs are charged directly to each piece of equipment. Operations cost include administration staff and their allocated share of central service support costs (facilities, telecommunications and work methods and safety training activities)

2.2.2 Depreciation (32% of Fleet Rate)

- Based on the current composition of the Fleet and the annual forecasted additions and deletions, the depreciation for each class is calculated based on the current depreciation policies in Hydro One. Operating leases are also included in this category. Fleet leases approximately 4% of its vehicles, predominantly light trucks.

2.2.3 Fuel Cost (9% of Fleet Rate)

- Fuel consumption cost is calculated based on past history, future fuel price projections and the composition of the class.

2.3 External Fleet Rentals

Due to the seasonal and fluctuating nature of the work program, Hydro One Distribution requires externally owned equipment to meet work program peaks. Similar to the process used to cost its own fleet, Hydro One Distribution calculates and uses standard rates to distribute these costs to programs and projects.

2.4 Material Cost and Standard Surcharge

Material costs charged to a project or program are based on the issue cost from Inventory, which is the Average Unit Price (AUP) or the direct-shipped purchase order price. On a monthly basis, the total monthly material charges are surcharged with a fixed percentage to cost effectively recover the costs associated with purchasing, transportation and inventory management. The percentages range from 5% to 14% depending on work program service requirements. The percentages are derived by assigning the costs of these activities to the work programs based on an annual assessment of the consumption of these services divided by the annual forecast of purchased material. The Supply Chain Management details are described in Attachment B of this exhibit.

The costs recovered in the surcharge are as follows:

- Inergi Contract Costs: Procurement, investment recovery and management of in-bound transportation of material. (Approximately 45% of the total costs);
- Hydro One Supply Chain Costs: Warehousing and out-bound transportation of material. (Approximately 55% of the total costs)

2.5 Standard Rates

When using standard rates, residual costs naturally arise when actual costs incurred differ from the standards. These variances are accounted for on a monthly basis and assigned to both capital and maintenance programs. The monthly assignments of residual costs are made to OM&A and Capital based on the program and project cost activities responsible for generating the year to date variances.

In terms of the standard rates themselves, year over year variation in the labour rate is primarily due to payroll obligation costs (e.g. wage and benefit changes). Information about employee pensions and benefits may be found in Exhibit C1, Tab 4 Schedule 2. Year over year variations in the fleet rate are due primarily to fluctuations in depreciation expenses and changes in the staff mix associated with fleet maintenance activities. Year over year variation in the material surcharge rate are due to increased transportation costs.

FLEET
(Including Repair and Fueling)

1.0 INTRODUCTION

Fleet Management Services provides centralized and turn key services that include maintenance, administration, vehicle replacement and disposal. Vehicles are maintained to an optimum level to ensure public and employee safety and compliance with laws and Ministry regulations including but not limited to CSA225, Highway Traffic Act and Commercial Vehicle Operator's Registration Regulations. Fleet Management Services has the role of minimizing environmental impacts; optimize Lines of Business productivity by minimizing downtime, travel time and optimizing technological and continuous improvement opportunities.

Fleet Management Services has adapted to the changing needs of its business through the following means:

- Internal customers changed from a fixed zone service provider to a mobile and firehall model;
- Fleet and facility rationalization;
- Improved equipment downtime and equipment utilization;
- Competitive and cost efficient fleet support;
- Flexible service delivery model that matches the internal customer's nomadic and variable work programs, including service delivery options that mirror the private sector, including shift work, extended hours of service and mobile service delivery;
- Timely, strategic and cost efficient equipment procurement and disposal;
- Long range Capital Replacement Program;
- Data collection and information management systems that match the nomadic business unit requirements.

2.0 MAINTENANCE MODEL

Fleet Management Services has developed a balanced maintenance model of mobile service delivery and centralized facilities. This model provides the appropriate balance of 35 provincially centralized locations that are based on cost effective analysis and forecasting within the 2007 Business Plan, geographical customer requirements, travel time, third party vendor support and response time. Mobile/satellite repair units also minimize the cost by providing timely on-site field support for the different types of nomadic work programs including vegetation control, new construction, and off-road tower maintenance. The combination of the internal and external program meets the requirements and rigor of Fleet Management Services' service level agreements and its customers' requirements of a mobile and firehall operating model. Any significant changes to the Business Plan or the company will be supported by changes to this flexible business model.

3.0 MANAGED SYSTEMS

In 2003, a strategic alliance was developed with Automotive Resources International (ARI) to implement a fleet management system in 2004. The implementation of the fleet management system created an automated web-based system that uses a single credit card for each vehicle to capture all operating costs including fuel, parts and repairs. The fleet management system incorporates programs required to manage contracts such as tender agreements, and the system prescribes spending guidelines and negotiated discounts. The system/program measures a variety of targets that reconcile approved purchase orders, estimates versus actuals, spend by vendor, discount by vendor and vendor complaints.

The benefits of this program include:

- Improved scheduling of preventative maintenance, reduced repair times, travel time and reduced equipment downtime;
- Increased access to the number of vendors for fuel, repairs and parts, thus minimizing cost and downtime;
- Improved cost and efficiency, through increased procurement strategies and larger economies of scale, including improved volume discounts for fuel, parts and service;
- 1-800 number for repairs, roadside assistance and towing. This program is guided by Hydro One approved spending limits and guidelines, as well as approved spending limits authorized by Hydro One Fleet Management Services personnel;
- Improved reporting and data collection.

This management system uses a variety of linked programs that include the Fleet Web Site, Intellifleet and Virtual Garage. This system which is for all vehicles and equipment, manages the data and information for all facets of the business including internal and external repairs. This system and associated programs are operated in partnership with ARI take advantage of internal and external intelligence and technology.

The proactive and user friendly maintenance program minimizes avoidable and expensive repairs, minimizes equipment downtime, and improves equipment utilization. Both internal and external service providers have access to the appropriate information through state of the art automated management systems allowing for quality decision making in all levels of the maintenance program. Examples of the information include:

- Real time vehicle history;
- Warranty criteria and warranty recovery;
- Work and resources scheduling tool;
- Pending and overdue work information alert system;

- Product information, including vendor specific;
- Repair and safe practices manuals;
- Process and policy information;
- Invoice and cost management details;
- Monthly and ad-hoc reports;
- Work order management;
- 24 hour roadside assistance.

Fleet Management Services controls and manages approximately 5,185 vehicles and other equipment primarily for distribution and transmission work (see Appendix A). Inventory levels are controlled and set by the Hydro One Lines of Business and Fleet Management Services within the guidelines set for staffing versus fleet ratio, type and volume of work programs, geographic locations and utilization targets. Fleet Management Services maintains 35 facilities to support 19 Forestry locations and four Brushing Crews, 1200 Distribution Stations and 280 Transmission Stations, 53 Provincial Lines Distribution locations and five Transmission Locations.

4.0 FLEET COMPLEMENT & UTILIZATION

As Capital Programs and OM&A have increased since 2000 the options to meet the increased equipment demand include; purchase additional equipment, lease/rent additional equipment or increase utilization of existing equipment. The optimum option is to increase utilization, which minimizes capital investment and maximizes the advantage of owned core equipment versus the additional cost of external rentals. The comparison of external equipment rental costs is 35 percent more than owned equipment rates. This is based on an internal study of the actual costs of equipment rentals versus the comparison of owned core equipment.

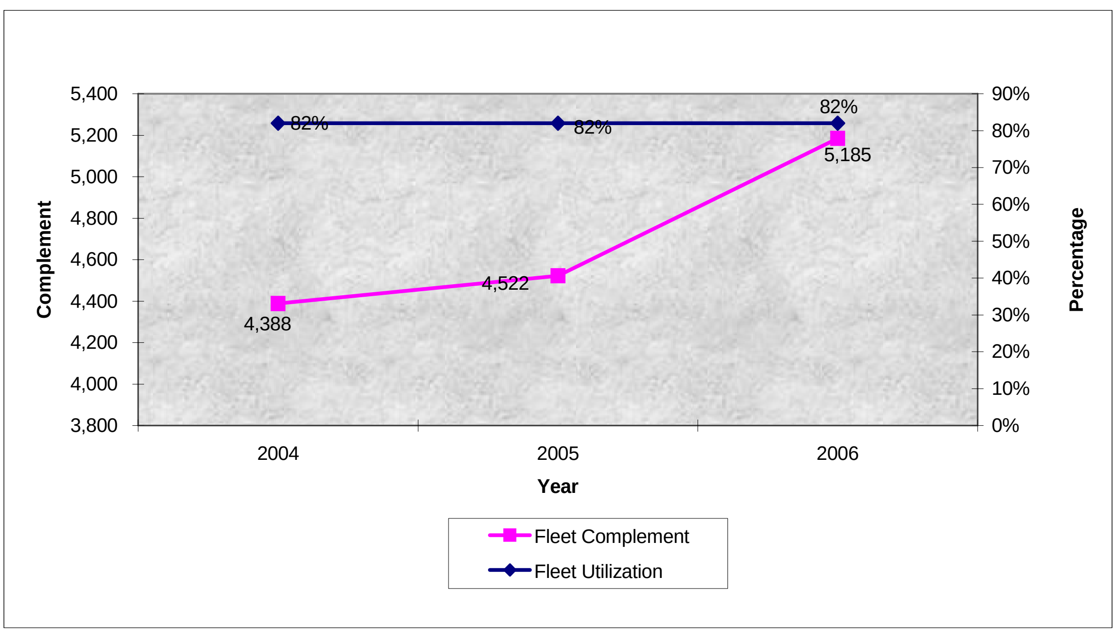
Benefits of Improving Utilization:

- Minimizes long term capital requirements
- Maximizes ability to respond to fluctuations in work programs
- Minimizes rental costs

Fleet Management Services has seen equipment utilization averages increase from approximately 65 percent in 2001 to approximately 82 percent in 2006 resulting in additional hours of yearly equipment utilization. The 2006 average equipment rate is $21.13; this is established by averaging all the individual equipment rates.

The increase in Fleet complement is directly related to the increase in Work Program and staffing levels.

Figure 1 Fleet Complement & Utilization



5.0 OM&A BUDGET

Fleet Management Services operating, maintenance and administration yearly budget is developed and managed based on the following criteria and all in costs of operating the fleet:

- Historical and forecasted costs based on estimated fixed and variable costs including fuel, depreciation, maintenance and repair, labour/staffing, external rentals and corporate allocations;
- Work program forecasts;
- Capital/Vehicle replacement program;
- Projected escalators.

Fleet Services develops an OM&A budget on a yearly basis for the following calendar year.

The total of the accounts that comprise the budget is based on:

- Historical cost and mechanical fitness evaluations;
- Work program forecast provided by LOB;
- Estimates provided by internal and external suppliers;
- Vehicle replacement program;
- Projected escalators.

Table 1
Fleet Management Services
Operating, Maintenance and Administration Yearly (OM&A) Budget Expenditures
($ millions)

	Historic			**Bridge**	**Test**
	2004	**2005**	**2006**	**2007**	**2008**
Operations & Repairs	41.4	43.3	47.0	48.4	48.4
Depreciation	25.1	24.0	26.0	27.3	27.6
Fuel	12.9	16.6	18.8	17.5	17.5
Subtotal	**79.4**	**83.9**	**91.8**	**93.2**	**93.5**
Rentals	10.5	10.7	8.1	11.5	11.5
Total	**89.9**	**94.6**	**99.9**	**104.7**	**105.0**

The higher number of fleet units, along with higher fuel prices, is directly related to the increase in the Operations & Repairs and Fuel expenditures.

5.1 Operations & Repair Costs

This cost category primarily consists of repair costs (labour and parts) which are derived based on a forecast of the annual maintenance schedules for each piece of equipment. The age and the history of the vehicles are considered in the calculation. Throughout the year, all repair costs are charged directly to each piece of equipment. Operations cost include wages, allocated share of facility and telecommunication cost and work methods and safety training activities.

5.1.1 <u>Depreciation</u>

Based on the current composition of the Fleet and the annual forecasted additions and deletions, the depreciation for each class is calculated based on the current depreciation policies in Hydro One. Lease costs associated with Fleet's operating leases are also included in this category. Fleet leases approximately 6 percent of its vehicles, predominately light trucks.

5.1.2 <u>Fuel Cost</u>

Fuel cost is calculated based on past history and the current composition of the class. Throughout the year, fuel costs are charged directly to the particular piece of equipment consuming the fuel.

5.1.3 <u>External Fleet Rentals</u>

Due to the seasonal and fluctuating nature of our work program, Hydro One requires externally owned equipment to meet the peaks in our programs. Similar to the process used to cost our own fleet, standard rates are calculated and used to distribute these costs to our Programs and Projects.

APPENDIX A

Table 1
Vehicle Profile by Category

	Rentals	Heavy Transport	Light Transport	Radial Boom Derricks	Bucket Trucks	Trailers and Misc	Off Road
Total	153	343	2,239	209	437	1,703	254

1.0 VEHICLE PROFILE

Hydro One Fleet Services has six categories of equipment that are used to support the Dx structure. These include:

Light Transport Equipment - The equipment in this category is made up of:

- Cars;
- Vans;
- SUVs
- Pickups under 10,000 lb. Gross Vehicle Weight Rating (GVWR).

The primary use of these units is for transportation and minor services, meter reading and protection and control inspections.

Heavy Transport Equipment - The equipment in this category is made up of trucks and vans over 10,000 lb. GVWR, with either no attachments or with minor attachments (eg, ladder van). These units are used primarily for work that does not require attachments and support vehicles (eg, service trucks, cube vans, stake trucks and highway tractors).

Bucket Trucks - The equipment in this category is made up of units composed of a chassis, body and aerial device. The aerial devices' size range from 37 ft to 80 ft. Hydro One's standards in this class are:

- 42 ft single buckets;
- 46 ft double buckets c/w material handling;
- 55 ft double buckets c/w material handling;
- 65 ft double buckets c/w material handling;
- 80 ft double buckets c/w material handling.

Radial Boom Derricks - The equipment in this category is made of units composed of a chassis, body and radial boom derricks. This equipment is primarily used for the digging and setting of poles. Our present standards in this class are:

- Single axle;
- Tandem axle (great capacity and reach).

Off Road - The equipment in this category is made up of units that are used primarily for off road and that have been outfitted with either an aerial device, RBD or spray equipment for a specific type of work program. This class is all non-licensed equipment.

Trailers and Miscellaneous - The equipment in this category is mainly trailers used for moving material and equipment or storage. The miscellaneous equipment covered in this category includes, but is not limited to, boats, compressors, forklifts and backhoes.

Rentals - The equipment in this category is external rental units consisting of light transport equipment and work equipment used to support the seasonal and hiring hall requirements.

SUPPLY CHAIN MANAGEMENT

1.0 INTRODUCTION

Hydro One delivers end-to-end Supply Chain Services for the Distribution, Transmission and Remotes business. The focus is on the right product with the right quality, at the right place, right time and at the right cost. These services include strategic sourcing (purchase) of materials and services, storage and distribution of materials, transportation, inventory management, and investment recovery of disposed assets.

The 2008 cost for Supply Chain services is $26.5 million, with these costs allocated to work programs and projects through the material surcharge rate discussed in the main section of this schedule (section 2.3).

This Exhibit describes the cost levels in Section 1.1, followed by a description of components of Supply Chain Management in Sections 2.0 through 6.0: Policies and Procedures, Strategic Sourcing (purchase) of Materials and Services, Storage and Distribution of Materials – Warehousing, Transportation and Investment Recovery.

1.1 Supply Chain

Table 1
Supply Chain ($ million)

	Historic			Bridge	Test
	2004	**2005**	**2006**	**2007**	**2008**
Total	**20.3**	**17.1**	**18.7**	**24.2**	**26.5**

Note: Costs exclude waste management costs (part of Transmission and Distribution OM&A) which were included in previous filings.

The growth in Supply Chain costs is a result of the growing work program. Supply Chain is planned to grow by 42% from 2006 through to 2008, supporting the growth in transmission and distribution work programs which is planned to grow by this same amount over this period. This growth in Supply Chain is driven by increasing volumes of works, as well as increased planning, sourcing, warehousing, transportation and inspection costs. Over the 2006 to 2008 period, the material surcharge rates have essentially remained the same.

In early 2002, Hydro One reached an agreement with Cap Gemini Ernst and Young Inc. in which non-core services were outsourced to Inergi LLP. Refer to Exhibit C1, Tab 2, Schedule 6 for further details. The Supply Chain of Hydro One was a part of this outsourcing contract. The components of Supply Chain performed by Inergi include purchase of materials and services, contract management and investment recovery.

The Inergi outsourcing agreement was contracted for the same service levels at a declining price over the term of the contract. The increasing overall cost levels represent increased volume of work and service levels to meet the business needs.

2.0 POLICIES AND PROCEDURES

Hydro One operates a fair and transparent procurement process that gives all companies equal opportunity to do business with Hydro One, consistent with its Procurement Policy and Principles.

Tenders and proposals are evaluated based on predefined evaluation criteria by cross-functional teams. The outcome of the evaluation is the foundation for awarding procurement contracts.

3.0 STRATEGIC SOURCING OF MATERIALS AND SERVICE

Hydro One manages its procurement and supply base by using strategic sourcing methodologies and processes in the acquisition of goods and services, representing in excess of $650 million in Hydro One annual expenditures for 2006. Strategic Sourcing is a disciplined business process for purchasing goods and services on a company-wide basis using cross- functional teams to manage the supply base as a valued resource.

The Strategic Sourcing methodology is a five-step process that includes expenditure analysis, market analysis, the development of a sourcing strategy, negotiation and award, and contract management. The main steps of sourcing strategies are described below:

- Involvement of internal stakeholders to communicate their business needs for the products and services.
- Cost reduction by increased leverage of company wide expenditures.
- Reduced total life cycle cost for materials and services, e.g. when purchasing equipment, the specifications are reviewed to ensure consistency with business needs, maintenance requirements are reviewed, installation services are identified, warranty services defined, order and invoice processes are evaluated to determine where greater efficiencies can be realized, lead time, inventory requirements etc.
- Improved security of supply through negotiating long-term agreements with fixed prices, or formula pricing, to ensure that Hydro One achieves best value.
- Improved and/or consistent quality of material and services.

4.0 STORAGE AND DISTRIBUTION OF MATERIALS - WAREHOUSING

In December 2004, Hydro One consolidated eight provincial warehouse locations into a central warehouse in Barrie. The central operating model included a change to the warehouse and distribution business model to re-deploy 18 field stock keepers to service

64 field service centres, and nine stock keepers assigned to the central warehouse. The field stock keepers are responsible for up to five sites, which they visit weekly to meet the delivery truck to receive shipments, put away material and order material. The central warehouse operation is responsible for the storage and distribution of materials for the service centres. Lastly, the private fleet was eliminated and deliveries to the service centres contracted to a third party transportation carrier. The benefits of the consolidated warehousing included total cost savings of $7 million in present value over 10 years.

The objective of the Warehousing operations is to maximize efficiencies in the central warehouse to realize the benefits of the warehouse consolidation. This requires such activities as:

- Continuously improving business processes such as receipting, shipping and cycle counting.
- Evaluating opportunities to streamline direct shipping and minimize cross-docking.
- Exploring the options of technology such as bar coding to improve operating efficiencies such as receipting, cycle counting, shipping and tracking inventory.
- Effectively managing and coordinating the delivery of materials on the scheduled delivery date to the service centres to ensure that the field operation receives the right material at the right time.
- Improving receipting efficiency by integrating with the contracted transportation company to provide visibility into the supply chain and scheduling the inbound shipment.

5.0 TRANSPORTATION

Hydro One manages its inbound and outbound transportation of materials through contracts with third party transportation companies. The transportation strategy is to actively manage the transportation cost of inbound and outbound traffic and reduce transportation cost year over year. Executing the transportation objectives will position Hydro One to improve transportation cost and operations throughout the supply chain.

6.0 INVESTMENT RECOVERY

The final step of the Supply Chain is the disposal and investment recovery of end-of-life assets. The revenue from the sale of the asset typically is applied back to the benefiting work. A breakdown of the sale of assets is as follows:

Table 2
Breakdown of Sales of Assets through Investment Recovery Program ($ Million)

Type of Sale	Recovery 2004	Recovery 2005	Recovery 2006	Recovery 2007	Recovery 2008
Vehicle Sales	2.2	1.7	1.8	2.0	2.0
Scrap Metal	0.9	1.9	1.7	2.0	2.0
Tools	0.0	0.1	0.0	0.0	0.0
Total	**3.1**	**3.7**	**3.5**	**4.0**	**4.0**

Hydro One will continue to focus on extracting the maximum value possible from the sale of end-of-life assets.

COST EFFICIENCY

BACKGROUND

Hydro One identifies cost efficiency initiatives as part of its business planning processes, and also uses benchmarking to help identify areas requiring improvement. Provided below is an overview of Hydro One's efforts to improve cost efficiency in the past and initiatives being undertaken to continue improving cost efficiency in the future.

In the OEB's Decision With Reasons on Hydro One's recent Transmission rate filing (Ref EB-2006-0501), issued on August 16, 2007, the Board stated "in the [compensation] study that Hydro One is [now] preparing, the Board expects it to provide empirical evidence which reveals the relative productivity of its workforce in comparison to other utilities". Since the Transmission Decision was issued on August 16, 2007, the day after Hydro One was required to submit its 2008 Distribution revenue requirement application, the Company has provided the additional information on cost efficiency initiatives which follows. This information includes a broad indicator of workforce productivity improvement which has been benchmarked against other large Ontario LDC's.

1.0 INTRODUCTION

Cost efficiency is a core element of the Hydro One Distribution strategy. Hydro One will continue to make prudent and responsible economic efficiency improvements consistent with its business strategy in order to deliver steady financial performance, sustain company assets and deliver safe, economic and reliable electrical energy. In this context, the focus on cost efficiency supports the Corporation's 2010 strategic performance goals and targets provided in Exhibit A, Tab 3, Schedule 1 including: creating an injury free work place with zero serious injuries and zero near misses; becoming a leading customer-focused company with a 90% level of customer satisfaction for all customer segments; and, becoming a leading ("top quartile") distribution and transmission utility in reliability, based upon like for like comparisons.

Hydro One Distribution has a strong track record of implemented initiatives and related cost savings over the past 6 years, having achieved over $380 million in cost savings, as it has focused on all aspects of the business including: labour utilization and productivity; new technology improvements; material and services costs; overhead costs; fleet costs; facility costs; business processes; and, out-sourcing of non-core business activities. Many of these business aspects are addressed elsewhere in the prefiled evidence. This exhibit summarizes and describes a number of the initiatives undertaken by Hydro One Distribution to manage costs in the past and other gradual improvements which are presently being undertaken.

Going forward, Hydro One is faced with a unique confluence of challenges:

1. Major growth in work programs;
2. IT infrastructure end of life; and
3. Staff demographic and hiring challenges;

These coincident changes in the operational environment provide Hydro One with an opportunity to transform its business in a step level change over the next few years. Through this business transformation, Hydro One anticipates that beyond the 2008 test year, it may be capable of rising to the challenge of meeting an annual 1% productivity target, as was the case in the OEB's second generation IRM.

2.0 PAST AND CURRENT COST EFFICIENCY INITIATIVES

Inline with the Company's continued focus on its core distribution business in Ontario, a number of new initiatives will be or have been identified and introduced in 2007 and

2008 to further streamline the business. These are in addition to many initiatives that commenced prior to 2007, as identified in the Company's evidence filed in EB-2005-0378 and EB-2006-0501, which have been or are being fully implemented or enhanced over the 2007-2008 period and beyond.

The following is a summary list of some major cost savings initiatives that have provided or will provide incremental cost savings for the distribution business over the 2004 – 2008 period. These initiatives have been selected based on their illustrative nature and their broad significance across the Hydro One Distribution business contributing to the resulting incremental cost savings:

- Developing a more multi-skilled workforce
- Increased staffing flexibility (e.g. use of hiring hall) to execute peak seasonal and project work
- Implementation of focused trades training programs
- New tools and technologies, such as the full implementation of information technology used for new connections
- Implementation of new processes and tools in the field to enable improved planning, scheduling and reporting of work
- Improvements in the fleet management business.
- The full use of temporary headquarters for work crews, which will reduce travel time and thereby increase "wrench" time on the job
- Targeted savings from strategic sourcing initiatives
- The centralized operation of the transmission and distribution systems
- Continued outsourcing of non-core work activities
- Improvements to collective agreements
- Integration and bundling of work, such as improvements to the management of equipment outages
- Smart meters installation

The company continues to look for opportunities to drive efficiencies and reduce compensation costs with its unionized staff, through joint participation between management and the unions on work efficiency improvements, as well as collective agreements. The gains associated with Hydro One's labour agreements are described in Exhibit C1, Tab 3, Schedule 2.

Hydro One also uses benchmarking and best practice information to find better ways to run its business, thus gaining cost efficiencies and improving work program effectiveness, as well as to provide some indication of progress across the key elements of Hydro One's 2010 strategic goals and performance targets (see Exhibit A, Tab 3, Schedule 1 pages 1 and 2). Hydro One's benchmarking efforts consist of both internal and external studies. The internal studies compare best practices between the various geographic work centres; this helps promote internal competition and ensures internally developed best practices are leveraged across the company. The primary purpose of the external studies is to identify best practices others are using which may improve Hydro One's performance. Examples of recent Hydro One benchmarking efforts are contained in Exhibit A, Tab 15, Schedule 2 – Distribution Benchmarking Studies. Benchmarking and best practice results are provided to our planners and service provider staff to help them develop performance and productivity improvement initiatives. Examples include;

- Lowering costs through use of Hiring Hall resources for lower skill manual brush cutting work.
- Reviewing forestry practices to ensure that the most effective methods of forestry management are being used. (e.g. using mechanical brush cutting)

The identification and implementation of additional cost efficiency initiatives will be a greater challenge as identifiable incremental efficiency gains are expected to be smaller in terms of potential cost savings and implementation is typically more challenging for a number of reasons including the need to leverage information technology based solutions coupled with business process changes and the challenges of implementing improvements which cross business unit boundaries.

For purposes of the business planning model, the cost savings are identified as year over year "incremental savings" defined as savings over and above those already embedded in the costs of individual programs. Accordingly, the first year impact of a new initiative or enhancements to an initiative are identified and the target associated with that initiative is subsequently monitored to establish the actual savings achieved. Under this concept of incremental savings, the savings beyond the first year are considered to be "embedded" savings for purposes of the annual business plans and are therefore not included in the annual estimates of incremental savings unless enhancements to those initiatives are made. As a result, the incremental savings estimates substantially understate the savings from those initiatives that have a cost efficiency impact over more than one year.

Table 1 identifies the estimated total incremental cost savings achieved from 2004 to 2006, as well as the incremental savings to be achieved in 2007 through to 2008 for Hydro One Distribution. While all savings estimates are for gross savings, it should be noted that the implementation costs are taken into consideration as part of the business planning process described in Exhibit A, Tab 14, Schedule 1.

Table 1
Total Incremental Cost Savings – Distribution

	2004	2005	2006	2007 Bridge	2008 Test	Total
OM&A Savings ($M)	13.4	10.5	5.9	3.3	7.5	40.7
Capital Savings ($M)	9.5	8.1	4.6	1.0	2.1	25.4
Total Savings ($M)	23.0	18.6	10.5	4.4	9.6	66.1
Total Spend** ($M)	**618**	**679**	**797**	**1,006**	**1,055**	**4,155**
Savings as % of Total Spend	**3.7%**	**2.7%**	**1.3%**	**0.4%**	**0.9%**	**1.6%**

** Total Spend includes capital plus OM&A expenditures

As compared to the first half of this decade, incremental savings between 2006 and 2008 are trending lower and are projected to remain lower, both in absolute and percentage terms, with the completion of many major cost efficiency initiatives and the implementation of smaller, fewer, and more challenging cross-business unit opportunities. Despite the challenges associated with identifying and implementing further efficiency gains, Hydro One anticipates that beyond the 2008 test year, it may be capable of rising to the challenge of meeting an annual 1% productivity target. As outlined in the following section, coincident changes in Hydro One's operational environment provide the Company with an opportunity to transform its business in a step level change over the next few years, which in turn may facilitate meeting this productivity target.

3.0 CONTINUED COST EFFICIENCY FOCUS & STEP LEVEL CHANGE

An ongoing focus for Hydro One's Distribution business has been the implementation and nurturing of a continuous improvement culture that recognizes the need to look for positive change in everything we do. As discussed in the previous section, this continuous improvement culture has resulted in the realization of substantial improvements and productivity gains earlier this decade and smaller gradual improvements more recently.

In addition to continuing to utilize benchmarking and best practice information, Hydro One is taking advantage of a unique set of circumstances to transform its business in a step level change over the next few years. Through this business transformation, Hydro One anticipates that beyond the 2008 test year, it may be capable of rising to the challenge of meeting an annual 1% productivity target. These coincident unique circumstances include:

- **Major growth in work programs** requiring increased staffing resources and support systems. This work program growth is driven by changes in conservation initiatives, installation of smart meters, vegetation management, increased demand in specific geographic areas, the need to replace aging assets, system expansion and generation mix. This will provide the opportunity to achieve greater economies of scale, leverage standardized processes and design standards, implement new work methods, etc
- **Replacement of the core enterprise wide IT systems**, which have reached end-of-life. Many of these systems are being replaced within an integrated corporate business transformation project named Cornerstone. This project will facilitate changes in business processes to allow for more effective use of information resulting in improved work execution.
- **Substantial shift in staff demographics** which will result in a large proportion of current staff retiring over the next decade, and backfilling with new staff on a relative scale not seen in decades. As the result of a renewed collective agreement, new Society-represented staff will be brought in at lower salary ranges

(the salary range for all bands will be equivalent to 70-100% of current bands, replacing the existing 80-115% ranges); different skill mixes could be sought while at the same time allowing for skills and knowledge transfer from senior staff; different work methods can be implemented; new staff will be trained on the new replacement core business process and IT systems (as noted in the previous bullet) and will not need retraining as required by existing staff, etc.

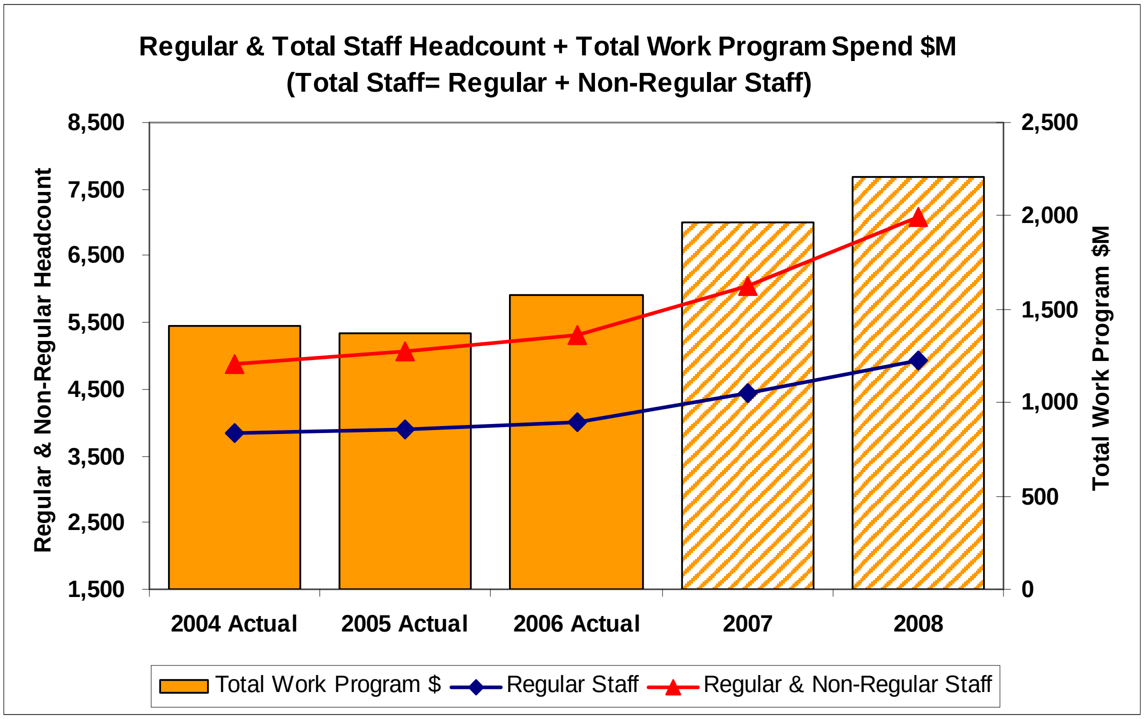
This set of changes in the operational environmental provides Hydro One with an opportunity to transform its business in a step level change over the next few years which will result in a variety of efficiency and effectiveness improvements over this period.

3.1 MAJOR GROWTH IN THE WORK PROGRAM

The growth in the total work program over the 2004 to 2008 period provides Hydro One with an opportunity to achieve better utilization of staff to accomplish this work.

One broad indicator of the better utilization of staff is shown in the following Figure 1 which provides a snapshot of the growth in Networks total work program expenditures (the sum of Distribution and Transmission business OM&A and capital expenditures) and total staffing resources (both permanent or regular and temporary or non-regular staff).

Figure 1



Despite a projected 40% increase in Hydro One Networks Distribution and Transmission businesses' work program expenditures between 2006 and 2008, whereas over this same time period the regular staff count is expected to only have grown by 23% and total staff resources (regular and non-regular) by 34%. This is an indication that Hydro One is getting more work done without a corresponding increase in resource levels.

The increase in the work program has also been enabled by Hydro One's work-based approach to staffing as discussed in Exhibit C1 Tab3 Schedule 1. Specifically, to address the fluctuating and seasonal nature of work programs, the Company maintains as much flexibility as possible by not hiring all regular (permanent) staff. Rather, knowledgeable, experienced and highly skilled internal staff plan and direct the "peak" work of non-regular (temporary, hiring hall and contract) staff, which provides the needed flexibility to manage in a cost effective manner. This flexibility provides a variable workforce which is matched to the peaking requirements of the workload at minimum costs. Specifically, the workload volume ramps up in the second quarter of the year and peaks in the third quarter; the flexible external workforce of non-regular staff is engaged in numbers to match this varying volume of work. To the degree possible, within the constraints of our labour agreements, contractors are also engaged to undertake "turn-key" projects.

Other work program improvements that leverage economies of scale include:

- Strategic alliances with suppliers and contractors can be modified to enable faster turnaround times for material and services.
- Hydro One has the opportunity to use higher efficiency customized transport and work equipment versus off–the-shelf equipment at an advantageous cost that is available to the Company because of the large volume of transactions it does with fleet equipment suppliers.

The implementation of the IT Architecture Strategy, as discussed in the next section, will also provide Hydro One with additional opportunities to glean further economy of scale savings as its work programs expand. For example, as Hydro One streamlines its businesses processes in conjunction with implementation of Cornerstone Phase I, with the increased volume of the Company's work programs, it will gain further savings than it otherwise would have.

In addition, one of the primary contributors to the increase in work program expenditures, installation of smart meters, when in place throughout Hydro One's distribution system early in the next decade, will in itself provide a live flow of high quality, detailed information which previously was not available. Hydro One is planning to apply, and leverage to the extent its economical, this new information to the advantage of its customers, by making more effective and efficient operating, replacement, maintenance and system expansion decisions.

3.2 IT ARCHITECTURE STRATEGY

The improvement of internal business processes is facilitated by an IT Architecture Strategy, which is driven by the need to replace outmoded end-of-life core business information systems. The replacement of these core IT systems will allow standardization and streamlining of work processes along with the integration of multiple databases that are currently used by different organizational units across the company. Implementation of Cornerstone Phase 1, as discussed in detail in Exhibit D, Tab 3, Schedule 5, is anticipated to contribute productivity gains through its lifetime, for total cost efficiency gains equal to about $200 million cumulative over the seven year lifetime of the new IT systems beginning in 2009.

These cost efficiency gains are derived largely from three key value levers underpinned by the Cornerstone Phase 1 application, process and organizational changes. These value levers are:

1) A single asset registry with a uniform hierarchy and selective integration to legacy databases. This saves time when inputting data, processing information, and searching for information.
2) Greater process transparency, integration and collaboration (enabled through the application and process changes) across Hydro One's lines of business. This results in fewer unique business processes thereby reducing learning and time to complete work tasks. This improves the quality of the information for better decisions and reduces the cross checking time required to reconcile errors.
3) Enhanced compliance to the underlying processes and data requirements.

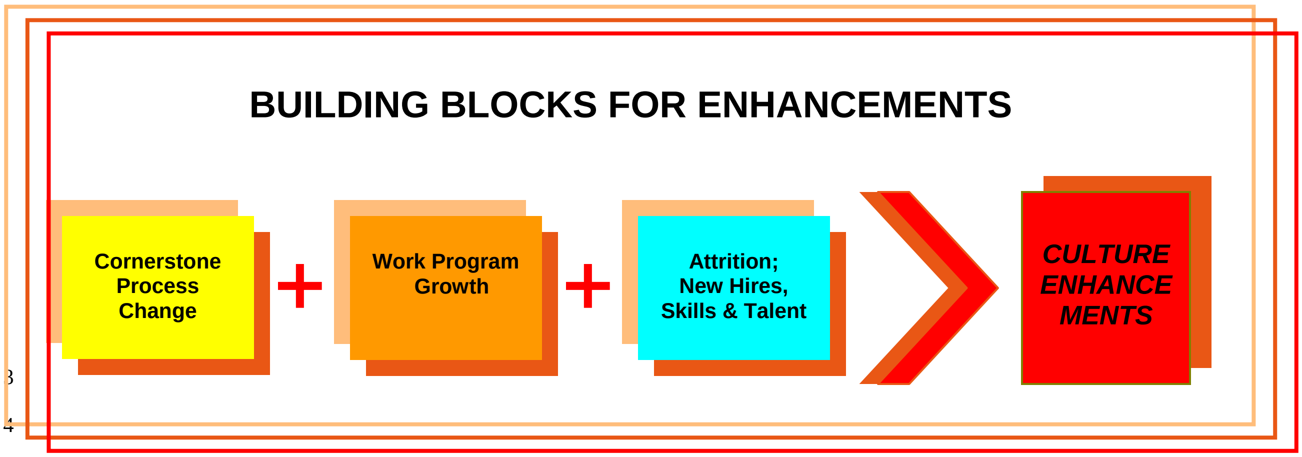
As the various phases of Cornerstone are implemented, further benefits from each phase are anticipated. With the move to an integrated and off the shelf vendor supported platform, Hydro One will also consider the integration of its GIS applications and implementation of integrated mobile technology solutions. It is expected that the use of mobile work applications and the use of GIS information will increase field force productivity. By leveraging all the new data which implementation of the IT Architecture Strategy and the smart meters program will deliver, Hydro One will become an even more proactive company in managing its assets. The extent of these future efficiency and productivity improvements is not yet fully known; preliminary work is being carried out to assess how best to use integrated technology platforms.

3.3 CULTURE CHANGE

With the impending substantial staff attrition due to demographics and coincident creation of new positions due to work program growth, Hydro One will use this opportunity to build on the existing corporate culture to further enhance its core characteristic of continuous improvement. As discussed in detail in Exhibit C1, Tab 3, Schedule 1, the Hydro One staffing strategy is focused on hiring through partnering with universities, colleges and Hydro One unions, as well as skills development and retention. In parallel with this, the enhanced corporate culture will build on the existing employee engagement, enthusiasm and innovation. Employees will continue to be encouraged and challenged to provide new ideas to move the company forward, in a collegial, motivating, and supportive environment.

As outlined earlier and illustrated below, Hydro One is at a stage in its evolution where the major change in its operational environment is providing an opportunity to build on the existing corporate culture so as to enable further productivity gains.

Figure 2



The rollout of the enhanced culture change process is currently underway:

1. A revised Human Resources Strategy has been approved by the Hydro One Board of Directors.
2. The Hydro One management team is ensuring that all levels in the organization are aware of the strategy, and are adhering to it.
3. Senior managers will be meeting directly with staff to ensure they understand the required cultural emphasis in the company.
4. Managers will be held accountable for ensuring that this emphasis is occurring in their organization
5. In order to assist with the change process, a new corporate template for change has been approved and is into the process of being rolled out. It is called “Organizational Alignment”, and will ensure each unit approaches change in the same manner.
6. This will be a long term program, and will coincide with the significant staff turnover which will be taking place over the next five to ten years.

Additional keys to the culture change being undertaken include:

- Hiring to a set of cultural selection criteria based on corporate values
- Expedited technical training and development
- Increased emphasis on leadership and cultural development programs based on corporate values

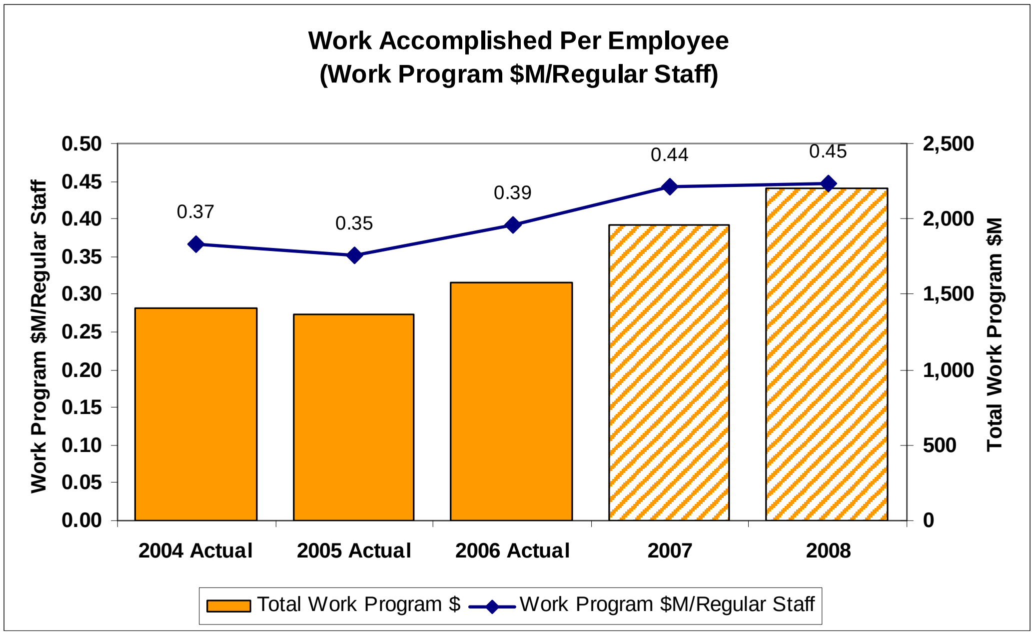
Concurrent factors to the culture change include:

- Increasing the level of business skills within the company to complement the technical skill base.
- An increase in the use of a balanced performance reporting system to identify effectiveness not just efficiency improvements. In addition, this balanced reporting will be cascaded down to the first line manager levels which will be populated by the new staff over time.

4.0 PRODUCTIVITY INDICATOR

In the OEB's Decision With Reasons on Hydro One's recent Transmission rate filing (Ref EB-2006-0501), issued on August 16, 2007, the Board stated "in the [compensation] study that Hydro One is [now] preparing, the Board expects it to provide empirical evidence which reveals the relative productivity of its workforce in comparison to other utilities". A broad indicator of workforce productivity improvement is provided in Figure 3, which displays the amount of work accomplished per regular staff count (as indicated by work program spend in $million per regular staff count) for Hydro One Networks (total Distribution and Transmission businesses).

Figure 3



Between 2004 and 2008 the work program accomplished (in $million) per regular staff count is projected to increase by 22% while the work program is expected to increase by over 50% in the same period. As outlined earlier in section 3.0, Hydro One is taking advantage of a unique set of circumstances to transform its business in a step level change over the next few years; this will enable the Company to continue to successfully and efficiently undertake increased work programs with proportionally fewer full-time staff.

As shown in the following Table 2, using the 2006 to 2008 data provided in their most recent rate filings, Hydro One Networks accomplishes substantially more work per regular staff count than the three largest Ontario LDC's. This is the case even when the large proportion of non-regular staff engaged by Hydro One to complete work, under the direction of regular staff, are factored into this measure. Note that it is Hydro One's understanding that LDC's typically employ large numbers of non-regular staff, however quantitative data on non-regular staff was not provided by LDC's in their most recent rate filings.

Table 2

Work Accomplished Per Employee+

Work Program $M/Regular Staff	2006 Actual	2007 Forecast	2008 Forecast
Hydro One	0.39	0.44	0.45
Hydro One Total Staff**	0.30	0.33	0.31
Horizon Utilities Corporation*	0.17	0.23	0.26
Ottawa Hydro	0.23	0.24	0.22
THESL *	0.22	0.22	0.23

+ A larger number is favourable as it indicates more work accomplished per employee
***Regular Staff FTE's**
**** Total Staff = Regular + Non-Regular Staff**

5.0 SUMMARY

In combination with ongoing incremental cost efficiency initiatives under way across the Company, three new major initiatives will together allow Hydro One Networks to transform its business in a step level change over the next few years:

1. Utilization of better economies of scale due to the larger OM&A and Capital work programs;
2. Implementation of the IT Architecture Strategy and Cornerstone; and
3. The culture change program currently underway.

Through these efforts, beyond the 2008 test year Hydro One anticipates that it may be capable of rising to the challenge of achieving an annual 1% productivity target, as was the case in the OEB's second generation IRM.

COMMON CORPORATE COSTS
COST ALLOCATION METHODOLOGY

Allocation of common costs to the distribution and transmission businesses and to each Hydro One affiliate is based on clearly articulated shared services and an established cost allocation approach based on cost causality principles.

The Common Corporate Costs OM&A programs include the provision of Corporate Common Functions and Services ('CCF&S'), Asset Management, Information Management Services, Operating programs, and Customer Care Services to support the Hydro One Networks Distribution and Transmission business.

Corporate Common Functions and Services include finance, human resources, legal, communications, risk management, internal audit, regulatory, corporate management activities, and strategic planning. Asset Management programs include developing asset strategies, policies and standards; identifying, planning and prioritizing specific OM&A and Capital work on distribution and transmission systems; real estate facility services and monitoring the execution of the annual work program.

A description of the Common Corporate costs has been provided at Exhibit C1, Tab 2, Schedule 6.

In RP-1998-0001, the Board issued a directive stating as follows: "The Board believes that OHSC should adopt a consistent approach to allocating overhead costs to distribution and transmission in order to ensure that customers of transmission and distribution pay a fair share of the costs associated with the services received by these respective business units. Therefore, in subsequent applications, the Board expects the Company to adopt a consistent allocation methodology to be used by NAM (Network Asset Management) and Network Services. OHSC should also be prepared, in the next rate application, to provide the rationale and justification for the approach selected."

In 2005, the Company commissioned a study by R. J. Rudden Associates (“Rudden”) to determine a methodology to allocate common costs among the business entities using the common services. The methodology developed represents industry best practices, identifying appropriate cost drivers to reflect cost causality and benefits received.

Hydro One accepted the results of the Rudden study as providing a reasonable and equitable approach to the assignment of common costs among the business entities using the common services. This methodology was utilized and subsequently endorsed by the Board in the previous Distribution rate decision RP-2005-0020/EB-2005-0378. The Board also considered it reasonable for the Company to employ the Rudden methodology in the subsequent Transmission rate application; this was done in EB-2006-0501. Hydro One’s test year submission in this Application reflects the same Rudden study methodology.

The elements of the OEB accepted Rudden methodology are outlined below:

- Identify the functions and services included in CCF&S
- Identify activities that are performed in order to provide CCF&S
- Distribute the 2008 budgeted cost to perform each function and service amongst the activities required to perform it, based on time and/or cost studies

- Distribute the cost of each activity amongst the business units based on direct assignment when possible, and based on cost drivers when not
- Allocate Asset Management activities on a detailed time study

Cost drivers were selected on the basis of cost causation. Where this methodology could not be implemented or established, cost drivers were based on benefits received. Other factors considered in assigning cost drivers included practicality, stability, and materiality.

As a result of the Rudden study, approximately 30% of the total Corporate Common Functions and Services OM&A expenditures have been directly assigned to the business units. The remaining 70% have been allocated based on the established cost drivers.

Hydro One's management participated in the study on behalf of the Transmission and Distribution businesses, reviewed the model and the results, and was satisfied that the overall allocation is reasonable. As well, the Hydro One subsidiaries have accepted the results as being reasonable.

In addition to the Rudden study addressing allocation of CCF&S, a time study was completed to allocate the balance of the Common Costs for Asset Management, Operating and Customer Care.

The allocation of Asset Management, Operating and Customer Care Management costs is based on a time study, as submitted in the Transmission submission EB-2006-0501 Exhibit C1-5-1. This time study is still relevant and yields an appropriate result.

Table 1 below reflects the results of the cost allocation for all common costs for Transmission, Distribution and other entities.

Table 1
Total Common Costs 2008
Allocation to Transmission, Distribution, and Other ($ Millions)

Function/Service	**Total**	**Transmission**	**Distribution**	**Other***
Common Corporate Costs	227.9	73.3	122.6	32.0
Asset Management	118.9	72.6	46.3	-
Operating	41.3	31.8	9.5	-
Customer Care Management	7.5	0.3	7.2	-
Total	**395.6**	**178.0**	**185.6**	**32.0**

* (Includes Hydro One Telecom, Hydro One Brampton, Remote Communities, Hydro One Inc. and Material Surcharge)

Table 2 identifies the results of the Hydro One Networks Inc. time study that are used to further break down costs between OM&A and Capital.

Table 2
Time Study Cost Allocation

	Transmission		**Distribution**	
	Oper. and Maint.	Capital Projects	Oper. and Maint.	Capital Projects
Operating	70%	7%	20%	3%
Customer Care Management	3%	1%	94%	2%
Asset Management (excl. facility cost)	42%	26%	23%	9%

The 2008 Asset Management costs of $118.9 million identified in Table 1 includes $10.8 million of real estate and other costs, $33.2 million in facility costs and $74.9 million in other Asset Management function costs as described in Exhibit C1, Tab 2, Schedule 6. The $33.2 million in facility costs can be further broken down into common head office facility costs of $14.7 million, and field facility costs consisting of $1.7 million for the Ontario Grid Control Centre, and $16.8 million for other field facilities. Table 3 provides the Distribution allocation for these costs. This results in $46.3 million allocated to Distribution in 2008 (Table 1).

Table 3
Asset Management Cost Allocation

	Transmission	Distribution
Asset Management – Excluding Facility Cost	68%	32%
Facility Cost		
- Common, Head Office Facilities	53%	47%
- Ontario Grid Control Centre	77%	23%
- Other Field Facilities	32%	68%
Total Asset Management	60%	40%

The following table provides the allocation of 2008 CCF&S costs to all business units.

Table 4
Allocation of 2008 CCF&S Costs ($ Millions)

Description	Total	Transmission	Distribution	Hydro One Telcom	Hydro One Brampton	Hydro One Remotes	Hydro One Inc.
Corporate Management	5.3	2.8	2.3	0.1	0.1	0.0	0.0
Finance	26.9	13.7	12.1	0.6	0.2	0.3	0.1
Human Resources	12.6	5.9	6.4	0.1	0.0	0.1	0.0
Corporate Communications	6.6	2.3	4.4	0.0	0.0	0.0	0.0
General Counsel & Secretariat	7.5	4.1	2.9	0.1	0.1	0.2	0.1
Regulatory Affairs	19.7	9.4	10.3	0.0	0.0	0.0	0.0
Corporate Security	2.5	1.3	1.2	0.0	0.0	0.0	0.0
Internal Audit	3.0	1.9	0.9	0.0	0.1	0.1	0.0
Total CCF&S Costs	**84.2**	**41.3**	**40.5**	**0.9**	**0.5**	**0.7**	**0.2**

OVERHEAD CAPITALIZATION RATE

This evidence will discuss the methodology used to allocate Common Corporate Functions and Services (CCF&S) and Asset Management costs to Capital Projects.

Hydro One capitalizes costs that are directly attributable to capital projects and also capitalizes overheads supporting capital projects. The Overhead Capitalization Rate is a calculated percentage representing the amount of overhead costs that are required to support capital projects in a given year.

In 2005, the company commissioned a study by RJ Rudden Associates to recommend a method to derive its overhead capitalization rate for CCF&S and Asset Management costs. In RP-2005-0020/EB-2005-0378, the Ontario Energy Board (OEB) accepted the study's methodology, recommendations and the allocation of costs for the test year from the study. The 2008 overhead capitalization rate is calculated consistent with the methodology accepted in the Rudden study.

Capitalized overheads for the Distribution business for the historical years and bridge year are shown in Table 1:

Table 1
Overhead Capitalized
Historical Years (2004-2006) & Bridge Year (2007)

	Historic			**Bridge**
	2004	**2005**	**2006**	**2007**
Total capitalized overheads ($M)	45.0	46.2	59.8	46.6
Capitalized overhead rate (%)	17.0	16.0	17.0	10.5

The Rudden overhead capitalization rate methodology, submitted in RP-2005-0020/EB-2005-0378, recommended a true-up (referred to as an E-Factor) in determining the overhead capitalization rate. The E-Factor represents the true-up between the amount of overhead costs actually capitalized for a prior year and the amount that would have been capitalized for that year using actual data instead of the estimates used in calculating the overhead capitalization rate. The study recommended the inclusion of an E-Factor in the calculation of the overhead capitalization rate for subsequent years. The actual data for 2006 would result in an E-Factor adjustment to be included in the overhead capitalization rate calculation for 2008. The E-Factor adjustment for the true-up of 2006 capitalized overheads was calculated to be ($14.4M). This amount is included as an adjustment to the derivation of the 2008 overhead capitalization rate.

Table 2 summarizes the overhead capitalization rates as determined by the Rudden methodology and the resultant allocation of costs.

Table 2
Overhead Capitalized
2008 Test Year

Overhead Cost Category	Capitalization Rate	Amount Capitalized ($M)
Corporate Functions and Services	7.9%	43.1
Asset Management and Operators	1.3%	7.2
Sub-Total	9.2%	50.3
E-Factor Adjustment (for 2006)	(2.7%)	(14.4)
Total (Including E-Factor)	6.5%	35.9

Note: For planning and actual charging purposes, the overhead capitalization rate is rounded to the nearest whole percentage point.

In 2007, the Rudden overhead capitalization rate methodology true-up principle continues to be adhered to, however it is being implemented in a more efficient manner. Beginning in 2007, Hydro One Networks is adjusting the overhead capitalization rate several times within the year as required to reflect actual changes in capital expenditures spending. This will improve the timeliness of the potential E-Factor true-up and result in a better alignment of overhead costs with the capital projects that they support. It is also proposed that the year-end E-Factor true-up, going forward, will be in included in the calculation of the overhead capitalization rate for the subsequent year.

COMMON ASSET ALLOCATION

This evidence will discuss the nature of Common Fixed Assets ("Shared Assets") and the method by which the costs of these assets are assigned to the Distribution and Transmission business units.

Similar to the common corporate costs discussed in Exhibit C1, Tab 5, Schedule 1, Hydro One has been able to maximize efficiencies through the centralization of the maintenance, management and purchase of shared assets at the corporate level. These assets include shared land and buildings, telecommunication equipment, computer equipment, applications software, tools and transportation and work equipment (“T&WE”).

1.0 SHARED ASSETS AND FACILITIES COSTS

Most fixed assets are directly assigned to the appropriate business unit. The remaining assets (4% of total assets) are considered shared assets, and are allocated to Transmission and Distribution as described later in this exhibit. Table 1, below, summarizes the total gross fixed assets and identifies the proportion of allocated shared assets.

Table 1
Summary of Gross Fixed Assets
as at December 31, 2006 ($ Million)

	Transmission	Distribution	Total
Total Fixed Assets	**9,793.3**	**5,866.5**	**15,659.8**
Shared Assets (in Total)	275.2	430.0	705.2
Shared Asset %	39.0%	61.0%	100%

Shared assets are sub-divided into two categories. Major Fixed Assets consist of land, buildings, applications software, and telecommunications equipment. Minor Fixed Assets include office furniture, computer equipment, tools and T&WE. Table 2, below, shows the proportion of major and minor shared fixed assets, accumulated depreciation and net book value as of December 31, 2006.

Table 2
Details of Shared Net Fixed Assets
as at December 31, 2006 ($ Million)

Asset	Gross Asset Value	Accumulated Depreciation	Net Book Value
Shared Major Assets	230.2	113.8	116.4
Shared Minor Assets	474.9	311.0	163.9
Total Shared Assets	**705.2**	**424.8**	**280.3**

2.0 ALLOCATION OF SHARED ASSETS IN SERVICE

Due to the nature of Hydro One's business, Shared Assets are not directly attributable to either the Transmission or Distribution business units. In addition, from year to year, the use of these shared assets changes, based upon changes in the underlying transmission and distribution work programs. Consequently, the methodology by which shared assets are allocated to the Transmission and Distribution business units is subject to periodic review. The intent of such a review is to ensure that the assignment of assets is reflective of their true use and that the costs are apportioned appropriately amongst the business units.

In 2005, the Company commissioned a study by R. J. Rudden Associates ("Rudden") to determine a methodology to allocate the assets which are not directly attributable to Transmission or Distribution. The methodology developed represents industry best practices, identifying appropriate cost drivers to reflect cost causality and benefits received. The Rudden study resulted in the allocation of shared assets based on the relative usage by Transmission and Distribution or by cost drivers, similar to those used for the common corporate functions and services.

The Company has accepted the approach of the Rudden study as a reasonable representation of the use of shared assets amongst the business units. This methodology was utilized and subsequently endorsed by the Board in the previous Distribution rate decision RP-2005-0020/EB-2005-0378, and also used in the subsequent Transmission rate Application EB-2005-0501. Hydro One's test year submissions in this Application reflect the same Rudden study methodology.

Table 3 below shows the Hydro One Common Asset allocation as at December 31, 2006.

Table 3
Hydro One Common Asset Allocation
as at December 31, 2006 ($ Million)

Total Gross Value All Hydro One Transmission & Distribution Assets $15,660 million			
Transmission (Total)	$9,793 m	Distribution (Total)	$5,867 m
Transmission (Direct)	$9,518 m	Distribution (Direct)	$5,436 m
Transmission (Common)	$275 m	Distribution (Common)	$430 m

DEPRECIATION AND AMORTIZATION EXPENSES

1.0 INTRODUCTION

The purpose of this evidence is to summarize the method and cost of Hydro One Distribution's depreciation and amortization expense for the 2008 test year.

The depreciation and amortization expense for Hydro One's Distribution business in its 2006 test year submission in RP-2005-0020/EB-2005-0378 was supported by an independent study by Foster Associates which was completed in June 2005. The Ontario Energy Board (OEB) accepted the costs flowing from the Depreciation Study for the purpose of supporting Distribution rates in 2006.

2.0 DEPRECIATION EXPENSE

The aforementioned Foster methodology was used in determining the depreciation expense for the 2008 test year.

Detailed depreciation schedules are filed at Exhibits C2, Tab 5, Schedule 1.

Hydro One Distribution implemented the new depreciation system in accordance with the OEB's decision (EB-2006-0501), reflecting the Foster Associates recommendations.

Table 1
Distribution Depreciation Expense
$ Million

Description	Historic			Bridge	Test
	2004	2005	2006	2007	2008
Depreciation On Fixed Assets	151.7	155.3	159.1	164.0	196.9
Less Capitalized Depreciation	(8.3)	(8.6)	(9.7)	(10.8)	(12.4)
Asset Removal Costs	22.5	24.0	30.4	26.5	22.8
Losses/(Gains) On Asset Disposition	(0.6)	(2.4)	(1.2)	n/a	n/a
Total	165.3	168.3	178.6	179.7	207.4

The increase in 2008 depreciation on fixed assets amount relative to the 2007 amount is due to the higher level of fixed assets in service in 2008, which includes Smart Meters and Cornerstone. Major and Minor Fixed Asset additions amounts for 2007 and 2008 are filed at Exhibit D2, Tab 3, Schedule 1.

Capitalized depreciation refers to depreciation on transport & work equipment and other minor fixed assets (e.g. tools) that is charged to capital work projects. For purposes of calculating the revenue requirement, capitalized depreciation is deducted from annual depreciation expense, as it is treated as capital expenditures.

Fixed asset removal costs are charged to depreciation expense on an “as incurred” basis.

Losses/gains on asset disposition relate to the sale of assets. Losses/gains on asset disposition are based on historic actuals and are not separately forecast for the bridge or test years.

3.0 AMORTIZATION EXPENSE

Amortization expense pertains to costs the Board has allowed Hydro One Distribution to defer for recognition at a future date. The Board has, in past decisions, approved the amount of the cost to be deferred for future recovery, the prescribed period or method of amortization, and prescribed time period over which the costs in each account should be amortized.

Historical, bridge and test year amortization schedules are filed at Exhibit C2, Tab 5, Schedule 1.

Table 2
Distribution Amortization Expense
$ Million

Description	Historic			Bridge	Test
	2004	2005	2006	2007	2008
Other Post Employment Benefits	23.7	23.7	23.7	23.6	23.6
Environmental Assets	9.5	7.1	11.6	8.4	7.9
Other Amortization	0.1	0.1	0.1	0.1	0.1
Total	33.3	30.9	35.4	32.1	31.6

3.1 Other Post Employment Benefits (OPEB)

Employee future benefits other than pension are recorded in Hydro One Distribution's financial statements using the accrual method as required by Canadian GAAP. The Ontario Energy Board has allowed for the recovery of past service costs, which arose on the adoption of the accrual method, in the revenue requirement on a straight-line basis over a 10-year period per the Board's RP-1998-0001 Decision. Hydro One recorded a regulatory asset of $419 million in 1999 to reflect the OEB's Decision and allocated this amount to the regulated businesses.

3.2 Environmental Assets

Hydro One Distribution provides for the net present value of estimated future expenditures required to remediate legacy environmental contamination. Since these expenditures are expected to be recovered in future rates, Hydro One Distribution has recognized these amounts as a regulatory asset. This balance is amortized on a basis consistent with the pattern of actual expenditures expected to be incurred, currently estimated to continue until the year 2030. Hydro One Distribution received approval for this deferral account as part of the Board's RP-2000-0023 Decision. There is a corresponding credit to OM&A for the environmental asset expenditures and this is discussed further in Section 6.2 of Exhibit C1, Tab 2, Schedule 6.

PAYMENTS IN LIEU OF CORPORATE INCOME TAXES

1.0 INTRODUCTION

Under the *Electricity Act, 1998*, Hydro One Networks Inc. is required to make payments in lieu of corporate income taxes (PILS) relating to taxable income earned by its distribution business. The Ontario Energy Board (OEB) has directed that the taxes payable method should also be used for regulatory purposes (2006 EDR Handbook section 7.1 "OEB 2006 regulatory expense methodology").

Under the taxes payable method, no provision is made for future income taxes that result from timing differences between the tax basis of assets and liabilities and their carrying amounts for accounting purposes. Accordingly, the taxes payable method will result in the PILS income tax payable being different than the amount that would have been recorded, had the combined Canadian Federal and Ontario statutory income tax rate been applied to the regulatory net income before tax. When unrecorded future income taxes become payable, it is expected that they will be included in the rates approved by the OEB and recovered from the customers at that time.

PILS installments are remitted by Networks to OEFC at the end of each month. Any balance owing at the end of the year is required to be paid by February 28th of the following year.

The 2008 Hydro One Distribution regulatory tax calculation has been prepared in accordance with the 2006 EDR Handbook and the 2006 EDR Tax Model.

2.0 INCOME TAX RATE (FEDERAL AND ONTARIO):

A combined rate of 34.50% has been used for 2008 (Federal 20.50% and Ontario 14%) Prior to 2008, a 36.12% combined Federal and Ontario income tax rate had been in effect from 2004.

3.0 RECONCILIATION BETWEEN REGULATORY NET INCOME BEFORE TAX AND TAXABLE INCOME

A reconciliation between the regulatory net income before tax (NIBT) and taxable income for the test year 2008 is provided in Exhibit C2, Tab 6, Schedule 1, Attachment A. This schedule contains the income tax component of the PILS computation. It also shows how the taxable income is computed by making adjustments to the regulatory NIBT for items such as depreciation, capital cost allowance (CCA) etc.

A reconciliation between the accounting NIBT and taxable income for the historical years is provided in Exhibit C2, Tab 6, Schedule 1, Attachment C.

In order to make it easier for parties to follow the historic reconciliations, we have grouped adjustments made to regulatory NIBT to arrive at taxable income into the following five categories:

1) Recurring items that must be added (deducted) because they have been included in the OM&A expenses in arriving at the revenue requirement or for which appropriate tax adjustments are made (e.g. depreciation vs. CCA);
2) Deferral accounts not included in the revenue requirement;
3) Reversal of accounting adjustments not included in the revenue requirement;
4) Recurring items not in the revenue requirement; and

5) Items where the impact is immaterial in total, and as such, have not been included in our business plan (applicable to test year only).

4.0 OVERVIEW OF PROCESS TO ARRIVE AT TAXABLE INCOME

The starting point for the computation of the Networks Distribution taxable income is the NIBT as shown on the utility's income statement for the year. There are typically many adjustments that are made to the NIBT to arrive at taxable income, since the NIBT is prepared using Canadian generally accepted accounting principles and taxable income is computed using the relevant tax legislation, interpretations and assessing practices. Essentially, the NIBT is increased by amounts that are not deductible for tax purposes (includes items such as depreciation, contingent liabilities, accounting losses, accounting provisions such as OPEB etc. and revenue that has been received but not recognized for accounting purposes (e.g. LV revenue)) and is reduced by amounts that are deductible for tax purposes but have not been deducted in computing NIBT (includes items such as CCA, the deductible portion of capitalized overhead, expenses incurred for which a deferral account has been set up on the balance sheet rather than being deducted through the income statement, accounting gains, OPEB payments etc).

Consequently, it is imperative that the NIBT be adjusted for amounts that have been included (or deducted) for accounting purposes that are not income (or deductible) for tax return purposes. This is a key point in comparing the historical years tax return data to that computed for the test year, since the tax return NIBT has been increased (or reduced) by amounts that have not been added (or deducted) in computing the regulatory NIBT (e.g. contingent liabilities, accounting gains, capitalized interest). That is, for test year 2008, only differences between the tax and accounting rules related to costs included in either the regulatory revenue requirement or rate base (e.g. CCA, capitalized overhead) are adjusted in arriving at taxable income.

5.0 TREAMENT DEFERRAL ACCOUNTS (REGULATORY ASSETS AND LIABILITIES)

Deferral accounts are typically recognized by utilities (i.e. on their balance sheet) for foregone revenue or for expenses that have been incurred for which recovery will be sought from ratepayers through future rates. Disposition of the deferral accounts is determined by the OEB often through a rate rider process.

For example, assuming that a $100 expense is incurred at a 35% tax rate, the utility will be allowed to deduct the $100 in computing taxable income for the year in which the expense has been incurred. If the OEB subsequently approves recovery of these expenses over a four year period through a rate rider, the income will be included in computing taxable income for the year in which it is billed to ratepayers. The net result is that the utility has recovered the $100 cost although the income/expense has been taxed or deducted in different years.

	Year 1	Year 2	Year 3	Year 4	Year 5	CUM
Income (deduction)	(100)	25	25	25	25	nil
Tax refund (payable)	35	(8.75)	(8.75)	(8.75)	(8.75)	nil
Cash inflow (outflow)	(65)	16.25	16.25	16.25	16.25	nil

Therefore, deferral accounts have not been included in computing tax payable for purposes of the revenue requirement since the tax benefit has or will be obtained through the tax system. It should be noted that this conclusion is consistent with the *"2006 EDR Handbook Report of the Board"* issued May 11, 2005 (Page 61) that stated as follows:"A PILS or tax provision is not needed for the recovery of deferred regulatory asset costs, because the distributors have deducted, or will deduct, these costs in calculating taxable income in their returns. The Handbook will reflect this treatment."

6.0 CONTINGENT LIABILITIES/ACCOUNTING RESERVES

Where an accounting provision is recognized for certain contingent costs that the utility may have to incur in the future (e.g. obsolescence provisions, lawsuits, staff reductions, etc.), the provision will reduce the NIBT of the utility. In each subsequent year, the balance for the contingent liability/accounting reserve is reviewed by the utility for reasonableness based upon the information available at that time. The balance may be adjusted upward or downward with NIBT either decreasing or increasing respectively. However, for tax purposes, a contingent liability or accounting reserve is not deductible. Rather, the amount will only be deductible (or capitalized) in computing taxable income for the taxation year in which the obligation has actually been settled. Therefore, to the extent that the current year NIBT has been increased (or decreased) by the contingent liability or accounting reserve provision, the NIBT must be adjusted to reverse the increase (or decrease) in computing taxable income.

No changes were forecast in those contingent liabilities reflected in 2008 and as such, it is not necessary to adjust the 2008 NIBT for contingent liabilities in computing taxable income. Therefore, such amounts are not included in the tax computation for purposes of the revenue requirement.

The contingent liabilities movement resulting in a $20.6 million deduction in 2004 and a $2.3 million add back in 2005 (Exhibit C2, Tab 6, Schedule 1, Attachment C, line 26), is required to reverse the accounting income inclusion resulting from the net reduction in the various contingent liability balances and/or the deduction of actual payments. As stated above, contingent liabilities are not relevant in computing taxable income.

7.0 REVERSAL OF 2004 ACCOUNTING GAIN RE: REGULATORY ASSETS

As a result of the uncertainty created by the Electricity Pricing, Conservation and Supply Act, 2002, Hydro One did not recognize certain regulatory assets such as those for suspended low voltage service costs (see Exhibit C2, Tab 6, Schedule 1, Attachment C, line 28). Such amounts were subsequently approved by the OEB in December, 2004 allowing Hydro One under the accounting rules to recognize the establishment of the underlying regulatory assets resulting in the $102 million accounting gain. Assuming that the current stable environment will continue, Hydro One anticipates full recovery for prudently incurred costs and therefore does not anticipate the recording of any significant gains that would be attributable to the recognition of unrecorded regulatory amounts in 2008.

It should be noted that for tax purposes, the accounting gain included in the accounting NIBT, is required to be reversed since tax is paid on the revenue for the year in which it is billed to ratepayers and not when recognized under the accounting rules.

8.0 CLASS 45, DISTRIBUTION ASSETS 55% CCA RATE:

In deriving the 2008 utility income taxes, Hydro One Distribution has reflected the proposed 10% increase in CCA rate for Class 45 to 55% (from 45%), for new assets acquired subsequent to March 19, 2007 (see Exhibit C2, Tab 6, Schedule 1, Attachment B).

9.0 FEDERAL LARGE CORPORATION TAX ("LCT"):

The LCT has been eliminated effective January 1, 2006, accordingly for 2008, no LCT component has been included in the PILS computation on Exhibit C2, Tab 6, Schedule 1, Attachment A.

10.0 ONTARIO CAPITAL TAX

Networks pays Ontario capital tax on its taxable capital as defined by the Corporations Tax Act (Ontario). However, for regulatory purposes, it recovers capital tax computed by reference to its rate base net of the applicable Ontario exemption, as directed by the OEB. Please refer to Exhibit C2, Tab 4, Schedule 1 for the calculation of the Ontario capital tax. For the test year, the Ontario capital tax rate used is the rate proposed in the March 23, 2006 Ontario budget of 0.285%. This compares to a capital tax rate of 0.3% applicable to the historical and bridge years.

The Ontario exemption is allocated amongst the related regulated entities, based on rate base.

HYDRO ONE NETWORKS INC.
DISTRIBUTION
Cost of Service
Historical (2004, 2005, 2006), Bridge (2007) and Test (2008) Years
Year Ending December 31
($ Millions)

Line No.	Particulars	2004	2005	2006	2007	2008
		(a)	(b)	(c)	(e)	(f)
1	Total Operation, Maintenance & Administrative Expenses	346.0	362.1	404.1	492.6	477.7
2	Depreciation & Amortization Expenses	216.0	219.2	249.5	255.1	238.9
3	Capital Taxes	10.0	11.0	12.0	11.0	11.3
4	Income Taxes	43.8	56.5	64.3	50.7	38.8
5	**Total Cost of Service**	**615.8**	**648.8**	**729.9**	**809.4**	**766.9**

COMPARISON OF OM&A EXPENSE BY MAJOR CATEGORY

Distribution OM&A ($millions)	2004	2005	2006	2007	2008
Sustaining					
Distribution Lines Maintenance					
Trouble Call, Cable Locates and Connect/Re-connect	67.2	73.8	89.2	78.6	76.9
Line Maintenance	15.2	19.3	26.7	30.2	28.8
PCB Testing & Waste Management	2.7	2.8	3.2	3.1	3.0
Other Services	7.3	9.4	7.4	11.2	9.4
Total Lines OM&A	92.4	105.3	126.5	123.1	118.1
Stations OM&A					
Planned Maintenance	6.6	8.9	12.1	13.1	12.9
Demand and Corrective	6.2	6.7	7.0	6.9	6.1
Land Assessment & Remediation	5.6	4.3	6.9	5.1	5.9
Total Stations OM&A	18.4	19.9	26.0	25.0	24.9
Metering OM&A					
Customer Retail Meters	8.0	7.2	8.1	8.5	6.0
Smart Meters		2.4	4.9	6.2	9.7
Wholesale Meters	0.2	0.7	1.0	1.0	1.9
Total Metering OM&A	8.2	10.3	14.0	15.7	17.6
Forestry OM&A					
Customer Notification	6.9	6.8	6.8	6.5	7.9
Line Clearing	55.6	52.9	50.6	74.1	76.8
Brush Control	19.6	21.1	25.2	26.9	28.2
Demand Work	6.2	5.3	6.1	6.9	6.0
Asset Condition Assessment	0.5	0.2	0.5	0.5	0.5
Total Forestry OM&A	88.9	86.4	89.1	115.0	119.4
Total "Sustaining"	207.9	222.0	255.6	278.8	280.0
Development	5.5	4.8	4.2	8.0	9.1

	2004	2005	2006	2007	2008
Operations					
Operating Support	3.3	3.2	4.1	4.1	3.9
Operators	13.0	8.1	10.8	8.5	9.5
Total Operations	16.3	11.2	14.9	12.6	13.4
Customer Care					
Base Services	80.1	76.8	80.9	80.8	84.6
Bad Debt	11.8	9.7	17.3	13.5	13.0
Regulatory Compliance	7.1	6.6	4.1	0.7	3.6
Service Enhancements	4.0	3.1	1.4	2.1	2.6
Total Customer Care	103.0	96.3	103.7	97.1	103.8
Shared Services and Other Costs					
Common Asset Management Costs	26.0	20.7	40.9	38.1	46.3
Common Corporate Costs	21.1	24.4	33.2	35.6	40.5
Information Management Services	37.1	38.2	38.5	42.8	43.9
Business Telecom	4.4	4.3	8.3	8.5	8.7
Cost of Sales	28.1	15.3	6.6	6.9	5.9
Overheads Recovered on Capex	(45.0)	(46.2)	(59.8)	(46.6)	(47.7)
Environmental Provision Credits	(9.5)	(7.1)	(11.6)	(6.3)	(7.9)
Indirect Depreciation Embedded in Rates	(9.0)	(9.9)	(11.6)	(10.5)	(10.3)
Other	(44.0)	(16.2)	(23.3)	23.3	(12.4)
Total Shared Services and Other Costs	9.3	23.3	21.2	91.9	66.9
Property Taxes & Rights Payments	4.0	4.6	4.5	4.2	4.5
Total Distribution OM&A	**346.0**	**362.1**	**404.1**	**492.6**	**477.7**

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HYDRO ONE NETWORKS INC.
DISTRIBUTION
Mapping of OM&A Expenditures to Grouped USofA Accounts
As at December 31
($ Millions)

Line No.	Particulars	USoA	2006	2007	2008
1	Operation	5005, 5010, 5012, 5014, 5015, 5016, 5017, 5020, 5025, 5030, 5035, 5055, 5065, 5070, 5075, 5085, 5095	41.1	61.8	62.8
2	Maintenance	5105, 5112, 5114, 5120, 5125, 5130, 5135, 5145, 5150, 5155, 5160, 5170, 5172, 5175, 5195	196.3	210.7	218.8
3	Billing and Collecting	5310, 5315, 5320, 5330, 5335, 5340	103.9	86.6	87.2
4	Community Relations	5410, 5415, 5420, 5425	0.9	1.1	1.0
5	Administrative & General Expenses	5605, 5610 5615, 5625, 5630, 5635, 5640, 6545, 5655, 5665, 5670, 5675, 5680	51.5	106.6	96.7
6	Other	1565, 4380, 6105	10.4	23.3	11.3
7	**Total OM&A**		**404.1**	**490.0**	**477.7**

COMPARISON OF WAGES AND SALARIES

1.0 REGIONAL MAINTAINER LINES – (PWU-REPRESENTED)

The following summarizes the key elements of this job classification and related compensation:

- works on transmission and distribution lines and associated apparatus using a range of mechanical and electrical skills and knowledge.
- Grade 12 plus six-year apprenticeship.

Table 1

Year	Total Wages	Base	Overtime	Incentive	Other*
2004	$98,822	$67,987	$26,377	$2,483	$1,975
2005	$102,325	$70,208	$29,186	$760	$2,170
2006	$111,439	$74,117	$34,639	$0	$2,683
2007	$114,782	$76,340	$35,679	$0	$2,764
2008	$118,226	$78,630	$36,749	$0	$2,847

NOTE: all of the above are average dollars.

2.0 SOCIETY REPRESENTED MP4 (Example -ENGINEER – JOURNEYPERSON LEVEL)

The following summarizes the key elements of this job classification and related compensation:

- Professional Engineer with 8-10 years experience;

- participates in the design and development of strategies and proposes effective recommendations related to the application and design and performance of various systems, e.g., electrical power systems/telecommunication;
- provides technical guidance and supervision to technical staff.

Table 2
Annual Salary (MP4)

Year	Total Wages	Base	Overtime	Incentive	Other*
2004	$96,423	$85,578	$8,028	$0	$2,817
2005	$69,200	$62,420	$3,125	$0	$3,656
2006	$95,524	$92,564	$1,207	$0	$1,753
2007	$98,390	$95,341	$1,243	$0	$1,806
2008	$101,342	$98,202	$1,281	$0	$1,860

NOTE: - 2005 results are lower due to the impact of the labour strike.
- all of the above are average dollars.

3.0 MANAGER – BAND 7 (MANAGEMENT COMPENSATION PLAN)

The following summarizes the key elements of this job classification and related compensation:

- university degree with several years experience;
- provides direction with respect to corporate strategies and policies, budget and programs, compliance and performance targets and expectations of continuous improvement;
- manages the coordination of work activities of supervisory professional staff;
- coordinates the activities of others in the performance of technical projects related to program processes, technical/operational business standards and procedures.

Table 3
Annual Salary

Year	Total Wages	Base	Overtime	Incentive	Other*
2004	$107,813	$90,068	$423	$11,620	$5,702
2005	$107,938	$89,136	$1,187	$7,806	$9,808
2006	$114,332	$96,066	$222	$3,139	$14,905
2007	$117,762	$98,948	$0	$11,200	$7,615
2008	$121,295	$101,916	$0	$11,600	$7,779

NOTE: all of the above are average dollars.

* Other includes: travel time, vacation bonus, unused vacation days paid out, standby allowance, shift allowance, vacation pay on termination, depending on the nature of the position.

HYDRO ONE NETWORKS INC.
DISTRIBUTION
Capital Taxes
Test Year (2008)
Year Ending December 31
($ Millions)

Line No.	Particulars		2008	
	Capital Taxes			
1	Rate Base (year end):			
2	Gross Plant at Cost	$	6,723.0	
3	Less Accumulated Depreciation		(2,437.9)	
4	Net Plant in Service		4,285.1	
7	Cash Working Capital		273.2	
8	Materials and Supplies		23.4	
9	Total Working Capital	$	296.6	
10	Rate Base (net plant in service + working capital)	$	4,581.7	
11	Less Cumulative Excess of Book Value Over Tax Value		(595.3)	
12	Taxable Capital	$	3,986.4	
13	Less Provincial Exemption		(5.8)	
14	Net Taxable Capital	$	3,980.6	
15	Capital Tax Rate		0.285	%
16	Total Capital Taxes	$	11.3	

HYDRO ONE NETWORKS INC.
DISTRIBUTION

Depreciation & Amortization Expenses
Bridge Year (2007) and Test Year (2008)
Year Ending December 31
($ Millions)

Line No.	Particulars	2007 Depreciation Rate %	2007 Provision	2008 Depreciation Rate %	2008 Provision
		(a)	(b)	(c)	(d)
	Depreciation Expenses				
1	Major Fixed Assets	2.41%	132.2	2.62%	160.0
2	Minor Fixed Assets	9.98%	31.8	10.81%	36.9
3	Depreciation on Fixed Assets		164.0		196.9
4	Less Capitalized Depreciation		(10.8)		(12.4)
5	Asset Removal Costs		26.5		22.8
6	Losses/(Gains)		0.0		0.0
7	Total Depreciation Expenses		179.7		207.4
	Amortization Expenses				
8	OPEB		23.6		23.6
9	Environmental Costs		8.4		7.9
10	Other Regulatory Amortization *		43.4		0.0
11	Other Amortization		0.1		0.1
12	Total Amortization Expenses		75.4		31.6
13	Total Depreciation & Amortization Expenses		255.1		238.9

* Amortization of regulatory assets excluded from revenue requirement in test year.

HYDRO ONE NETWORKS INC.
DISTRIBUTION
Depreciation & Amortization Expenses
Historical Years (2004, 2005 and 2006)
Year Ending December 31
($ Millions)

Line No.	Particulars	2004 Depreciation Rate %	2004 Provision	2005 Depreciation Rate %	2005 Provision	2006 Depreciation Rate %	2006 Provision
		(a)	(b)	(a)	(b)	(a)	(b)
	Depreciation Expenses						
1	Major Fixed Assets	2.55%	127.4	2.59%	132.1	2.48%	133.4
2	Minor Fixed Assets	10.31%	24.3	9.10%	23.2	8.49%	25.7
3	Depreciation on Fixed Assets		151.7		155.3		159.1
4	Less Capitalized Depreciation		(8.3)		(8.6)		(9.7)
5	Asset Removal Costs		22.5		24.0		30.4
6	Losses/(Gains) on Asset Disposition		(0.6)		(2.4)		(1.2)
7	Total Depreciation Expenses		165.3		168.3		178.6
	Amortization Expenses						
8	OPEB		23.7		23.7		23.7
9	Environmental Costs		9.5		7.1		11.6
10	Other Regulatory Amortization		17.4		20.0		35.5
11	Other Amortization		0.1		0.1		0.1
12	Total Amortization Expenses		50.7		50.9		70.9
13	Total Depreciation & Amortization Expenses		216.0		219.2		249.5

CALCULATION OF UTILITY INCOME TAXES

Attachment A:	Calculation of Utility Income Taxes Test Year (2008)
Attachment B:	Calculation of Capital Cost Allowance Test Year (2008)
Attachment C:	Calculation of Utility Income Taxes Historic Years (2004, 2005, 2006)
Attachment D:	Calculation of Capital Cost Allowance Historic (2004, 2005, 2006) & Bridge Year (2007)

HYDRO ONE NETWORKS INC.
DISTRIBUTION

Calculation of Utility Income Taxes
Test Year (2008)
Year Ending December 31
($ Millions)

Line No.	Particulars		2008	
	Determination of Taxable Income			
1	Regulatory Net Income (before tax)	$	190.3	
2	Book to Tax Adjustments:			
3	Other Post Employment Benefits expense		34.6	
4	Other Post Employment Benefits payments		(25.1)	
5	Inergi pension payments		0.0	
6	Depreciation and amortization		238.9	
7	Capital Cost Allowance		(283.0)	
8	Removal costs		(3.5)	
9	Environmental costs		(7.9)	
10	Hedge loss - amortization		0.5	
11	Non-deductible meals & entertainment		2.1	
12	Research & Development ITC		0.3	
13	Ontario education credits		0.8	
14	Capitalized overhead costs		(8.8)	
15	Capitalized pension costs		(23.4)	
16		$	(74.5)	
17	Regulatory Taxable Income	$	115.8	
	Calculation of Utility Income Taxes			
18	Corporate Income Tax Rate		34.50	%
19	Subtotal	$	39.9	
20	Less: R&D ITC		(0.3)	
21	Less: Ontario education credits		(0.8)	
22	Regulatory Income Tax	$	38.8	
	Tax Rates			
23	Federal Tax		20.50	%
24	Federal Surtax		0.00	%
25	Provincial Tax		14.00	%
26	Total Tax Rate		34.50	%

HYDRO ONE NETWORKS INC.
DISTRIBUTION
Calculation of Capital Cost allowance (CCA)
Test Year
2008 Networks Allocation to DX
Year Ending December 31
($ Millions)

2008 CCA Class	Opening UCC	Net Additions	UCC pre-1/2 yr	50% net additions	UCC for CCA	CCA Rate	CCA	Closing UCC
1.0	2032.5	(0.0)	2032.5	0.0	2032.5	4%	81.3	1951.2
2.0	396.4	0.0	396.4	0.0	396.4	6%	23.8	372.6
3.0	17.4	2.6	19.9	0.1	18.6	5%	0.9	19.0
6.0	8.6	1.3	9.9	0.6	9.3	10%	0.9	9.0
8.0	38.4	7.6	46.0	3.8	42.2	20%	8.4	37.6
10.0	67.6	35.9	103.5	17.9	85.6	30%	25.7	77.8
12.0	15.9	86.7	102.6	43.3	59.3	100%	59.3	43.3
13.0	1.8	0.2	2.0	0.1	1.9	10 yrs	0.4	1.6
17.0	2.3	0.4	2.7	0.2	2.5	8%	0.2	2.5
42.0	0.4	0.0	0.4	0.1	0.3	12%	0.0	0.4
45.0	6.7	(0.0)	6.7	0.0	6.7	45%	3.0	3.7
45.1	3.4	7.4	10.8	3.7	7.1	55%	3.9	7.0
47.0	725.3	407.8	1133.1	204.0	929.1	8%	74.3	1058.8
Dx CCA	3,316.61	549.90	3,866.50	273.80	3,591.50		282.25	3,584.35
Dx CEC Continuity	39.6	0.0	39.6	0.0	39.6	7%	2.8	36.8
					Less goodwill portion		(2.0)	
					Total CCA relating to regulatory		283.0	

HYDRO ONE NETWORKS INC.
DISTRIBUTION
Calculation of Utility Income Taxes
Historic Years
2004 - 2006 Networks Tax Return Allocation to Distribution
Year Ending December 31
($ Millions)

Line No.	Particulars		2004		2005		2006
	Calculation of Federal and ON Income Tax						
1	Net Income Before Tax (NIBT)	$	203.3	$	152.9	$	172.8
2							
3	Required Adjustments to Accounting NIBT						
4	Recurring items included in Revenue Requirement (RR):						
5	Other Post Employment Benefit expense		29.4		33.9		39.0
6	Other Post Employment Benefit payments		(19.1)		(18.8)		(18.0)
7	Depreciation and amortization		220.4		219.3		249.4
8	Capital Cost Allowance		(178.9)		(160.9)		(188.9)
9	Removal costs		(4.0)		(3.0)		(3.4)
10	Environmental costs paid		(9.5)		(7.1)		(11.6)
11	Hedge loss net of amortization		0.9		(1.9)		1.0
12	Non-deductible Meals & entertainment		2.6		1.9		2.1
13	Smart meter costs deferred		0.0		0.0		(1.5)
14	Research & Development		(0.3)		0.6		0.1
15	Capitalized overhead costs deducted		(12.7)		(12.4)		(14.4)
16	Pension cost deductions		(52.7)		(57.9)		(33.4)
17		$	(23.9)	$	(6.4)	$	20.4
18	Deferral accounts not part of RR:						
19	RSVA		29.6		15.7		17.5
20	RARA and other Revenues deferred		0.0		0.0		19.1
21	LV revenue received, deferred in regulatory a/c's		14.6		(4.7)		(8.1)
22	Regulatory Asset -OEB costs deferred		(4.4)		0.0		(0.7)
23		$	39.8	$	11.0	$	27.8
24	Reversal of accounting adjustments not part of RR:						
25	Building reserve		1.5		0.0		0.0
26	Contingent liability movement		(20.6)		2.3		(20.4)
27	Items in gain reversal part of contingency movement		8.5		0.0		0.0
28	Reversal of accounting gain re regulatory assets		(102.0)		0.0		0.0
29	Mkt ready costs previously deducted for tax		8.2		0.0		0.0
30	Capitalized interest deductible for tax		(5.3)		(15.8)		(16.8)
31		$	(109.7)	$	(13.5)	$	(37.2)
32	Recurring items not part of RR:						
33	Cumulative Eligible Capital		(3.0)		(3.4)		(3.2)
34			(3.0)		(3.4)		(3.2)
35	Immaterial items not in business plan detail:						
36	Computer application/systems software deducted for accounting		4.6		1.3		0.3
37	Taxable capital gain		0.3		0.1		0.4
38	Amortization of prospectus & underwriting costs		0.8		0.9		0.8
39	WSIB		(1.0)		(1.0)		(1.0)
40	Tenant Inducement		(0.3)		0.2		(0.2)
41	Bond Discount Amortization		(0.2)		(0.3)		(0.3)
42	Deferred prospectus & underwriting costs deducted for tax		(2.0)		(1.0)		(1.1)
43	Capital tax provision overaccrual vs. return		(0.4)		0.7		0.0
44	Ontario hiring credits		0.0		0.2		0.8
45	Other		(0.3)		(0.1)		0.1
46			1.5		1.1		(0.2)
47							
48	NET Adjustments to Accounting NIBT	$	(95.3)	$	(11.2)	$	7.6
49							
50	Taxable Income federal	$	108.0	$	141.7	$	180.4

Line No.	Particulars		2004		2005		2006	
51	Taxable Income federal	$	108.0	$	141.7	$	180.4	
52	Deduct SRED claim added for Federal not taxable for Ontario		(0.9)		1.9		(0.1)	
53	Taxable Income Ontario	$	107.1		143.6	$	180.3	
54								
55								
56	Corporate Income Tax Rate		36.1	%	36.1	%	36.1	%
57								
58	Subtotal	$	38.8	$	51.1	$	65.2	
59	Less: Tax credits		(1.2)		(0.1)		(0.9)	
60	Income Tax	$	37.6	$	51.0	$	64.3	
61								
62								
63	Summary of Utility Income Taxes							
64								
65	Income Taxes (Line 55)	$	37.6	$	51.0	$	64.3	
66	Large Corporation Tax		6.2		5.5		0.0	
67	Total Taxes	$	43.8	$	56.5	$	64.3	
68								
69	Tax Rates							
70								
71	Federal Tax		21.0	%	21.0	%	21.0	%
72	Federal Surtax		1.1	%	1.1	%	1.1	%
73	Provincial Tax		14.0	%	14.0	%	14.0	%
74	Total Tax Rate		36.1	%	36.1	%	36.1	%

See Exhibit C1, Tab 7, Schedule 1 for additional information

HYDRO ONE NETWORKS INC.
DISTRIBUTION

Calculation of Capital Cost allowance (CCA)
Historic Years
2004 - 2005 Networks Tax Return Allocation to Distribution
Year Ending December 31
($ Millions)

2004

CCA Class	Opening UCC	Net Additions	UCC pre-1/2 yr	50% net additions	UCC for CCA	CCA Rate	CCA	Closing UCC
1	2,182.9	211.9	2,394.9	106.0	2,288.9	0.0	98.1	2,296.7
2	507.8		507.8	-	507.8	0.1	30.5	477.3
3	15.6	0.8	16.3	0.4	16.0	0.1	0.8	15.5
6	8.8	1.3	10.1	0.6	9.4	0.1	0.9	9.1
8	20.4	2.9	23.3	1.5	21.9	0.2	4.4	18.9
10	58.2	20.9	79.2	10.5	68.7	0.3	20.6	58.6
12	15.9	8.8	24.7	1.7	23.0	1.0	23.0	1.7
13	2.0	-	2.0	-	2.0	5.0	0.3	1.6
17	2.4	0.1	2.5	0.1	2.5	0.1	0.2	2.3
42	0.4	0.0	0.4	0.0	0.4	0.1	0.1	0.4
Dx CCA	**2,814.5**	**246.7**	**3,061.2**	**120.7**	**2,940.5**		**178.9**	**2,882.4**
Dx CEC Continuity	**42.3**	**0.0**	**42.4**	**-**	**42.4**	**0.1**	**3.0**	**39.4**

2005

CCA Class	Opening UCC	Net Additions	UCC pre-1/2 yr	50% net additions	UCC for CCA	CCA Rate	CCA	Closing UCC
1	2296.7	0.2	2296.9	17.4	2279.5	4%	91.2	2205.8
2	477.3	0.0	477.3	0.0	477.3	6%	28.6	448.7
3	15.5	1.6	17.1	0.1	17.0	5%	0.9	16.3
6	9.1	0.9	10.0	0.4	9.6	10%	1.0	9.1
8	18.9	15.1	34.0	7.7	26.3	20%	5.3	28.8
10	58.6	18.2	76.8	9.1	67.7	30%	20.3	56.5
12	1.7	5.1	6.8	2.5	4.3	100%	4.3	2.5
13	1.6	1.3	2.9	0.0	2.9	6 yrs	0.5	2.4
17	2.3	0.1	2.4	0.1	2.3	8%	0.2	2.3
42	0.4	0.0	0.4	0.0	0.4	12%	0.0	0.3
45	0.0	10.2	10.2	5.1	5.1	45%	2.3	7.9
47	0.0	159.7	159.7	79.8	79.9	8%	6.4	153.3
Dx CCA	**2882.4**	**212.4**	**3094.8**	**122.2**	**2972.6**		**160.9**	**2933.8**
Dx CEC Continuity	**39.4**	**9.8**	**49.2**	**0.0**	**49.2**	**0.1**	**3.4**	**45.7**

HYDRO ONE NETWORKS INC.
DISTRIBUTION

Calculation of Capital Cost allowance (CCA)
Historic and Bridge Years
2006 - 2007 Networks Allocation to Distribution
Year Ending December 31
($ Millions)

2006		Net						
CCA Class	Opening UCC	Additions	UCC pre-1/2 yr	50% net additions	UCC for CCA	CCA Rate	CCA	Closing UCC
1	2,205.76	(0.36)	2,205.40	-	2,205.40	4%	88.22	2,117.18
2	448.71	-	448.71	-	448.71	6%	26.92	421.79
3	16.30	0.20	16.50	0.10	16.50	5%	0.83	15.68
6	9.08	0.12	9.20	0.10	9.10	10%	0.91	8.29
8	28.77	19.03	47.80	9.50	38.30	20%	7.66	40.14
10	56.46	25.74	82.20	12.90	69.30	30%	20.79	61.41
12	2.50	25.70	28.20	12.80	15.40	100%	15.40	12.80
13	2.45	(0.25)	2.20	-	2.20	10 yrs	0.40	1.80
17	2.26	0.14	2.40	0.10	2.30	8%	0.18	2.22
42	0.34	(0.04)	0.30	(0.11)	0.41	12%	0.05	0.25
45	7.91	7.90	15.80	3.90	11.90	45%	5.26	10.55
47	153.31	250.49	403.80	125.30	278.50	8%	22.28	381.52
Dx CCA	**2,933.84**	**328.67**	**3,262.51**	**164.59**	**3,098.02**		**188.89**	**3,073.62**
Dx CEC Continuity	**45.70**	**0.10**	**45.80**	**-**	**45.80**	**7%**	**3.21**	**42.59**
					Less goodwill portion		**(2.40)**	
					Total CCA relating to regulatory		**189.70**	

2007		Net						
CCA Class	Opening UCC	Additions	UCC pre-1/2 yr	50% net additions	UCC for CCA	CCA Rate	CCA	Closing UCC
1	2,117.16	-	2,117.20	-	2,117.20	4%	84.69	2,032.51
2	421.79	-	421.70	-	421.70	6%	25.30	396.40
3	15.74	2.46	18.20	1.20	17.00	5%	0.85	17.35
6	8.29	1.21	9.50	0.60	8.90	10%	0.89	8.61
8	40.10	7.00	47.10	3.40	43.70	20%	8.74	38.36
10	61.41	28.99	90.40	14.50	75.90	30%	22.77	67.63
12	12.80	31.90	44.70	15.90	28.80	100%	28.80	15.90
13	1.80	0.40	2.20	0.20	2.00	10 yrs	0.40	1.80
17	2.22	0.28	2.50	0.10	2.40	8%	0.19	2.31
42	0.30	0.10	0.40	0.10	0.30	12%	0.04	0.36
45	10.50	1.20	11.70	0.60	11.10	45%	5.00	6.71
45.1	-	4.70	4.70	2.30	2.40	55%	1.32	3.38
47	381.50	389.80	771.30	194.90	576.40	8%	46.01	725.29
Dx CCA	**3,073.61**	**468.04**	**3,541.60**	**233.80**	**3,307.80**		**225.00**	**3,316.61**
Dx CEC Continuity	**42.59**	**0.01**	**42.60**	**-**	**42.60**	**7%**	**2.98**	**39.62**
					Less goodwill portion		**(2.2)**	
					Total CCA relating to regulatory		**225.8**	

2006 HYDRO ONE NETWORKS INCOME TAX RETURN

Attachment A:	Federal and Ontario Income Tax Return
Attachment B:	Calculation of Utility Income Taxes (Transmission and Distribution)
Attachment C:	Calculation of Capital Cost Allowance (Transmission and Distribution)

ATTACHMENT A

Federal and Ontario Income Tax Return

Canada Revenue Agency / Agence du revenu du Canada

200

T2 CORPORATION INCOME TAX RETURN

055 Do not use this area

This form serves as a federal, provincial, and territorial corporation income tax return, unless the corporation is located in Quebec, Ontario, or Alberta. If the corporation is located in one of these provinces, you have to file a separate provincial corporation return.

Parts, sections, subsections, and paragraphs mentioned on this return refer to the *Income Tax Act*. This return may contain changes that had not yet become law at the time of printing. For more information on how to complete the return, see the *T2 Corporation – Income Tax Guide* (T4012).

Send one completed copy of this return, including schedules and the *General Index of Financial Information* (GIFI), to your tax services office or tax centre. You have to file the return within six months after the end of the corporation's tax year. For more information on when and how to file T2 returns, refer to the Guide under the heading "Before you start."

Identification

Business Number (BN) 001 87086 5821 RC0001

Corporation's name
002 Hydro One Networks Inc.

Has the corporation changed its name since the last time we were notified? 003 1 Yes [ ] 2 No [X]

If *Yes*, do you have a copy of the articles of amendment? . . . 004 1 Yes [ ] 2 No [ ]

Address of head office
Has this address changed since the last time we were notified? . . . . 010 1 Yes [ ] 2 No [X]
(If *Yes*, complete lines 011 to 018)

011 483 Bay Street, 8th Floor
012 South Tower

City	Province, territory, or state
015 Toronto	016 ON
Country (other than Canada)	**Postal code/Zip code**
017	018 M5G 2P5

Mailing address (if different from head office address)
Has this address changed since the last time we were notified? . . . . 020 1 Yes [ ] 2 No [X]
(If *Yes*, complete lines 021 to 028)

021 c/o
022
023

City	Province, territory, or state
025	026
Country (other than Canada)	**Postal code/Zip code**
027	028

Location of books and records
Has the location of books and records changed since the last time we were notified? . . . . 030 1 Yes [ ] 2 No [X]
(If *Yes*, complete lines 031 to 038)

031 483 Bay Street, 8th Floor
032 South Tower

City	Province,territory, or state
035 Toronto	036 ON
Country (other than Canada)	**Postal code/Zip code**
037	038 M5G 2P5

040 Type of corporation at the end of the taxation year

1 [X] Canadian-controlled private corporation (CCPC)
2 [ ] Other private corporation
3 [ ] Public corporation
4 [ ] Corporation controlled by a public corporation
5 [ ] Other corporation (specify, below)

If the type of corporation changed during the tax year, provide the effective date of the change . . . . 043 ______ YYYY MM DD

To which tax year does this return apply?

Tax year start 060 2006-01-01 (YYYY MM DD)
Tax year end 061 2006-12-31 (YYYY MM DD)

Has there been an acquisition of control to which subsection 249(4) applies since the previous tax year? 063 1 Yes [ ] 2 No [X]

If *Yes*, provide the date control was acquired . . . . 065 ______ YYYY MM DD

Is the corporation a professional corporation that is a member of a partnership? . . . . 067 1 Yes [ ] 2 No [X]

Is this the first year of filing after:
Incorporation? . . . . 070 1 Yes [ ] 2 No [X]
Amalgamation? . . . . 071 1 Yes [ ] 2 No [X]
If *Yes*, complete lines 030 to 038 and attach Schedule 24.

Has there been a windup of a subsidiary under section 88 during the current tax year? . . . . 072 1 Yes [ ] 2 No [X]
If *Yes*, complete and attach Schedule 24.

Is this the final tax year before amalgamation? . . . . 076 1 Yes [ ] 2 No [X]

Is this the final return up to dissolution? . . . . 078 1 Yes [ ] 2 No [X]

Is the corporation a resident of Canada?
080 1 Yes [X] 2 No [ ] If *No*, give the country of residence on line 081 and complete and attach Schedule 97.
081

Is the non-resident corporation claiming an exemption under an income tax treaty? . . . . 082 1 Yes [ ] 2 No [X]
If *Yes*, complete and attach Schedule 91.

If the corporation is exempt from tax under section 149, tick one of the following boxes:
085
1 [ ] Exempt under paragraph 149(1)(e) or (l)
2 [ ] Exempt under paragraph 149(1)(j)
3 [ ] Exempt under paragraph 149(1)(t)
4 [ ] Exempt under other paragraphs of section 149

Do not use this area

091	092	093	094	095	096
100					

Attachments

Financial statement information: Use GIFI schedules 100, 125, and 141.

Schedules – Answer the following questions. For each *Yes* response, attach to the T2 return the schedule that applies.

		Yes	Schedule
Is the corporation related to any other corporations?	150	X	9
Is the corporation an associated Canadian-controlled private corporation?	160	X	23
Is the corporation an associated Canadian-controlled private corporation that is claiming the expenditure limit?	161		49
Does the corporation have any non-resident shareholders?	151		19
Has the corporation had any transactions, including section 85 transfers, with its shareholders, officers, or employees, other than transactions in the ordinary course of business? Exclude non-arm's length transactions with non-residents	162		11
If you answered *Yes* to the above question, and the transaction was between corporations not dealing at arm's length, were all or substantially all of the assets of the transferor disposed of to the transferee?	163		44
Has the corporation paid any royalties, management fees, or other similar payments to residents of Canada?	164		14
Is the corporation claiming a deduction for payments to a type of employee benefit plan?	165		15
Is the corporation claiming a loss or deduction from a tax shelter acquired after August 31, 1989?	166		T5004
Is the corporation a member of a partnership for which a partnership identification number has been assigned?	167		T5013
Did the corporation, a foreign affiliate controlled by the corporation, or any other corporation or trust that did not deal at arm's length with the corporation have a beneficial interest in a non-resident discretionary trust?	168		22
Did the corporation have any foreign affiliates during the year?	169		25
Has the corporation made any payments to non-residents of Canada under subsections 202(1) and/or 105(1) of the federal *Income Tax Regulations*?	170	X	29
Has the corporation had any non-arm's length transactions with a non-resident?	171		T106
For private corporations: Does the corporation have any shareholders who own 10% or more of the corporation's common and/or preferred shares?	173	X	50
Has the corporation made payments to, or received amounts from, a retirement compensation plan arrangement during the year?	172		
Is the net income/loss shown on the financial statements different from the net income/loss for income tax purposes?	201	X	1
Has the corporation made any charitable donations; gifts to Canada, a province, or a territory; or gifts of cultural or ecological property?	202		2
Has the corporation received any dividends or paid any taxable dividends for purposes of the dividend refund?	203	X	3
Is the corporation claiming any type of losses?	204		4
Is the corporation claiming a provincial or territorial tax credit or does it have a permanent establishment in more than one jurisdiction?	205		5
Has the corporation realized any capital gains or incurred any capital losses during the tax year?	206	X	6
i) Is the corporation claiming the small business deduction and reporting income from: a) property (other than dividends deductible on line 320 of the T2 return), b) a partnership, c) a foreign business, or d) a personal services business; or ii) is the corporation claiming the refundable portion of Part I tax?	207	X	7
Does the corporation have any property that is eligible for capital cost allowance?	208	X	8
Does the corporation have any property that is eligible capital property?	210	X	10
Does the corporation have any resource-related deductions?	212		12
Is the corporation claiming reserves of any kind?	213		13
Is the corporation claiming a patronage dividend deduction?	216		16
Is the corporation a credit union claiming a deduction for allocations in proportion to borrowing or an additional deduction?	217		17
Is the corporation an investment corporation or a mutual fund corporation?	218		18
Was the corporation carrying on business in Canada as a non-resident corporation?	220		20
Is the corporation claiming any federal or provincial foreign tax credits, or any federal or provincial logging tax credits?	221		21
Is the corporation a non-resident-owned investment corporation claiming an allowable refund?	226		26*
Does the corporation have any Canadian manufacturing and processing profits?	227		27
Is the corporation claiming an investment tax credit?	231		31
Is the corporation claiming any scientific research and experimental development (SR&ED) expenditures?	232	X	T661
Is the total taxable capital employed in Canada of the corporation and its related corporations over $10,000,000?	233		33/34/35
Is the corporation a member of a related group with one or more members subject to gross Part I.3 tax?	236		36
Is the corporation claiming a surtax credit?	237		37
Is the corporation subject to gross Part VI tax on capital of financial institutions?	238		38
Is the corporation claiming a Part I tax credit?	242		42
Is the corporation subject to Part IV.1 tax on dividends received on taxable preferred shares or Part VI.1 tax on dividends paid?	243		43
Is the corporation agreeing to a transfer of the liability for Part VI.1 tax?	244		45
Is the corporation subject to Part II - Tobacco Manufacturers' surtax?	249		46
For financial institutions: Is the corporation a member of a related group of financial institutions with one or more members subject to gross Part VI tax?	250		39
Is the corporation claiming a Canadian film or video production tax credit refund?	253		T1131
Is the corporation claiming a film or video production services tax credit refund?	254		T1177
Is the corporation subject to Part XIII.1 tax?	255		92 *

*** We do not print this schedule.**

Attachments – continued from page 2

		Yes	Schedule
Did the corporation have any foreign affiliates that are not controlled foreign affiliates?	256		T1134-A
Did the corporation have any controlled foreign affiliates?	258		T1134-B
Did the corporation own specified foreign property in the year with a cost amount over $100,000?	259		T1135
Did the corporation transfer or loan property to a non-resident trust?	260		T1141
Did the corporation receive a distribution from or was it indebted to a non-resident trust in the year?	261		T1142
Has the corporation entered into an agreement to allocate assistance for SR&ED carried out in Canada?	262		T1145
Has the corporation entered into an agreement to transfer qualified expenditures incurred in respect of SR&ED contracts?	263		T1146
Has the corporation entered into an agreement with other associated corporations for salary or wages of specified employees for SR&ED?	264		T1174

Additional information

Is the corporation inactive?	280	1 Yes [ ]	2 No [X]
Has the major business activity changed since the last return was filed? (enter *Yes* for first-time filers)	281	1 Yes [ ]	2 No [X]

What is the corporation's major business activity? 282 ______
(Only complete if *Yes* was entered at line 281.)

If the major business activity involves the resale of goods, show whether it is wholesale or retail 283 1 Wholesale [ ] 2 Retail [ ]

Specify the principal product(s) mined, manufactured, sold, constructed, or services provided, giving the approximate percentage of the total revenue that each product or service represents.

284	Electricity	285	100.000 %
286		287	%
288		289	%

Did the corporation immigrate to Canada during the tax year?	291	1 Yes [ ]	2 No [X]
Did the corporation emigrate from Canada during the tax year?	292	1 Yes [ ]	2 No [X]

Taxable income

Net income or (loss) for income tax purposes from Schedule 1, financial statements, or GIFI.			300	545,572,415	A
Deduct: Charitable donations from Schedule 2	311				
Gifts to Canada, a province, or a territory from Schedule 2	312				
Cultural gifts from Schedule 2	313				
Ecological gifts from Schedule 2	314				
Taxable dividends deductible under section 112 or 113, or subsection 138(6) from Schedule 3	320				
Part VI.1 tax deduction from Schedule 43 *	325				
Non-capital losses of preceding tax years from Schedule 4	331				
Net capital losses of preceding tax years from Schedule 4	332				
Restricted farm losses of preceding tax years from Schedule 4	333				
Farm losses of preceding tax years from Schedule 4	334				
Limited partnership losses of preceding tax years from Schedule 4	335				
Taxable capital gains or taxable dividends allocated from a central credit union	340				
Prospector's and grubstaker's shares	350				
Subtotal			►		B
Subtotal (amount A **minus** amount B) (if negative, enter "0")				545,572,415	C
Add: Section 110.5 additions or subparagraph 115(1)(a)(vii) additions			355		D
Taxable income (amount C **plus** amount D)			360	545,572,415	
Income exempt under paragraph 149(1)(t)			370		
Taxable income for a corporation with exempt income under paragraph 149(1)(t) (line 360 **minus** line 370)				545,572,415	Z

* This amount is equal to 3 times the Part VI.1 tax payable at line 724.

Small business deduction

Canadian-controlled private corporations (CCPCs) throughout the tax year

Income from active business carried on in Canada from Schedule 7	400	544,935,563	A
Taxable income from line 360, **minus** 10/3 of the amount on line 632*, **minus** 3 times the amount on line 636**, and **minus** any amount that, because of federal law, is exempt form Part I tax	405	545,572,415	B

Calculation of the business limit:

For all CCPCs, calculate the amount at line 4 below.

250,000	x	Number of days in the tax year in 2004 / Number of days in the tax year	/ 365	=		1
300,000	x	Number of days in the tax year in 2005 and in 2006 / Number of days in the tax year	365 / 365	=	300,000	2
400,000	x	Number of days in the tax year after 2006 / Number of days in the tax year	/ 365	=		3
		Add amounts at lines 1, 2, and 3			300,000	4

Business limit (see notes 1 and 2 below) . . . 410 ______ C

Notes: 1. For CCPCs that are not associated, enter the amount from line 4 on line 410. However, if the corporation's tax year is less than 51 weeks, prorate the amount from line 4 by the number of days in the tax year divided by 365, and enter the result on line 410.

2. For associated CCPCs, use Schedule 23 to calculate the amount to be entered on line 410.

Business limit reduction:

Amount C ______ x 415 *** 23,269,267 D / 11,250 = . . . ______ E

Reduced business limit (amount C **minus** amount E) (if negative, enter "0") . . . 425 ______ F

Small business deduction

Whichever amount is the least A, B, C or F . . . ______ G1

Amount G1		x	Number of days in the tax year before 2008 / Number of days in the tax year	365 / 365	x	16.00 %	=	G2
Amount G1		x	Number of days in the tax year in 2008 / Number of days in the tax year	/ 365	x	16.50 %	=	G3
Amount G1		x	Number of days in the tax year after 2008 / Number of days in the tax year	/ 365	x	17.00 %	=	G4

Small business deduction – total of amounts G2, G3, and G4 (enter amount G on line 9) . . . 430 ______ G

* Calculate the amount of foreign non-business income tax credit deductible on line 632 without reference to the refundable tax on the CCPC's investment income (line 604) and without reference to the corporate tax reductions under section 123.4.

** Calculate the amount of foreign business income tax credit deductible on line 636 without reference to the corporate tax reductions under section 123.4.

*** **Large corporations**

- The amount to be entered at line 415 is the total taxable capital employed in Canada **minus** $10,000,000 x 0.225%, calculated on Schedule 33, *Part I.3 Tax On Large Corporations*, Schedule 34, *Part I.3 Tax On Financial Institutions* **or** Schedule 35, *Part I.3 Tax On Large Insurance Companies.*
- If the corporation is not associated with any corporations in both the current and the preceding tax years, use the applicable schedule for the **prior** year. (Amount **P** in Part 6 of Schedule 33; Amount **O** in Part 6 of Schedule 34; Amount **DD** in Part 6 of Schedule 35)
- If the corporation is not associated with any corporations in the current tax year, but was associated in the preceding tax year, use the applicable schedule for the **current** year.
- For corporations associated in the current tax year, see Schedule 23 for the special rules that apply.

Accelerated tax reduction

Canadian-controlled private corporations throughout the taxation year that claimed the small business deduction

Reduced business limit (amount from line 425) ____ x 300,000 / line 4 above =			A
Net active business income (amount from line 400) *		544,935,563	B
Taxable income from line 360 **minus** 3 times the amount at line 636** on, and **minus** any amount that, because of federal law, is exempt from Part I Tax	545,572,415 C		
Deduct:			
Aggregate investment income (amount from line 440)	636,852 D		
Amount C **minus** amount D (if negative, enter "0")	544,935,563 ▶	544,935,563	E
Amount A, B, or E above, whichever is less			F
Amount Z from Part 9 of Schedule 27 ____ x 100 / 7 =	G		
Amount QQ from Part 13 of Schedule 27	H		
Taxable resource income (amount from line 435)	I		
Amount used to calculate the credit union deduction (amount E in Part 3 of Schedule 17)	J		
Amount on line 400, 405, 410, or 425 of the small business deduction, whichever is less	K		
Total of amounts G, H, I, J, and K	▶		L
Amount F **minus** amount L (if negative, enter "0")			M
Accelerated tax reduction – 7.00 % of amount M (enter amount N on line 637)			N

* If the amount at line 450 of Schedule 7 is positive, members of partnerships need to use Schedule 70 to calculate net active business income.

** Calculate the amount of foreign business income tax credit deductible at line 636 without reference to the corporate tax reductions under section 123.4.

Resource deduction

Taxable resource income [as defined in subsection 125.11(1)]				435	A
Amount A ____ x	Number of days in the tax year in 2004 / Number of days in the tax year	____ / 365	x 2 % =		B
Amount A ____ x	Number of days in the tax year in 2005 / Number of days in the tax year	____ / 365	x 3 % =		C
Amount A ____ x	Number of days in the tax year in 2006 / Number of days in the tax year	365 / 365	x 5 % =		D
Amount A ____ x	Number of days in the tax year after 2006 / Number of days in the tax year	____ / 365	x 7 % =		E
Resource deduction – total of amounts B, C, D, and E (enter amount F on line 10)				438	F

General tax reduction for Canadian-controlled private corporations

Canadian-controlled private corporations throughout the tax year

Taxable income from line 360		545,572,415	A
Amount Z1 from Part 9 of Schedule 27	B		
Amount QQ from Part 13 of Schedule 27	C		
Taxable resource income from line 435 above	D		
Amount used to calculate the credit union deduction (amount E in Part 3 of Schedule 17)	E		
Amount on line 400, 405, 410, or 425, whichever is the least	F		
Aggregate investment income from line 440	636,852 G		
Amount used to calculate the accelerated tax reduction (amount M)	H		
Total of amounts B, C, D, E, F, G, and H	636,852 ▶	636,852	I
Amount A **minus** amount I (if negative, enter "0")		544,935,563	J

Amount J 544,935,563 x	Number of days in the tax year before 2008 / Number of days in the tax year	365 / 365	x 7 % =	38,145,489	K1
Amount J 544,935,563 x	Number of days in the tax year in 2008 / Number of days in the tax year	____ / 365	x 7.5 % =		K2
Amount J 544,935,563 x	Number of days in the tax year in 2009 / Number of days in the tax year	____ / 365	x 8 % =		K3
Amount J 544,935,563 x	Number of days in the tax year after 2009 / Number of days in the tax year	____ / 365	x 9 % =		K4
General tax reduction for Canadian-controlled private corporations – total of amounts K1, K2, K3, and K4 (enter amount K on line 638)				38,145,489	K

General tax reduction

Corporations other than a Canadian-controlled private corporation, an investment corporation, a mortgage investment corporation, or a mutual fund corporation; and for tax years starting after May 1, 2006, any corporation with taxable income that is not subject to the full tax rate of 38% (eg. deposit insurance company).

Taxable income from line 360			L
Amount Z1 from Part 9 of Schedule 27		M	
Amount QQ from Part 13 of Schedule 27		N	
Taxable resource income from line 435 above		O	
Amount used to calculate the credit union deduction (amount E in Part 3 of Schedule 17)		P	
Total of amounts M, N, O, and P		▶	Q
Amount L **minus** amount Q (if negative, enter "0")			R

Amount R		x	Number of days in the tax year before 2008 / Number of days in the tax year	365 / 365	x	7 %	=	S1
Amount R		x	Number of days in the tax year in 2008 / Number of days in the tax year	/ 365	x	7.5 %	=	S2
Amount R		x	Number of days in the tax year in 2009 / Number of days in the tax year	/ 365	x	8 %	=	S3
Amount R		x	Number of days in the tax year after 2009 / Number of days in the tax year	/ 365	x	9 %	=	S4

General tax reduction – total of amounts S1, S2, S3, and S4 (enter amount S on line 639) .... S

Refundable portion of Part I tax

Canadian-controlled private corporations throughout the tax year

Aggregate investment income **440** 636,852 x 26 2 / 3 % = (amount O from Part 1 of Schedule 7)		169,827	A
Foreign non-business income tax credit from line 632			
Deduct:			
Foreign investment income **445** x 9 1 / 3 % = (amount L from Part 2 of Schedule 7) (if negative, enter "0")	▶		B
Amount A **minus** amount B (if negative, enter "0")		169,827	C

Taxable income from line 360 545,572,415

Deduct:

Amount on line 400, 405, 410, or 425, whichever is the least ....

Foreign non-business income tax credit from line 632 ______ x 25 / 9 = ______

Foreign business income tax credit from line 636 ______ x 3 = ______ ▶

545,572,415 x 26 2 / 3 % = 145,485,977 D

Part I tax payable minus investment tax credit refund (line 700 **minus** line 780)	120,767,655		
Deduct: Corporate surtax from line 600	6,110,411		
Net amount	114,657,244 ▶	114,657,244	E
Refundable portion of Part I tax – Amount C, D, or E, whichever is the least **450**		169,827	F

Refundable dividend tax on hand

Refundable dividend tax on hand at the end of the preceding tax year	460	28,250	
Deduct: Dividend refund for the previous tax year	465	28,250	
		▶	G
Add the total of:			
Refundable portion of Part I tax from line 450 above		169,827	
Total Part IV tax payable from line 360 of Schedule 3			
Net refundable dividend tax on hand transferred from a predecessor corporation on amalgamation, or from a wound-up subsidiary corporation	480		
		169,827 ▶	169,827 H
Refundable dividend tax on hand at the end of the tax year – Amount G **plus** amount H	485		169,827

Dividend refund

Private and subject corporations at the time taxable dividends were paid in the tax year

Taxable dividends paid in the tax year from line 460 of Schedule 3	195,468,483	x 1 / 3	65,156,161 I
Refundable dividend tax on hand at the end of the tax year from line 485 above			169,827 J
Dividend refund – Amount I or J, whichever is less (enter this amount on line 784)			169,827

Part I tax

Base amount of Part I tax – 38.00 % of taxable income (line 360 or amount Z, whichever applies) . . . 550 207,317,518 A

Corporate surtax calculation

Base amount from line A above	207,317,518	1
Deduct:		
10 % of taxable income (line 360 or amount Z, whichever applies)	54,557,242	2
Investment corporation deduction from line 620 below		3
Federal logging tax credit from line 640 below		4
Federal qualifying environmental trust tax credit from line 648 below		5

For a mutual fund corporation or an investment corporation throughout the tax year, enter amount a, b, or c below on line 6, whichever is the least:

28.00 % of taxable income from line 360		a		
28.00 % of taxed capital gains		b		6
Part I tax otherwise payable (line A **plus** lines C and D **minus** line F)		c		

Total of lines 2 to 6	54,557,242	7
Net amount (line 1 **minus** line 7)	152,760,276	8

Corporate surtax

line 8 152,760,276 × 4 % × Number of days in the tax year before 2008 365 / Number of days in the tax year 365 = 600 6,110,411 B

Recapture of investment tax credit from line OO in Part 17 of Schedule 31 . . . 602 ______ C

Calculation for the refundable tax on the Canadian-controlled private corporation's (CCPC) investment income
(if it was a CCPC throughout the tax year)

Aggregate investment income from line 440		636,852	i
Taxable income from line 360	545,572,415		
Deduct:			
Amount on line 400, 405, 410, or 425, whichever is the least			
Net amount	545,572,415 ▶	545,572,415	ii

Refundable tax on CCPC's investment income – 6 2 / 3 % of whichever is less: amount i or ii . . . 604 42,457 D

Subtotal (add lines A, B, C, and D) 213,470,386 E

Deduct:

Small business deduction from line 430			9
Federal tax abatement	608	54,557,242	
Manufacturing and processing profits deduction from amount BB or amount RR of Schedule 27	616		
Investment corporation deduction	620		
(taxed capital gains 624 ______)			
Additional deduction – credit unions from Schedule 17	628		
Federal foreign non-business income tax credit from Schedule 21	632		
Federal foreign business income tax credit from Schedule 21	636		
Accelerated tax reduction from amount N	637		
Resource deduction from line 438			10
General tax reduction for CCPCs from amount K	638	38,145,489	
General tax reduction from amount S	639		
Federal logging tax credit from Schedule 21	640		
Federal political contribution tax credit	644		
Federal political contributions 646 ______			
Federal qualifying environmental trust tax credit	648		
Investment tax credit from Schedule 31	652		
Subtotal		92,702,731 ▶	92,702,731 F

Part I tax payable – Line E **minus** line F (enter amount G on line 700) . . . 120,767,655 G

Summary of tax and credits

Federal tax

Part I tax payable	700	120,767,655
Part I.3 tax payable from Schedule 33, 34, or 35	704	
Part II surtax payable from Schedule 46	708	
Part IV tax payable from Schedule 3	712	
Part IV.1 tax payable from Schedule 43	716	
Part VI tax payable from Schedule 38	720	
Part VI.1 tax payable from Schedule 43	724	
Part XIII.1 tax payable from Schedule 92	727	
Part XIV tax payable from Schedule 20	728	
Total federal tax		120,767,655

Add provincial or territorial tax:

Provincial or territorial jurisdiction 750 Ontario
(if more than one jurisdiction, enter "multiple" and complete Schedule 5)

Net provincial or territorial tax payable (except Québec, Ontario, and Alberta)	760	
Provincial tax on large corporations (New Brunswick and Nova Scotia)	765	

Total tax payable 770 120,767,655 A

Deduct other credits:

Investment tax credit refund from Schedule 31	780	
Dividend refund	784	169,827
Federal capital gains refund from Schedule 18	788	
Federal qualifying environmental trust tax credit refund	792	
Canadian film or video production tax credit refund (Form T1131)	796	
Film or video production services tax credit refund (Form T1177)	797	
Tax withheld at source	800	
Total payments on which tax has been withheld	801	
Allowable refund for non-resident-owned investment corporations from Schedule 26	804	
Provincial and territorial capital gains refund from Schedule 18	808	
Provincial and territorial refundable tax credits from Schedule 5	812	
Tax instalments paid	840	120,597,828
Total credits	890	120,767,655

Total credits ▶ 120,767,655 B

Refund code 894 Overpayment

Balance (line A minus line B)

If the result is negative, you have an **overpayment**.
If the result is positive, you have a **balance unpaid**.
Enter the amount on whichever line applies.
Generally, we do not charge or refund a difference of $2 or less.

Balance unpaid

Enclosed payment 898

Direct deposit request

To have the corporation's refund deposited directly into the corporation's bank account at a financial institution in Canada, or to change banking information you already gave us, complete the information below:

☐ Start ☐ Change information 910 Branch number

914 Institution number 918 Account number

If the corporation is a Canadian-controlled private corporation throughout the tax year, does it qualify for the one-month extension of the date the balance of tax is due? 896 1 Yes ☐ 2 No ☒

Certification

I, 950 ALICANDRI (Last name) 951 VINCENT (First name) 954 Vice President, Corporate Tax (Position, office, or rank)

am an authorized signing officer of the corporation. I certify that I have examined this return, including accompanying schedules and statements, and that the information given on this return is, to the best of my knowledge, correct and complete. I further certify that the method of calculating income for this tax year is consistent with that of the previous year except as specifically disclosed in a statement attached to this return.

955 Date (yyyy/mm/dd) — Signature of the authorized signing officer of the corporation — 956 (416) 345-6778 Telephone number

Is the contact person the same as the authorized signing officer? If *No*, complete the information below 957 1 Yes ☐ 2 No ☒

958 BRIAN SOARES (Name) 959 (416) 345-6782 (Telephone number)

Language of correspondence – Langue de correspondance

990 Indicate your language of correspondence by entering 1 for English or 2 for French.
Indiquez votre langue de correspondance en inscrivant 1 pour anglais ou 2 pour français.

1 English / Anglais ☒ 2 Français / French ☐

Canada Revenue Agency | Agence du revenu du Canada

SCHEDULE 141

NOTES CHECKLIST

Corporation's name	Business Number	Tax year end Year Month Day
Hydro One Networks Inc.	87086 5821 RC0001	2006-12-31

- This schedule should be completed from the perspective of the person who prepared or reported on the **financial statements**. This person is referred to as the "accounting practitioner", in this schedule.
- For more information, see RC4088, *Guide to the General Index of Financial Information (GIFI) for Corporations* and T4012, *T2 Corporation – Income Tax Guide.*
- Attach a copy of this schedule, along with any Notes to the financial statements, to the GIFI.

Part 1 – Accounting practitioner information

Does the accounting practitioner have a professional designation? . . . . . **095** 1 Yes [X] 2 No [ ]

Is the accounting practitioner connected* with the corporation? . . . . . **097** 1 Yes [X] 2 No [ ]

* A person connected with a corporation can be: (i) a shareholder of the corporation who owns more than 10% of the common shares; (ii) a director, an officer, or an employee of the corporation; or (iii) a person not dealing at arm's length with the corporation.

Note
If the accounting practitioner does not have a professional designation **or** is connected with the corporation, you do not have to complete Parts 2 and 3 of this schedule. However, you do have to complete Part 4.

Part 2 – Type of involvement

Choose the option that represents the highest level of involvement of the accounting practitioner: **198**

Completed an auditor's report . . . . . 1 [ ]

Completed a review engagement report . . . . . 2 [ ]

Conducted a compilation engagement . . . . . 3 [ ]

Part 3 – Reservations

If you selected option "1" or "2" under **Type of involvement** above, answer the following question:

Has the accounting practitioner expressed a reservation? . . . . . **099** 1 Yes [ ] 2 No [ ]

Part 4 – Other information

Were notes to the financial statements prepared? . . . . . **101** 1 Yes [X] 2 No [ ]

If *Yes*, complete lines 102 to 107 below:

Are any values presented at other than cost? . . . . . **102** 1 Yes [ ] 2 No [X]

Has there been a change in accounting policies since the last return? . . . . . **103** 1 Yes [ ] 2 No [X]

Are subsequent events mentioned in the notes? . . . . . **104** 1 Yes [X] 2 No [ ]

Is re-evaluation of asset information mentioned in the notes? . . . . . **105** 1 Yes [ ] 2 No [X]

Is contingent liability information mentioned in the notes? . . . . . **106** 1 Yes [X] 2 No [ ]

Is information regarding commitments mentioned in the notes? . . . . . **107** 1 Yes [X] 2 No [ ]

Does the corporation have investments in joint venture(s) or partnership(s)? . . . . . **108** 1 Yes [ ] 2 No [X]

If *Yes*, complete line 109 below:

Are you filing financial statements of the joint venture(s) or partnership(s)? . . . . . **109** 1 Yes [ ] 2 No [ ]

Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 1

NET INCOME (LOSS) FOR INCOME TAX PURPOSES

orporation's name	Business Number	Tax year end Year Month Day
Hydro One Networks Inc.	87086 5821 RC0001	2006-12-31

- The purpose of this schedule is to provide a reconciliation between the corporation's net income (loss) as reported on the financial statements and its net income (loss) for tax purposes. For more information, see the T2 *Corporation Income Tax Guide*.
- Please provide us with the applicable details in the identification area, and complete the applicable lines that contain a numbered black box. You should report amounts in accordance with the Generally Accepted Accounting Principles (GAAP).
- Sections, subsections, and paragraphs referred to on this schedule are from the *Income Tax Act*.

Net income (loss) after taxes and extraordinary items per financial statements				427,144,424	A
Add:					
Provision for income taxes – current		101	160,864,387		
Amortization of tangible assets		104	490,825,077		
Taxable capital gains from Schedule 6		113	636,852		
Non-deductible meals and entertainment expenses		121	5,311,393		
Reserves from financial statements – balance at the end of the year		126	989,863,029		
Subtotal of additions			1,647,500,738 ▶	1,647,500,738	
Other additions:					
Capital items expensed		206	471,979		
Debt issue expense		208	2,259,203		
Recapture of SR&ED expenditures – Form T661		231	153,159		
Miscellaneous other additions:					
600 Other additions (see attached)		290	31,869,924		
601 Capital tax expensed (a/c 683010)		291	28,360,123		
603b Ontario Specified Tax Credits	1,038,515				
Total	1,038,515	293	1,038,515		
Subtotal of other additions		199	64,152,903 ▶	64,152,903	
Total additions		500	1,711,653,641 ▶	1,711,653,641	
Deduct:					
Capital cost allowance from Schedule 8		403	481,880,414		
Cumulative eligible capital deduction from Schedule 10		405	9,145,676		
Deferred and prepaid expenses		409	4,318,091		
Reserves from financial statements – balance at the beginning of the year		414	880,775,268		
Subtotal of deductions			1,376,119,449 ▶	1,376,119,449	
Other deductions:					
Miscellaneous other deductions:					
700 Interest cap for acct, exp for tax (761410-12)		390	35,399,691		
701 Capital tax - 2006		391	27,911,692		
702 Environmental int imp & cost capitalized in Sch013 movement		392	6,246,425		
703 Deduct OPEB costs capitalized in Sch013 movement		393	48,721,611		
704 Other deductions (see attached)		394	98,826,782		
Subtotal of other deductions		499	217,106,201 ▶	217,106,201	
Total deductions		510	1,593,225,650 ▶	1,593,225,650	
Net income (loss) for income tax purposes – enter on line 300 of the T2 return				545,572,415	

T2 SCH 1 E (06)

Canada

Attached Schedule with Total

Line 290 – Amount for line 600

Title C-Sch 001 - Misc. Other Additions (line 290)

Description	Amount	
Hedging loss amortization, add back accounting (761770)	2,348,744	00
Contingent liabilities transfer to capital accounts	9,093,967	00
Reverse Deferral RE: tax change impact (275210)	2,759,864	00
MEU enviromental provision movement (413200)	1,247,393	00
Revenue received-RARA (275400,1,2)	16,235,879	00
Loss re: OEB decision (550310)	86,635	00
MEU acquisition post retirement benefits included in sch 134 opeb liability	97,442	00
Total	31,869,924	00

Attached Schedule with Total

Line 394 – Amount for line 704

Title F-Sch 001-Other Deductions (Line 394)

Description	Amount	
Removal Costs (non capital)	6,339,312	00
LV revenue recoginized not received	8,091,546	00
Building provision (110190)	627,162	00
Landscaping	1,979,587	00
Smart Meters	1,462,287	00
Amortization-Frequency Stdization Incent (751000)		
Amortization - Capital contribution (751010)	234,036	00
Amortization of WSIB Gain incl in income	1,769,496	00
Capitalized overheads-general and admin	31,180,572	00
OEB Deferred Costs (275020, 275047)	709,151	00
Pension Cost Deductions	43,224,553	00
Inergi Pension Deduction	3,209,080	00
Total	98,826,782	00

Attached Schedule with Total

Line 409 – Deferred and prepaid expenses

Title D-Sch 001 - Deferred or prepaid expenses deducted for tax(line 409)

Description	Amount	
Def Underwriting costs deductible for tax	3,056,105	00
Def Prospectus fees deductible for tax	522,379	00
Bond Discount amortization	739,607	00
Total	4,318,091	00

Attached Schedule with Total

Line 206 – Capital items expensed

Title A-Sch 001 - Capital items expensed added back for tax (line 206)

Description	Amount
Computer system software (A/C 620040)	393,302 00
Computer Application Software (A/C 620046)	78,677 00
Total	471,979 00

Attached Schedule with Total

Line 208 – Debt issue expense

Title B-Sch 001- Debt issue expenses added back for tax (line 208)

Description	Amount	
Acc amortization of Prospectus fees (761780)	540,467	00
Acc amortization of Underwriting fees (761790)	1,718,736	00
Total	2,259,203	00

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DIVIDENDS RECEIVED, TAXABLE DIVIDENDS PAID, AND PART IV TAX CALCULATION

SCHEDULE 3

Name of corporation	Business Number	Tax year end Year Month Day
Hydro One Networks Inc.	87086 5821 RC0001	2006-12-31

- This schedule is for the use of any corporation to report:
  - non-taxable dividends under section 83;
  - deductible dividends under subsection 138(6);
  - taxable dividends deductible from income under section 112, subsection 113(2) and paragraphs 113(1)(a), (b) or (d); or
  - taxable dividends paid for purposes of a dividend refund.
- The calculations in this schedule apply only to private or subject corporations.
- Parts, sections, subsections, and paragraphs referred to on this schedule are from the federal *Income Tax Act*.
- A recipient corporation is connected with a payer corporation at any time in a taxation year, if at that time the recipient corporation:
  - controls the payer corporation, other than because of a right referred to in paragraph 251(5)(b); or
  - owns more than 10% of the issued share capital (with full voting rights), and shares that have a fair market value of more than 10% of the fair market value of all shares of the payer corporation.
- File one completed copy of this schedule with your *T2 Corporation Income Tax Return*.
- For more information, see the sections about Schedule 3 in the *T2 Corporation Income Tax Guide*.
- "X" under column A if dividend received from a foreign source (connected corporation only).
- "X" under column B if the payer corporation is connected.
- "X" under column F1 if the dividends received are eligible to an addition of 45% for the purposes of the dividend tax credit for individuals.
- F2 – Enter the code that applies to the deductible taxable dividend.

Part 1 – Dividends received during the taxation year

Do not include dividends received from foreign non-affiliates.

			Complete if payer corporation is connected	
Name of payer corporation (Use only one line per corporation, abreviating its name if necessary) 200	A	B 205	C Business Number 210	D Taxation year end of the payer corporation in which the sections 112/113 and subsection 138(6) dividends were paid YYYY/MM/DD 220
1				

Note: If your corporation's taxation year end is different than that of the connected payer corporation, your corporation could have received dividends from more than one taxation year of the payer corporation. If so, use a separate line to provide the information for each taxation year of the payer corporation.

				If payer corporation is not connected, leave these columns blank.		
E Non-taxable dividend under section 83 230	F Taxable dividends deductible from taxable income under section 112, subsections 113(2) and 138(6), and paragraphs 113(1)(a), (b), or (d) 240	F1	F2	G Total taxable dividends paid by connected payer corporation 250	H Dividend refund of the connected payer corporation 260	I Part IV tax before deductions F x 1 / 3 * 270
1						
Total (enter amount of column F on line 320 of the T2 return)						J

For dividends received from connected corporations: Part IV tax equals: $\frac{\text{Column F x Column H}}{\text{Column G}}$

* Life insurers are not subject to Part IV tax on subsection 138(6) dividends.
Public corporations (other than subject corporations) do not need to calculate Part IV tax.

Part 2 – Calculation of Part IV tax payable

Part IV tax before deductions (amount J in Part 1)		
Deduct:		
Part IV.I tax payable on dividends subject to Part IV tax	320	
Subtotal		

Deduct:

Current-year non-capital loss claimed to reduce Part IV tax	330	
Non-capital losses from previous years claimed to reduce Part IV tax	335	
Current-year farm loss claimed to reduce Part IV tax	340	
Farm losses from previous years claimed to reduce Part IV tax	345	
Total losses applied against Part IV tax		x 1 / 3 =
Part IV tax payable (enter amount on line 712 of the T2 return)	360	

Part 3 – Taxable dividends paid in the taxation year for purposes of a dividend refund

	A	B	C	D
	Name of connected recipient corporation	Business Number	Taxation year end of connected recipient corporation in which the dividends in column D were received YYYY/MM/DD	Taxable dividends paid to connected corporations
	400	410	420	430
1	Hydro One Inc.		2006-12-31	195,468,483
2				

Note
If your corporation's taxation year end is different than that of the connected recipient corporation, your corporation could have paid dividends in more than one taxation year of the recipient corporation. If so, use a separate line to provide the information for each taxation year of the recipient corporation.

Total 195,468,483

Total taxable dividends paid in the taxation year to other than connected corporations	450	
Total taxable dividends paid in the taxation year for the purposes of a dividend refund (total of column D above plus line 450)	460	195,468,483
Eligible dividends paid that are included in line 460 (memo) (Press F1 for additional information)		

Part 4 – Total dividends paid in the taxation year

Complete this part if the total taxable dividends paid in the taxation year for purposes of a dividend refund (line 460 above) is different from the total dividends paid in the taxation year.

Total taxable dividends paid in the taxation year for the purposes of a dividend refund (from above)	460	195,468,483
Other dividends paid in the taxation year (total of 510 to 540)		
Total dividends paid in the taxation year	500	195,468,483

Deduct:

Dividends paid out of capital dividend account	510	
Capital gains dividends	520	
Dividends paid on shares described in subsection 129(1.2)	530	
Taxable dividends paid to a controlling corporation that was bankrupt at any time in the year	540	
Subtotal		▶
Total taxable dividends paid in the taxation year for purposes of a dividend refund		195,468,483

Part 2 – Amount to be included in income arising from disposition

(complete this part only if the amount at line K is negative)

Amount from line K (show as positive amount)					N
Total of cumulative eligible capital (CEC) deductions from income for taxation years beginning after June 30, 1988		400		1	
Total of all amounts which reduced CEC in the current or prior years under subsection 80(7)		401		2	
Total of CEC deductions claimed for taxation years beginning before July 1, 1988	402		3		
Negative balances in the CEC account that were included in income for taxation years beginning before July 1, 1988	408		4		
Line 3 minus line 4 (if negative, enter "0")		►		5	
Total of lines 1, 2 and 5				6	
Amounts included in income under paragraph 14(1)(b), as that paragraph applied to taxation years ending after June 30, 1988 and before February 28, 2000, to the extent that it is for an amount described at line 400			7		
Amounts at line T from Schedule 10 of previous taxation years ending after February 27, 2000			8		
Subtotal (line 7 plus line 8)	409	►		9	
Line 6 minus line 9 (if negative, enter "0")				►	O
Line N minus line O (if negative, enter "0")					P
Line 5			× 1 / 2 =		Q
Line P minus line Q (if negative, enter "0")					R
Amount R			× 2 / 3 =		S
Amount N or amount O, whichever is less					T
Amount to be included in income (amount S plus amount T) (enter this amount on line 108 of Schedule 1)				410	

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SCHEDULE 7

CALCULATION OF AGGREGATE INVESTMENT INCOME AND ACTIVE BUSINESS INCOME

Name of corporation	Business Number	Tax year end Year Month Day
Hydro One Networks Inc.	87086 5821 RC0001	2006-12-31

- This schedule is for the use of Canadian-controlled private corporations to calculate:
  - aggregate investment income and foreign investment income for the purpose of determining the refundable portion of Part I tax, as defined in subsection 129(4) of the *Income Tax Act;*
  - specified partnership income for members of one or more partnership(s); and
  - income from an active business carried on in Canada for the small business deduction.
- For more information, see the sections called "Small Business Deduction" and "Refundable Portion of Part 1 Tax" in the *T2 Corporation – Income Tax Guide.*

Part 1 and Part 2 – Aggregate and foreign investment income calculation

	Canadian investment income	Foreign investment income	Aggregate investment income	
The eligible portion of taxable capital gains included in income for the year	636,852	001	002 636,852	A
Eligible portion of allowable capital losses for the year (including allowable business investment losses)		009	012	B
Net capital losses of other years claimed on line 332 on the T2 return			022	C
Total of amounts B and C				D
Amount A **minus** amount D (if negative, enter "0")	636,852		636,852	E
Total income from property (in box 32 include income from a specified investment business carried on in Canada other than income from a source outside Canada)				
Taxable dividends				
Other property income				
Total income from property		019	032	F
Exempt income		029	042	G
Amounts received from NISA Fund No. 2 (CAIS) that were included in computing the corporation's income for the year			052	H
Taxable dividends deductible (total of Column F on Schedule 3)		049	062	I
Business income from an interest in a trust that is considered property income under paragraph 108(5)(a)		059	072	J
Total of amounts G, H, I, and J				K
Amount F **minus** amount K				L
Total of amount E **plus** amount L	636,852		636,852	M
Total losses from property (in box 82 include losses from a specified investment business carried on in Canada other than a loss from a source outside Canada)		069	082	N
Amount M **minus** amount N (if negative, enter "0")	636,852	079 L	092 O 636,852	

Note: The aggregate investment income is the aggregate world source income.
Enter amount L, foreign investment income, on line 445 of the T2 return.
Enter amount O, aggregate investment income, on line 440 of the T2 return.

Net taxable dividends	Canadian	Foreign	Total
Taxable dividends deducted per schedule 3			
Less: Expenses related to such dividends			
Total expenses			
Net taxable dividends			

Part 3 – Specified partnership income

A	B	C
Partnership name 200	Total income (loss) of partnership from an active business 300	Corporation's share of amount in column B 310

D	E	F	G	H	I
Adjustments [add prior-year reserves under subsection 34.2(5), and deduct expenses incurred to earn partnership income, including any reserve under subsection 34.2(4)] 315	Corporation's income (loss) of the partnership (column C **plus** column D) 320	Number of days in the partnership's fiscal period 325	Prorated business limit (column C ÷ column B) × [business limit* × (column F ÷ 365)] (if column C is negative, enter "0")** 330	Column E **minus** column G (if negative, enter "0")	Lesser of columns E and G (if column E is negative, enter "0") 340
Total	350			Total 385	360

Corporation's losses for the year from an active business carried on in Canada (other than as a member of a partnership) – enter as a positive amount .... **370** ____________

Specified partnership loss of the corporation for the year – enter as a positive amount (total of all negative amounts in column E) .... **380** ____________

Total of lines 370 and 380 .... ____________ ▶ ____________ J

Amount at line 385 or line J, whichever is less .... **390** ____________

Specified partnership income (line 360 **plus** line 390) .... **400** ____________

* Use one of the following business limits to calculate column G, whichever applies:

- $250,000 if the corporation's tax year ends in 2004;
- $300,000 if the corporation's tax year ends in 2005 or 2006; or
- $400,000 if the corporation's tax year ends after 2006.

** When a partnership carries on more than one business, one of which generates income and another of which realizes a loss, the loss is not netted against the partnership's income.

Part 4 – Determination of partnership income

Corporation's share of partnership income from active businesses carried on in Canada after deducting related expenses – from line 350 above (if the net amount is negative, enter "0" on line O) .... ____________ K

Add: Specified partnership loss (from line 380 above) .... ____________ L

Subtotal ____________ M

Deduct: Specified partnership income (from line 400 above) .... ____________ N

Partnership income (enter on line S below) .... **450** ____________ O

Part 5 – Income from active business carried on in Canada

Net income for income tax purposes from line 300 of the T2 return			545,572,415	F
Deduct: Foreign business income after deducting related expenses*	500			
Taxable capital gains **minus** allowable capital loss – amount A **minus** amount B* (page 1)**		636,852		
Net property income = amount F **minus** amount G, H, and N* (page 1)				Q
Personal services business income after deducting related expenses*	520			
		636,852 ►	636,852	
		Net amount	544,935,563	R
Deduct: Partnership income (line 450 above)				S
Income from active business carried on in Canada (enter on line 400 of the T2 return – if negative, enter "0")			544,935,563	T

* If negative, **add** instead of **subtracting**.
**This amount may only be negative to the extent of any allowable business investment losses.

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SCHEDULE 8

CAPITAL COST ALLOWANCE (CCA)

Name of corporation	Business Number	Tax year end Year Month Day
Hydro One Networks Inc.	87086 5821 RC0001	2006-12-31

For more information, see the section called "Capital Cost Allowance" in the *T2 Corporation Income Tax Guide*.

Is the corporation electing under regulation 1101(5q)? **101** 1 Yes [ ] 2 No [X]

	1 Class number 200	Description	2 Undepreciated capital cost at the beginning of the year (undepreciated capital cost at the end of last year) 201	3 Cost of acquisitions during the year (new property must be available for use)* 203	4 Net adjustments** 205	5 Proceeds of dispositions during the year (amount not to exceed the capital cost) 207	6 50% rule (1/2 of the amount, if any, by which the net cost of acquisitions exceeds column 5)*** 211	7 Reduced undepreciated capital cost	8 CCA rate % 212	9 Recapture of capital cost allowance (line 107 of Schedule 1) 213	10 Terminal loss (line 404 of Schedule 1) 215	11 Capital cost allowance (column 7 multiplied by column 8; or a lower amount) (line 403 of Schedule 1)**** 217	12 Undepreciated capital cost at the end of the year (column 6 plus column 7 minus column 11) 220
1	1		5,265,396,883		-589,048	1,049,790		5,263,758,045	4	0	0	210,550,322	5,053,207,723
2	2		1,443,191,112			0		1,443,191,112	6	0	0	86,591,467	1,356,599,645
3	3		272,879,000	30,407,234		0	15,203,617	288,082,617	5	0	0	14,404,131	288,882,103
4	6		32,916,543	1,338,522		15,716	661,403	33,577,946	10	0	0	3,357,795	30,881,554
5	7		108,970			0		108,970	15	0	0	16,346	92,624
6	8		49,427,836	26,085,276		164,743	12,960,267	62,388,102	20	0	0	12,477,620	62,870,749
7	10		172,134,264	60,640,560		1,391,450	29,624,555	201,758,819	30	0	0	60,527,646	170,855,728
8	12		5,537,219	40,796,787		0	20,398,394	25,935,612	100	0	0	25,935,612	20,398,394
9	42		72,257,601	9,934,331		0	4,967,166	77,224,766	12	0	0	9,266,972	72,924,960
10	17		13,205,891	1,961,166		0	980,583	14,186,474	8	0	0	1,134,918	14,032,139
11	9		1,473,167			0		1,473,167	25	0	0	368,292	1,104,875
12	35		489,608			0		489,608	7	0	0	34,273	455,335
13	45	cl.10 post Mar 22/04	15,391,799	12,778,171		0	6,389,086	21,780,884	45	0	0	9,801,398	18,368,572
14	46	cl.8 post Mar 22/04	3,182,606	16,235,548		0	8,117,774	11,300,380	30	0	0	3,390,114	16,028,040
15	13		1,918,828	316,013		0	158,007	2,076,834	N/A	0	0	346,139	1,888,702
16	47		342,843,405	437,427,987	-31,180,572	0	218,713,994	530,376,826	8	0	0	43,677,369	705,413,451
		Total	7,692,354,732	637,921,595	-31,769,620	2,621,699	318,174,846	7,977,710,162				481,880,414	7,814,004,594

Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 10

CUMULATIVE ELIGIBLE CAPITAL DEDUCTION

Name of corporation	Business Number	Tax year end Year Month Day
Hydro One Networks Inc.	87086 5821 RC0001	2006-12-31

- For use by a corporation that has eligible capital property. For more information, see the *T2 Corporation Income Tax Guide*.
- A separate cumulative eligible capital account must be kept for each business.

Part 1 – Calculation of current year deduction and carry-forward

Cumulative eligible capital - Balance at the end of the preceding taxation year (if negative, enter "0")			200	130,644,309 A
Add: Cost of eligible capital property acquired during the taxation year	222	11,601		
Other adjustments	226			
Subtotal (line 222 plus line 226)		11,601 x 3 / 4 =	8,701 B	
Non-taxable portion of a non-arm's length transferor's gain realized on the transfer of an eligible capital property to the corporation after December 20, 2002	228	x 1 / 2 =	C	
amount B minus amount C (if negative, enter "0")			8,701 ►	8,701 D
Amount transferred on amalgamation or wind-up of subsidiary			224	E
Subtotal (add amounts A, D, and E)			230	130,653,010 F
Deduct: Proceeds of sale (less outlays and expenses not otherwise deductible) from the disposition of all eligible capital property during the taxation year	242	669 G		
The gross amount of a reduction in respect of a forgiven debt obligation as provided for in subsection 80(7)	244	H		
Other adjustments	246	I		
(add amounts G,H, and I)		669 x 3 / 4 =	248	502 J
Cumulative eligible capital balance (amount F minus amount J) (if amount K is negative, enter "0" at line M and proceed to Part 2)				130,652,508 K
Cumulative eligible capital for a property no longer owned after ceasing to carry on that business			249	
amount K	130,652,508			
less amount from line 249				
Current year deduction	130,652,508 x 7.00 % =		250	9,145,676 *
(line 249 plus line 250) (enter this amount at line 405 of Schedule 1)			9,145,676 ►	9,145,676 L
Cumulative eligible capital – Closing balance (amount K minus amount L) (if negative, enter "0")			300	121,506,832 M

* You can claim any amount up to the maximum deduction of 7%. The deduction may not exceed the maximum amount prorated by the number of days in the taxation year divided by 365.

T2 SCH 10 (04)

Canada

Continuity of financial statement reserves (not deductible)

Financial statement reserves (not deductible)

	Description	Balance at the beginning of the year	Transfer on amalgamation or wind-up of subsidiary	Add	Deduct	Balance at the end of the year
1	OPEB Liability Short Term	35,075,000				35,075,000
2	OPEB Liability Long Term	688,996,332		87,101,443		776,097,775
3	Enviromental Short Term	13,010,000			50,000	12,960,000
4	Environmental Long Term	58,386,976			9,339,296	49,047,680
5	Contingent Liabilities	66,344,735			36,374,358	29,970,377
6	Deferred export Tx Svs Cr	32,050,051		16,709,121		48,759,172
7	RSVA Liabilities	37,518,166	-52,846,883	17,495,923		2,167,206
8	Tenant Inducement	2,240,891			544,865	1,696,026
9	Earnings Sharing - TX			34,089,793		34,089,793
10						
	Reserves from Part 2 of Schedule 13					
	Totals	933,622,151	-52,846,883	155,396,280	46,308,519	989,863,029

The total opening balance plus the total transfers should be entered on line 414 of Schedule 1 as a deduction.
The total closing balance should be entered on line 126 of Schedule 1 as an addition.

Ontario Ministry of Finance
Corporations Tax
33 King Street West
PO Box 620
Oshawa ON L1H 8E9

2006 CT23 Corporations Tax and Annual Return

For taxation years commencing after December 31, 2003

Corporations Tax Act – Ministry of Finance (MOF)
Corporations Information Act – Ministry of Government Services (MGS)

This form is a combination of the Ministry of Finance (MOF) **CT23 Corporations Tax Return** and the Ministry of Government Services (MGS) **Annual Return**. Page 1 is a common page required for both Returns. For tax purposes, depending on which criteria the corporation satisfies, it must complete either the **Exempt from Filing (EFF)** declaration on page 2 or file the **CT23 Return** on pages 3-17. Corporations that **do not** meet the EFF criteria but **do** meet the Short-Form criteria, may request and file the **CT23 Short-Form Return** (see page 2).

The **Annual Return** (common page 1 and MGS Schedule A on pages 18 and 19, and Schedule K on page 20) contains non-tax information collected under the authority of the *Corporations Information Act* for the purpose of maintaining a public database of corporate information. This return must be completed by Ontario share-capital corporations or Foreign-Business share-capital corporations that have an extra-provincial licence to operate in Ontario.

Ministry Use

MGS Annual Return Required? *(Not required if already filed or Annual Return exempt. Refer to Guide)* ☐ Yes ☒ No

Corporation's Legal Name *(including punctuation)*: Hydro One Networks Inc.	**Ontario Corporations Tax Account No. (MOF)**
Mailing Address: 483 Bay Street, 8th Floor South Tower Toronto ON CA M5G 2P5	This Return covers the Taxation Year Start (year month day): 2006-01-01 End (year month day): 2006-12-31
Has the mailing address changed since last filed CT23 Return? ☐ Yes — Date of Change (year month day):	Date of Incorporation or Amalgamation (year month day): 1999-03-04
Registered/Head Office Address: 483 Bay Street, 8th Floor South Tower Toronto ON CA M5G 2P5	Ontario Corporation No. (MGS): 1344260
Location of Books and Records: 483 Bay Street, 8th Floor South Tower Toronto ON CA M5G 2P5	Canada Revenue Agency Business No. If applicable, enter: 87086 5821 RC0001
Name of person to contact regarding this CT23 Return: BRIAN SOARES — Telephone No.: (416) 345-6782 — Fax No.: (416) 345-6978	Jurisdiction Incorporated: Ontario
Address of Principal Office in Ontario *(Extra-Provincial Corporations only)* (MGS): Ontario Canada	If not incorporated in Ontario, indicate the date Ontario business activity commenced and ceased: Commenced (year month day): Ceased (year month day): ☒ *Not Applicable*
Former Corporation Name *(Extra-Provincial Corporations only)* ☒ *Not Applicable* (MGS)	Preferred Language / *Langue de préférence*: ☒ English *anglais* ☐ French *français*
Information on Directors/Officers/Administrators must be completed on MGS Schedule A or K as appropriate. If additional space is required for Schedule A, only this schedule may be photocopied. State number submitted (MGS). No. of Schedule(s):	Ministry Use
If there is **no** change to the Directors'/Officers'/Administrators' information previously submitted to MGS, please check (X) this box. Schedule(s) A and K are not required (MGS). ☒ No Change	

Certification (MGS)

I certify that all information set out in the **Annual Return** is true, correct and complete.

Name of Authorized Person *(Print clearly or type in full)*

Title: D ☐ Director O ☐ Officer P ☒ Other individuals having knowledge of the Corporation's business activities

Note: Sections 13 and 14 of the *Corporations Information Act* provide penalties for making false or misleading statements or omissions.

CT23 Corporations Tax Return

Identification continued (for CT23 filers only)

Please check applicable (X) box(es) and complete required information.

Type of corporation

1

1 [X] Canadian-controlled Private (CCPC) all year (Generally a private corporation of which 50% or more shares are owned by Canadian residents.) (fed.s.125(7)(b))

2 [ ] Other Private

3 [ ] Public

4 [ ] Non-share Capital

5 [ ] Other *(specify)* ▼

Share Capital with full voting rights owned by Canadian Residents (nearest percent): 100 %

2

1 [ ] Family Farm corporation s.1(2)

2 [ ] Family Fishing corporation s.1(2)

3 [ ] Mortgage Investment corporation s.47

4 [ ] Credit Union s.51

5 [ ] Bank Mortgage subsidiary s.61(4)

6 [ ] Bank s.1(2)

7 [ ] Loan and Trust corporation s.61(4)

8 [ ] Non-resident corporation s.2(2)(a) or (b)

9 [ ] Non-resident corporation s.2(2)(c)

10 [ ] Mutual Fund corporation s.48

11 [ ] Non-resident owned Investment corporation s.49

12 [ ] Non-resident ship or aircraft under reciprocal agreement with Canada s.28(b)

14 [ ] Bare Trustee corporation

15 [ ] Branch of Non-resident s.63(1)

16 [ ] Financial institution prescribed by Regulation only

17 [ ] Investment Dealer

18 [ ] Generator of electrical energy for sale or producer of steam for use in the generation of electrical energy for sale

19 [X] Hydro successor, municipal electrical utility or subsidiary of either

20 [ ] Producer and seller of steam for uses other than for the generation of electricity

21 [ ] Insurance Exchange s.74.4

22 [ ] Farm Feeder Finance Co-operative corporation

23 [ ] Professional corporation (incorporated professionals only)

[ ] This is the first year filing after incorporation or an amalgamation (If checked, attach Ontario Schedule 24.)

[ ] Amended Return

[ ] Taxation year end change – Canada Revenue Agency approval required

[ ] Final taxation year up to dissolution *(Note: for discontinued businesses, see guide.)*

[ ] Final taxation year before amalgamation

[ ] The corporation has a floating fiscal year end

[ ] There has been a transfer or receipt of asset(s) involving a corporation having a Canadian permanent establishment outside Ontario

[ ] There was an acquisition of control to which subsection 249(4) of the federal *Income Tax Act* (ITA) applies since the previous taxation year

If checked, date control was acquired: year ___ month ___ day ___

[ ] The corporation was involved in a transaction where all or substantially all (90% or more) of the assets of a non-arm's length corporation were received in the taxation year and subsection 85(1) or 85(2) of the federal ITA applied to the transaction (If checked, attach Ontario Schedule 44.)

[ ] First year filing of a parent corporation after winding-up a subsidiary corporation(s) under section 88 of the federal ITA during the taxation year. (If checked, attach Ontario Schedule 24.)

[ ] Section 83.1 of the CTA applies (redirection of payments for certain electricity corporations)

Yes	No	
[ ]	[X]	Was the corporation inactive throughout the taxation year?
[X]	[ ]	Has the corporation's Federal T2 Return been filed with the Canada Revenue Agency?
		Are you requesting a refund due to:
[ ]	[X]	the Carry-back of a Loss?
[ ]	[X]	an Overpayment?
[ ]	[X]	a Specified Refundable Tax Credit?
[ ]	[X]	Are you a member of a Partnership or Joint Venture?

Complete if applicable

Ontario Retail Sales Tax Vendor Permit no. (Use head office no.):

Ontario Employer Health Tax Account no. (Use head office no.):

Specify major business activity

Trans & Dist

of Electricity

Allocation – If you carry on a business through a permanent establishment in a jurisdiction outside Ontario, you may allocate that portion of taxable income deemed earned in that jurisdiction to that jurisdiction (s.39) (Int.B. 3008).

DOLLARS ONLY

Net Income (loss) for Ontario purposes (per reconciliation schedule, page 15)	±	From 690	545,419,25(
Subtract: Charitable donations	–	1	
Subtract: Gifts to Her Majesty in right of Canada or a province and gifts of cultural property *(Attach schedule 2)*	–	2	
Subtract: Taxable dividends deductible, per federal Schedule 3	–	3	
Subtract: Ontario political contributions *(Attach Schedule 2A)* (Int.B. 3002R)	–	4	
Subtract: Federal Part VI.1 tax ____ x 3	–	5	
Subtract: Prior years' losses applied – Non-capital losses	–	From 704	
Net capital losses (page 16) From 715 ____ x inclusion rate 50.000000 % =	–	714	
Farm losses	–	From 724	
Restricted farm losses	–	From 734	
Limited partnership losses	–	From 754	
Taxable Income (Non-capital loss)	=	10	545,419,256

Addition to taxable income for unused foreign tax deduction for federal purposes + 11 ____

Adjusted Taxable Income 10 + 11 (if 10 is negative, enter 11) = 20 545,419,256

Taxable Income

Number of Days in Taxation Year

From 10 (or 20 if applicable) 545,419,256 x 30 100.0000 % (Ontario Allocation) x 12.5 % x (Days after Dec. 31, 2002 and before Jan. 1, 2004) 33 ____ ÷ (Total Days) 73 365 = + 29 ____

From 10 (or 20 if applicable) 545,419,256 x 30 100.0000 % (Ontario Allocation) x 14 % x (Days after Dec. 31, 2003) 34 365 ÷ (Total Days) 73 365 = + 32 76,358,696

Income Tax Payable (before deduction of tax credits) 29 + 32 = 40 76,358,696

Incentive Deduction for Small Business Corporations (IDSBC) (s.41)

If this section is not completed, the IDSBC will be denied.

Did you claim the federal Small Business Deduction (fed.s.125(1)) in the taxation year or would you have claimed the federal Small Business Deduction had the provisions of fed.s.125(5.1) not been applicable in the taxation year? (X) ☐ Yes ☒ No

* Income from active business carried on in Canada for federal purposes (fed.s.125(1)(a)) 50 ____

Federal taxable income, less adjustment for foreign tax credit (fed.s.125(1)(b)) + 51 ____

Add: Losses of other years deducted for federal purposes (fed.s.111) + 52 ____

Subtract: Losses of other years deducted for Ontario purposes (s.34) – 53 ____

= ____ ▶ 54 ____

Federal Business limit (line 410 of the T2 Return) for the year before the application of fed.s.125(5.1) 55 ____

Ontario Business Limit Calculation

320,000 x (Days after Dec. 31, 2002 and before Jan. 1, 2004) 31 ____ ÷ ** 365 = + 46 ____

400,000 x (Days after Dec. 31, 2003) 34 365 ÷ ** 365 = + 47 400,000

Business Limit for Ontario purposes 46 + 47 = 44 400,000 x (Percentage of Federal Business limit (from T2 Schedule 23). Enter 100% if not associated.) 48 100.0000 % = 45 400,000

Income eligible for the IDSBC From 30 100.0000 % (***Ontario Allocation) x 56 ____ (Least of 50, 54 or 45) = 60 ____

* *Note: Modified by s.41(6) and (7) for corporations that are members of a partnership. (Refer to Guide.)*

** *Note: Adjust accordingly for a floating taxation year and use 366 for a leap year.*

*** *Note: Ontario Allocation for IDSBC purposes may differ from* 30 *if Taxable Income is allocated to foreign jurisdictions. See special rules (s.41(4)).*

continued on Page 5

Income Tax *continued from Page 4*

Number of Days in Taxation Year

Calculation of IDSBC Rate 7 % x [31] (Days after Dec. 31, 2002 and before Jan. 1, 2004) ÷ [73] 365 (Total Days) = + [89] .

8.5 % x [34] 365 (Days after Dec. 31, 2003) ÷ [73] 365 (Total Days) = + [90] 8.5000

IDSBC Rate for Taxation Year [89] + [90] = [78] 8.5000

Claim From [60] . x From [78] 8.5000 % = [70] .

Corporations claiming the IDSBC must complete the Surtax section below if the corporation's taxable income (or if associated, the associated group's taxable income) is greater than the amount 400,000 in [114] below.

Surtax on Canadian-controlled Private Corporations (s.41.1)

Applies if you have claimed the Incentive Deduction for Small Business Corporations.

Associated Corporation - The Taxable Income of associated corporations is the taxable income for the taxation year ending on or before the date of this corporation's taxation year end.

***Taxable Income of the corporation** From [10] (or [20] if applicable) + [80] 545,419,256 .

If you are a member of an associated group (X) [81] X (Yes)

Name of associated corporation (Canadian & foreign) *(if insufficient space, attach schedule)*	Ontario Corporations Tax Account No. (MOF) (if applicable)	Taxation Year End		* Taxable Income (if loss, enter nil)
See schedule			+ [82]	.
			+ [83]	.
			+ [84]	.

Aggregate Taxable Income [80] + [82] + [83] + [84], etc. = [85] 545,419,256 .

Number of Days in Taxation Year

320,000 x [31] (Days after Dec. 31, 2002 and before Jan. 1, 2004) ÷ [73] 365 (Total Days) = + [115] .

400,000 x [34] 365 (Days after Dec. 31, 2003) ÷ [73] 365 (Total Days) = + [116] 400,000 .

[115] + [116] = 400,000 . – [114] 400,000 .

(If negative, enter nil) = [86] 545,019,256 .

Number of Days in Taxation Year

Calculation of Specified Rate for Surtax 4.6670 % x [38] 365 (Days after Dec. 31, 2002) ÷ [73] 365 (Total Days) = + [97] 4.6670

From [86] 545,019,256 . x From [97] 4.6670 % = [87] 25,436,049 .

From [87] 25,436,049 . x From [60] . ÷ From [114] 400,000 . = [88] .

Surtax Lesser of [70] or [88] = [100]

**** Note: Short Taxation Years*** – Special rules apply where the taxation year is less than 51 weeks for the corporation and/or any corporation associated with it.

continued on Page 6

DOLLARS ONLY

Additional Deduction for Credit Unions (s.51(4)) *(Attach schedule 17)* - - - - - - - - - - - - - 110 ______

Manufacturing and Processing Profits Credit (M&P) (s.43)

Applies to Eligible Canadian Profits from manufacturing and processing, farming, mining, logging and fishing carried on in Canada, as determined by regulations.

Eligible Canadian Profits from mining are the "resource profits from the mining operations", as determined for Ontario depletion purposes, after deducting depletion and resource allowances but excluding amounts from sale of Canadian resource property, rentals or royalties. If you are claiming this credit, attach a copy of Ontario schedule 27.

The whole of the active business income qualifies as Eligible Canadian Profits if: **a)** your active business income from sources other than manufacturing and processing, mining, farming, logging or fishing is 20% or less of the total active business income and **b)** the total active business income is $250,000 or less.

Eligible Canadian Profits - + 120 ______ •

Subtract: Income eligible for the Incentive Deduction for Small Business Corporations (IDSBC) - - - - - - - - − From 56 ______ •

Add: Adjustment for Surtax on Canadian-controlled private corporations

From 100 ______ • ÷ From 30 100.0000 % ÷ From 78 8.5000 % = 121 ______ •

*Ontario Allocation

Lesser of 56 or 121 - + 122 ______ •

120 − 56 + 122 - = 130 ______ •

Taxable Income - + From 10 545,419,256 •

Subtract: Income eligible for the Incentive Deduction for Small Business Corporations (IDSBC) - - - - - - - - − From 56 ______ •

Add: Adjustments for Surtax on Canadian-controlled private corporations - - - - - - - - - - - - - - - + From 122 ______ •

Subtract: Taxable Income 10 545,419,256 X Allocation % to jurisdictions outside Canada ______% - - - − 140 ______ •

Subtract: Amount by which Canadian and foreign investment income exceeds net capital losses - - - - - - - - − 141 636,852 •

10 − 56 + 122 − 140 − 141 - = 142 544,782,404 •

Claim

Number of Days in Taxation Year

143 ______ • X From 30 100.0000 % X 1.5 % X (Days after Dec. 31, 2002 and before Jan. 1, 2004: 33 ______ ÷ Total Days: 73 365) = + 154 ______ •

Lesser of 130 or 142 — Ontario Allocation

143 ______ • X From 30 100.0000 % X 2 % X (Days after Dec. 31, 2003: 34 365 ÷ Total Days: 73 365) = + 156 ______ •

Lesser of 130 or 142 — Ontario Allocation

M&P claim for taxation year 154 + 156 - = 160 ______ •

***Note:** *Ontario Allocation for M&P Credit purposes may differ from* 30 *if Taxable Income is allocated to foreign jurisdictions. See special rules (s.43(1))*

Manufacturing and Processing Profits Credit for Electrical Generating Corporations = 161 ______ •

Manufacturing and Processing Profits Credit for Corporations that Produce and Sell Steam for uses other than the Generation of Electricity - - - - - - - - - - - = 162 ______ •

Credit for Foreign Taxes Paid (s.40)

Applies if you paid tax to a jurisdiction outside Canada on foreign investment income (Int.B. 3001R). *(Attach schedule).* - 170 ______ •

Credit for Investment in Small Business Development Corporations (SBDC)

Applies if you have an unapplied, previously approved credit from prior years' investments in new issues of equity shares in Small Business Development Corporations. Any unused portion may be carried forward indefinitely and applied to reduce subsequent years' income taxes. (Refer to the former *Small Business Development Corporations Act*)

Eligible Credit 175 ______ • Credit Claimed 180 ______ •

Subtotal of Income Tax 40 − 70 + 100 − 110 − 160 − 161 − 162 − 170 − 180 - - - - = 190 76,358,69(

continued on Page 7

Income Tax *continued from Page 6*

Specified Tax Credits *(Refer to Guide)*

Ontario Innovation Tax Credit (OITC) (s.43.3) ***Applies*** to scientific research and experimental development in Ontario.
Eligible Credit From [5620] OITC Claim Form *(Attach original Claim Form)* + [191] .

Co-operative Education Tax Credit (CETC) (s.43.4) ***Applies*** to employment of eligible students.
Eligible Credit From [5798] CT23 Schedule 113 *(Attach Schedule 113)* + [192] 225,753 .

Ontario Film & Television Tax Credit (OFTTC) (s.43.5)
Applies to qualifying Ontario labour expenditures for eligible Canadian content film and television productions. Name of Production [204]
Eligible Credit From [5850] of the Certificate of Eligibility issued by the Ontario Media Development Corporation (OMDC)
(Attach the original Certificate of Eligibility) + [193] .

Graduate Transitions Tax Credit (GTTC) (s.43.6) No. of Graduates From [6596]
Applies to employment of eligible unemployed post secondary graduates, for employment commencing prior to July 6, 2004 and expenditures incurred prior to January 1, 2005. [194]
Eligible Credit From [6598] CT23 Schedule 115 (*Attach Schedule 115*) + [195] .

Ontario Book Publishing Tax Credit (OBPTC) (s.43.7)
Applies to qualifying expenditures in respect of eligible literary works by eligible Canadian authors.
Eligible Credit From [6900] OBPTC Claim Form *(Attach **both** the original Claim Form and the Certificate of Eligibility)* + [196] .

Ontario Computer Animation and Special Effects Tax Credit (OCASE) (s.43.8)
Applies to labour relating to computer animation and special effects on an eligible production.
Eligible Credit From [6700] of the Certificate of Eligibility issued by the Ontario Media Development Corporation (OMDC)
(Attach the original Certificate of Eligibility) + [197] .

Ontario Business-Research Institute Tax Credit (OBRITC) (s.43.9)
Applies to qualifying R&D expenditures under an eligible research institute contract.
Eligible Credit From [7100] OBRITC Claim Form *(Attach original Claim Form)* + [198] .

Ontario Production Services Tax Credit (OPSTC) (s.43.10)
Applies to qualifying Ontario labour expenditures for eligible productions where the OFTTC has not been claimed.
Eligible Credit From [7300] of the Certificate of Eligibility issued by the Ontario Media Development Corporation (OMDC)
(Attach the original Certificate of Eligibility) + [199] .

Ontario Interactive Digital Media Tax Credit (OIDMTC) (s.43.11)
Applies to qualifying labour expenditures of eligible products for the taxation year.
Eligible Credit From [7400] of the Certificate of Eligibility issued by the Ontario Media Development Corporation (OMDC)
(Attach the original Certificate of Eligibility) + [200] .

Ontario Sound Recording Tax Credit (OSRTC) (s.43.12)
Applies to qualifying expenditures in respect of eligible Canadian sound recordings.
Eligible Credit From [7500] OSRTC Claim Form *(Attach **both** the original Claim Form and the Certificate of Eligibility)* + [201] .

Apprenticeship Training Tax Credit (ATTC) (s.43.13) No. of Apprentices From [5896]
Applies to employment of eligible apprentices. [202] 196
Eligible Credit From [5898] CT23 Schedule 114 (*Attach Schedule 114*) + [203] 812,762 .

Other (specify) + [203.1] .

Total Specified Tax Credits [191] + [192] + [193] + [195] + [196] + [197] + [198] + [199] + [200] + [201] + [203] + [203.1] = [220] 1,038,515 .

Specified Tax Credits ***Applied to reduce Income Tax*** = [225] 1,038,515 .

Income Tax [190] – [225] **OR Enter NIL if reporting Non-Capital Loss** *(amount cannot be negative)* = [230] 75,320,181 .

To determine if the Corporate Minimum Tax (CMT) is applicable to your Corporation, see **Determination of Applicability** section for the CMT on **Page 8.** If CMT is not applicable, transfer amount in [230] to Income Tax in **Summary** section on **Page 17.**

If CMT is not applicable for the current taxation year but your corporation has CMT Credit Carryovers that you want to apply to reduce income tax otherwise payable, then proceed to and complete the **Application of CMT Credit Carryovers** section part B, on **Page 8.**

Corporate Minimum Tax (CMT)

DOLLARS ONLY

Total Assets of the corporation	+ 240	11,364,755,229 •
Total Revenue of the corporation	+ 241	4,151,572,00(

The above amounts include the corporation's and associated corporations' share of any partnership(s) / joint venture(s) total assets and total revenue.

If you are a member of an associated group (X) 242 [ ] (Yes)

Name of associated corporation (Canadian & foreign) *(if insufficient space attach schedule)*	Ontario Corporations Tax Account No. (MOF) (if applicable)	Taxation Year End	Total Assets	Total Revenue
			+ 243 •	+ 244 •
			+ 245 •	+ 246 •
			+ 247 •	+ 248 •
Aggregate Total Assets 240 + 243 + 245 + 247, etc.			= 249 11,364,755,229 •	
Aggregate Total Revenue 241 + 244 + 246 + 248, etc.				= 250 4,151,572,000 •

Determination of Applicability

Applies if *either* Total Assets 249 exceeds $5,000,000 *or* Total Revenue 250 exceeds $10,000,000.

Short Taxation Years – Special rules apply for determining total revenue where the taxation year of the corporation or any associated corporation or any fiscal period of any partnership(s) / joint venture(s) of which the corporation or associated corporation is a member, is less than 51 weeks.

Associated Corporation – The total assets or total revenue of associated corporations is the total assets or total revenue for the taxation year ending on or before the date of the claiming corporation's taxation year end.

If CMT is applicable to current taxation year, complete section **Calculation: CMT** below and **Corporate Minimum Tax Schedule 101**.

Calculation: CMT *(Attach Schedule 101.)*

Gross CMT Payable - - CMT Base From Schedule 101 2136 588,008,811 • (If negative, enter zero) X From 30 100.0000 % (Ontario Allocation) X 4 % = 276 23,520,352 •

Subtract: Foreign Tax Credit for CMT purposes *(Attach Schedule)*	– 277	
Subtract: Income Tax	– From 190	76,358,696
Net CMT Payable (If negative, enter Nil on Page 17.)	= 280	-52,838,344 •

If 280 is less than zero and you do not have a CMT credit carryover, transfer 230 from **Page 7 to Income Tax Summary, on Page 17.**

If 280 is less than zero and you have a CMT credit carryover, complete A & B below.

If 280 is greater than or equal to zero, transfer 230 to **Page 17** and transfer 280 to **Page 17, and to Part 4 of Schedule 101: Continuity of CMT Credit Carryovers.**

CMT Credit Carryover available From Schedule 101 From 2333 •

Application of CMT Credit Carryovers

A.	Income Tax (before deduction of specified credits)			+ From 190	76,358,696 •
	Gross CMT Payable	+ From 276	23,520,352 •		
	Subtract: Foreign Tax Credit for CMT purposes	– From 277	•		
	If 276 – 277 is negative, enter NIL in 290	=	23,520,352 •	– 290	23,520,352 •
	Income Tax eligible for CMT Credit			= 300	52,838,344 •
B.	Income Tax (after deduction of specified credits)			+ From 230	75,320,181 •
	Subtract: CMT credit used to reduce income taxes			– 310	•
	Income Tax			= 320	75,320,181 •

Transfer to page 17

If A & B apply, 310 ***cannot exceed the lesser of*** 230, 300 ***and your CMT credit carryover available*** 2333.

If only B applies, 310 ***cannot exceed the lesser of*** 230 ***and your CMT credit carryover available*** 2333.

Capital Tax *(Refer to Guide and Int.B. 3011R)*

/our corporation is a Financial Institution (s.58(2)), complete lines 480 and 430 on page 10 then proceed to page 13.

If your corporation is not a member of an associated group and/or partnership and the Gross Revenue and Total Assets as calculated on page 10 in 480 and 430 are both $3,000,000 or less, your corporation is exempt from Capital Tax for the taxation year, except for a branch of a non-resident corporation. A corporation that meets these criteria should disregard all other Capital Tax items (including the calculation of Taxable Capital). Enter NIL in 550 on page 12 and complete the return from that point. All other corporations must compute their Taxable Capital in order to determine their Capital Tax payable.

Members of a partnership (limited or general) or a joint venture, must attach all financial statements of each partnership or joint venture of which they are a member. The Paid-up Capital of each corporate partner must include its share of liabilities that would otherwise be included if the partnership were a corporation. If Investment Allowance is claimed, Total Assets must be adjusted by adding the corporation's share of the partnership's Total Assets and by deducting investments in the partnership as it appears on the corporation's balance sheet, in addition to any other required adjustments (s.61(5)). Special rules apply to limited partnerships (Int.B. 3017R).

Any Assets and liabilities of a corporation that are being utilized in a joint venture must be included along with the corporation's other Assets and liabilities when calculating its Taxable Paid-up Capital.

Special rules and rates apply to Non-Resident corporations (s.63, s.64 and s.69(3)).

Paid-up Capital of Non-resident: Paid-up capital employed in Canada of a non-resident subject to tax by virtue of s.2(2)(a) or 2(2)(b), and whose **business is not carried on solely in Canada** is deemed to be the greater of (1) taxable Income in Canada divided by 8 percent or (2) total assets in Canada minus certain indebtedness in accordance with the provisions of s.63(1)(a) (Int.B. 3010).

Paid-up Capital

Paid-up capital stock (Int.B. 3012R and 3015R)	+	350	3,362,893,010
Retained earnings (if deficit, deduct) (Int.B. 3012R)	±	351	785,133,048
Capital and other surpluses, excluding appraisal surplus (Int.B.3012R)	+	352	4,107,012
Loans and advances *(Attach schedule)* (Int.B. 3013R)	+	353	5,698,687,971
Bank loans (Int.B. 3013R)	+	354	
Bankers acceptances (Int.B. 3013R)	+	355	
Bonds and debentures payable (Int.B. 3013R)	+	356	
Mortgages payable (Int.B. 3013R)	+	357	
Lien notes payable (Int.B. 3013R)	+	358	
Deferred credits (including income tax reserves, and deferred revenue where it would also be included in paid-up capital for the purposes of the large corporations tax) (Int.B. 3013R)	+	359	
ontingent, investment, inventory and similar reserves (Int.B. 3012R)	+	360	847,711,568
her reserves not allowed as deductions for income tax purposes *(Attach schedule)* (Int.B. 3012R)	+	361	
Share of partnership(s) or joint venture(s) paid-up capital *(Attach schedule(s))* (Int.B. 3017R)	+	362	
Subtotal	=	370	10,698,532,609
Subtract: Amounts deducted for income tax purposes in excess of amounts booked *(Retain calculations. Do not submit.)* (Int.B. 3012R)	–	371	1,369,940,011
Deductible R & D expenditures and ONTTI costs deferred for income tax if not already deducted for book purposes (Int.B. 3015R)	–	372	
Total Paid-up Capital	=	380	9,328,592,598
Subtract: Deferred mining exploration and development expenses (s.62(1)(d)) (Int.B. 3015R)	–	381	
Electrical Generating Corporations Only – All amounts with respect to electrical generating assets, except to the extent that they have been deducted by the corporation in computing its income for income tax purposes for the current or any prior taxation year, that are deductible by the corporation under clause 11(10)(a) of the *Corporations Tax Act*, and the assets are used both in generating electricity from a renewable or alternative energy source and are qualifying property as prescribed by regulation	–	382	
Net Paid-up Capital	=	390	9,328,592,598

Eligible Investments *(Refer to Guide and Int.B. 3015R)*

Attach computations and list of corporation names and investment amounts. Short-term investments (bankers acceptances, commercial paper, etc.) are eligible for the allowance only if issued for a term of and held for 120 days or more prior to the year end of the investor corporation.

Bonds, lien notes and similar obligations, (similar obligations, e.g. stripped interest coupons, applies to taxation years ending after October 30, 1998)	+	402	
Mortgages due from other corporations	+	403	
Shares in other corporations (certain restrictions apply) *(Refer to Guide)*	+	404	
Loans and advances to unrelated corporations	+	405	16,249,053
Eligible loans and advances to related corporations (certain restrictions apply) *(Refer to Guide)*	+	406	
Share of partnership(s) or joint venture(s) eligible investments *(Attach schedule)*	+	407	
tal Eligible Investments	=	410	16,249,053

continued on Page 10

Total Assets (Int.B. 3015R)

			DOLLARS ONLY
Total Assets per balance sheet	+	420	11,359,289,000
Mortgages or other liabilities deducted from assets	+	421	
Share of partnership(s)/joint venture(s) total assets *(Attach schedule)*	+	422	
Subtract: Investment in partnership(s)/joint venture(s)	−	423	
Total Assets as adjusted	=	430	11,359,289,000
Amounts in 360 and 361 (if deducted from assets)	+	440	
Subtract: Amounts in 371, 372 and 381	−	441	1,369,940,011
Subtract: Appraisal surplus if booked	−	442	
Add or Subtract: Other adjustments (specify on an attached schedule)	±	443	
Total Assets	=	450	9,989,348,989

Investment Allowance (410 ÷ 450) x 390 Not to exceed 410	=	460	15,174,242
Taxable Capital 390 − 460	=	470	9,313,418,356

Gross Revenue (as adjusted to include the share of any partnership(s)/joint venture(s) Gross Revenue)	480	4,151,572,000
Total Assets (as adjusted)	From 430	11,359,289,000

Calculation of Capital Tax for all Corporations except Financial Institutions

***Note:** This version (2006) of the CT23 may only be used for a taxation year that commenced after December 31, 2003.*

Financial Institutions use calculations on page 13.

Important: If the corporation is a family farm corporation, family fishing corporation or a credit union that is not a Financial Institution, complete only Section A below.

OR If the corporation is **not** a member of an associated group and/or partnership, complete Section B below, then review only the Capital Tax calculations in Section C below, selecting and completing the one specific subsection (e.g. C3) that applies to the corporation.

OR If the corporation **is** a member of an associated group and/or partnership, complete Section B below and Section D on page 11, and if applicable, complete Section E or Section F on page 12. Note: if the corporation is a member of a connected partnership, please refer to the CT23 Guide for additional instructions before completing the Capital Tax section.

SECTION A

This section applies only if the corporation is a family farm corporation, a family fishing corporation or a credit union that is not a Financial Institution (Int.B. 3018).

Enter NIL in 550 on page 12 and complete the return from that point.

SECTION B

Calculation of Taxable Capital Deduction (TCD)

Number of Days in Taxation Year

Amount		Days		Total Days			
5,000,000	x	35 (Days before Jan. 1, 2005)	÷ 73	365	= +	500	
7,500,000	x	36 (Days after Dec. 31, 2004 and before Jan. 1, 2006)	÷ 73	365	= +	501	
10,000,000	x	37 (Days after Dec. 31, 2005 and before Jan. 1, 2007) 365	÷ 73	365	= +	502	10,000,000

Taxable Capital Deduction (TCD) 500 + 501 + 502 = 503 10,000,000

SECTION C

This section applies if the corporation is **not a member of an associated group and/or partnership.**

C1. If 430 and 480 on page 10 are both $3,000,000 or less, enter NIL in 550 on page 12 and complete the return from that point.

C2. If Taxable Capital in 470 **is equal to or less than the TCD** in 503, enter NIL in 550 on page 12 and complete the return from that point.

C3. If Taxable Capital in 470 **exceeds the TCD** in 503, complete the following calculation and transfer the amount from 523 to 543 on page 12, and complete the return from that point.

+ From 470 ____

− From 503 ____

= 471 ____ x From 30 100.0000 % (Ontario Allocation) x 0.3 % x 555 365 (Days in taxation year) = + 523 ____

365 (366 if leap year) *If floating taxation year, refer to Guide.*

Transfer to 543 on page 12 and complete the return from that point

continued on Page 11

Capital Tax Calculation *continued from Page 10*

SECTION D

This section applies ONLY to a corporation that is a member of an associated group (excluding Financial Institutions and corporations exempt from Capital Tax) and/or partnership. You must check either 509 or 524 and complete this section before you can calculate your Capital Tax Calculation under either Section E or Section F.

D1. [ ] 509 (X if applicable) All corporations that you are associated with do **not** have a permanent establishment in Canada.

If Taxable Capital 470 on page 10 is equal to or less than the TCD 503 on page 10, enter NIL in 550 on page 12 and complete the return from that point.

If Taxable Capital 470 on page 10 exceeds the TCD 503 on page 10, proceed to **Section E**, enter the TCD amount in 542 in Section E, and complete Section E and the return from that point.

D2. [X] 524 (X if applicable) One or more of the corporations that you are associated with **maintains** a permanent establishment in Canada.

You and your associated group may continue to allocate the TCD by completing the Calculation below. Or, the associated group **may file an election** under subsection 69(2.1) of the *Corporations Tax Act*, whereby total assets are used to allocate the TCD among the associated group. Once a ss.69(2.1) election is filed, all members of the group will then be required to file in accordance with the election and allocate a portion (portion is henceforth referred to as **Net Deduction**) of the capital tax effect relating to the TCD to each corporation in the group on the basis of the ratio that each corporation's total assets multiplied by its Ontario allocation is to the total assets of the group.

The total asset amounts and Ontario allocation percentages to be used for this calculation must be taken from each corporation's financial information from its last taxation year ending in the immediately preceding calendar year.

In addition, although each corporation in the associated group may deduct its Net Deduction amount as apportioned by the total asset formula, the group may, at the group's option, reallocate the group's total Net Deduction among the group on what ever basis the corporate group wishes, as long as the total of the reallocated amounts does not exceed the group's total Net Deduction amount originally calculated for the associated group.

Calculation

Do **not** complete this calculation if ss.69(2.1) election is filed

Taxable Capital From 470 on page 10 . . . . . + From 470 9,313,418,356

Determine aggregate taxable capital of an associated group (excluding financial institutions and corporations exempt from capital tax) and/or partnership having a permanent establishment in Canada

Names of associated corporations (excluding Financial Institutions and corporations exempt from Capital Tax) having a permanent establishment in Canada *(if insufficient space, attach schedule)*	Ontario Corporations Tax Account No. (MOF) (if applicable)	Taxation Year End		Taxable Capital
See schedule			+ 531	455,682,589
			+ 532	
			+ 533	

Aggregate Taxable Capital 470 + 531 + 532 + 533, etc. . . . . . = 540 9,769,100,945

If 540 above is equal to or less than the TCD 503 on page 10, the corporation's Capital Tax for the taxation year, is NIL.

Enter NIL in 523 in section E on page 12, as applicable.

If 540 above is greater than the TCD 503 on page 10, the corporation must compute its share of the TCD below in order to calculate its Capital Tax for the taxation year under Section E on page 12.

From 470 9,313,418,356 ÷ From 540 9,769,100,945 x From 503 10,000,000 = 541 9,520,897

Transfer to 542 in Section E on page 12

Ss.69(2.1) Election Filed

[ ] 591 (X if applicable) **Election filed.** *Attach a copy of Schedule 591 with this CT23 Return.* Proceed to **Section F** on page 12.

continued on Page 12

DOLLARS ONLY

Capital Tax Calculation *continued from Page 11*

SECTION E

This section applies if the corporation is a member of an associated group and/or partnership whose total aggregate Taxable Capital [540] on page 11 exceeds the TCD [503] on page 10.

Complete the following calculation and transfer the amount from [523] to [543], and complete the return from that point.

+ From [470]	9,313,418,356 •						**Total Capital Tax for the taxation year**
− [542]	9,520,897 •				Days in taxation year		
= [471]	9,303,897,459 •	x From [30] 100.0000 % Ontario Allocation	x	0.3 %	x [555] 365 / 365* (366 if leap year)	= + [523]	27,911,692 •
							Transfer to [543] *and complete the return from that point*

SECTION F

This section applies if a corporation is a member of an associated group and the associated group has filed a ss.69(2.1) election

+ From [470]	•	x From [30] 100.0000 % Ontario Allocation	x	0.3 %	= + [561]	•
− Capital tax deduction from [995] relating to **your corporation's** Capital Tax deduction, on Schedule 591					− From [995]	•
					= [562]	•
						Total Capital Tax for the taxation year
Capital Tax	[562] •	x	Days in taxation year [555] 365 / 365* (366 if leap year)		= [563]	•
						Transfer to [543] *and complete the return from that point*

* *If floating taxation year, refer to Guide.*

Capital Tax before application of specified credits	= [543]	27,911,692 •
Subtract: Specified Tax Credits applied to reduce capital tax payable *(Refer to Guide)*	− [546]	•
Capital Tax [543] − [546] *(amount cannot be negative)*	= [550]	27,911,692 •
		Transfer to Page 17

continued on Page 13

Capital Tax *continued from Page 12*

Calculation of Capital Tax for Financial Institutions

1.1 Credit Unions only

For taxation years commencing **after May 4, 1999** enter NIL in [550] on page 12, and complete the return from that point.

1.2 Other than Credit Unions

(Retain details of calculations for amounts in boxes [565] and [570]. Do not submit with this tax return.)

[565] ________ x 0.6 % x From [30] 100.0000 % (Ontario Allocation) x [555] 365 (Days in taxation year) ÷ * 365 (366 if leap year) = + [569] ________

Lesser of adjusted Taxable Paid Up Capital and Basic Capital Amount in accordance with Division B.1

[570] ________ x [571] ________ (Capital Tax Rate *(Refer to Guide)*) x From [30] 100.0000 % (Ontario Allocation) x [555] 365 (Days in taxation year) ÷ * 365 (366 if leap year) = + [574] ________

Adjusted Taxable Paid Up Capital in accordance with Division B.1 in excess of Basic Capital Amount

Capital Tax for Financial Institutions – other than Credit Unions (before Section 2) [569] + [574] = [575] ________

* *If floating taxation year, refer to Guide.*

Small Business Investment Tax Credit

(Retain details of eligible investment calculation and, if claiming an investment in CSBIF, retain the original letter approving the credit issued in accordance with the Community Small Business Investment Fund Act. Do not submit with this tax return.)

Allowable Credit for Eligible Investments – [585] ________

Financial Institutions: Claiming a tax credit for investment in Community Small Business Investment Fund (CSBIF)? (X) ☐ Yes

Capital Tax - Financial Institutions [575] – [585] = [586] ________

Transfer to [543] on Page 12

Premium Tax (s.74.2 & 74.3) *(Refer to Guide)*

(1) Uninsured Benefits Arrangements [587] ________ x 2 % = [588] ________
Applies to Ontario-related uninsured benefits arrangements.

(2) Unlicensed Insurance (enter premium tax payable in [588] and attach a detailed schedule of calculations. If subject to tax under (1) above, add both taxes together and enter total tax in [588].)
Applies to Insurance Brokers and other persons placing insurance for persons resident or property situated in Ontario with unlicensed insurers.

Deduct: Specified Tax Credits applied to reduce premium tax *(Refer to Guide)* – [589] ________

Premium Tax [588] – [589] = [590] ________
Transfer to page 17

DOLLARS ONLY

Reconcile net income (loss) for federal income tax purposes with net income (loss) for Ontario purposes if amounts differ

Net Income (loss) for federal income tax purposes, per federal T2 Schedule 1 ± [600] 545,572,415. *Transfer to Page 15*

Add:

Federal capital cost allowance	+ [601]	481,880,414
Federal cumulative eligible capital deduction	+ [602]	9,145,676
Ontario taxable capital gain	+ [603]	636,852
Federal non-allowable reserves. Balance beginning of year	+ [604]	880,775,268
Federal allowable reserves. Balance end of year	+ [605]	
Ontario non-allowable reserves. Balance end of year	+ [606]	989,863,029
Ontario allowable reserves. Balance beginning of year	+ [607]	
Federal exploration expenses (e.g. CEDE, CEE, CDE, COGPE)	+ [608]	
Federal resource allowance *(Refer to Guide)*	+ [609]	
Federal depletion allowance	+ [610]	
Federal foreign exploration and development expenses	+ [611]	
All Crown charges, royalties, rentals, etc. deducted for Federal purposes *(Refer to Guide)*	+ [617]	

Management fees, rents, royalties and similar payments to non-arms' length non-residents ▼

Number of Days in Taxation Year

[612] ________ × 5 / 12.5 × ([33] Days after Dec. 31, 2002 and before Jan. 1, 2004 ________ ÷ [73] Total Days 365) = + [633] ________

[612] ________ × 5 / 14 × ([34] Days after Dec. 31, 2003 365 ÷ [73] Total Days 365) = + [634] ________

Total add-back amount for Management fees, etc. [633] + [634] = ________ ▶ + [613] ________

Federal Scientific Research Expenses claimed in year from line [460] of fed. form T661 excluding any negative amount in [473] from Ont. CT23 Schedule 161 + [615] ________

Add any negative amount in [473] from Ont. CT23 Schedule 161 + [616] ________

Federal allowable business investment loss + [620] ________

Total of other items not allowed by Ontario but allowed federally *(Attach schedule)* + [614] ________

Total of Additions [601] to [611] + [617] + [613] + [615] + [616] + [620] + [614] = 2,362,301,239 ▶ [640] 2,362,301,239. *Transfer to Page 15*

Deduct:

Ontario capital cost allowance (excludes amounts deducted under [675])	+ [650]	481,880,414
Ontario cumulative eligible capital deduction	+ [651]	9,145,676
Federal taxable capital gain	+ [652]	636,852
Ontario non-allowable reserves. Balance beginning of year	+ [653]	880,775,268
Ontario allowable reserves. Balance end of year	+ [654]	
Federal non-allowable reserves. Balance end of year	+ [655]	989,863,029
Federal allowable reserves. Balance beginning of year	+ [656]	
Ontario exploration expenses (e.g. CEDE, CEE, CDE, COGPE) *(Retain calculations. Do not submit.)*	+ [657]	
Ontario depletion allowance	+ [658]	
Ontario resource allowance *(Refer to Guide)*	+ [659]	
Ontario current cost adjustment *(Attach schedule)*	+ [661]	
CCA on assets used to generate electricity from natural gas, alternative or renewable resources.	+ [675]	

Subtotal of deductions for this page [650] to [659] + [661] + [675] [681] 2,362,301,239. *Transfer to Page 15*

continued on Page 15

Reconcile net income (loss) for federal income tax purposes with net income (loss) for Ontario purposes if amounts differ

Continued from Page 14

Net Income (loss) for federal income tax purposes, per federal Schedule 1 - - - From ± [600] 545,572,415 .

Total of Additions on page 14 - - - From = [640] 2,362,301,239 .

Sub Total of deductions on page 14 - - - From = [681] 2,362,301,239 .

Deduct:

Ontario New Technology Tax Incentive (ONTTI) Gross-up
(*Applies* only to those corporations whose Ontario allocation is less than 100% in the current taxation year.)

Capital Cost Allowance (Ontario) (CCA) on prescribed qualifying intellectual property deducted in the current taxation year - - - [662] ______ .

ONTTI Gross-up deduction calculation:

Gross-up of CCA

[From [662] ______ . x 100 / From [30] 100.0000 Ontario Allocation] – From [662] ______ . = [663] ______ .

Workplace Child Care Tax Incentive (WCCT)
(*Applies* to eligible expenditures incurred prior to January 1, 2005.)

Qualifying expenditures: [[665] ______ . x 30 % x 100 / From [30] 100.0000 Ontario allocation] = [666] ______ .

Workplace Accessibility Tax Incentive (WATI)
(*Applies* to eligible expenditures incurred prior to January 1, 2005.)

Qualifying expenditures: [[667] ______ . x 100 % x 100 / From [30] 100.0000 Ontario allocation] = [668] ______ .

Number of Employees accommodated [669] ______

Ontario School Bus Safety Tax Incentive (OSBSTI)
(*Applies* to the eligible acquisition of school buses purchased after May 4, 1999 and before January 1, 2006.) *(Refer to Guide)*

Qualifying expenditures: [[670] ______ . x 30 % x 100 / From [30] 100.0000 Ontario allocation] = [671] ______ .

Educational Technology Tax Incentive (ETTI)
(*Applies* to eligible expenditures incurred prior to January 1, 2005.)

Qualifying expenditures: [[672] ______ . x 15 % x 100 / From [30] 100.0000 Ontario allocation] = [673] ______ .

Ontario allowable business investment loss - - - + [678] ______ .

Ontario Scientific Research Expenses claimed in year in [477] from Ont. CT23 Schedule 161 + [679] ______ .

Amount added to income federally for an amount that was negative on federal form T661, line 454 or 455 (if filed after June 30, 2003) - - - + [677] 153,159 .

Total of other deductions allowed by Ontario *(Attach schedule)* - - - + [664] ______ .

Total of Deductions [681] + [663] + [666] + [668] + [671] + [673] + [678] + [679] + [677] + [664] = 2,362,454,398 . ▶ [680] 2,362,454,398 .

Net income (loss) for Ontario Purposes [600] + [640] – [680] - - - = [690] 545,419,256 .
Transfer to Page 4

DOLLARS ONLY

Continuity of Losses Carried Forward

		Non-Capital Losses (1)	Total Capital Losses	Farm Losses	Restricted Farm Losses	Listed Personal Property Losses	Limited Partnership Losses (6)
Balance at Beginning of Year		700 (2)	710 (2)	720 (2)	730	740	750
Add:	Current year's losses (7)	701	711	721	731	741	751
	Losses from predecessor corporations (3)	702	712	722	732		752
Subtotal		703	713	723	733	743	753
Subtract:	Utilized during the year to reduce taxable income	704 (2)	715 (2)(4)	724 (2)	734 (2)(4)	744 (4)	754 (4)
	Expired during the year	705		725	735	745	
	Carried back to prior years to reduce taxable income (5)	706 (2) to Page 17	716 (2) to Page 17	726 (2) to Page 17	736 (2) to Page 17	746	
Subtotal		707	717	727	737	747	757
Balance at End of Year		709 (8)	719	729	739	749	759

Analysis of Balance at End of Year by Year of Origin

	Year of Origin (oldest year first) year month day	Non-Capital Losses	Non-Capital Losses of Predecessor Corporations	Total Capital Losses from Listed Personal Property only	Farm Losses	Restricted Farm Losses
800	9th preceding taxation year 1998-03-31	817 (9)	860 (9)		850	870
801	8th preceding taxation year 1999-03-31	818 (9)	861 (9)		851	871
802	7th preceding taxation year 1999-12-31	819 (9)	862 (9)		852	872
803	6th preceding taxation year 2000-12-31	820	830	840	853	873
804	5th preceding taxation year 2001-12-31	821	831	841	854	874
805	4th preceding taxation year 2002-12-31	822	832	842	855	875
806	3rd preceding taxation year 2003-12-31	823	833	843	856	876
807	2nd preceding taxation year 2004-12-31	824	834	844	857	877
808	1st preceding taxation year 2005-12-31	825	835	845	858	878
809	Current taxation year 2006-12-31	826	836	846	859	879
Total		829	839	849	869	889

Notes:

(1) Non-capital losses include allowable business investment losses, fed.s.111(8)(b), as made applicable by s.34.

(2) Where acquisition of control of the corporation has occurred, the utilization of losses can be restricted. See fed.s.111(4) through 111(5.5), as made applicable by s.34.

(3) Includes losses on amalgamation (fed.s.87(2.1) and s.87(2.11)) and/or wind-up (fed.s.88(1.1) and 88(1.2)), as made applicable by s.34.

(4) To the extent of applicable gains/income/at-risk amount only.

(5) Generally a three year carry-back applies. See fed.s.111(1) and fed.s.41(2)(b), as made applicable by s.34.

(6) Where a limited partner has limited partnership losses, attach loss calculations for each partnership.

(7) Include amount from 11 if taxable income is adjusted to claim unused foreign tax credit for federal purposes.

(8) Amount in 709 must equal total of 829 + 839.

(9) Include non-capital losses incurred in taxation years ending after March 22, 2004.

Request for Loss Carry-Back (s.80(16))

pplies to corporations requesting a reassessment of the return of one or more previous taxation years under s.80(16) with respect to one or more types of losses carried back.

- If, after applying a loss carry-back to one or more previous years, there is a balance of loss available to carry forward to a future year, it is the corporation's responsibility to claim such a balance for those years following the year of loss within the limitations of fed.s.111, as made applicable by s.34.
- Where control of a corporation has been acquired by a person or group of persons, certain restrictions apply to the carry-forward and carry-back provisions of losses under fed.s.111(4) through 111(5.5), as made applicable by s.34.
- Refunds arising from the loss carry-back adjustment may be applied by the Minister of Finance to amounts owing under **any Act administered by the Ministry of Finance**.
- Any late filing penalty applicable to the return for which the loss is being applied will not be reduced by the loss carry-back.
- The application of a loss carry-back will be available for interest calculation purposes on the day that is the latest of the following:
  1) the first day of the taxation year after the loss year,
  2) the day on which the corporation's return for the loss year is delivered to the Minister, or
  3) the day on which the Minister receives a request in writing from the corporation to reassess the particular taxation year to take into account the deduction of the loss.
- If a loss is being carried back to a **predecessor corporation**, enter the predecessor corporation's account number and taxation year end in the spaces provided under Application of Losses below.

Application of Losses

	Predecessor Ontario Corporation's Tax Account No. (MOF)	Taxation Year Ending year month day	Non-Capital Losses	Total Capital Losses	Farm Losses	Restricted Farm Losses
Total amount of loss			910	920	930	940
Deduct: Loss to be carried back to preceding taxation years and applied to reduce taxable income						
i) 3rd preceding	901	2003-12-31	911	921	931	941
ii) 2nd preceding	902	2004-12-31	912	922	932	942
iii) 1st preceding	903	2005-12-31	913	923	933	943
Total loss to be carried back			From 706	From 716	From 726	From 736
Balance of loss available for carry-forward			919	929	939	949

Summary

Income Tax	+ From 230 or 320	75,320,181
Corporate Minimum Tax	+ From 280	
Capital Tax	+ From 550	27,911,692
Premium Tax	+ From 590	
Total Tax Payable	= 950	103,231,873
Subtract: Payments	– 960	104,555,674
Capital Gains Refund (s.48)	– 965	
Qualifying Environmental Trust Tax Credit *(Refer to Guide)*	– 985	
Specified Tax Credits *(Refer to Guide)*	– 955	
Other, specify	–	
Balance	= 970	-1,323,801
If payment due	Enclosed* 990	
If overpayment: Refund *(Refer to Guide)*	= 975	
Apply to year month day 2007-12-31	980	1,323,801 *(Includes credit interest)*

* Make your cheque (drawn on a Canadian financial institution) or a money order in Canadian funds, payable to the **Minister of Finance** and print your Ontario Corporation's Tax Account No. (**MOF**) on the back of cheque or money order. *(Refer to Guide for other payment methods.)*

Certification

I am an authorized signing officer of the corporation. I certify that this CT23 return, including all schedules and statements filed with or as part of this CT23 return, has been examined by me and is a true, correct and complete return and that the information is in agreement with the books and records of the corporation. I further certify that the financial statements accurately reflect the financial position and operating results of the corporation as required under section 75 of the *Corporations Tax Act*. The method of computing income for this taxation year is consistent with that of the previous year, except as specifically disclosed in a statement attached.

Name *(please print)*

VINCENT ALICANDRI

Title

Vice President, Corporate Tax

Full Residence Address

c/o 483 Bay Street
South Tower, 8th floor
Toronto,
ON CA M5G 2P5

Signature | Date

Note: Section 76 of the *Corporations Tax Act* provides penalties for making false or misleading statements or omissions.

Attached Schedule with Total

Amounts deducted for income tax purposes in excess of amounts booked (Retain calculations. Do not submit.) (Int.B. 3012R)

Title CT 23 Line 371

Description	Amount	
NBV	10197820432	00
Future Use Land	-63,168,977	00
Less: Land	-299,188,201	00
Less: Construction in progress	-463,399,144	00
UCC	-7,814,004,594	00
ECE	-121,506,832	00
Goodwill per F/S	-72,236,592	00
Unamortized ADS/DRS Hedges (304200)	11,638,334	00
LV revenue recoginized not received	32,515,963	00
Undeducted Prospectus & underwriting costs (book)	23,509,610	00
Undeducted Prospectus & underwriting costs (tax)	-6,663,540	00
Market Ready Deferral (275022)	13,197,993	00
1999 Permanent Difference	-46,717,962	00
2000 Permanent Difference	-2,672,096	00
2001 Permanent Difference	-18,093,905	00
2002 Permanent Difference	-392,946	00
2003 Permanent Difference	-265,897	00
2004 Permanent Difference	102,042	00
2005 Permanent Difference	-530,777	00
2006 Permanent Difference	-2,900	0
Total	1,369,940,011	00

Attached Schedule with Total

Loans and advances to unrelated corporations

Title Line 405 - CT23 - Supplementary Schedule

Description	Amount	
Trade receivables over 365 days	2,940,052	00
Prepaid OEB Costs (277960)	2,587,591	00
Prepaid insurance(277180)	341,393	00
Prepaid GWL insurance(277290)	1,298,688	00
Prepaid Inergi (277190)	9,081,329	00
Total	16,249,053	00

Attached Schedule with Total

Retained earnings (if deficit, deduct) **(Int.B.** 3012R)

Title Retained earnings (line 351)

Description	Amount	
Retained earnings, opening	553,457,107	00
Net income	427,144,424	00
Dividends	-195,468,483	00
Total	785,133,048	00

Attached Schedule with Total

Contingent, investment, inventory and similar reserves (Int.B. 3012R)

Title Contingent, investment, inventory and similar reserves (Int.B. 3012R)

Description	Amount	
Schedule 13 reserves	989,863,029	00
Rate Ryder 1	-55,313,945	00
Rate Ryder 2	-86,837,516	00
Total	847,711,568	00

Ontario Ministry of Finance
Corporations Tax Branch
PO Box 620
33 King Street West
Oshawa ON L1H 8E9

Paid-Up Capital: Loans and Advances

Corporation's Legal Name	Ontario Corporations Tax Account No. (MOF)	Taxation Year End
Hydro One Networks Inc.	1800029	2006-12-31

Loans or Advances Credited or Advanced to Corporation
(includes accounts payable to related parties outstanding at the taxation year end for 120 days or more, and accounts payable to non-related parties outstanding for 365 days or more at the taxation year end)

Inter-company demand facility (FS) A/C 356100	+	119,024,092
LT Debt payable within a year	+	340,000,000
Long term debt	+	5,169,000,000
Customer deposit (390000)	+	31,528,194
Mallett Refundable contribution (413300)	+	97,500
P/Port Amounts withheld from contracts (425001)	+	1,542,884
Prepayments (211820/810)	+	2,011,073
Dividends payable	+	5,113,529
Bond Premium unamortized net of discount (304100)	+	14,687,839
WSIB (451070)	+	8,864,985
Banked Vacation over 365 days(362100)	+	6,382,212
Capital Contribution Repayment (413720)	+	435,663
	+	
	+	
	+	
	+	
	+	
	+	
	+	
	+	
	+	
	+	
	+	
Total Transfer to 353 of the CT23	=	5,698,687,971

Ontario Ministry of Finance
Corporations Tax Branch
PO Box 620
33 King Street West
Oshawa ON L1H 8E9

Ontario Capital Cost Allowance
Schedule 8

Corporation's Legal Name	Ontario Corporations Tax Account No. (MOF)	Taxation Year End
Hydro One Networks Inc.	1800029	2006-12-31

Is the corporation electing under regulation 1101(5q)? 1 ☐ Yes 2 ☒ No

1 Class number	2 Ontario undepreciated capital cost at the beginning of the year (undepreciated capital cost at the end of the prior year's CCA schedule)	3 Cost of acquisitions during the year (new property must be available for use) See note 1 below	4 Net adjustments (show negative amounts in brackets)	5 Proceeds of dispositions during the year (amount not to exceed the capital cost)	6 Ontario undepreciated capital cost (column 2 plus column 3 or minus column 4 minus column 5)	7 50% rule (1/2 of the amount, if any, by which the net cost of acquisitions exceeds column 5) See note 2 below	8 Reduced undepreciated capital cost (column 6 minus column 7)	9 CCA rate %	10 Recapture of capital cost allowance	11 Terminal loss	12 Ontario capital cost allowance (column 8 multiplied by column 9; or a lower amount)	13 Ontario undepreciated capital cost at the end of the year (column 6 minus column 12)
1	5,265,396,883		-589,048	1,049,790	5,263,758,045		5,263,758,045	4	0	0	210,550,322	5,053,207,723
2	1,443,191,112			0	1,443,191,112		1,443,191,112	6	0	0	86,591,467	1,356,599,645
3	272,879,000	30,407,234		0	303,286,234	15,203,617	288,082,617	5	0	0	14,404,131	288,882,103
6	32,916,543	1,338,522		15,716	34,239,349	661,403	33,577,946	10	0	0	3,357,795	30,881,554
7	108,970			0	108,970		108,970	15	0	0	16,346	92,624
8	49,427,836	26,085,276		164,743	75,348,369	12,960,267	62,388,102	20	0	0	12,477,620	62,870,749
10	172,134,264	60,640,560		1,391,450	231,383,374	29,624,555	201,758,819	30	0	0	60,527,646	170,855,728
12	5,537,219	40,796,787		0	46,334,006	20,398,394	25,935,612	100	0	0	25,935,612	20,398,394
42	72,257,601	9,934,331		0	82,191,932	4,967,166	77,224,766	12	0	0	9,266,972	72,924,960
See schedule	378,505,304	468,718,885	-31,180,572		816,043,617	234,359,444	581,684,173				58,752,503	757,291,114
Totals	7,692,354,732	637,921,595	-31,769,620	2,621,699	8,295,885,008	318,174,846	7,977,710,162				481,880,414	7,814,004,594
								Enter in boxes	650	650	650	on the CT23.

Note 1. Include any property acquired in previous years that has now become available for use. This property would have been previously excluded from column 3. List separately any acquisitions that are not subject to the 50% rule. See Regulation 1100(2) and (2.2) of the *Income Tax Act* (Canada).

Note 2. The net cost of acquisitions is the cost of acquisitions plus or minus certain adjustments from column 4.

Note 3. If the taxation year is shorter than 365 days, prorate the CCA claim.

Note 4. Ontario recapture should be included in net income after deducting the federal recapture and the Ontario terminal loss is deducted from net income after including the federal terminal loss.

Ontario Capital Cost Allowance

Schedule 8

Corporation's Legal Name	Ontario Corporations Tax Account No. (MOF)	Taxation Year End
Hydro One Networks Inc.	1800029	2006-12-31

1 Class number	2 Ontario undepreciated capital cost at the beginning of the year (undepreciated capital cost at the end of the prior year's CCA schedule)	3 Cost of acquisitions during the year (new property must be available for use) See note 1 below	4 Net adjustments (show negative amounts in brackets)	5 Proceeds of dispositions during the year (amount not to exceed the capital cost)	6 Ontario undepreciated capital cost (column 2 plus column 3 or minus column 4 minus column 5)	7 50% rule (1/2 of the amount, if any, by which the net cost of acquisitions exceeds column 5) See note 2 below	8 Reduced undepreciated capital cost (column 6 minus column 7)	9 CCA rate %	10 Recapture of capital cost allowance	11 Terminal loss	12 Ontario capital cost allowance (column 8 multiplied by column 9; or a lower amount)	13 Ontario undepreciated capital cost at the end of the year (column 6 minus column 12)
17	13,205,891	1,961,166		0	15,167,057	980,583	14,186,474	8	0	0	1,134,918	14,032,139
9	1,473,167			0	1,473,167		1,473,167	25	0	0	368,292	1,104,875
35	489,608			0	489,608		489,608	7	0	0	34,273	455,335
45	15,391,799	12,778,171		0	28,169,970	6,389,086	21,780,884	45	0	0	9,801,398	18,368,572
46	3,182,606	16,235,548		0	19,418,154	8,117,774	11,300,380	30	0	0	3,390,114	16,028,040
13	1,918,828	316,013		0	2,234,841	158,007	2,076,834	N/A	0	0	346,139	1,888,702
47	342,843,405	437,427,987	-31,180,572	0	749,090,820	218,713,994	530,376,826	8	0	0	43,677,369	705,413,451
Totals	378,505,304	468,718,885	-31,180,572		816,043,617	234,359,444	581,684,173				58,752,503	757,291,114

Ontario Ministry of Finance
Corporations Tax Branch
PO Box 620
33 King Street West
Oshawa ON L1H 8E9

Ontario Cumulative Eligible Capital Deduction
Schedule 10

orporation's Legal Name	Ontario Corporations Tax Account No. (MOF)	Taxation Year End
Hydro One Networks Inc.	1800029	2006-12-31

- **For use by a corporation that has eligible capital property.**
- **A separate cumulative eligible capital account must be kept for each business.**

Part 1 – Calculation of current year deduction and carry-forward

Ontario Cumulative eligible capital – balance at end of preceding taxation year *(if negative, enter zero)*				130,644,309 A
Add: Cost of eligible capital property acquired during the taxation year	+	11,601 B		
Amount transferred on amalgamation or wind-up of subsidiary	+	C		
Other adjustments	+	D		
Total of B + C + D	=	11,601	x 3 / 4 =	8,701 E
Subtotal A + E			=	130,653,010 F
Deduct: Ontario proceeds of sales (less outlays and expenses not otherwise deductible) from the disposition of all eligible capital property during the taxation year	+	669 G		
The gross amount of a reduction in respect of a forgiven debt obligation as provided for in subsection 80(7) of the *Income Tax Act* (Canada)	+	H		
Other adjustments	+	I		
Total of G + H + I	=	669	x 3 / 4 =	502 J
Ontario cumulative eligible capital balance F - J			=	130,652,508 K

If K is negative, enter zero at line M and proceed to Part 2

Current year deduction 130,652,508 K x 7 % * = 9,145,676 L

* *The maximum current year deduction is 7%. However, you can claim any amount up to the maximum.*

Enter amount in box 651 *of the CT23*

ntario cumulative eligible capital – closing balance K - L *(if negative, enter zero)* = 121,506,832 M

Note: Any amount up to the maximum deduction of 7% may be claimed. Taxation years starting after December 21, 2000, the deduction may **not** exceed the maximum amount prorated for the number of days in the taxation year divided by 365 or 366 days.

Part 2 – Amount to be included in income arising from disposition

Only complete this part only if the amount at line K is negative

Amount from line K above *show as a positive amount*			N
Total cumulative eligible capital deductions from income for taxation years beginning after June 30, 1988		1	
Total of all amounts which reduced cumulative eligible capital in the current or prior years under subsection 80(7) of the ITA		2	
Total of cumulative eligible capital deductions claimed for taxation years beginning before July 1, 1988	3		
Negative balances in the cumulative eligible capital account that were included in income for taxation years beginning before July 1, 1988	4		
Line 3 deduct line 4		5	
Total lines 1 + 2 + 5		6	
Line T from previous Ontario Schedule 10 for taxation years ending after February 27, 2000		7	
Deduct line 7 from line 6			O
N - O *(cannot be negative)*			P
Amount on line 5 ____ x 1 / 2			Q
P - Q			R
Amount on line **R** ____ x 2 / 3			S
Lesser of line **N** or line **O**			T
mount to be included in income S + T			

Note: For taxation years ending after February 27, 2000 and before October 18, 2000 use 8/9 to calculate **S**

Ontario Ministry of Finance
Corporations Tax Branch
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Oshawa ON L1H 8E9

Ontario Continuity of Reserves
Schedule 13

Corporation's Legal Name	Ontario Corporations Tax Account No. (MOF)	Taxation Year End
Hydro One Networks Inc.	1800029	2006-12-31

For use by a corporation to provide a continuity of all reserves claimed which are allowed for tax purposes.

Part 1 – Capital gains reserves

Description of property	Ontario balance at the beginning of the year $	Transfer on amalgamation or wind-up of subsidiary $	Add	Deduct	Ontario balance at the end of the year $
1					
Totals	A	B			C

The total capital gains reserve at the beginning of the taxation year **A** plus the total capital gains reserve transfer on amalgamation or wind-up of subsidiary **B**, should be entered on Schedule 6; and the total capital gains reserve at the end of the taxation year **C**, should also be entered on Schedule 6.

Part 2 – Other reserves

Description	Ontario balance at the beginning of the year $	Transfer on amalgamation or wind-up of subsidiary $	Add	Deduct	Ontario balance at the end of the year $
Reserve for doubtful debts					
Reserve for undelivered goods and services not rendered					
Reserve for prepaid rent					
Reserve for December 31, 1995 income					
Reserve for refundable containers					
Reserve for unpaid amounts					
Other tax reserves					
Totals	D	E			F

The amount from **D** plus the amount from **E** should be entered in 607 of the CT23.
The amount from **F** should be entered in 654 of the CT23.

Part 3 – Continuity of non-deductible reserves

Reserve	Ontario opening balance	Transfers	Ontario additions	Ontario deductions	Other adjustments	Ontario closing balance
OPEB Liability Short Term	35,075,000					35,075,000
OPEB Liability Long Term	688,996,332		87,101,443			776,097,775
Enviromental Short Term	13,010,000			50,000		12,960,000
See schedule	196,540,819	-52,846,883	68,294,837	46,258,519		165,730,254
Reserves from Part 2						
Totals	933,622,151	-52,846,883	155,396,280	46,308,519		989,863,029
	Enter in box 653 *of the CT23*					*Enter in box* 606 *of the CT23*

Ontario Continuity of Reserves
Schedule 13

orporation's Legal Name	Ontario Corporations Tax Account No. (MOF)	Taxation Year End
Hydro One Networks Inc.	1800029	2006-12-31

Part 3 – Continuity of non-deductible reserves

Reserve	Ontario opening balance	Transfers	Ontario additions	Ontario deductions	Other adjustments	Ontario closing balance
Environmental Long Term	58,386,976			9,339,296		49,047,680
Contingent Liabilities	66,344,735			36,374,358		29,970,377
Deferred export Tx Svs Cr	32,050,051		16,709,121			48,759,172
RSVA Liabilities	37,518,166	-52,846,883	17,495,923			2,167,206
Tenant Inducement	2,240,891			544,865		1,696,026
Earnings Sharing - TX			34,089,793			34,089,793
Totals	196,540,819	-52,846,883	68,294,837	46,258,519		165,730,254

Ontario Ministry of Finance
Corporations Tax Branch
PO Box 620
33 King Street West
Oshawa ON L1H 8E9

Ontario Scientific Research and Experimental Development Expenditures CT23 Schedule 161

Corporation's Legal Name	Ontario Corporations Tax Account No. (MOF)	Taxation Year End
Hydro One Networks Inc.	1800029	2006-12-31

This schedule is used to calculate Ontario Scientific Research and Experimental Development Expenditures (SR & ED). The rules used in the calculation of Ontario SR & ED follow the federal rules with the exception of the new Ontario measure introduced in the 2001 Ontario Budget and implemented in Bill 127 which received Royal Assent on December 5, 2001.

This schedule must be completed by all corporations performing qualified Ontario SR & ED in a "specified taxation year" or in the taxation year immediately preceding the first specified taxation year of the corporation and filed with the current CT23 or CT8. Other corporations may use this schedule, if they have claimed or are claiming a different SR & ED amount for Ontario than for federal income tax purposes.

- **"Specified Taxation Year" (STY)** is the taxation year of the corporation that begins after February 29, 2000 **and** ends after December 31, 2000.
- **"Investment Tax Credit Amount" (ITC)** means, in respect of a corporation for a taxation year, an amount deducted by the corporation for a preceding taxation year under subsection 127(5) or (6) of the *Income Tax Act* (Canada) (ITA).
- **"Qualified Ontario SR & ED Expenditure" (QORD)** means,
  - A. A qualified expenditure within the meaning of subsection 12(1) of the *Corporations Tax Act* (CTA) that is made or incurred by a corporation in a STY or in the taxation year immediately preceding the first STY of the corporation, or
  - B. An expenditure made or incurred by a partnership in a fiscal period that ends in a STY of a corporation if,
    - the corporation is member of the partnership at any time in the STY, and
    - the expenditure would be a qualified expenditure within the meaning of subsection 12(1) of the CTA if it were made by a corporation.
- **"Ontario Allocation Factor" (OAF)** has the meaning given to that expression by subsection 12(1) of the CTA.

- If a corporation includes a federal ITC amount in determining the amount of the Ontario pool of deductible SR & ED expenditures for a STY, the following amounts are adjusted by the OAF:
  - Amount of recaptured federal ITC relating to QORD for property disposed of in the preceding taxation year in 442 on page 2.
  - Amount of federal ITC relating to QORD claimed federally in the preceding taxation year(s) in 462 on page 2.
  - Amount of federal ITC relating to QORD allocated from partnerships in the current taxation year in 465 on page 2.

- Federal ITCs earned on shared-use equipment (SUE) reduce the capital cost of the property acquired for federal and Ontario income tax purposes in the taxation year after the taxation year in which the ITC is claimed federally. The amount of the federal ITC that relates to QORD on SUE is added to the SR & ED pool for Ontario purposes in the taxation year after the taxation year in which the ITC is claimed federally.

Ontario Scientific Research and Experimental Development Expenditures CT23 Schedule 161

Corporation's Legal Name	Ontario Corporations Tax Account No. (MOF)	Taxation Year End
Hydro One Networks Inc.	1800029	2006-12-31

Ontario Pool of Deductible SR & ED Expenditures for the current taxation year

Total allowable SR & ED expenditures (capital and current) (From line 400 federal T661 (T2 SCH32))			+ 400	
Less: Government and non-government assistance (From line 430 federal T661 (T2 SCH32))			− 430	
Preceding year's amount of federal ITC claimed for SR & ED (From line 435 federal T661 (T2 SCH32))			− 435	153,159
Sale of SR & ED capital assets and other deductions (From line 440 federal T661 (T2 SCH32))			− 440	
Amount of recaptured federal ITC (From line 453 federal T661 (T2 SCH32)) relating to QORD for property disposed of in the preceding taxation year	442			
Gross-up for Ontario allocation factor From 442 [ ] ÷ 100.0000 % (From 30 of the CT23 or CT8)			− 444	
Subtotal: 400 − 430 − 435 − 440 − 444			= 445	-153,159
Add: Repayments of government and non-government assistance (From line 445 federal T661 (T2 SCH32))			+ 446	
SR & ED expenditure pool transferred on amalgamation or wind-up (From line 452 federal T661 (T2 SCH32))			+ 452	
Amount of federal ITC recaptured in the preceding taxation year (From line 453 federal T661 (T2 SCH32))			+ 453	
Preceding year's balance in pool of deductible Ontario SR & ED expenditures (From 480 of the preceding taxation year)			+ 460	
Federal ITC relating to QORD **claimed** federally in the preceding taxation year(s)	+ 462	153,159 (From 575 on Page 3)		
Amount of federal ITC relating to QORD allocated from partnerships in the current taxation year	+ 465			
Subtotal 462 + 465	= 468	153,159		
Gross-up for Ontario allocation factor From 468 [153,159] ÷ 100.0000 % (From 30 of the CT23 or CT8)			+ 470	153,159
Subtotal: 445 + 446 + 452 + 453 + 460 + 470 (If the amount in 473 is negative, enter zero, in 475, 477 and add 473 to 615 of the 2002 CT23 or CT8 or 616 of the 2003 or later CT23 or CT8. If the amount in 473 is positive, enter the amount in 475.)			= 473	
Amount available for deduction			= 475	
Deduction claimed in the taxation year for Ontario (Enter the SR & ED expenditure pool deduction claimed in the taxation year in 679 of the CT23 or CT8)			− 477	
Ontario current taxation year closing balance in pool of deductible SR & ED expenditures 475 − 477			= 480	

(Transfer this amount to 460 as the carry forward amount for the next taxation year.)

Ontario Scientific Research and Experimental Development Expenditures CT23 Schedule 161

Corporation's Legal Name	Ontario Corporations Tax Account No. (MOF)	Taxation Year End
Hydro One Networks Inc.	1800029	2006-12-31

Calculation of Preceding Taxation Year Amount and Account Balances - Federal ITC from SR & ED Expenditures relating to QORD.

- This page is used to calculate the amount of the federal ITC that relates to SR & ED performed in Ontario for certain taxation years and is used to increase the amount of the Ontario SR & ED pool on page 2.
- All amounts on this page are based on the preceding taxation year since the amount of the federal ITC that relates to QORD can only be used to increase the Ontario pool for SR & ED in the current taxation year if there was a federal ITC claimed for federal purposes in the preceding taxation year that related to QORD.
- **Do not include amounts** of federal ITCs that relate to QORD that were **allocated from a partnership.** These amounts are added to your SR & ED pool for Ontario in the taxation year that they are allocated from a partnership to a corporation, not in the year after they are claimed federally.

Opening Balance: (Enter amount 590 from Schedule 161 of the preceding taxation year, if any)	+	500	
Add: Amount of federal ITC earned, relating to QORD (QORD portion of line 540 federal T2 SCH31 for the preceding taxation year)	+	510	153,159.
Amount of federal ITC earned, relating to QORD, transferred on amalgamation or wind-up (QORD portion of line 530 federal T2 SCH31 for the preceding taxation year)	+	520	
Subtotal: 500 + 510 + 520	=	535	153,159.
Deduct: Amount of federal ITC, relating to QORD, claimed federally (QORD portion of line 560 federal T2 SCH31 for the preceding taxation year)	+	540	153,159
Amount of federal ITC, relating to QORD, carried back federally to a preceding taxation year(s) (QORD portion of line P federal T2 SCH31 for the preceding taxation year	+	550	
A refund of federal ITC, relating to QORD, claimed federally (QORD portion of line 610 federal T2 SCH31 for the preceding taxation year)	+	560	
Amount of federal ITC, relating to QORD, deemed as a remittance of co-op corporations (QORD portion of line 510 federal T2 SCH31 for the preceding taxation year)	+	570	
Subtotal: 540 + 550 + 560 + 570 (Transfer this amount to 462 on Page 2)	=	575	153,159.
Deduct: Amount of federal ITC, relating to QORD, expired per the ITA after 10 taxation years (QORD portion of line 515 federal T2 SCH31 for the preceding taxation year)	–	580	
Closing Balance: 535 – 575 – 580 (Transfer this amount to 500 as the opening balance for the next taxation year.)	=	590	

Ontario Scientific Research and Experimental Development Expenditures CT23 Schedule 161

orporation's Legal Name	Ontario Corporations Tax Account No. (MOF)	Taxation Year End
Hydro One Networks Inc.	1800029	2006-12-31

Continuity Schedule for Federal ITC relating to SR & ED Expenditures for the Preceding Taxation Year

- All amounts on this page are based on the preceding taxation year.
- Amounts on this page should tie into Part 11 of federal T2 SCH31 completed for the preceding taxation year.

Yr. of Origin (Oldest yr. first) yyyy mm dd	Opening Balance	Additions	Deductions (other than amounts that were allocated from a partnership)	Deductions (only amounts that were allocated from a partnership)	Closing Balance
1996-03-31					
1997-03-31					
1998-03-31					
1999-03-31					
1999-12-31					
2000-12-31					
2001-12-31					
2002-12-31					
2003-12-31					
2004-12-31					
2005-12-31		153,159	153,159		
Totals (see note 1, 2 and 3)	725	740 153,159	755 153,159	770	785

otes:

1. The amount in 725 should equal the amount of the investment tax credit at the end of the preceding taxation year less line 515 in Part 12 of the federal T2 SCH31 for the preceding taxation year.
2. The amount in 785 should equal the closing balance in line 620 in Part 12 of the federal T2 SCH31 for the preceding taxation year.
3. It is important that the amounts in the deductions columns on this page correctly reflect the year of origin of the federal ITC claimed because only amounts relating to QORD can be used to increase the Ontario SR & ED pool.

Ontario Scientific Research and Experimental Development Expenditures
CT23 Schedule 161

Corporation's Legal Name	Ontario Corporations Tax Account No. (MOF)	Taxation Year End
Hydro One Networks Inc.	1800029	2006-12-31

Continuity Schedule for the Amount of Federal ITC from SR & ED Expenditures relating to QORD for the Preceding Taxation Year

- This page is required to record the amount of the ITC that relates to QORD by year of origin.
- All amounts on this page are based on the preceding taxation year.
- **Do not** include amounts of federal ITCs that relate to QORD that were **allocated from a partnership** (see text at the top of page 3).

Yr. of Origin (Oldest yr. first) yyyy mm dd	Opening Balance	Additions	Deductions	Closing Balance
2000-12-31				
2001-12-31				
2002-12-31				
2003-12-31				
2004-12-31				
2005-12-31		153,159	153,159	
Totals (see note 1 - 6)	825	840 153,159	855 153,159	870

Notes:

1. The amount in 825 should equal 500 on page 3.
2. The amount in 840 should equal the total of 510 and 520 on page 3.
3. The amount in 855 should equal 575 on page 3.
4. The amount in 870 should equal 590 on page 3.
5. Any deductions that are recorded in the deduction column on this page must be taken out of the same year of origin as indicated in the deduction column on page 4. These deductions must be related to QORD and must not have been allocated from a partnership.
6. The amount of federal ITC relating to QORD will expire if the federal ITC it relates to expires before it is claimed federally.

HYDRO ONE NETWORKS INC.
DISTRIBUTION
Calculation of Utility Income Taxes
Historic Years
2006 Networks Tax Return Allocation to TX and DX
Year Ending December 31
($ Millions)

Line No.	Particulars		NETWORKS		TX		DX
	Calculation of Federal and ON Taxable Income						
1	Net Income Before Tax (NIBT)	$	588.0	$	415.2	$	172.8
2	Required Adjustments to accounting NIBT						
3	Recurring items included in Revenue Requirement (RR):						
4	Other Post Employment Benefit expense		70.2		31.2		39.0
5	Other Post Employment Benefit payments		(31.8)		(13.8)		(18.0)
6	Depreciation and amortization		490.8		241.4		249.4
7	Capital Cost Allowance		(481.9)		(293.0)		(188.9)
8	Removal costs		(6.3)		(2.9)		(3.4)
9	Environmental costs paid		(15.7)		(4.1)		(11.6)
10	Hedge loss -net		2.4		1.4		1.0
11	Non-deductible Meals & entertainment		5.3		3.2		2.1
12	Smart meter costs deferred		(1.5)		-		(1.5)
13	Research & Development ITC (prior year's claim add back)		0.2		0.1		0.1
14	Capitalized overhead costs deducted		(31.1)		(16.7)		(14.4)
15	Pension cost deductions		(46.4)		(13.0)		(33.4)
16		$	(45.8)	$	(66.2)	$	20.4
17	Deferral accounts not part of RR:						
18	Earnings Sharing Mechanism		34.1		34.1		-
19	RSVA DX/ TX Export credit		34.2		16.7		17.5
20	RARA and other Revenues deferred		19.1		-		19.1
21	OEB costs deferred		(0.7)		-		(0.7)
22	LV revenue received, deferred in regulatory a/c's		(8.1)		-		(8.1)
23		$	78.6	$	50.8	$	27.8
24	Reversal of accounting adjustments not part of RR:						
25	Contingent liability movement		(26.0)		(5.6)		(20.4)
26	Capitalized interest deductible for tax		(35.4)		(18.6)		(16.8)
27		$	(61.4)	$	(24.2)	$	(37.2)
28	Recurring items not part of RR:						
29	Cumulative Eligible Capital		(9.1)		(5.9)		(3.2)
30			(9.1)		(5.9)		(3.2)
31	Immaterial items not in business plan detail:						
32	Computer application software deducted for accounting		0.5		0.2		0.3
33	Taxable capital gain		0.7		0.3		0.4
34	Amortization of prospectus costs		0.6		0.4		0.2
35	Amortization of underwriting fees		1.7		1.1		0.6
36	WSIB		(1.8)		(0.8)		(1.0)
37	Building Provision		(0.6)		(0.6)		-
38	Amortization Capital Contribution		(0.3)		(0.2)		(0.1)
39	Tenant Inducement		(0.5)		(0.3)		(0.2)
40	Bond Discount Amortization		(0.7)		(0.4)		(0.3)
41	Deferred prospectus costs		(0.6)		(0.4)		(0.2)
42	Underwriting fees		(3.0)		(2.1)		(0.9)
43	Capital tax provision overaccrual vs. return		0.4		0.2		0.2
44	Landscaping costs deductible		(2.0)		(2.0)		-
45	Ontario Specified credits		1.1		0.3		0.8
46	Insurance proceeds		-		-		-
47	Rounding		(0.2)		(0.2)		-
48			(4.7)		(4.5)		(0.2)
49							
50	NET Adjustments to Accounting NIBT	$	(42.4)	$	(50.0)	$	7.6
51							
52	Taxable Income federal	$	545.6	$	365.2	$	180.4
53							
54	Deduct SRED claim added for Federal not taxable for Ontario		(0.2)		(0.1)		(0.1)
55							
56	Taxable Income Ontario	$	545.4		365.1	$	180.3

HYDRO ONE NETWORKS INC.
DISTRIBUTION

Calculation of Capital Cost allowance (CCA)
Historic and Bridge Years
2006 Networks Tax Return CCA Allocation to TX and DX
Year Ending December 31
($ Millions)

2006 DX

CCA Class	Opening UCC	Net Additions	UCC pre-1/2 yr	50% net additions	UCC for CCA	CCA Rate	CCA	Closing UCC
1	2,205.8	(0.4)	2,205.4	-	2,205.4	4%	88.2	2,117.2
2	448.7	-	448.7	-	448.7	6%	26.9	421.8
3	16.3	0.2	16.5	0.1	16.5	5%	0.8	15.7
6	9.1	0.1	9.2	0.1	9.1	10%	0.9	8.3
8	28.8	19.0	47.8	9.5	38.3	20%	7.7	40.1
10	56.5	25.7	82.2	12.9	69.3	30%	20.8	61.4
12	2.5	25.7	28.2	12.8	15.4	100%	15.4	12.8
13	2.4	(0.2)	2.2	-	2.2	10 yrs	0.4	1.8
17	2.3	0.1	2.4	0.1	2.3	8%	0.2	2.2
42	0.3	(0.0)	0.3	(0.1)	0.4	12%	0.0	0.3
45	7.9	7.9	15.8	3.9	11.9	45%	5.3	10.5
47	153.3	250.5	403.8	125.3	278.5	8%	22.3	381.5
Dx CCA	**2,933.8**	**328.7**	**3,262.5**	**164.6**	**3,098.0**	**0%**	**188.9**	**3,073.6**
Dx CEC Continuity	**45.7**	**0.1**	**45.8**	**-**	**45.8**	**7%**	**3.2**	**42.6**

2006 TX

CCA Class	Opening UCC	Net Additions	UCC pre-1/2 yr	50% net additions	UCC for CCA	CCA Rate	CCA	Closing UCC
1	3,059.3	(0.9)	3,058.4	-	3,058.4	4%	122.3	2,936.1
2	994.5	-	994.5	-	994.5	6%	59.7	934.8
3	256.6	30.1	286.7	15.1	271.6	5%	13.6	273.1
6	24.0	1.1	25.1	0.6	24.5	10%	2.5	22.7
8	20.6	6.9	27.5	3.4	24.1	20%	4.8	22.7
9	1.5	-	1.5	-	1.5	25%	0.5	1.1
10	115.7	33.5	149.2	16.8	132.4	30%	39.7	109.5
12	3.0	15.2	18.2	7.6	10.6	100%	10.6	7.6
13	-	-	-	-	-	10 yrs	-	-
17	11.0	1.8	12.8	0.9	11.9	8%	1.0	11.8
35	-	0.5	0.5	-	0.5	7%	0.0	0.5
42	72.0	9.8	81.8	4.9	76.9	12%	9.2	72.6
45	7.4	5.0	12.4	2.5	9.9	45%	4.5	7.9
46	3.2	16.2	19.4	8.1	11.3	30%	3.4	16.0
47	189.6	155.7	345.3	77.8	267.5	8%	21.3	324.0
Tx CCA	**4,758.4**	**274.9**	**5,033.3**	**137.7**	**4,895.6**		**293.0**	**4,740.4**
Tx CEC Continuity	**84.8**	**-**	**84.8**	**-**	**84.8**	**7%**	**5.9**	**78.9**

RATE BASE

1.0 INTRODUCTION

This exhibit provides the forecast of Hydro One Distribution's rate base for the 2008 test year and provides a detailed description of each of the rate base components.

In accordance with the 2006 Electricity Distribution Rate Handbook ("Handbook"), the rate base underlying the test year revenue requirement includes a forecast of net fixed assets, calculated on a mid-year average basis, plus a working capital allowance. Net fixed assets are gross plant in service minus accumulated depreciation and contributed capital[1]. Working capital includes an allowance for cash working capital and materials and supplies inventory.

2.0 UTILITY RATE BASE

Utility rate base for the distribution system for the test year is filed at Exhibit D2, Tab 1, Schedule 1. The calculation of Net Utility Plant is provided at Exhibit D2, Tab 3, Schedule 1 and 2.

Hydro One Distribution's forecast rate base for the test year is $4,382.0 million.

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[1] Contributed capital refers to amounts contributed by third parties to specific capital projects, e.g. Joint Use Assets, Customer Contributions

Table 1
Distribution Rate Base ($ Millions)

Description	Test 2008
Gross Plant	6,450.1
Accumulated Depreciation	(2,364.6)
Net Plant	4,085.5
Cash Working Capital	273.2
Materials and Supplies Inventory	23.3
Distribution Rate Base	**4,382.0**

The mid-year gross plant balance reflects the capital expenditure programs forecast for the bridge and test years. These programs are described in detail in the company's written evidence at Exhibits D1, Tab 3, Schedules 1 through 5 and in the supporting schedules filed at Exhibit D2, Tab 2, Schedule 2. The justification for capital projects in excess of $1 million are filed at Exhibit D2, Tab 2, Schedule 3.

The net plant component of the 2006 rate base approved in the RP-2005-0020/EB-2005-0378 was $3,423.3 million. The 2008 net plant of $4,085.5 million is $662 million or 19.3% higher than that last approved. Continuity schedules are provided in Exhibit D2, Tab 3.

Table 2
Continuity of Fixed Assets Summary ($ Million)

Description	Historic			Bridge	Test
	2004	2005	2006	2007	2008
Opening Gross Asset Balance	4,941.9	5,224.8	5,492.7	5,866.5	6,177.3
In-Service Additions	285.1	290.7	379.9	513.7	595.9
Retirements	(31.8)	(23.2)	(10.9)	(210.1)	(50.8)
Sales	(16.3)	(3.6)	(10.3)	-	-
Transfers	45.9	4.0	15.1	7.2	0.6
Closing Gross Asset Balance	5,224.8	5,492.7	5,866.5	6,177.3	6,723.0
Mid Year Gross Asset Balance	5,083.4	5,358.8	5,679.6	6,021.9	6,450.1

In-service additions reflect the placing in service of Hydro One Distribution's capital programs. These programs are described in detail at Exhibit D1, Tab 3, Schedules 1 through 5.

In its RP-2005-0020/EB-2005-0378 Decision, the Board accepted the application of the Foster Associates depreciation study, which Hydro One indicated would be implemented for GAAP purposes in 2007. The depreciation study requires that plant older than the proposed amortization period be immediately retired from service. As a result, retirements in 2007 include a one-time adjustment to reflect the write-off of minor fixed assets ($52 million) that reached the end of their normal service life and the removal of conventional meters ($121 million) due to replacement as part of the Smart Meter program. Normal retirements ($37M) comprise the remainder.

In 2008, retirements of $51 million consist of $14 million resulting from assets reaching their end of life, $11 million due to the retirement of the Distribution portion of Passport, and $25 million from normal retirements.

Transfers over the period reflect the company's efforts to properly reflect the use of its shared service assets by the transmission and distribution systems as asset use changes over time. During 2004, the company conducted a thorough review of these shared assets to determine an allocation basis that more accurately reflected their proposed use. The 2006 transfers primarily reflect the transfer of wholesale meters to Distribution due to the deregistration of the meters.

The nature and composition of Hydro One Distribution's assets are described in detail in Exhibit D1, Tab 1, Schedule 2.

3.0 WORKING CAPITAL

Per OEB direction, in RP-2005-0020/EB-2005-0378 Hydro One Distribution retained Navigant Consulting Inc. to undertake a lead-lag study. The OEB accepted the results of the Navigant study and the provision for working capital in 2008 incorporates the results of this study.

The Cash Working Capital requirement for the distribution system is based on the following factors:

- the forecast of OM&A,
- the retail cost of power,
- capital and income taxes,
- the net lead-lag days determined.

The other component of Working Capital is materials and supplies inventory.

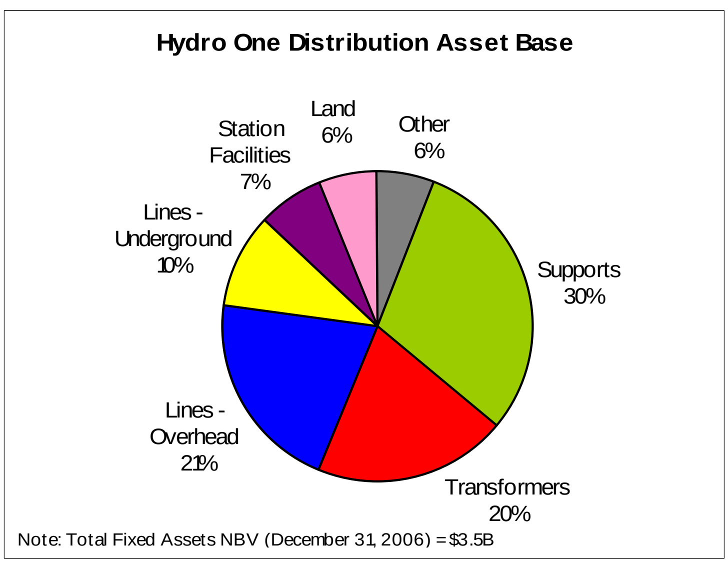
The application of the methodology from the lead lag study results in a net cash working capital requirement including the impact of GST of $273.2 million for the test year. This is an increase of $7.6 million from the $265.6 million level approved by the Board in RP-2005-0020/EB-2005-0378. Details of the Working Capital requirements for Hydro One Distribution are filed at Exhibit D1, Tab 1, Schedule 3 and Exhibit D2, Tab 4, Schedule 1 for the test year.

DISTRIBUTION ASSETS

1.0 INTRODUCTION

At Dec. 31, 2006, Hydro One Distribution managed $3.5 billion of distribution net fixed assets to provide the safe and reliable delivery of electricity, from transmission and generation systems, to approximately 1.2 million customers across the Province of Ontario. The assets consist of about 119,900 circuit kilometers of distribution line, 1006 distributing stations (including 75 regulating stations).The major power system components include; conductors, switches, transformers, insulators, reactors, capacitors, connecting hardware, associated protection and control equipment, foundations, grounding systems and revenue meters. The functional breakout of Hydro One Distribution’s asset base is shown in Figure 1 below.

Figure 1



Note: Lines-Underground includes all feeder type, i.e., subtransmisison, primary and secondary distribution feeders.

2.0 KEY CHARACTERISTICS OF THE DISTRIBUTION SYSTEM

Hydro One Distribution operates in a large service territory characterized by low customer densities. The distribution system has been designed and is operated to industry standards. The system is mainly radial in design, with very little redundancy in supplies to customers, which is consistent with rural utilities. Due to this configuration, most component failures require immediate repair to restore service.

Almost exclusively, with the exception of voltage transformation at 88 high voltage distribution stations (HVDSs), Hydro One Distribution's power system assets are operated at voltages below 50kV, and all of Hydro One Distribution customers are supplied at voltages below 50 kV.

The key characteristics of Hydro One Distribution's system are shown in Table 1 below.

Table 1

Hydro One Distribution System Assets		
Customers	Distribution	1,170,000
	Large Users > 5 MW	44
	LDC	34
Fixed Assets (NBV YE2006)		$3.5 Billion
Distribution Operating Centre		1
Distribution System Voltages (kV)		44 , 27.6 , 25 , 22 , 13.8 , 12.48 , 8.32, 4.16
Overhead Subtransmission Feeders		744 (24,800 km)
Overhead Primary Distribution Feeders		2,348 (95,100 km)
Underground Cable & Submarine Cable (included in the above kilometer figures)		6,400 km

Hydro One Distribution System Assets	
Secondary Distribution Feeders	48,000 km
Poles (line supports)	1.65 million
Distribution Stations	931
Regulating Stations	75
Station Transformers and Regulators	1,477
Pole-mount & Pad-mount Transformers	475,000

WORKING CAPITAL AND LEAD/LAG

1.0 INTRODUCTION

Working capital is the amount of funds required to finance the day-to-day operations of a regulated utility and is included as part of rate base for ratemaking purposes. The determination of working capital relies on a lead-lag study.

In 2005, Hydro One commissioned Navigant to carry out a lead-lag study. In the OEB's RP-2005-0020/EB-2005-0378 Decision with Reasons, the OEB accepted the results of the Navigant lead-lag study.

2.0 SUMMARY

Hydro One Distribution's net cash working capital requirement for the 2008 test year is $273.2 million or 11.2% of OM&A ($477.7M) and Cost of Power expenses ($1,959.3M). The net cash working capital requirement was calculated using the Navigant methodology accepted in RP-2005-0020/EB-2005-0378. Table 1 summarizes the net cash working capital requirements determined by using the lead/lag days from the Navigant study filed in RP-2005-0020/EB-2005-0378 and updated to reflect the 2008 test year revenue, expense and GST amounts (Table 2).

The methodology used to determine the net working cash required is based on the Navigant study that was accepted by the OEB, and it takes the following into consideration:

- the three most important elements of revenue lags i.e., service, billing and collections;
- the most important elements of expense lead such as payroll and benefits, operations, maintenance, administration expenses, cost of power, taxes and interest;

Table 1
Distribution Net Cash Working Capital Requirement
(All Data in $M Except Lead/Lag Days)

	Revenue Lag (Days)	**Expense Lag (Days)**	**Net Lag (Lead) (Days)**	**2008 Test Year Amount**
	(A)	(B)	(C)	(D)
Expenses				
Cost of Power	68.41	32.96	35.45	1,959.3
OM&A Expenses	68.41	16.87	51.54	477.7
Removal Costs	68.41	15.69	52.72	22.8
Environment Costs	68.41	15.69	52.72	7.9
Interest on Long-term Debt	68.41	74.66	(6.25)	132.9
Income & Capital Tax	68.41	15.61	52.8	50.2
Total				**2,650.8**
GST (See Table 2)				37.7
TOTAL AMOUNTS PAID / ACCRUED				**$2,688.6**
Working Capital Required (Calculations based on above values, for each expense category, calculated using the following formula: Col (D)*Col (C)/366)				
Cost of Power				189.8
OM&A Expenses				67.3
Removal Costs				3.3
Environment Costs				1.1
Interest on Long-term Debt				(2.3)
Income & Capital Tax				7.2
Total				266.4
GST (See Table 2)				6.8
NET WORKING CASH REQUIRED				**$273.2**

Table 2
Distribution Summary of GST Cash Working Capital Requirement
(All Data in $M Except Lead-Lag Days)

GST Category	**2008 Test Year**	**6% GST Projection**
	(A)	(B)
Revenue	3,026.1	181.6
Cost of Power	(1,959.3)	(117.6)
OM&A Expenses	(187.8)	(11.3)
Removal Cost	(22.8)	(1.4)
Environmental Cost	(7.9)	(0.5)
Capital	(219.1)	(13.1)
TOTAL		**$37.7**
GST (Benefit) Cost	**Expense Leads (Days)**	**GST Amounts**
	(C)	(D)
The values shown in the Col (D) labeled “GST Amounts” are calculated using the expense leads shown in Col (C) divided by 366 and multiplied by the 6% GST projected amount in Col (B)		
Revenue	20.20	10.0
Cost of Power	43.08	(13.8)
OM&A Expenses	36.88	(1.1)
Removal Cost	44.50	(0.2)
Environmental Cost	44.50	(0.1)
Capital	44.50	(1.6)
TOTAL		**($6.8)**

MATERIALS AND SUPPLIES INVENTORY

1.0 STRATEGY

Hydro One Distribution is committed to optimizing materials and supplies inventory in support of our customer satisfaction and reliability strategic objectives, as well as meeting OEB service quality indicator targets. Having the right material at the right work location at the right time is key to meeting these objectives.

Significant strides have been made to reduce inventory levels through various initiatives managed through supply chain. However, the need to maintain additional inventory to supply growing work program levels and higher material costs have offset the reduction of inventory levels.

2.0 INVENTORY

As of December 31, 2006, Hydro One Distribution carried inventory valued at $23.1 million. Table 1 below provides the inventory levels for 2004 – 2008. Included are both the year-end levels and annual average for each year due to the monthly fluctuations that occur during the year.

Table 1
Inventory Levels 2004 – 2008 ($ Million)

$ M	2004	2005	2006	2007 Forecast	2008 Forecast
Year End Actual					
- **Materials & Supplies**	15.7	16.7	22.6	23.2	23.4
- **Smart Meters**		5.4	0.5		
Total Year End Actual	15.7	22.1	23.1	23.2	23.4
Annual Average Materials & Supplies	16.3	17.4	25.2	23.1	23.3

Over the 2004 – 2006 period, particularly in 2006, annual inventory levels excluding smart meters increased by 44%. Further slight increases are expected over 2007-2008 period and onward.

The slight increase in inventory is primarily driven by a growing work program and increased material prices. A large number of aging assets required refurbishment and replacement, contributing to the required inventory levels. The unit prices have increased with the suppliers for the new contracts due to the market increase in the price of steel and other commodities. This increase is reflected in the inventory value of transformers, wire and cable, insulators, arresters and some poles.

Most of Hydro One Distribution's materials and supplies are sourced from inventoried stock. The basis of forecasting inventory levels assumes that historical inventory patterns are maintained, and modified as appropriate to reflect planned work program changes.

Inventory is held for the maintenance of existing assets and new development activities. Inventory primarily includes component parts - lines, poles, wire and cable, switches, transformers, protective devices, metering systems, minor parts such as circuit breaker contacts, pallet switches, insulators – and consumable items such as lubricants, gaskets, and protective clothing.

Key drivers that influence the inventory level include the OEB customer service quality indicator for connection of new services that require LDC's to connect new services in 5 or less working days for at least 90% of the requests for new connections, vendor lead-time, and demand levels for the forecasted work program.

2.1 Monthly Inventory Levels 2004-2006

The actual monthly inventory numbers for 2004 - 2006 are shown in Table 2 below.

The inventories of consumable material are seasonal in nature, driven primarily by storm season and new connections. Monthly inventories are ramped up to meet these increased needs. The trend indicates lower inventories at the beginning and end of each year, with an increase during the spring and early summer. This spring and summer timeframe increase is due to the building of storm inventory for distribution transformers and related hardware. The drop at the end of the year is due to the consumption of storm stock. December 2005 also included $5.4 million of smart meters inventory, which were consumed during 2006, resulting in an ending balance of only $0.5 million.

Table 2
Historical Monthly Inventory Levels 2004 – 2006

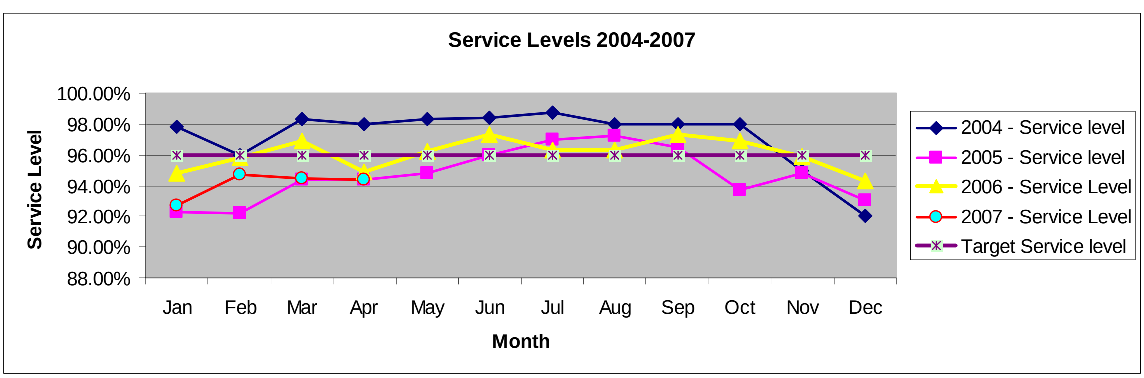
Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2004	15.3	16.6	17.2	16.7	15.9	16.3	16.6	17.3	16.3	16.3	15.2	15.7
2005	16.8	16.8	17.3	17.2	20.1	16.3	16.5	15.9	16.6	16.1	16.6	22.1
2006	23.9	25.3	27.4	27.6	26.8	26.0	26.3	24.9	23.3	23.7	23.6	23.1

3.0 PERFORMANCE METRICS

3.1 Service Levels

As a mean of driving improvement in the provision of materials from inventory, a service level metric has been adopted which represents the percentage of the time the warehouse was able to fill an order by the required date. Table 3 below provides the monthly trend of the service level metric over the 2004 to May 2007 period. The current target for the service level metric is at 96%.

Table 3
Inventory Service Level Monthly Trend



Inventory service levels are within the 96%-98% range for most of 2004. The decline in service level at the end of 2004 and part way through 2005 was due to a transition period of closing warehouses across the province and opening the Barrie central warehouse..

The 2006 inventory service levels fluctuated within approximately 1% of the current target of 96%. This reflects efforts to optimize inventory to ensure the required material is available when needed as well as collaborative forecasting with key suppliers to ensure product is available.

The inventory service level dips at the beginning and end of 2006 as well as at the beginning of 2007 were due to a large number of storms and associated inventory "stock-outs". The 2007 service level is increasing and is expected to reach the current target of 96%.

3.2 Inventory Turns

Another performance metric associated with materials and supplies is inventory turns.

Inventory turns are a measure of how quickly a company replenishes its entire stock of materials and supplies annually. The more turnovers there are, the less time inventory sits idle, which helps improve cash flow.

Inventory turns are calculated by dividing the value of annual issues from the warehouse by the yearly average value of inventory on hand. The 2006 inventory turns is 3.6. This indicates Hydro One Distribution replaces its inventory, on average, approximately every three months. For 2007, inventory turns are projected to improve to about four.

ASSET CONDITION ASSESSMENT & ANALYSIS

1.0 INTRODUCTION

This Schedule summarizes Hydro One Distribution's Asset Condition Assessment (ACA) practices, processes and ACA findings for key distribution system components, equipment, and facilities. Hydro One Distribution's ACA practices are based on studies carried out by Acres International Ltd, comparisons with other members in the electrical utility industry and expert opinion available within Hydro One. The practices are also based on a review of good utility practice.

ACA is one of the tools that are used to detect and quantify the extent of asset degradation of distribution system equipment and to provide a means of estimating remaining asset life based on condition. The rate of change in asset condition over time helps to identify deterioration trends. This information also helps to establish maintenance, refurbishment or replacement requirements based on the asset's ability to perform reliably. It must be recognized that the level of ongoing maintenance can have a pronounced effect on the life of some assets, and where this is the case, it is the ACA results that provide a barometer to assess the effectiveness of these maintenance programs, as well as identifying future end-of-life (EOL) replacement requirements.

Hydro One Distribution monitors the condition of its assets through a number of activities that include targeted asset condition assessments, maintenance activities, EOL assessment studies and incident investigations. These techniques are used to identify assets whose performance could have serious negative impact on Hydro One's business values and therefore require refurbishment or replacement, or in some cases, removal. The information is also used to decide on changes to maintenance practices when this is the economical solution. ACA information is a significant factor in determining the priority of work requirements for Sustaining Capital and OM&A programs.

2.0 OVERVIEW

The effective and efficient operation of the asset management model requires accurate, timely and sufficient asset information for decision making purposes. This information is used to support investment decision processes by enabling the assessment of risks to the Business Values ("BVs") and Key Performance Indicators ("KPIs") for various alternatives. For additional information concerning the BVs and KPIs refer to Exhibit A, Tab 3, Schedule 1.

The effective management of distribution assets requires the identification and optimum mitigation of risk to the BVs. This is achieved by balancing lifecycle costs and the related asset performance. If the asset management focus were strictly on improving or maintaining asset condition without due consideration of the resultant risk mitigation, then the result would be unnecessarily high expenditure levels. A specific asset health or condition does not automatically prescribe a set course of action or its timing. Other considerations include operating conditions (e.g. loading levels), technical obsolescence, asset demographics, spare parts availability, asset performance (e.g. asset failure rates, reliability trends), environmental factors, financial implications and the long term strategy for managing a particular asset type. Additional details concerning work program prioritization can be found in Exhibit A, Tab 14, Schedule 5.

Recognizing that gathering detailed condition information on every individual asset and every "nut and bolt" is both practically infeasible and not required, distribution assets were grouped into 20 logical asset classes. These classes were prioritized and further grouped into three categories, Priority 1 (P1); Priority 2 (P2); and Priority 3 (P3) based on their value to the business. These priorities determine the importance of acquiring condition information. The asset priority results are shown below.

Figure 1: Prioritization of Assets

Priority 1 (P1) • High Value • High Risk	Priority 2 (P2) • Moderate Value • High Risk	Priority 3 (P3) • Low Value • Lower Risk
Asset Class	Asset Class	Asset Class
Station Transformers	Station Reclosers & Breakers	Other Spares
Station Land Assessment & Remediation (Site Contamination)	Station HV Switches & Fuses	AC/DC Service Equipment
Overhead Line Sections	Station Sites and Structures	Feeder Protection (Switch/Fuse)
Wood Poles	Mobile Substations	Oil Containment
Right of Way (ROW) Vegetation	Transformer Spares	PCBs – Stations
	Submarine Cables	Switches – Lines
	Underground Cables	Reclosers - Lines
		Transformers - Lines

P1 assets represent the highest priority assets and are of high value (in terms of total sustaining program expenditures) and high risk to the business. P2 assets are second in priority with moderate program expenditures and high risk; and P3 assets are lowest in priority with low program expenditures and lower risk to the business. For the high value/high risk P1 assets, detailed asset condition assessments are carried out that involve documenting asset description, demographics, condition criteria, and condition assessment results. For P2 assets, in some cases detailed asset condition assessments are carried out, but not to the same level of detail as with P1, and in other cases, the management of condition relies on routine or time based maintenance programs.

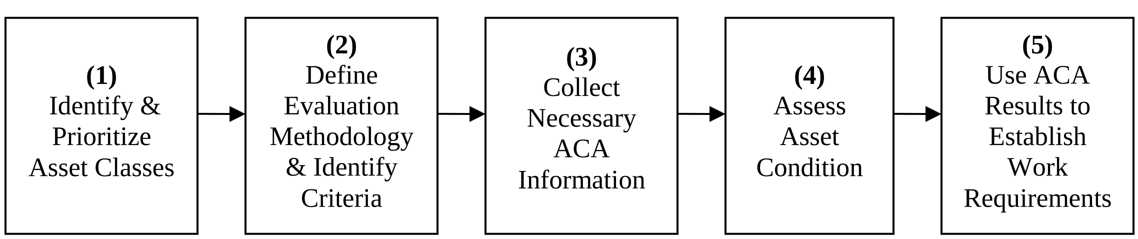
The P3 assets are managed to a great extent using routine programs (e.g. line patrols, defect corrections, trouble call response) that collect condition data as necessary and ensure they are maintained to Hydro One Distribution's standards. The routine programs put in place for P3 assets have longer cycles and use data to trigger asset management actions.

3.0 THE ACA PROCESS

Hydro One Distribution carries out asset condition assessments using an approach that describes the ACA objectives, prioritization, process, and criteria to be used for assessing the condition of its distribution assets. Hydro One Distribution assesses the condition of its assets through inspections, testing, and preventative maintenance activities, making improvements to its data collection process and carrying out special condition surveys or EOL assessment studies when required. Valuable asset condition information may also be obtained through incident investigations and special EOL studies for specific assets.

An outline of the steps involved in the asset condition assessment process is illustrated in Figure 1 below.

Figure 2: General ACA Process



The major steps in the ACA process as depicted in Figure 1 are:

1. Identify asset classes and prioritize them (i.e. P1, P2, P3) based on the value the assets represent to the business, which in turn determines the importance of acquiring condition information.

2. Define the asset information needed to determine and evaluate asset condition against predefined condition indicators based on failure mode analysis and expected results or specifications for higher priority asset classes.

3. Collect the necessary asset condition information. Define the measurements, and coordinate and schedule the necessary work to collect relevant asset condition information that will enable the development of appropriate work programs or projects to respond to condition deficiencies and mitigate the BV risks. This information may be obtained through regular testing, surveys, inspections or studies.

4. Analyze the asset condition and performance information to identify population condition, performance trends and high risks and impacts of asset condition on meeting business objectives, including service quality standards.

5. Use the asset condition assessment results to support detailed Sustaining and Development Capital and OM&A programs and projects. ACA information is a critical input to determine the level of work required in conjunction with other factors such as equipment performance, environmental considerations, availability of spares and customer reliability.

3.1 Asset Condition in Comparison to Asset Defects

The ACA process is intended to measure asset degradation, the criticality of the degradation, and the remaining asset “life.” When considering ACA, it is important to understand the differences between defect management and regular maintenance versus long term asset degradation and asset condition assessment. Defects are usually well defined and associated with failed or defective components which make up an asset and affect the operation and reliability of the asset well before end of life. These do not normally affect the life of the asset itself, if detected early and corrected. Defects are routinely identified during inspection and dealt with by maintenance activities to repair or replace failed components and thereby ensure continued reliable operation of the asset.

Long term degradation is generally less well defined and is not easily determined by routine visual inspection. The asset condition assessment's purpose is to detect and quantify long-term degradation and provide some means of quantifying remaining asset life. This includes identifying assets that are of "high risk" or at end of life that will require major capital expenditure to refurbish or replace, or eliminate altogether.

4.0 ASSET CONDITION SUMMARY AND RESULTS

The following sections highlight the prioritized asset classes that Hydro One Distribution uses and provides the most recent set of summarized ACA results for high priority asset classes. Subsequently, detailed, analysis and comments are provided on the results.

4.1 Detailed ACA Results for P1 Assets

The application of the ACA process to each asset quantifies the proportion of the assets that will require work through planned sustaining and development programs. A summary of the P1 asset conditions based on data collected up to the end of 2006 are shown in Table 4.1 below.

Table 4.1: Summary of Priority 1 (P1) ACA Results

Asset	ACA Results		
	"Poor" or "Very Poor"	"Fair"	"Good" or "Very Good"
Stations			
Transformers	3%	1%	96%
Land Assessment & Remediation (LAR)	5%	0%	95%*
Lines			
Distribution Line Sections	-	-	-
Wood Poles	4%	1%	95%
ROW Vegetation Management	31%	39%	30%

* Includes sites that are contaminated but that have been addressed through remediation activities, or present low environmental risks. The low risk contaminated sites are included in the "good to very good" category as there are no plans in place for further remediation in the foreseeable future based on site specific risk assessments.

A consistent approach has been used in developing asset condition assessment results so that the meaning of the categories is generally understood across the asset classes. It must be recognized that condition ratings in the table above represent a snapshot in time and may not include factors that may accelerate deterioration or increase the percentage of assets which are in a deteriorated state in the future. These factors include changing demographics (a large number of assets reaching the critical stage where degradation accelerates, as is the case with wood poles), degree of damage caused by failures of sub-systems (as may be the case with transformers where a fault may shorten the life of a transformer), or environmental factors that may be influenced by changes in regulations. The categories developed are:

- "Very Poor" and "Poor" condition assets are high risk and will require replacement, refurbishment or other remedial action within the next 5 years to correct significant deterioration. The exception is for rights-of-way vegetation as explained below.
- Fair" condition assets have experienced noticeable deterioration but should survive another 5 years with regular maintenance, and future work will be based on subsequent risk assessments.

- "Good" to "Very Good" Condition assets are currently at a lower risk than the other categories.

As noted above, Rights-of-Way vegetation does not fall into the time frames noted, as conditions change more rapidly for vegetation than with other asset classes. The more suitable descriptions for rights-of-way vegetation are: "Very Poor" and "Poor" category relates to feeders that will require maintenance within 2 years; "Fair" which relates to rights-of-way that may require maintenance in 3 to 4 years depending on further analysis; and "Good" to "Very Good" which relates to rights-of-way that have been recently (i.e. within 3 years) maintained or those that will not require attention within the next 4 years.

The following sections provide details on the key asset groups and highlight ACA results based on information and observations gathered up to December 31, 2006.

4.1.1 <u>Distribution Station Transformers</u>

The condition of station transformers is assessed using the following methods:

- Dissolved Gas in oil Analysis (DGA) and Standard Oil Tests involve withdrawing a sample of oil from a transformer with follow-up laboratory analysis to determine quantities and type of gas in the oil and the condition of the oil. The results provide an indication concerning the degradation of oil and insulating material.
- Furan testing is an additional oil test that provides information regarding the condition of the paper insulation in the core of the transformer. Degradation of paper causes it to lose its tensile strength and results in release of furans.
- Winding Doble Test is an electrical test used to identify the insulation quality within the transformer core measuring the dielectric loss of leakage current.

- Bushings, control cabinets, transformer tanks and cooling systems are inspected visually.

Hydro One Distribution makes use of proactive measures and diagnostic methods and tools such as noted above to facilitate early detection of deteriorating transformer condition and incipient failure to detect the remaining life of these costly assets. Based on DGA results, about 3% of distribution station transformers are at high risk of failure and will need to be replaced within the next five years. These transformers will be proactively taken out of service should their condition deteriorate further to prevent failures and reduce impacts to Hydro One Distribution's customers.

It must be recognized that transformers are a very important class of distribution assets. At this time, 97% of in-service transformers are in "Fair" to "Good" or "Very Good" condition, but this could change relatively quickly if they are not maintained in an ongoing and prudent manner. Events that can lead to rapid deterioration include; electrical failures of components or faults occurring from animal contact, lightning, contamination of equipment, etc; mechanical failure caused by movement of internal windings, or failures caused by malfunctioning cooling systems. These failures can cause damage that is not easily detected and can lead to rapid deterioration of condition, especially in aging equipment, as is the case with Hydro One Distribution's transformers. As a result, station transformers can move from the "Fair" and "Good" categories into the "Poor" category very rapidly due to normal wear and exposure.

Hydro One Distribution's proactive efforts based on ACA results appear to be showing some improvement in transformer failures. This is highlighted in Table 4.2 below that identifies the number of transformer failures experienced during 2004 to 2006. It must be recognized that the proactive maintenance strategy adopted during 2005 is in the initial stages, as such the change in the number of failures is not conclusive, but is providing a directionally positive indicator.

Table 4.2: Summary of Transformer Failures 2004 to 2006

Year	Number of Transformer Failures (Forced Outages)
2004	37
2005	32
2006	25

In total, Hydro One Distribution purchases about six to ten transformers annually to replace failed units that are beyond repair and to maintain adequate spares coverage. The proposed Sustaining OM&A (Exhibit C1, Tab 2, Schedule 2) and Capital (Exhibit D1, Tab 3, Schedule 2) programs provide appropriate funds to effectively manage the life cycle of these costly assets and will address those transformers identified to be at high risk over the next 5 year period, either by replacement or refurbishment if it is determined to be a cost effective solution.

4.1.2 Site Contamination – Land Assessment & Remediation

Hydro One Distribution assesses the environmental condition of Distribution Stations by examining soil, ground water and the surface run off from a site. Soil contamination is determined by the laboratory analysis of soil samples. Soil samples can be obtained from shallow open excavations or by drilling to gain samples at various depths. Ground water quality is determined by the laboratory analysis of ground water samples taken from monitoring wells that are installed on station property or adjacent property. Surface water runoff quality is determined by the laboratory analysis of runoff water samples taken by automated sampling devices. The results of these lab tests is then compared to contaminant levels permitted in provincial and federal regulations.

The chemical contaminants that exist on some sites were as a result of leaks and spills from equipment, or from previous industry accepted applications of certain long lasting chemicals (e.g. wood preservatives, herbicides) that complied with environmental regulations at the time that they were used. The primary contaminants of concern are:

- Arsenic (AS) – From arsenic trioxide, a registered herbicide at the time, used for total vegetation control within Distribution Stations from the 1950s until about 1965
- Total Petroleum Hydrocarbons (TPH) - From leaked or spilled transformer mineral insulating oil
- Polychlorinated Biphenols (PCBs) – From leaked or spilled transformer insulating oil
- Pentachlorophenol (PCP) – From treated wood poles

Hydro One Distribution has assessed all distribution station sites for site contamination and has found that about 45% do contain some degree of contamination, and of those, 5% still require remediation to ensure the contaminates do not present any threat to humans and the surrounding environment.

Remediation activities are scheduled using a risk based ranking system that focuses on high risk sites and on mitigating the risk of off-property impacts related to human and ecological exposure. Medium risk sites, are those containing some degree of contamination that is unlikely to migrate off-site but the risks are high enough to warrant sampling and monitoring on an ongoing basis. The remaining sites may contain some degree of contamination, but the risk of off site contamination is very low, or samples do not show any significant levels of arsenic, PCBs or TPH.

The plan that is being implemented under the Land Assessment and Remediation (LAR) program is highlighted in Sustaining OM&A under Stations (Exhibit C1, Tab 2, Schedule 2).

4.1.3 Distribution Overhead Line Sections

Hydro One Distribution does not conduct asset condition assessments on Overhead Lines Sections in the same manner as other P1 assets. This particular asset is considered unique compared to other P1 assets as it consists of a grouping of diverse overhead line components (e.g. conductor, insulators and wood poles) each of which have very different characteristics, condition deterioration factors, and maintenance requirements. It is for this reason, and the fact that it would be extremely costly to collect ACA information system wide on all of the lower level components that comprise a line section, that Table 4.1 above does not contain a percentage breakdown for Overhead Lines Sections.

The most practical and cost-effective approach for assessing the condition of distribution line sections is to collect relevant information on individual components. This includes collecting information on degradation levels of components that make up the line section. The information is obtained through:

- pole testing and line patrol activities as outlined in Sustaining OM&A (Exhibit C1, Tab 2, Schedule 2), which provides information on defects and condition of wood poles.
- a business process whereby field staff report suspect conditions that require more detailed assessments.
- reliability information indicating poor performance of a feeder or section.

When a critical mass of components reaches end-of-life, such that it is more cost-effective to refurbish an entire line section than to replace components individually, then a Line (Refurbishment) Project is undertaken as proposed in Sustaining Capital (Exhibit D1, Tab 3, Schedule 2).

As noted above, it is cost prohibitive to collect asset condition information on all distribution line sections nor is it necessary, as many of the line sections are in good condition. The process noted above is considered to be the most practical and cost effective means to manage the condition of these assets.

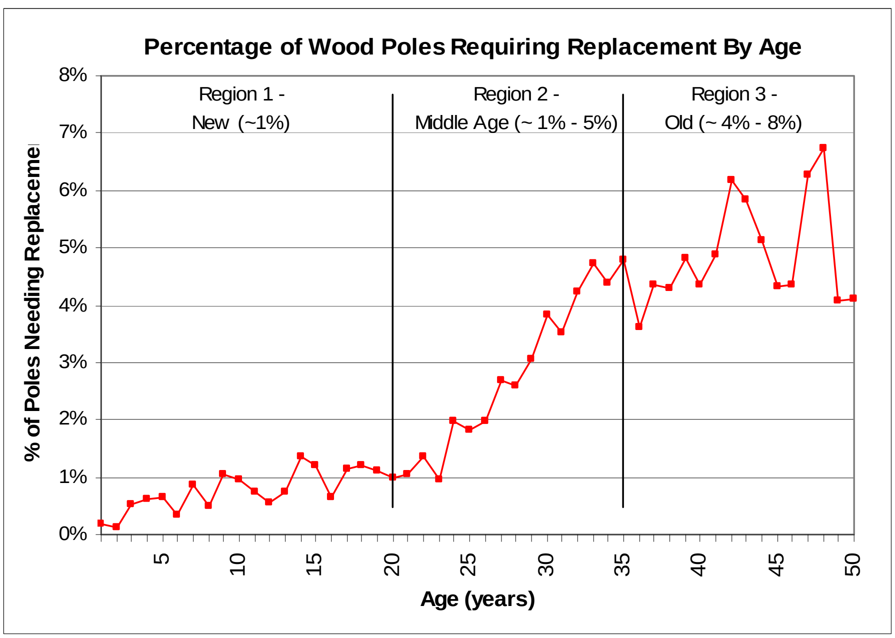
4.1.4 Wood Poles

Information used for determining the condition of wood poles is gathered from pole inspections and tests. Visual inspections identify numerous defects such as split tops, leaning poles, lightning damage, broken poles, wood pecker damage, rodent damage, shell rot, fire damage, insect infestation and other mechanical damage. The number and severity of these defects is used to assess condition. In addition, sounding tests using a hammer are employed to detect the presence hollow areas in the pole, shell separation, or external decay. Poles that appear to have internal rot are further tested using a drill test that measures the shell thickness (amount of wood in good condition in the outer area of a pole).

Based on inspection and testing results accumulated up to the end of 2006, Hydro One Distribution estimates that approximately 4% of the wood poles in the system are in “Poor” to “Very Poor” condition. The exact locations of these poles are identified during the normal course of the inspection cycle. Once identified, poles that are found to be in very poor condition are replaced in an expedient manner and those found to be in poor condition are replaced as part of the Wood Pole Structure Replacement Program as described in Exhibit D1, Tab 3, Schedule 2. The finding that approximately 4% of poles are at risk supports the need to maintain pole assessment plans proposed in Sustaining OM&A (Exhibit C1, Tab 2, Schedule 2) and to maintain pole replacements at levels proposed in Sustaining Capital (Exhibit D1, Tab 3, Schedule 2).

ACA results have also been analyzed in relation to Hydro One Distribution's wood pole demographics. Figure 3 below, indicates the percentage of poles that required replacement (i.e. "Poor" or "Very Poor" condition) relative to their age based on inspection and testing data.

Figure 3: Wood Pole Inspection & Testing Results Relative to Pole Age



The results indicate that the likelihood of a pole requiring replacement during its first 20 years is relatively low (i.e. approximately 1% - Region 1). Between years 20 and 35, the likelihood of a replacement increases rapidly (i.e. over 4% - Region 2). Beyond year 35 indications are that replacement rates are in the 4% to 8% range.

Figure 4: Hydro One Distribution Wood Pole Demographics

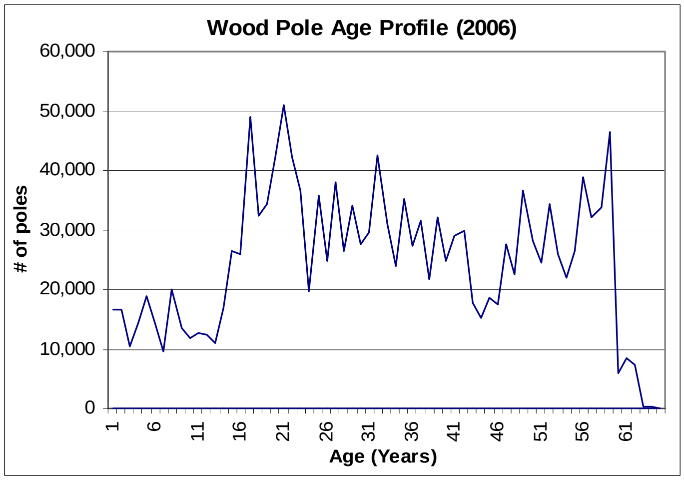


Figure 4 above is a representation of Hydro One Distribution's wood pole demographics and of particular interest is the large number of poles that are currently between 15 and 20 years of age. These poles will move through Region 2 illustrated in Figure 3, over the next 10 years where the replacement rates increase rapidly from approximately 1% to over 4%. In the past, the number of poles/year that have entered this Region has been about 30,000 to 35,000, but over the next 10 years the number will increase to as much as 50,000, thereby increasing the number of poles expected to be found at end of life. This information indicates that in the future one can expect an increasing number of pole replacements.

The leading indicator discussed above and the results from the current pole assessment program, support the need to replace those poles found to be substandard under the pole assessment program, as the number of replacements in the future will in all likelihood increase.

4.1.5 Rights-of-Way Vegetation

Vegetation asset condition assessments are undertaken by collecting data on various vegetation parameters including tree clearances (i.e. percentage of trees within 1m of the conductor), overhang (i.e. percentage of trees overhanging the conductor), danger trees, tree densities, and average brush height and average brush density (i.e. stems per line span). This information is combined to yield asset condition assessment results for feeders and is used to prioritize line clearing and brush control programs.

Assessment of vegetation conditions identify that about 31% (31,000 km) of rights-of-way are in the “Very Poor” and “Poor” category and are at risk and require clearance work within the next two years. The increase in percentage of rights-of-way in this category (about 3%) over the last two years is primarily attributed to a need to redirect resources during 2006 in response to the unusually high number of storms, and the 2005 labour disruption. As a result, accomplishment levels were below plan.

ACA results and the performance of specific feeders are the primary inputs that are used to schedule line clearing and brush control work on overhead lines. For Hydro One Distribution, the condition of rights of way is of great concern, as vegetation caused interruptions are the single greatest contributor to unreliability, as illustrated in Exhibit A, Tab 3, Schedule 1, and Exhibit C1, Tab 2, Schedule 2.

The projected accomplishment of 12,900 km during 2007 and the 12,500 km during 2008 will not fully address the “Poor” and “Very Poor” locations over these two years. These conditions will diminish over the next few years, but will not be fully addressed until one maintenance cycle has been achieved.

4.2 Comments on ACA results for P2 Assets

The following sections provide ACA information for P2 assets. It is recognized that P2 assets are of lower priority, and as a result, detailed analysis is not carried out to the same extent as with P1 assets. In a number of cases it may not be cost effective or practical to acquire the necessary information to support detailed ACA analysis, in which case maintenance processes and reliability indicators are used to manage the assets. This is further discussed in each of the asset groups below.

4.2.1 Station Reclosers

Hydro One Distribution currently manages approximately 6,000 distribution station reclosers consisting of single-phase and three-phase units, and about 170 circuit breakers. These pieces of equipment are currently on a six-year maintenance interval for refurbishment or replacement and amount to 1,000 units/year. Due to the comprehensive maintenance program, separate detailed asset condition assessments are not completed for station reclosers and breaker assets. The condition of these assets is monitored through reliability/performance data and the ongoing maintenance program funded under the Stations Program in Exhibit C1, Tab 2, Schedule 2.

4.2.2 High Voltage Fuses

There are approximately 1,000 3-phase sets of High Voltage fuses installed on the Hydro One Distribution system. The cost effective method of collecting ACA information on this asset group is to inspect these devices during regular station maintenance activities, Devices that are found to be in substandard condition are replaced in an expedient manner under the Station Program in Exhibit C1, Tab 2, Schedule 2.

4.2.3 Station Sites and Structures

Based on ongoing inspections carried out during regular maintenance and asset condition assessment findings, stations that require significant improvements to site facilities are completed as part of the station refurbishment work described in Exhibit D1, Tab 3, Schedule 2. This work includes, as appropriate, the refurbishment or replacement of fences, high voltage and low voltage structures, buildings, yards and roads. The first phase of the assessment is completed during the regular station inspections and if required, a more detailed assessment is made to establish the condition of wood poles, steel structures, building envelope and roof, etc. The refurbishment plans in Capital Sustaining (Exhibit D1, Tab 3, Schedule 2) will address those sites that have been identified to be in poor condition.

4.2.4 Mobile Substations

Mobile substations are comprised of a trailer and distribution equipment such as transformers, switches, fuses or reclosers as well as ancillary electrical systems. Trailers are inspected on a regular basis as required by the Ministry of Transportation and electrical equipment is inspected in detail on an annual basis. Inspection standards for the related electrical equipment are identical to that of a distribution station, but more frequent, as these assets must perform when called upon to do so. Any significant defects are logged and immediate plans are made to correct these. Minor defects are corrected as part of the Stations Program in Exhibit C1, Tab 2, Schedule 2.

Out of Hydro One Distribution's 28 mobile substations, 2 need to be refurbished during 2008 to maintain an operational fleet of 28 units. Replacement of major electrical equipment and refurbishment of the trailers is carried out under sustaining capital; refer to Exhibit D1, Tab 3, Schedule 2.

4.2.5 Transformer Spares

Hydro One Distribution utilizes 1,477 in-service transformers and regulators, ranging in size from 0.5 to 40 MVA in 71 different categories and requires a complement of spare transformers in order to respond to about 32 failures per year (average over the last four years). The majority of spare transformers are stored in a central location and are inspected on an annual basis to ensure that they are serviceable when required. Primary activities include the visual inspections of main components, i.e., bushings, cabinets, tanks and cooling systems. The visual inspection standards for spare transformers are identical to that of in-service units, and if required oil samples are taken and analysed. Spare transformers are maintained in a serviceable condition, such that they are available for deployment if required.

A comprehensive transformer spare complement strategy has been developed to ensure the correct number and types of spares are available. Additional details are provided in Sustaining Capital, Exhibit D2, Tab 2, Schedule 3.

4.2.6 Submarine and Underground Cables

Hydro One Distribution's system contains about 4,200 km of underground cable and 2,200 km of submarine cable. The maintenance activities for these assets involve a three-year inspection for urban circuits and a 6-year inspection for rural circuits in accordance with the requirements of the Distribution System Code.

For underground cables, the inspections involve visual examination of the components associated with the cable termination, pothead, elbows, and cable riser poles. For the large majority of cables, which are buried directly underground, no examination of cable or splices is undertaken. For a few cables that are in ducts some examination of the external condition may be carried out for troublesome or critical circuits. For submarine cables, the inspections involve visual examination of the cable between the transformer and where it enters the water. A specific area of concern is the location where cables enter the water, as this is the location where damaging corrosion of the armour wires (neutral wires) has been observed. Neutral corrosion has been identified as a potential safety issue.

Hydro One Distribution’s management practices for underground and submarine cables also include performance criteria: two failures within a section of cable would normally lead to the decision to replace the cable. The decision whether to repair or replace is made on condition information from a visual assessment and performance of the cable, and if deemed necessary, laboratory testing is carried out before decisions are made concerning replacement. The condition of these assets is managed on an ongoing basis form data gathered during inspections and performance monitoring. The underground cable system is relatively new and has not shown any significant deterioration trends, but this is not the case with submarine cable. Over the last 5 years, a number of cable locations have been identified during inspections as requiring section replacements due to corrosion of the neutral wires at the shore. Funding for these repairs is discussed in Exhibit D1, Tab 3, Schedule 2.

Hydro One Distribution’s program for managing distribution underground and submarine cables is generally consistent with the approach adopted by many other utilities for such cables.

SUMMARY OF CAPITAL EXPENDITURES

1.0 SUMMARY OF CAPITAL EXPENDITURES

The requested capital expenditures result from a rigorous business planning and work prioritization process that reflects risk-based decision-making to ensure that the appropriate and cost-effective solutions are put into place to meet Hydro One Distribution objectives set out below. This process is described in detail at Exhibit A, Tab 14, Schedule 1 through 5.

The capital expenditures in this filing represent investments in items that will ultimately become in-service capital assets supporting the Hydro One Distribution business. Specifically, these expenditures include:

a) Planning, purchase, construction and commissioning of specific assets providing future economic benefits;
b) additions to or replacement of specific assets; and
c) betterments that result in improvement of capacity, efficiency, useful life span, or economy of specific assets.

The capital programs address Hydro One Distribution's integrated set of needs to meet its objectives of: public and employee safety; compliance with the market and regulatory code and rules (the Distribution System Code), environmental requirements and Government direction; maintenance of distribution business service quality and reliability at targeted performance levels; and meeting system growth and assets end-life requirements. The development of programs to sustain and enhance assets takes the comprehensive asset condition data into consideration, as discussed in Exhibit D1, Tab 2, Schedule 1, as well as other factors.

Hydro One Distribution's capital expenditures are grouped into four different investment categories: Sustaining, Development, Operations, and Shared Services & Other Capital , the latter of which includes Customer Care capital expenditures and expenditures for fleet, service equipment, real estate, information technology and telecom. Table 1 provides a summary of Hydro One Distribution’s capital expenditures for the historical, bridge and test years.

Table 1
Summary of Distribution Capital Expenditures ($ Million)
Including Capitalized Overheads and AFUDC

Description	**Historic**			**Bridge**	**Test**
	2004	**2005**	**2006**	**2007**	**2008**
Sustaining	104.9	117.3	186.3	223.6	317.1
Development	138.6	141.7	146.8	154.2	167.7
Operations	6.3	4.7	2.1	2.0	3.6
Shared Services & Other Capital	22.2	53.4	57.4	96.7	77.8
TOTAL	272.0	317.2	392.6	476.6	566.2

Capital expenditures totaled $393 million in 2006 and $477 million in 2007 and are forecasted to be $566 million in 2008. The growth in capital is primarily due to increases in Sustaining Capital related to the requirements for smart meters and associated systems; increased Development Capital requirement related to customer growth; and, requirements in other Capital Programs related to the information technology initiative called Cornerstone. Investment Justification Documents (IJDs) in support of capital projects or programs in excess of $1 million are filed at Exhibit D2, Tab 2, Schedule 3.

In accordance with the accepted Rudden recommendation on overhead capitalization rate, beginning in 2007 Hydro One Networks is adjusting the overhead capitalization rate within the year to reflect projected changes in spending. This will better align the overhead capitalization rate with overhead costs of the capital projects supported. This adjustment, called E-Factor, trues up 2006 capitalized overheads by -$14.4 million. This is included as an adjustment to the derivation of the 2008 overhead capitalization rate. The Rudden E-Factor adjustment for the overhead capitalization rate is described in detail at Exhibit C1, Tab 5, Schedule 2.

2.0 SUSTAINING

The Sustaining capital expenditures include the costs for investments required to ensure that existing distribution system facilities function as originally designed. Hydro One Distribution manages its distribution sustaining program within three program categories, namely stations, lines and meters (includes smart meters). Details of the expenditures under this program are filed at Exhibit D1, Tab 3, Schedule 2.

3.0 DEVELOPMENT

The Development capital expenditures consist of the investments required to serve new customers and meet increased demand of existing customers. Development capital includes programs for customer connections and capacity reinforcements. Details of the expenditures under this program are filed at Exhibit D1, Tab 3, Schedule 3.

4.0 OPERATIONS

The Operations capital program represents investments in infrastructure required to sustain the Central Distribution Operations function, which is operated from Hydro One's Ontario Grid Control Centre. Details of the expenditures under this program are filed at Exhibit D1, Tab 3, Schedule 4.

5.0 SHARED SERVICES & OTHER CAPITAL

Shared Services & Other Capital consists of the sustainment and enhancement of existing equipment and infrastructure, including computer-related hardware and software and transport and work equipment ("T&WE") as well as projects initiated to improve business support functions. The capital requirements for the Cornerstone Project and Customer Care are also incorporated in Shared Services & Other Capital. Details of the expenditures under this program are filed at Exhibit D1, Tab 3, Schedule 5.

SUSTAINING CAPITAL

1.0 INTRODUCTION

Distribution Sustaining Capital represents investments required to ensure that existing distribution system facilities function as originally designed. Hydro One Distribution manages its distribution sustaining capital program by dividing the program into three program categories, namely: stations, lines and meters

Stations, lines and meter program categories include investments in equipment and related components required to deliver electricity through the distribution system, as well as investments that facilitate the efficient use of joint-use of assets. Investments covered under the Sustaining Capital program are proposed for the purpose of maintaining the long term and short term functionality of assets, to ensure public and employee safety, comply with regulations and contractual requirements and to provide a level of reliability that is aligned with corporate objectives.

Hydro One Distribution's Sustaining Capital programs and proposed spending levels for 2008 are described below.

2.0 DISCUSSION

Distribution stations, lines and meter assets, and their components, are subject to deterioration that will eventually impede their ability to function as originally designed. Asset deterioration depends on factors such as geographic environment/location, utilization, age, weather and maintenance practices. As assets deteriorate, equipment performance reliability usually suffers, resulting in increased environmental risks, an increase in potential safety hazards to the public and employees, and decreased system reliability. Ultimately, assets deteriorate to the point that they are no longer able to perform their function(s) in a cost-effective manner, at which point replacement becomes necessary rather than continue to repair or maintain.

Sustaining Capital programs fund both planned work and demand (unplanned) work. Planned work is required to preserve functionality of the existing distribution system by replacing deteriorated components with new components that are designed to perform an equivalent function. The identification of specific facilities for possible replacement is based on data collected during the Asset Condition Assessment (ACA) process described in Exhibit D1, Tab 2, Schedule 1. The condition of assets is one consideration in determining replacement. Other factors include historic performance, asset criticality, availability of spare equipment, load growth, and local customer impacts as well as the business drivers that form part of the work program prioritization process described in Exhibit A, Tab 14, Schedule 5. The prioritization process allows all distribution programs to be ranked and compared to one another so that investments can be directed to where they provide the maximum business value.

Demand capital work involves asset replacement that is required during service interruptions and in response to contractual and other commitments with road authorities and joint use partners, i.e., cable and telecommunication companies. The varying nature of this work requires Hydro One Distribution to forecast costs based on historical averages with adjustments made to reflect recent changes in expenditure patterns or work requirements.

Demand work requires an immediate or timely response to customer needs and is initiated by interruptions to service, line and station inspection findings, and by request from customer and property owners. Hydro One Distribution maintains infrastructure, equipment and resources to respond to these issues within the time lines specified by the

Distribution System Code. Planned work on the other hand, does not generally pose the same degree of urgency and is scheduled over time, based on knowledge of the condition of the assets.

The Sustaining Capital spending for 2008 and prior years is provided in Table 1 below.

Table 1
Sustaining Capital
($ Millions)

Description	Historic Cost			Bridge	Test
	2004	**2005**	**2006**	**2007**	**2008**
Stations	11.0	9.1	8.5	7.7	10.3
Lines	92.7	106.8	162.1	138.8	139.5
Meters	1.2	1.4	15.7	77.1	167.3
Total	**104.9**	**117.3**	**186.3**	**223.6**	**317.1**

The increase in spending for 2008 relative to historic expenditures is attributed to the following reasons:

- Implementation of smart meters, in accordance with government direction.
- Planned pole replacement during 2008 is greater than historic replacements based on ACA finding.
- An increase to the 2008 planned line refurbishment and component replacement levels to address end of life assets, and reliability and safety risks.
- Material and equipment increases in the order of 20% to 40%.
- An updated projection for storm response costs to reflect historical spending on this activity which is critical to providing customers with reliable service.

Additional details concerning these increases and year over year variations in spending are provided below.

2.1 Stations

Hydro One Distribution has 1,006 distributing and regulating station facilities, which are used for the delivery of power, voltage transformation and switching. Station facilities contain many of the following components: power transformers, instrument devices, reclosers, fuses, disconnect switches, bus, insulators, power cables, support structures, cable terminators, surge arrestors, station service supplies, grounding systems, fences, and buildings.

Hydro One Distribution's service to customers is also performed with a fleet of 28 mobile substations used primarily for emergency response to power disruption at stations. The mobile substations are also used during planned maintenance programs and capital refurbishment at distributing stations to reduce power interruptions. Investments for mobile substation are included in the Sustaining Capital program to ensure these mobile assets are available for the above purposes.

Stations Sustaining Capital funding covers capital investments required to replace or upgrade assets located within distributing and regulating stations, and mobile substations. The work is divided among three programs. Funding for 2008, along with the spending levels for the bridge and historic years are provided in Table 2 below.

Table 2
Stations Sustaining Capital
($ Millions)

Description	Historic Cost			Bridge	Test
	2004	**2005**	**2006**	**2007**	**2008**
Strategic Spare Transformers	4.8	1.7	2.8	0.6	3.5
Mobile Substation Refurbishment	1.1	0.4	1.0	0.3	1.5
Station Projects & Demand	5.1	7.0	4.7	6.8	5.3
Total	**11.0**	**9.1**	**8.5**	**7.7**	**10.3**

2.1.1 Management of Transformer Assets

Power transformers are devices used to reduce the voltage of the electricity being distributed, and to provide voltage control. Distribution power transformers convert a high level voltage (typically 115kV, 44kV, or 27.6kV) to a lower distribution voltage (typically 27.6, 25, 13.8, 12.47, 8.32 and 4.16 kV).

The management of transformer assets is a key component of the Stations Capital Sustaining program. The reliability of supply provided by power transformers is managed through proactive maintenance activities and a coordinated use of strategic spare transformers and mobile substations. These programs are interdependent and have proven to be a cost-effective approach for managing transformers for a largely rural utility such as Hydro One Distribution. This approach reduces capital expenditures for distribution facilities as discussed below while still providing reliable delivery of electricity to customers.

Hydro One Distribution's system is largely a radial system characterized by little or no load transfer capability, and by design the majority of distributing stations are equipped with only one power transformer. The consequence of this system design is that a transformer failure at a distributing station results in a service interruption to all customers supplied from that station. Since service to customers cannot be restored until the function of the distributing station is restored, in many instances mobile substations are dispatched to the affected station to provide service restoration. The mobile substation remains in place until such time as a spare transformer can be brought in to replace the failed unit. The extent to which spare transformers are available will influence the reliance on mobile stations for extended periods. Alternatives to this management process include having a spare a transformer at every distributing station or building added supply lines to provide a redundant supply. These alternatives have been assessed to be cost prohibitive on a system wide basis.

Mobile substations also facilitate maintenance at distributing stations by carrying the station load while the station is isolated for planned maintenance work. The extent to which mobile substations are in-service for an extended period of time, due to unavailability of spare transformers, will limit the ability to complete the required planned maintenance and capital work at distributing stations.

Details of the programs used to manage strategic spare transformers and mobile substations are provided below.

2.1.1.1 Strategic Spare Transformers

Hydro One Distribution has 1,337 station transformers and 140 regulators in service. Hydro One's distribution stations have experience an average of 32 major station failures a year over the last 4 years. In a number of instances, station failures require removing the transformer off site and subsequent replacement from the strategic spare transformer inventory. The strategic spare inventory is maintained by purchasing new transformers if required and by refurbishing existing, unserviceable units, i.e. transformers that failed or were required to be removed from service based on poor condition as determined through the ACA process.

The majority of distribution transformers that fail, or that are found to be unserviceable based on ACA results, can be refurbished economically. Repair costs can vary significantly, from $15,000 to $150,000 per transformer, depending on the nature of the failure and whether the damage results from external or internal faults. Before a transformer is refurbished, Hydro One Distribution first determines whether the transformer is needed as a spare, and estimates the refurbishment costs by dismantling the transformer and assessing the extent of damage. If refurbishing the transformer versus buying a new transformer is economically justified and is technically acceptable, the existing transformer is refurbished and added to the pool of strategic spare transformers.

Due to the importance of these system elements to customer reliability, Hydro One Distribution maintains a spares inventory of transformers and regulators that is based on the number and type of transformers and regulators in-service, reliability of equipment in use and the availability mobile substations. Historically, each year two to six station transformers cannot be returned to the spares inventory. In these cases, the complement of spare transformers is reduced unless replacement transformers are purchased, or transformers become available through system reinforcement projects, i.e. transformer replaced in response to an increase in customer load is freed-up for another use. This program funds the purchase of transformers to maintain a spares compliment that meets system needs and ensures reliability.

Funding of this program enhances customer reliability by reducing the reliance placed on mobile substations for extended periods, making them available to respond to emergencies and to assist in carrying out the planned maintenance on distributing stations, thereby ensuring equipment performance.

The 2008 spending requirement for this program is $3.5 million. Historically expenditures have fluctuated from year to year based on the number of failed transformers that are beyond repair and replaced by transformers from the spares pool. Those transformers removed from the spares pool that become permanent field installations need to be replaced in the spares inventory to maintain adequate spares coverage. In addition, system failures are monitored and if there is an appreciable increase in the failure rate of a specific class of transformer, there may be a need to increase the number of spares within the subject group to manage reliability to acceptable levels.

The 2008 spending involves the purchase of 3 new spare transformers and 1 regulator to increase the compliment of spares to the required levels.

Funding reductions in this program would result in an increased utilization of mobile substations at failed transformer locations thereby negatively impacting planned maintenance and jeopardizing reliability at a number of distribution stations.

For additional details refer to the Investment Justification Document (IJD) in Exhibit D2, Tab 2, Schedule 3.

2.1.1.2 Mobile Substation Refurbishment

A mobile substation is essentially a distribution station mounted on a trailer suitable for traveling on public roads. These mobile units consist of a transformer, high voltage and low voltage switches, high voltage and low voltage fuses, and connecting bus. There are 28 of these units strategically located across the Province. The primary purpose of mobile substations is to provide emergency backup to distributing stations and restore service to customers following the failure of a station, but they also facilitate planned maintenance programs at distributing station assets by mitigating power disruption to customers. Given Hydro One Distribution's largely radial distribution system with single transformer distributing stations, the utilization of mobile substations provides a cost effective alternative to constructing redundant transformation at stations.

As mobile substations age, the undercarriage, wheels, axles, and suspension require replacement when routine maintenance cannot restore the integrity of the components. Funding of this program allows for the efficient refurbishment of mobile substations based on the results of a monthly condition assessment required to ensure they are roadworthy and comply with Ministry of Transportation licensing requirements.

The 2008 spending requirement for this program is $1.5 million, which allows for the refurbishment of two mobile substations. The 2008 spending is higher than the bridge year and the historic expenditures, due to a need to replace a failed mobile substations transformer which was not part of the funding required in past years.

Inadequate funding would have an adverse impact on station emergency response and on planned station maintenance capability, and would jeopardize customer reliability.

For additional details refer to the IJD in Exhibit D2, Tab 2, Schedule 3.

2.1.2 Stations Projects and Demand (Unplanned)

Station Refurbishment Projects

The level of investment required to refurbish a station will vary as a function of the condition of the station. Some stations will require replacement of frost-heaved structures, power equipment components, and/or security fence replacements. In other cases, the work required may be more significant, such as transformer refurbishment or the complete rebuild of a station on an existing or a new site. The latter may be the case particularly for the older wood pole and timber structure station styles.

Station condition is determined using the ACA process as discussed in Exhibit D1, Tab 2, Schedule 1. About 8 to 15 stations are refurbished annually based on condition, utilization and environmental risks. The number of stations scheduled for refurbishment on an annual basis at this time is currently in the order of 1% of all Hydro One distributing stations. Considering the age of these assets, (i.e. 30 to 40 years) this is a relatively low number of annual refurbishments, largely attributable to Hydro One Distribution's comprehensive maintenance program and a proactive transformer spares management, as discussed in this Schedule and in Exhibit C1, Tab 2, Schedule 2.

Funding levels of this program will impact the amount of breakdown maintenance in future years and negatively impact customer reliability. The 2008 spending for station refurbishment work is $2.5 million. For additional details refer to the IJD in Exhibit D2, Tab 2, Schedule 3.

The station refurbishment program also includes the costs associated with refurbishment of spill containment facilities identified through station inspections as requiring work for the purpose of environmental compliance and performance. These projects are managed separately from the larger refurbishment work. The 2008 spending for spill containment facilities is $0.3 million.

Component Replacement & Demand

Component replacement projects involve replacing such defective equipment as reclosers, surge arrestors, fences and switches that have been determined to be at end of life. The condition of equipment and station components is assessed during routine inspections, ACA and during planned and unplanned maintenance activities.

The demand work completed under this program covers the capital component of work required to address the failure of distributing and regulating station components and to correct situations that could cause a power interruption or present a safety hazard. When station components fail, the consequence is typically a service interruption to customers. Station interruptions can impact a large number of customers, typically from 1,000 to 10,000 customers per interruption. Emergency and corrective work must be carried out in a timely manner in order to minimize the risks to customer reliability, and public and employee safety.

This program covers the capital costs of emergency and corrective work at stations that involve plant retirement. Work that does not involve plant retirement is covered under the Sustaining OM&A, Exhibit C1, Tab 2, Schedule 2.

In most cases, smaller components such as reclosers, insulators, connectors, switches, etc. will be repaired, temporarily bypassed, or replaced on site. The failure of a large component, such as a transformer, may require moving the equipment off site and repairing it at a central location and then returning it to that specific site. If a prolonged service interruption is anticipated, service is typically restored through the temporary use of a mobile substation or replacing the failed unit with a spare transformer.

The 2008 spending for both component replacement and demand work is $2.6 million. For additional details refer to the IJD in Exhibit D2, Tab 2, Schedule 3.

Summary

The 2008 spending requirement for all Stations Projects and Demand work totals $5.3 million. The proposed funding is within the range of historic expenditures. Spending from year to year can vary as the spending is based on a number of factors, e.g., number and type of stations to be refurbished, number of failures, condition of assets, asset performance, criticality of assets, availability of spare equipment and local reliability impacts.

Reductions in this program will result in defective equipment and station components remaining in service for longer periods of time, thereby increasing the risk of failure and adversely affecting customer supply reliability. Reduced funding would also increase environmental risks associated with oil entering the environment as a result of an increased likelihood of transformer failures.

2.2 Lines

Distribution lines total 119,900 circuit-km province-wide and are used to deliver power to Hydro One Distribution customers. Lines are constructed on road allowances where possible, or on rights-of-way for which Hydro One Distribution has legal rights to access and occupy. Line components include poles, conductor, transformers, switches, fuses, surge arresters, voltage regulators, capacitors, insulators, reclosers and grounding devices. A small proportion of distribution line inventory is located underground in some of the more urban locations or underwater (submarine) for servicing cottages and residences on islands. The underground and submarine inventory represents approximately 5 % of the total circuit-km.

Sustaining Capital funding for lines includes capital investments required to maintain existing assets associated with overhead, underground, and submarine distribution lines. The work is divided among three programs as noted in Table 3. Funding for 2008 and spending for the bridge and historic years are provided in Table 3 below.

Table 3
Lines Sustaining Capital
($ Millions)

Description	**Historic Cost**			**Bridge**	**Test**
	2004	**2005**	**2006**	**2007**	**2008**
Trouble Call & Storm Damage (d)	38.3	51.7	90.6	51.7	53.4
Joint Use & Relocations (d)	19.2	22.0	24.0	27.1	23.7
Asset Replacements	35.2	33.2	47.5	60.0	62.4
Total	**92.7**	**106.8**	**162.1**	**138.8**	**139.5**

(d) – indicates this is a demand program

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2.2.1 Trouble Call and Storm Damage Response

This demand program provides capital investment for responding to problems on distribution lines that require immediate attention as a result of trouble calls or storm damage. During 2006, an unusually high number of storms passed through Ontario that caused extensive damage to the distribution system.

A trouble call typically captures the work required to restore the supply of power to customers following an unplanned interruption. However, a trouble call may also be required in response to a customer complaint (e.g. about power quality) or to correct a defect on a distribution asset that, if not addressed, could present a safety concern or potentially result in an interruption of power to customers. Hydro One Distribution must address trouble calls in order to comply with legal and regulatory requirements, to correct known hazardous problems and to maintain reliable electric service in accordance with good utility practice.

The majority of costs associated with trouble calls are incurred in the Sustaining OM&A, Exhibit C1, Tab 2, Schedule 2. In cases where capital plant is replaced as part of a trouble call, all labour and material costs are capitalized under this program. Where a trouble call is as a result of damage to the distribution system caused by a third party (e.g. motor vehicle accident), Hydro One Distribution will endeavour to recover the cost of making the repairs. Any costs recovered are credited to this program. Historically, damage by third party interference has totaled about $4 million per year with recovery of approximately $2.5 million.

Hydro One Distribution also capitalizes storm restoration costs where a storm results in the replacement of capital plant units and the distribution system experiences significant damage. Storms normally interrupt the supply of power to many thousands of customers. The impact storms have on Hydro One Distribution's system during any given year will depend on the number, type (e.g. wind, snow, ice) and severity of the storms. Historically the number of storms varies widely and the number of days affected by storms has ranged from 20 to over 50 days annually. There is also variation in the number of "force majeure" storms impacting the distribution system, with force majeure defined as a major storm affecting more than 10% of Hydro One Distribution's customers. During 2004, Hydro One Distribution experienced one force majeure storm whereas during 2006 there were eight - an usually high number that caused extensive damage to the distribution system. Given the variability in the number, type and severity of storms, storm-related damage can change significantly from one year to the next

The extent of storm-related damage is also affected by work in other sustainment programs. Reducing vegetation management will increase the likelihood of trees and branches contacting a line under storm conditions as vegetation growth encroaches on the right-of-way and damaged or diseased trees remain near line facilities for longer periods of time. As well, if assets in need of repair or replacement are not addressed, there is an increased likelihood that assets such as poles may fail under adverse weather conditions.
All work associated with storm restoration, with the exception of overtime costs and the costs to clear vegetation (e.g. trees, brush) from the storm-impacted distribution lines, are

captured under this program. Overtime and forestry costs related to storm restoration are not capitalized, because these activities do not restore the capital assets to a better condition than existed before the storm, and provides no added benefit to future customers.

The funding level requested is based on an assessment of historical trends in costs and volume of work, taking into account any known factors that could impact historic trends.

The 2008 spending requirement for this program is $53.4 million, net of $2.5 million recovered for third party damage. The 2008 spending is close to that for the bridge year and 2005 actual. The 2008 spending is based on a 4-year average of historical spending with adjustments made to incorporate recent trending in volumes and cost.

The 2008 spending is considerably lower than in 2006, as that was an unusually high year for storm damage. During 2006 the company experienced eight major storms, requiring an unprecedented 36 days of storm damage restoration. Associated with the 2006 storm damage were expenditures of $62 million in capital (compared to a previous range of $14 million to $26 million) and $21 million in forestry and lines maintenance (compared to a previous range of $1 and $8 million). The majority of damage during these storms was attributed to falling trees and branches in close proximity to lines. These storms contributed 57% of SAIDI, and it is expected that the customer outage durations would have been significantly less under the vegetation management program planned for 2008.

Hydro One Distribution’s ability to quickly respond to the significant and repeated storm events in the summer and fall of 2006 resulted in the company winning the prestigious Edison Electric Institute's "Emergency Recovery Award" for outstanding efforts to restore electric service to its customers following such severe storms.

For additional details refer to the IJD in Exhibit D2, Tab 2, Schedule 3.

2.2.2 Joint Use and Line Relocations

Joint Use

The joint-use component of this program covers the work required to modify existing Hydro One distribution line assets to accommodate telecommunication or cable television lines, street lighting owned by municipalities, or power circuits for various Local Distribution Companies (LDCs).

Hydro One Distribution carries out joint-use projects in accordance with long-standing agreements between Hydro One Distribution and joint-use partners. The cost sharing provisions in these agreements allow Hydro One Distribution to recover its costs resulting from requests to add new attachments to poles. Historically, 25% to 35% of a joint-use project costs are recoverable. The recoverable portion represents the residual value of the line assets at the time the joint-use project is initiated plus the incremental cost for any modifications required for the new joint-use facilities. The unrecoverable portion of the costs recognizes that these projects generally result in increased life of the facilities that benefit Hydro One Distribution customers, due to a reduction of future investment needs.

All recoverable joint-use costs are paid by joint use partners at the time of the attachment. In addition, annual fees not included in this program are levied per attachment to compensate for on-going incremental maintenance costs due to the presence of these attachments on the pole. Revenues associated with these annual fees are discussed in Exhibit E3, Tab 1, Schedule 1.

The joint-use program is driven by external demand for work, which Hydro One Distribution is required to provide in accordance with existing agreements. The number of joint-use projects has historically ranged from 80 to over 200 projects per year. The variation is due in large measure to communication companies providing or enhancing service to their customers.

Line Relocations

The line relocation component of this program covers the work required in response to road modifications initiated by Provincial and municipal road authorities, or by individuals who require assets relocated for the purpose of developing their property. Hydro One Distribution is obligated to relocate plant at customers' request in accordance with the requirements specified in its Conditions of Service. The relocation of plant to accommodate road modifications must be done in a timely manner as per the requirements of the Public Service Works on Highways Act, R.S.O. 1990, and associated Ministry of Transportation guidelines. Relocations may entail the construction of new plant and the removal of old plant.

The cost of relocation projects is either fully or partially recoverable, depending on the specific circumstances of the project. Typically, a customer requesting a plant relocation must pay Hydro One Distribution for all costs incurred in moving the plant. In the case of projects associated with road relocations, the applicable statute defines the recoverable portion of the relocation work, which is typically 20% to 35% of the total cost. The unrecoverable portion of relocation costs represents the benefit to Hydro One Distribution, and its customers, of having new assets in place that reduce future investment needs.

The number of relocation projects can vary significantly from year-to-year depending on the number of government infrastructure improvement projects and economic conditions influencing individual third party development projects.

Summary

Since the number and scope of joint-use and line relocation projects is variable, the funding level requested for 2008 is based on historic costs, taking into account any observed trending and currently identified joint-use or relocation work.

The 2008 spending requirement for this program is $23.7 million, which is net of $9.0 million in recoverable costs. The 2008 spending maintains the spending during 2006 and is 12% below the bridge year expenditures.

For additional details refer to the IJD in Exhibit D2, Tab 2, Schedule 3.

2.2.3 Asset Replacement

Distribution lines asset replacement programs involve replacement of line components and line sections determined to be at end of life, and line modifications to address safety and reliability issues. These projects and programs are closely coordinated and integrated with System Capability Reinforcement plans (Exhibit D1, Tab 3, Schedule 3), where appropriate, in order to maximize the benefits of these expenditures.

The asset replacement work is divided into three programs with funding for 2008, and spending levels for the bridge and historic years, as provided in Table 4 below.

Table 4
Asset Replacement
($ Million)

Description	Historic Cost			Bridge	Test
	2004	2005	2006	2007	2008
Wood Structure Replacement	19.1	18.5	30.3	40.1	39.8
Waste Management Capital*	0.5	0.2	0.2	0.1	1.2
Line Projects	15.6	14.5	17.0	19.8	21.4
Total	**35.2**	**33.2**	**47.5**	**60.0**	**62.4**

* The 2004, 2005 and 2006 costs were for PCB transformer replacements.

2.2.3.1 Wood Structure Replacement

Wood poles deteriorate over time. When the condition has deteriorated to a point where there is a significant risk of failure under adverse weather conditions, poles are deemed to be at end of life and must to be replaced to ensure reliability and safety. Planned replacement of poles is much less costly than "emergency" or reactive type replacements, is less disruptive to customers, and eliminates safety issues. Replacing defective poles on a reactive basis not only costs more than planned replacement, but also results in increased overtime with longer outage durations to customers and increased safety risks. There is a strong business need to replace substandard poles before they negatively impact the system.

Over 50% of the distribution system's 1.65 million poles have been assessed since 2002 and about 4% of those poles tested were found to be in a sub-standard condition. The number of sub-standard poles in the system is forecast to be near a historic high and will increase unless the deteriorated poles are replaced. Refer to the Asset Condition Assessment and Analysis, Exhibit D1, Tab2, Schedule 1 for further details concerning the forecast for pole replacements. The need for pole replacements in 2008 is identified through the pole assessment and testing program carried out under the lines maintenance program as discussed in Exhibit C1, Tab 2, Schedule 2, section 3.2.2.1.

The 2008 funding will permit replacement of 7,000 poles which is an increase from the 5,200 poles replaced in 2006, and the 6,852 poles replaced in 2007. Candidates for replacement are determined through the pole assessment and testing program, which identifies poles that exhibit wood decay, checks and other defects that may jeopardize the structural integrity of a pole. The end of life determination for wood poles complies with the Canadian Standards Association (CSA) criteria for pole strength that specifies replacement when a pole has reached 65% of its original strength. This testing and replacement program maximizes reliability to customers, reduces public safety risks, complies with legal requirements and ensures optimal utilization of the wood pole population.

The 2008 spending requirement for this program is $39.8 million, which is an increase over the historic years. The increase is a result of the number of poles identified to be at end of life as a result of the pole assessment program. Historic expenditures prior to 2006 were in the $20 million per year range with an average accomplishment of 3,000 poles replaced. This compares to the 2008 level of 7000 poles. Year over year historic variations are attributed to variations in the number of poles assessed, and the number remaining to be replaced under this program, taking into account the integration with other programs. For example, sub-standard poles may also be replaced as part of system capability reinforcement and sustaining projects.

Reduced funding of the pole replacement program will increase reliability and safety risks and will prevent Hydro One Distribution from fully meeting due diligence obligations to remove known defective assets that present a hazard to workers and the public.

For additional details refer to the IJD in Exhibit D2, Tab 2, Schedule 3.

2.2.3.2 Waste Management Capital Program

The 2008 Waste Management Capital program funds the replacement of waste storage tanks that have been determined to be at end-of-life. The 2008 spending for this program is $1.2 million and is greater than the bridge year and historic years. Expenditures can vary significantly from one year to next depending on the particular need that must be addressed. Prior years' spending was to address PCB contaminated line transformers, as such the nature and need for the work was substantially different than that proposed for 2008, and a direct comparison of spending levels is not appropriate.

For additional details refer to the IJD in Exhibit D2, Tab 2, Schedule 3.

2.2.3.3 Line Projects

This program funds the refurbishment of entire feeders or sections of a feeder when the cost of maintaining individual components in the circuit becomes excessive, or a number of components have reached, or are near end-of-life, jeopardizing the reliability of the electrical supply. A decision as to the most appropriate course of action is made in each case taking into account overall condition of poles, wire and cables, condition of associated components, access for maintenance and repair, current and future load requirements and environmental considerations. These projects are further integrated with any system capacity reinforcement plans for the area.

Additional projects funded under this program address significant safety hazards and environmental issues. Specific projects in this category involve the replacement of submarine cable where the concentric neutral wires have corroded and present a hazard to the public, as well as line modifications to correct hazardous water crossings. The program also funds structural modifications required to accommodate osprey nesting sites where the location of the nest may cause power interruptions.

In addition to the projects noted above, this program funds the replacement of individual line components such as switches, reclosers and wood arms that have been determined to be defective.

The 2008 spending requirement for this program is $21.4 million and is 8% greater than the bridge year. The 2008 spending is 26% greater than 2006 expenditures. These increases are attributed to increased volume of line refurbishment, based on findings from the ACA, and an increase in planned component replacement to manage reliability and safety.

Reduced funding of this program would limit Hydro One Distribution’s ability to economically replace integrated groupings of assets identified through ACA. The alternative of replacing individual defective assets when they fail in service would be on a reactive basis and at a premium cost. Reactive replacement would result in more frequent and longer duration outages affecting customer reliability and public and employee safety.
For details concerning projects valued at $1 million or greater, refer to the IJDs in Exhibit D2, Tab 2, Schedule 3.

To illustrate the benefits of sustaining projects, Table 5 below highlights the change in reliability for a number of projects carried out over the 2004 to 2005 period. All of these projects involved replacement of end-of-life components. As can be seen in Table 5 below, the refurbishment projects resulted in appreciable improvements in the number of feeder interruptions experienced per year and the customer hours of interruption experienced per year.

Table 5: Sample of Distribution Feeder Refurbishment Projects and Associated Reliability Improvements

Number of Feeder Refurbishment Projects	Overall Average Improvement in Number of Interruptions per Year	Overall Average Improvement in Customer Hours of Interruption per Year
8	**52%**	**72%**

2.3 Meters

Meter capital addresses spending requirements for smart meter installations and customer retail meters. Funding for the meters program for 2008 and spending in the bridge and historic years, are provided in Table 6 below.

Table 6
Metering Capital
($Million)

Description	Historic			Bridge	Test
	2004	2005	2006	2007	2008
Smart Meters	-	-	14.1	76.7	164.8
Customer Retail Meters	1.2	1.4	1.6	0.4	2.5
Total	**1.2**	**1.4**	**15.7**	**77.1**	**167.3**

2.3.1 Smart Meters

On June 23, 2004 the Minister of Energy issued a directive to the Ontario Energy Board that establishes targets for the installation of smart meters for all Ontario customers by 2010. Hydro One Distribution's share, based on its proportionate share of customers in the province, is 240,000 by 2007 and approximately 1.2 million by 2010. The planned installation for 2008 is 370,000.

Hydro One is accountable for owning and installing the smart meters, collecting customer metering data over a telecommunications network ("AMRC" and "WAN") to a computer application ("AMCC"), passing the data to the data warehouse of the IESO which has been appointed as the Data Company ("DataCo"), and receiving the data back for customer billing purposes.

Hydro One's plan for the deployment of smart meters has been developed to ensure the highest long term customer value through a vision and a number of operating principles that will protect the investment from early obsolescence, while at the same time recognizing and balancing the inherent risks associated with new technology and large projects. Accordingly, Hydro One Distribution's smart metering plan is to deploy a solution that meets the Ministry of Energy's requirements at the lowest possible cost and is an enabler for other business processes and transformations. In pursuit of this plan, the Company has adopted the following operating principles:

- Develop and deploy an end-to-end architecture for both information technology and communications infrastructure that recognizes long term business needs and provides a migration path from the minimum requirements of a smart meter system;
- All hardware and devices will conform to industry standards and will be based on open architecture design (i.e. to the extent possible use non-proprietary applications);

- Material development will not occur until all, including third party, requirements are understood; and,
- A staged implementation will be deployed across all work streams to mitigate risk. This includes Advanced Metering Infrastructure ("AMI") technology, business process design, systems development and integration and customer communications.

With respect to its smart metering program, Hydro One Distribution has participated in or been affected by the following proceedings since late 2004:

- RP-2004-0203/ EB-2005-0198 – On March 17, 2005, the Board approved Hydro One Networks' plan for CDM, in which $7.8 million was allocated to smart metering to address initial start-up costs and deployment.
- EB-2005-0529 – The Board's Decision on Generic Issues respecting Smart Meters, issued March 21, 2006, which approved a $0.30 meter cost per residential customers per month, to be recovered through their monthly service charges, beginning May 1, 2006.
- EB-2006-0246 – Hydro One Networks Inc.'s Smart Meter Plan - 2006-2010 was submitted on December 15, 2006, according to the Board's Smart Meter Filing Guidelines and Requirements, issued October 26, 2006.
- EB-2007-0542 – The Board's Decision on Hydro One Networks' 2007 Distribution Rates issued April 21, 2007, approved an amount of $0.93 per month per metered customer, beginning May 1, 2007.
- EB-2007-0063 – Combined Proceeding on Smart Metering was initiated by the Board on May 18, 2007, to determine the prudence and recovery of costs associated with smart metering activities for 13 distributors, including Hydro One Networks Inc., which under the Regulations, are licensed to conduct discretionary metering activities. The Board's Decision was released on August 8, 2007. The Board determined that the purchasing decisions of the thirteen utilities involved in this

proceeding were implemented with the necessary due diligence and the terms of the contracts are prudent. The Board also allowed the cost of installation using internal staff and agreed the cost of installation in rural areas will be higher. The Board agreed with the overall costs incurred to May 31, 2007 related to the minimum functionality of all installed meters other than the cost of capital associated with project management – in this areas the Board disallowed half of the requested amount and provided Hydro One the opportunity to justify this remaining amount in this hearing. The justification of this amount is provided in Exhibit F1, Tab 1, Schedule 1.

As a result of these decisions (particularly the latter two), Hydro One Distribution's smart meter plans, including its assessments of minimum functionality and the required architecture, procurement process, contracts with vendors, plans for smart meter deployment, risk assessment and mitigation plan, and associated costs, have already been provided to the Board and will not be repeated in detail here.

The smart meter program is proceeding well. During 2006, Hydro One Distribution was able to pilot its meter installation process (with 28,000 installations) and automation tools, and to develop unit costing for mass market deployment. Statements of work and contracts were developed with the selected major vendors, which enabled detailed pricing for the majority of the products and services required. Total meter deployment from 2006 through 2007 is projected to meet the Company's target of 240,000 meter installations by the end of 2007. Other activities, such as installation of the network communications infrastructure are progressing. The "back-office" infrastructure and process design is underway and initial results from meter communications reliability testing are promising.

Hydro One Distribution's capital spending requirement of $164.8 million in 2008 reflects the continuing deployment of smart meters throughout its service territory. The related activities encompass both minimum and incremental functionality work:

- Activities associated generally with the government's regulations concerning minimum functionality, which account for $64.2 million and $136.5 million in 2007 and 2008 respectively, include the following work:
    - Installing additional smart meters and advanced metering communications devices ("AMCDs");
    - Building and expanding the advanced metering regional collector ("AMRC"), and underlying networks to accommodate an increasing number of meters coming on- stream; and
    - Commissioning and placing into service, hardware and software for the advanced metering control computer ("AMCC") to enable it to communicate and transmit quality meter data to and from the meter data management and meter data repository (MDM/R) and the Company's CIS.
- Incremental functionality activities associated with effective use of the smart meters to provide time-differentiated billing to customers and provide Hydro One the ability to leverage its AMI system for other business benefits, which account for $12.5 million and $28.3 million in 2007 and 2008 respectively, include the following work:
    - Upgrades to our CIS system to provide for Time of Use billing and related required settlement changes. This aspect of the Smart Meter program is rooted in the government's desire and directive to create a conservation culture of which time of use rates are an integral part;
    - Integration of the end to end systems including business process redesign, This integration ties the AMI systems implemented under minimum functionality with the IESO's MDMR and Hydro One's CIS system to

allow the collection of time differentiated consumption data required for TOU billing; and,

- The added cost of super capacitors in meters and batteries in the regional collectors (AMRC) that provide for real time outage reporting after and during loss of power. Having the ability to pin point outages and tie this information to our outage management system has the potential to increase customer service and reduce costs. When outages occur, especially during a major storm, there are instances where faults and damage are "nested". In these situations, without the knowledge of the state of individual services, it takes longer to locate outages and it is possible for crews to fix a problem and leave the area only to return to fix other problems downstream. This is inefficient and extends outage times. Since Hydro One is changing all its meters by 2010, this provides a good opportunity to deploy this functionality effectively.

- Project management activities associated with the overall smart meter program, which account for $2.4 million and $0.1 million in 2007 and 2008 respectively, are included in the costs above.
  - Due to the scope, complexity and specialized nature of the above tasks, the project management services and operation of a project management office (PMO) is provided by Capgemini. Capgemini was selected as the system integrator for Hydro One's smart meter program through a competitive RFP process in 2005. Although Hydro One is providing overall direction to Capgemini, the project management services and PMO are typically provided by the system integrator and is not a role that Hydro One is able to resource internally. Additional details on Capgemini's project management function are also provided as part of the

discussion in Exhibit F, Tab 1, Schedule 1 on smart meter Regulatory Asset accounts.

- The project management costs drop off in 2008 as the bulk of the PMO work Capgemini was engaged to do is planned to be largely complete by the end of 2007.
- The total project management costs incurred to the end of 2008 are forecast to be about $5 per installed smart meter unit. This is a substantial drop from the unit cost of $21.7 per installed smart meter unit reflected in the combined smart meter proceeding when the project management costs incurred to date were spread over the 62,194 units installed to the end of May, 2007.

The 2008 expenditure level is an increase over that of 2007, reflecting the higher number of planned meter installations of 370,000 in 2008 compared to 212,000 in 2007. Further details on this program are provided in the IJD in Exhibit D2, Tab 2, Schedule 3.

A reduction in the requested funding would compromise the Company's capability to deliver its planned results for 2008. These would include the installation of an additional 370,000 meters, continued development of the communication network needed to support the installed meters, modifications to the core systems to support TOU billing and the required re-engineering of business processes. Loss of this capability would severely jeopardize Hydro One's capability to meet the ambitious targets which have been set by the government.

2.3.2 Customer Retail Meters

The sustaining capital retail meter program includes the installation of meters at shared distribution stations, customer initiated meter upgrades, meter conversions at the acquired

LDCs, and sustainment of the retail meter inventory. Each of these initiatives are discussed in detail below.

The largest initiative during 2008 is an expenditure of $2.0 million related to the Company's installation of new meters at shared distribution stations. This expenditure is required to improve metering associated with Low Voltage facilities. For additional details, refer to the IJD in Exhibit D2, Tab 2, Schedule 3.

Meter upgrades are a customer-driven initiative. As required by the Distribution System Code, Hydro One Distribution upgrades an existing customer's demand meters to interval meters when their average annual monthly peak demand is equal to or greater than 1,000 kW. Hydro One Distribution's policy for new customers requires installations of interval meters if their average annual monthly peak demand is forecast to be greater than or equal to 200 kW. As well, Hydro One Distribution is planning to upgrade non-standard meters at acquired LDCs. In total, the spending for these initiatives is $0.4 million.

The Retail Meter Inventory Sustainment Program is required in order to efficiently replace in-service meters that fail, are obsolete, or that cannot be returned to service through the re-verification program. The historic level of about 2,000 new meter purchases annually need not continue in 2008, as the Smart Meter Program will cover the cost of replacing failed or obsolete meters. However, about 80,000 meters which do not qualify for smart meter replacement, still require an adequate inventory, with about 100 new meter purchases per year. The total spending for this initiative during 2008 is $0.1 million.

The 2008 spending requirement for this program is $2.5 million. This proposed funding level is $2.1 million higher than that for the bridge year and $1.1 million higher than the historic average. The increase is mainly due to the need to fund the new meter installations at shared distribution stations. These increases are offset to some degree by savings from the lower inventory of electro-mechanical meters required as a result of Measurement Canada's dispensation on meter testing ad verifications through the implementation of the smart meter program.

DEVELOPMENT CAPITAL

1.0 INTRODUCTION

Development capital are investments required to connect new load and generation customers and to enhance existing or construct new distribution facilities. These investments ensure the system's capability to provide a secure and reliable supply of electrical energy in response to new large customer connections and cumulative system-wide load growth demands and new generators. Growth is predicted through the combined use of load-forecast models, historical growth patterns, and specific load measurements taken at times of heavy loading during the year. Also considered in this program are system reconfiguration and additions in order to improve reliability.

2.0 DISCUSSION

Development capital programs fund both planned and demand (unplanned) work. Demand work represents the largest component of the program and involves work required to connect new customers or to modify customers' present service on an as required basis. Planned work includes projects designed to increase the capability of existing lines and stations, or to construct new lines and stations in response to system load growth forecasts. These programs follow the work prioritization process described in Exhibit A, Tab 14, Schedule 5.

The spending for 2008, along with the spending levels for the bridge and historic years are provided in Table 1 below.

Table 1
Summary of Development Capital
($ Million)

Description	**Historic**			**Bridge**	**Test**
	2004	**2005**	**2006**	**2007**	**2008**
Connections, Upgrades and Cancellations	94.2	100.3	104.6	105.9	103.9
System Capability Reinforcement	37.7	32.4	29.7	36.9	44.0
Distribution Generation Connection	0.0	0.3	1.5	1.8	8.4
Wholesale Revenue Meters	6.8	8.7	11.1	9.7	11.4
TOTAL	**138.6**	**141.7**	**146.8**	**154.2**	**167.7**

The 2008 proposed spending is approximately 18% above historic averages, with the increase primarily attributed to:

- Additional system reinforcement spending to address the cumulative impact of increased utilization of the distribution system.
- Material and equipment cost increases above forecasted escalation. Since 2005, the electrical industry has experienced increases in material and equipment costs in the order of 20% to 40%.
- Increase in anticipated Distribution Generation connections to meet Government Programs.
- Change in new customer connection mix moving towards more high cost subdivision connections.
- Increase in volume of the more costly full Wholesale Revenue Meter conversions to comply with market rules.

2.1 Connections, Upgrades and Cancellations

Connections, Upgrades, and Cancellations are considered demand work as these are driven by individual customer requests. The company must respond to these requests therefore they are not discretionary. The volume and funding levels of these programs for 2008 are based on consideration of historical cost and volumes, and forecast of economic variables such as Ontario GDP and Ontario Building Permits. The Investment Justification Documents (IJDs) for this program may be found in Exhibit D2, Tab 2, Schedule 3.

The Service Cancellations program involves the removal of Hydro One Distribution owned equipment. These costs are accounted for under depreciation and are therefore not identified in the capital cost tables.

The proposed funding for Customer Connections, Service Upgrades and Meter Purchases for 2008 and the spending levels for the bridge and historic years are provided in Table 2 below.

Table 2
Customer Connections & Service Upgrades
($ Million)

Description	Historic			Bridge	Test
	2004	2005	2006	2007	2008
Customer Connections	69.1	75.3	80.1	84.6	80.2
Service Upgrades	21.3	21.8	21.4	19.7	23.1
Meter Purchases	3.8	3.2	3.1	1.6	0.6
TOTAL	**94.2**	**100.3**	**104.6**	**105.9**	**103.9**

2.1.1 Customer Connections

To comply with its obligations under section 28 of the *Electricity Act, 1998*, Hydro One Distribution is required to provide a connection service to new industrial, commercial, residential, seasonal, and farm customers when requested. In response to OEB requirements, Hydro One Distribution has established service quality indicators to monitor the responsiveness of Hydro One Distribution to customer's requests. Hydro One Distribution determines the division of costs between Hydro One Distribution and the customer based on its connection policies, which are in accordance with the Distribution System Code requirements.

In 2005 and 2006 new connections averaged around 17,600 customers a year of varying types that include residential, seasonal, farm, commercial and industrial, with the largest number being residential. Hydro One Distribution provides services for all aspects of a new connection. Activities include line layout, staking, property approvals, installation of poles and conductor, installation of transformation and meters, and approvals required for any new Hydro One Distribution facilities. Customers located adjacent to a line are referred to as "lie along" customers, and under current connection policies, are not required to contribute to the connection cost for a standard type of connection. Customers requiring enhancements to the "standard connection" are required to pay for the incremental cost of these enhancements. As required by the Distribution System Code those non "lie-along" customers requiring line extensions are required to contribute to the cost of the connection, as are larger customers who require system modifications to accommodate a new increase in load.

It is estimated that about 17,600 new connections will be added to the Hydro One Distribution's system during 2008 which is in line with the recent historic average and validated by projected load forecasts. Exhibit, Tab 14, Schedule 3 sets out the distribution load forecasting details and the methodologies used. Customer capital contributions have averaged around $19 million over 2005 and 2006, and are expected to remain around that level. Included in capital contributions is the recovery of cost for connection activities such as line staking, service layout, etc. as regulated by the OEB. These miscellaneous connection charges are further discussed in section 2.5 of this Schedule.

Funding of $0.7 million has been included in this program in 2008 for the elimination of Long Term Load Transfers (LTLT). It is expected that the majority of these will be a "standard connection" type, but a number of these will require added facilities in order to connect to Hydro One Distribution's system. The elimination of LTLT is a requirement of the Distribution System Code.

The 2008 spending requirement for this program is $80.2 million after deducting amounts recovered from customers.

The 2008 spending is the same as 2006 and 6.5% greater than 2005 expenditures with the increase attributed to escalations and year over year variations in the mix and volumes of connection types.

2.1.2 Service Upgrades

To comply with its obligations under section 28 of the *Electricity Act, 1998*, Hydro One Distribution is required to respond to existing customers who require a larger service to accommodate additional load and/or modify the electrical service entrance. The costs are classified as upgrade costs. A service upgrade normally requires the replacement of secondary service wires and the preparation of a service design. Also, it may be necessary to upgrade transformer(s), replace meters or install additional transformers. Volumes of service upgrades for 2008 are projected to be 5,500 based on historic demand.

For standard service upgrades, Hydro One Distribution will provide a service layout, pole-mounted transformer, and a meter if required. Hydro One Distribution, in accordance with Distribution System Code requirements, has developed policies concerning the customer capital contributions. As such, cost for service modifications that exceed the standard upgrade installation type would be recovered from the customer on a user-pay basis. Over the 2005 and 2006 period these contributions have averaged about $4.0 million.

The 2008 spending requirement for this program is $23.1 million after deducting amounts recovered from customers, and is about 7% above average historic spending. The increase in cost over historical levels is largely attributed to escalation in equipment and material costs and change in customer mix and volume.

2.1.3 Meter Purchases

New Connections, and in some cases Service Upgrades require the purchase of new meters. Expenditures for these meters are highlighted in Table 2 above.

Projected spending for 2008 is $0.6 million which is 62% less than the bridge year and about 80% less than historic averages. The decrease in spending in this program is attributed to the expectation that most of the meters used in new connections and service upgrades will be smart meters, and will be funded under the smart meter program described in Exhibit D1, Tab 3, Schedule 2.

2.1.4 Service Cancellations

For a variety of reasons, customers may want to disconnect from the distribution system. In these cases, Hydro One Distribution owned equipment is removed, and the remaining installation is left in a safe condition. Costs related to this customer-driven activity are classified as cancellations, and Hydro One Distribution bears the cost of the work involved. Removals of this type are accounted for under depreciation.

Volume of Service Cancellations has been in the range of 4,700 to 5,300.

2.2 System Capability Reinforcement

Investments in System Capability Reinforcement provide for new and modified distribution system facilities to accommodate increase in customer load, system modifications and additions to improve system reliability, as well as additions to the system that will improve operations and asset life cycle planning. These investments are described below with details concerning spending levels provided in Table 1.
The IJDs for projects and programs greater than $1 million can be found in Exhibit D2, Tab 2, Schedule 3.

2.2.1 Capability Reinforcement

Funding for Capability Reinforcement includes investments required to ensure continued capability of the existing system to reliably supply customers in compliance with the Distribution System Code. The need for System Reinforcement projects is identified through system planning studies and load flow analysis funded under Development OM&A, Exhibit C1, Tab2, Schedule 3.

Each year new residential and rural customers are connected to the system, as are larger commercial and industrial customers. For those loads less than 500 kW, which are the majority of the new connections, system impact assessments are not required. As these customer connections accumulate over time, system elements such as conductors, transformers, regulators, switching elements are operated near their maximum ratings during periods of high load and require relief, or these elements will eventually fail resulting in damage to equipment and power interruptions. As well, the addition of customers may result in violations of service standards (i.e. voltage levels and protection criteria) if needed upgrades to system facilities are not done. For load connections greater then 500 kW, station and feeder capability assessments are completed to determine if the system is able to support the increase in load. System improvements for these situations are funded under this program with customer connection costs funded under the New Customer Connection and Service Upgrades program as outlined above in this Schedule.

Solutions to address increasing customer load can take the form of an increase in conductor size, new supply lines, a new regulating station, voltage conversion, new or increased transformation at a distribution station, or for a significant increase in customer load, the solution may involve new transmission facilities. Hydro One Distribution's planning approach assesses alternatives in a comprehensive manner that includes assessing both distribution and transmission alternatives to arrive at the optimum long-term solution. Changes in system losses are also calculated for alternatives and these become part of the decision criteria. For those situations where the preferred option involves the addition of a transmission facility, Hydro One Distribution is required to contribute to the cost of construction of transmission facilities as stipulated in the Transmission System Code.

Capability Reinforcement investments, for the most part, address customer growth after the fact except for the larger load connections that require significant modifications to the distribution system prior to connection. This program addresses customer growth that has in some cases occurred many years ago, but the system has remained within rated limits until such time as an incremental load increase will approach the system rating/service and/or protection limits. The system is monitored as detailed in the Development OM&A Exhibit C1, Tab 2, Schedule 3 to ensure that conditions that pose a threat to customer reliability and quality of power are addressed in a timely manner.

Investments under this program are designed to address both Hydro One end-use customer load growth and load growth within embedded LDCs supplied by Hydro One Distribution.

In order to maintain the integrity of Hydro One Distribution's system, address system load growth and comply with service quality standards, 2008 spending of $40.9 million is required for Capability Reinforcement Projects. IJDs for projects greater than $1 million are contained in Exhibit D2, Tab 2, Schedule 3.

2.2.2 Reliability Enhancement and System Monitoring Projects

Hydro One Distribution has established a reliability performance objective as highlighted in Exhibit A, Tab 3, Schedule 1, with the target of reaching first quartile distribution reliability by 2010 when compared to similar utilities, and thereby enhancing customer service. Analysis of potential reliability improvement initiatives has revealed that cost effective improvements can be achieved by increasing efforts in vegetation management and through improving the operability of the distribution system by adding sectionalizing capability at strategic locations on the system. During 2008 it is planned to spend $2.2 million on installing additional sectionalizing. For further details refer to the IJD contained in Exhibit D2, Tab 2, Schedule 3.

As Hydro One Distribution is predominantly a rural utility, real time monitoring of the system is not economically feasible on a system wide basis. However, Hydro One Distribution has implemented a program for real time data acquisition at strategic locations on the system. The areas of focus are heavily loaded stations that have significant risks of exceeding line and distribution station ratings. Improvements in the area of electrical system data acquisition will improve the operations of the system and customer supply. The 2008 spending for real time monitoring is $0.9 million.

2.2.3 Summary

Under System Capability Reinforcement, approximately one hundred projects are completed annually with costs ranging from $30,000 to $5 million and varying in duration from two months to more than a year. It is expected that this level of investment will be needed to address system capability issues as well as those anticipated to arise during future planning studies and load flow analysis.

The 2008 spending for System Capability Reinforcement is $44.0 million, which is an increase of 20% over the bridge year and 32% above the historic average. The increase over the historic period is in part attributed to escalation in equipment and material costs. The remaining increase is a reflection of the cumulative impact of increased utilization of the distribution system and the corresponding increase in volumes required to address local customer growth, as well as the continuation of the sectionalizing project planned for 2008.

Reduced funding in this program would result in overloading of system components, causing power quality degradation and resulting in an increased risk of substandard supply conditions with possible equipment failure. In turn, this would lead to customer complaints and more frequent and longer duration interruptions. As well, there is a risk that system protection and co-ordination schemes may be adversely affected, resulting in equipment damage.

2.3 Generation Connections

In accordance with its Distribution license, Hydro One Distribution is required to connect new generators that comply with the requirements of the Market Rules, the Distribution System Code, and all applicable codes, standards, and rules. The number of new generators applying for connection, and the potential number which will actually connect, have grown immensely due to the provincial government's initiatives to promote distributed generation, and the resulting procurements implemented by the OPA. In particular, the Renewable Energy Standard Offer Program (RESOP) has led to about 1,000 projects applying for either Initial Feasibility Assessments (IFAs) and/or more detailed Connection Impact Assessments (CIAs). The numbers of these renewable projects applying to Hydro One is a result of most high potential renewable areas in the province falling within our distribution service territory. There is also some demand resulting from the Net Metering program and from load displacement projects. Applications continue to be submitted under these programs and the OPA's recommendation to implement a new Clean Energy Standard Offer Program (CESOP) could lead to substantially more demand.

The actual number of projects that will connect is still quite uncertain. As of June 30, 2007, 34 of the 113 projects that have received a CIA have gone on to request an estimate and 8 projects have actually signed a Connection and Cost Recovery Agreement (CCRA) committing to pay for connection. The forecast number of connections on which the plan is based is shown in Table 3 below.

Table 3 – Generation Connections

Category	2008
Large Generators	4
Mid-size Generators	40
Small Generators	20
Net Metering Generators	20
Load Displace. Generators	1
Power Quality Monitoring	25

The investments included for generation connections cover connection facilities as well as local system improvements required for reliable generation incorporation into the distribution system and avoidance of negative impacts on other customers. Work may include reconductoring circuits, altering facilities including protective devices, and upgrading breakers because of increased short circuit values.

Generation developers are normally responsible for all connection costs resulting in the majority of these cost being recoverable through capital contributions. However, in some cases, the generator may not be the sole beneficiary of a required system improvement. Hydro One Distribution is required to pay for the portion that would benefit other distribution system customers. It is estimated that the costs related to benefits to others amount to about 30% for connection of generators in the large (>10MW) category, 25% for mid-size (500kW to 10MW) projects and 15% for small (<500kW) generators. In aggregate this results in $2.8 million of the net costs in 2008.

Upgrades to Hydro One's distribution lines (poles in particular) may also be required in cases where the customer chooses to make use of Hydro One facilities rather than build their own. Based on Hydro One's experience with joint use , it is anticipated that in these situations, Hydro One will be accountable for 83% of the upgrade costs and the customer will contribute 17%. Provision for the associated costs is included in this filing and results in net costs of $4.4 million in 2008.

Power quality (PQ) impacts on Hydro One's distribution system and customers is a key issue associated with certain types of generators (such as wind). To ensure this is appropriately understood and managed, Hydro One Distribution is installing PQ meters in the vicinity of possible wind generation connections to enable monitoring of customer PQ issues in these areas. The associated capital is not covered by contributions from generators and amounts to $1.2 million in net costs in 2008.

The total net 2008 Capital requirement of $8.4 million for this program is $6.6 million higher than the bridge year and $6.9 million higher than 2006 primarily due to a larger number of connections with some increase due to increased costs for shared use facilities.

2.4 Wholesale Revenue Metering

Wholesale revenue meters (WRM) are defined in the Market Rules as revenue metering that measures the flow of electricity from the IESO-controlled grid at transformer stations, distribution stations and other points of supply to distribution companies and direct wholesale customers. WRM's are used to settle the purchase of energy, and where the point of supply is directly connected to the IESO-controlled grid, they are used to settle the purchase of transmission services with the IESO administered market.

Wholesale meters fall into two categories: those under the transitional arrangement in accordance with the Market Rules and those assigned to Hydro One Distribution for wholesale settlement with the IESO-administered market.

In accordance with Market Rules, accountability for legacy WRM owned by Hydro One Transmission will move to market participants, including Hydro One Distribution, during the period 2003 to 2008. By the end of 2008, it is projected that Hydro One Distribution will be responsible for a total of 375 WRMs. This number has changed over time, as a number of meters that were transitioned have been de-registered from the Wholesale Market and are no longer categorized as WRMs.

In the year accountability is assumed by Hydro One Distribution the legacy WRM must be upgraded, either fully or partially, to comply with the Market Rules. Partial upgrades at a meter point include the upgrade of meters, and may include upgrades to some, but not all, current and voltage transformers. Measurement Canada and the IESO have made provision for the transition by allowing partial upgrades during the first seal expiry, with remaining non-compliant components to be upgraded at the second seal expiry if not already completed. This capital program funds the cost of these upgrades.

The 2008 spending requirement for this program is $11.4 million. These costs align with the schedule set out for WRM conversion driven by the seal expiry date as stipulated by Measurement Canada. Project costs vary from year to year based on volume of meters requiring conversion and on scope of work associated with the particular meter, i.e., partial or full conversion.

Further details on this program can be found in the IJD in Exhibit D2, Tab 2, Schedule 3.

2.5 Miscellaneous Connection Charges

Embedded within the capital contributions identified above for Customer Connections and Service Upgrades, there are a number of miscellaneous services as identified in Table 4 below. The rates for these services are approved and regulated by the OEB. The revenues that will be generated from these services are netted from the costs to undertake the work described below. The related costs and revenues are included in Section 2.1.1 –

Customer Connections. A description of these services and associated volumes are provided below.

Table 4 – Miscellaneous Services

Service Description
1. Crossing Applications – Pipeline, Railroad, Water
2. Line Staking
3. Service Layout Fee – Basic
4. Service Layout Fee –Complex
5. Central Metering (new) < 45kW
6. Conversion to Central Metering < 45kW, > 45kW
7. Temporary Service

2.5.1 Crossing Applications

When a customer requests new line construction where the overhead or underground/submarine line will cross existing pipelines, railroad lines, or bodies of water, approvals must be granted from the respective authorities prior to construction. In these cases, the line must be designed and the design, showing the proposed location, clearances, etc., transferred to an engineering drawing. The engineering drawing is then submitted for approval to the approving authority. The cost of the fieldwork, design, preparation of drawings, and processing the application and the cost from the approval authority if any, are borne by the customer.

	2004 volume	2005 volume	2006 volume	2007 volume	2008 Volume
Crossing Applications	**155**	**142**	**91**	**130**	**130**

2.5.2 Line Staking

For new line construction initiated by a customer, Hydro One Distribution specifies the route, the spacing of poles, the size of conductors, type of insulators, class and height of poles, and any tree or brush clearing required. The staking information is used by the customer's contractor or by Hydro One Inc.'s Customer Operations business to ensure the construction is in accordance with current standards.

	2004 volume	2005 volume	2006 volume	2007 volume	2008 Volume
Line Staking	**289**	**241**	**205**	**200**	**200**

2.5.3 Service Layout

Hydro One Distribution will provide an initial service design (layout) at no charge to the customer, regardless of the customer class or the complexity of the design. However, if the customer wishes to alter the initial design, the additional design costs, as determined by the complexity of the design, are recovered from the customer.

For the majority of service designs for residential, farm, and single-phase commercial services, the design is relatively simple and routine. For large three-phase commercial, industrial, and some farm services, the design complexity increases as the size of the load to be serviced dictates special consideration of transformation capability, special metering needs, conductor sizing, etc.

	2004 volume	2005 volume	2006 volume	2007 volume	2008 volume
Service Layouts (altered)	**232**	**264**	**264**	**260**	**260**

2.5.4 Central Metering

Pole-mounted central metering is an option a customer may choose when the customer has several buildings on one property that all require electrical service. One central metering installation replaces the need for each building to have its own service and its own metering resulting in savings to the customer.

For installations where the load is greater than 45kW, the expected revenue to Hydro One Distribution offsets the cost of the required instrument transformers. For installations where the load is less than 45kW, the customer is charged for the costs of the instrument transformers. These costs are considered incremental as the normal metering installation sized to a load of less than 45kW would not require the special transformers.

	2004 volume	2005 volume	2006 volume	2007 volume	2008 volume
Central Metering	**1,095**	**1,095**	**1,095**	**950**	**950**

2.5.5 Conversion to Central Metering < 45kW, > 45kW

Customers who request a conversion of conventional metering to central metering require a new service layout, a change in their account, the removal of existing meters and equipment, and installation of new equipment. This involves site visits for the layout and equipment modifications, and administrative work. If the installation is to supply a load of less than 45kW, the customer is charged for the associated labor plus the incremental cost of the instrument transformers. For loads in excess of 45kW, labor costs only are charged to the customer but there is no incremental cost to the customer for the instrument transformers.

	2004 volume	2005 volume	2006 volume	2007 volume	2008 volume
Conversion to Central Metering < 45kW, (approx. numbers)	**792**	**792**	**792**	**800**	**800**
Conversion to Central Metering > 45kW (approx. numbers)	**126**	**126**	**126**	**150**	**150**

2.5.6 Temporary Services

Temporary services are available to construction sites, etc., for any period requested by the Customer. In these circumstances, the customer is charged a fee to establish and remove the temporary service. If the customer also requires transformation, an additional charge is applicable.

	2004 volume	2005 volume	2006 volume	2007 volume	2008 volume
Temporary Services	**211**	**211**	**211**	**211**	**211**

OPERATIONS CAPITAL

1.0 INTRODUCTION

Operations capital investments are required to implement, enhance and modify the physical infrastructure, systems and tools that are required for distribution operations. These investments deliver improvements to Distribution System performance in the form of reduced outage duration, improved product quality, information required for regulatory reporting in accordance with the Distribution System Code and improved information to customers. They also deliver efficiency improvements to Hydro One Distribution's operating function and ensure that the sustaining costs for infrastructure, systems and tools are minimized.

2.0 DISCUSSION

During 2003 and 2004 Hydro One Distribution consolidated the central operations function to the Ontario Grid Control Centre (OGCC) and now operates the 27.6kV and 44kV subtransmission system and dispatches for the entire distribution system from one central location. Operations relies on a number of systems and tools to efficiently carry out the operating function at the OGCC. The primary systems are the Network Management System (NMS), the Outage Response Management System (ORMS) and the Interactive Voice Response (IVR) system. Details concerning each of these systems are provided in Exhibit C1, Tab 2, Schedule 4.

These systems are all functioning well and fully delivering their intended benefits. Further significant benefits can be achieved from the NMS and ORMS systems by enhancing the monitoring and control of the distribution network and improving the management of historical information. As well, Hydro One Distribution is carrying out a multi-year program to install smart meters. Incorporating the information from these smart meters into the ORMS system will improve the efficiency and performance of outage management and communication with customers. In addition, the smart meter initiative provides a communication network which enables remote control of new distribution equipment via the Network Management System.

The proposed spending for 2008 along with the spending levels for the bridge and historic years are provided in Table 1 below.

Table 1
Operations Capital

Description	Historic			Bridge	Test
	2004	2005	2006	2007	2008
Operations Capital	6.3	4.7	2.1	2.0	3.6

The increase in 2008 over the bridge and historic years is required to continue with the proposed investments to improve Operating efficiencies as noted above.

3.0 SYSTEM ENHANCEMENT PROJECTS

Specific projects planned for 2008 are described below. Investment Justification Documents (IJDs) for projects with net capital requirements over $1 million can be found in Exhibit D2, Tab 2, Schedule 3.

3.1 Distribution Operating Facilities Sustainment and Enhancement

Although the Operating amalgamation was completed in 2004, some Distribution Operating Facilities commissioned in 2001 and 2002, which were moved to the OGCC, will be requiring refurbishment and capacity expansion in 2008. This project work includes ORMS and a portion of the IVR system.

The enhancement based project work provides for real time feeder analysis in NMS to improve the management of the sub-transmission feeders, enabling the ability to deploy alternate feeder configurations quickly and expedite restoration of some or all of the affected customers.

The combined cost of these projects is $0.8M in 2008.

3.2 Outage Response Management for Smart Meters

ORMS currently gets all of its information on prevailing outages from customer phone calls. This is achieved through interfaces to the software used by the Call Centre agents and to the Call Centre IVR system. The installation of smart meters and the telecommunications to retrieve data from them creates the opportunity to improve the efficiency and accuracy of ORMS with respect to the prompt identification of the existence, location and extent of outages and the monitoring of momentary outages.

The cumulative benefits to ORMS will be improved reliability performance through better and more complete monitoring and reporting, enabling quicker response times and timely correction of emerging issues.

This investment will require new hardware and software features in the central smart meter data collection facilities and in ORMS to allow this information exchange to take place in near real time. It is expected that it will take one to two years for Hydro One's suppliers of these systems to deliver these features. Funding of $0.5 million is required in 2008 for the first phase of this project to complete detailed requirements and pilot testing.

3.3 System-Data Archiving and Historical Data Management for Distribution Operations

NMS and ORMS contain a large quantity of data on the historical performance of the Distribution System assets, response times to outages, customer supply performance, outage causes, etc. Extracting the data from the existing databases involves a large amount of manual effort and time delays. This is costly and severely curtails the discovery process needed to identify all the asset and performance issues. This investment will provide long term archiving of distribution operations data as well as data mining and analysis facilities that will allow distribution system planning staff the ability, on a self-serve basis, to retrieve and analyse information to improve system planning and asset investment decisions. The benefits will be better decision-making on distribution system investments, as well as saving labour costs in the data extraction, reporting and analysis processes. Hydro One originally planned to complete this work earlier, but adjusted the schedule to allow integration with the Cornerstone architecture. This integration should reduce implementation cost and allow improved correlation between this historical information and such data as work program accomplishments contained in the new work management system. The 2008 cost for this project is $1.3 million. For additional details, refer to the IJD in Exhibit D2, Tab2, Schedule 3.

3.4 NMS Enhancements for Distribution Monitoring and Control

Hydro One has a program to install sectionalizers on feeders and monitoring and control facilities in Distribution Stations. The program targets the worst performing feeders and most heavily loaded Distribution Stations and is an element of Hydro One's strategy to improve Distribution System reliability performance. While sectionalizers and Distribution Station monitoring facilities deliver benefits while operating on a stand-alone basis in automatic configuration, greater benefits are achieved when they can be remotely monitored and operated from the control centre. This investment provides the system enhancements required at the OGCC to deliver those benefits. The 2008 cost for this project is $1 million. For additional details, refer to the IJD in Exhibit D2, Tab2, Schedule 3.

SHARED SERVICES AND OTHER CAPITAL

1.0 INTRODUCTION

Capital expenditures under the Shared Services program support the Sustainment, Development, and Operations work programs of Hydro One Networks Inc. As such they consist of assets that are largely shared by both the Distribution and Transmission businesses. Shared assets include Information Technology installations such as applications software and computer equipment, land, buildings, office equipment, transportation and work equipment (T&WE), tools, and service equipment.

Shared services cost levels are fully reviewed as part of the annual business planning process described in Exhibit A, Tab 14, Schedule 1.

Table 1
Shared Services & Other Capital Allocated to Distribution 2004-2008 ($ Millions)

	Historic			**Bridge**	**Test**
	2004	2005	2006	2007	2008
Information Technology	10.6	19.5	19.3	46.7	43.3
Facilities & Real Estate	2.8	1.8	2.1	6.4	4.4
Transport & Work Equipment	8.8	30.4	31.3	31.2	39.2
Service Equipment	3.2	1.6	2.2	4.5	5.3
Conservation & Demand Management	0.0	0.0	2.9	7.9	0.0
Other	(3.2)	0.1	(0.5)	0.1	(14.4)
Total	22.2	53.4	57.4	96.7	77.8

Table 1 is a summary of the Distribution portion of the Shared Services Capital over the Historical, Bridge, and Test year. Exhibit C1, Tab 5, Schedule 3 outlines the appropriate cost allocation drivers that have been utilized to derive the Distribution allocation of this capital.

The following table provides an overview of the various cost categories for the period 2004 through 2008, highlighting the total capital spending for Shared Services and Other Capital, as well as the portion allocated to the distribution business.

Table 2
Total Shared Services & Other Capital ($ Millions)

	Historic			**Bridge**	**Test**	
	2004	2005	2006	2007	2008	2008 Dx
Information Technology*	20.0	39.6	34.3	95.2	90.2	43.3
Facilities & Real Estate	5.9	2.6	3.6	9.6	9.8	4.4
Transport & Work Equipment (T&WE)	13.5	40.5	41.2	41.1	51.6	39.2
Service Equipment	4.9	3.1	3.9	7.9	9.3	5.3
Conservation & Demand Management	0.0	0.0	2.9	7.9	0.0	0.0
Other	(2.2)	3.1	6.1	1.8	(14.4)	(14.4)
Total	42.1	88.9	92.0	163.4	146.4	77.8

* include Customer Care capital expenditures

The growth in Shared Services and Other Capital is primarily driven by the need to support a larger work program and, accordingly, a larger work force. The need for additional T&WE and facilities is need to support the activities associated with the execution of the Hydro One Distribution work program. In addition, this capital cost growth is associated with an over-all IT strategy that includes the replacement of many of the current large information systems (i.e. Work Management) as they reach their ‘end of life’. The Cornerstone initiative, part of the Information Management costs shown above, is a major business transformation initiative that deals with not only end of life replacement issues but also provides a platform for further effectiveness and efficiency gains at Hydro One. (Reference Section 2.0 of this exhibit)

Sections 2.0 through 8.0 details the capital requirements which make up the Shared Services Capital program.

2.0 INFORMATION TECHNOLOGY

Information Technology (IT) refers to computer systems (hardware, software and applications) that support business processes used by employees throughout the organization. IT infrastructure includes the voice and data telecommunication networks; data centre installations; and computer equipment (servers, computers and printers) that enable employees to access IT systems. Staff access software applications from offices, and field locations using the wide area network, local area networks or through virtual private network connections.

Capital programs include annual maintenance investments so that existing IT assets are kept current to maintain continuity of operations and minimize risks of interruption or failure. IT capital programs also include investments in newly developed projects to either replace old technology or to introduce new technological processes to serve the business operations.

For accounting purposes, IT capital expenditures are defined to include software expenditures for projects and programs that in total cost more than $2 million. Also included in this category are minor fixed assets and hardware expenditures such as desktop computers, which are required as part of ongoing refresh and replacement programs. IT investments are made in accordance with approved business strategies, follow the IT Governance process described in Exhibit C1, Tab 2, Schedule 6, and are subject to a formal review process.

A significant capital investment in major enterprise applications and systems was made concurrently with the de-merger of Ontario Hydro in 1999 to ensure the new company would have the required business systems and to ensure the de-merged systems would be Y2K compliant.

Investments in enterprise applications made at or around that time were "best of breed" applications and included: Customer One - customer information and billing system (1998); PassPort - accounts payable, purchasing, inventory and supply management system (1999); PeopleSoft - financial and human resources system (1999). Other than in 2002, when an upgrade was made to the PeopleSoft system, the applications have not been upgraded. Certain of the applications have undergone significant customization to provide additional functionality since the date of their installation.

These applications have reached, or are approaching, their end of life. An application approaches its end of life when the application does not provide sufficient functionality or does not have additional capacity to be redesigned or modified to add such functionality to meet current and foreseen business needs. Additionally these older versions are no longer, or will no longer be, supported by the software vendors. Work which is planned for the major application replacement program (Cornerstone) in 2006, 2007 and 2008 is discussed below under the heading Development Projects.

Hydro One's approach to ensuring ongoing reliability and capacity is to upgrade and/or renew/replace applications and systems when required to either meet changing business needs, when the software application or systems are no longer vendor supported, or to mitigate business risks. Hydro One's objective is to maintain its systems as near to a current basis as possible to ensure its technology environment is vendor supported.

In addition to the replacement cycle for existing systems, organic business growth and increased reliance on technology requires the systems to grow to accommodate the business needs. In data storage, Hydro One has observed increases averaging 30% per annum. According to a June 2006 White Paper by IBM, this is in line with Industry expectations estimated at 37% per annum. Faster processing speeds to address upgraded application requirements are also facilitated through server and storage improvements or replacements. The increasingly heavy reliance of technology in the field and at field locations has continued to place an upward demand on the IT data infrastructure in terms of volume, speed, connectivity and concurrent use. Field office locations are increasingly utilizing larger more complex business applications such as Passport, Customer One, ArcFM (Geographic Information Spatial application used for Distribution design work) and outage management applications (ORMS). Data networks (wide area and local area networks) are monitored on an ongoing basis and upgrades are made as required to address the business needs and to ensure that application performance is acceptable.

2.1 Total IT Capital Expenditures

As noted above IT capital expenditures are driven by the business need to upgrade applications and hardware that are no longer vendor supported, to mitigate business risks, to address additional business requirements, to maintain system performance and to meet the custodial requirement of ensuring technology assets are being properly and appropriately managed and maintained.

Table 3 lists the capital expenditures for programs and projects**.**

Table 3
Total IT Capital Expenditure
($ Millions)

	Historic			Bridge	Test	
Description	**2004**	**2005**	**2006**	**2007**	**2008**	**2008 DX**
Software Refresh & Maintence	**3.0**	**14.2**	**8.6**	**11.9**	**7.1**	**3.3**
Minor Fixed Assets Program	**8.8**	**14.6**	**13.2**	**17.5**	**14.6**	**8.3**
Development Projects	**8.2**	**10.8**	**12.5**	**65.8**	**68.6**	**31.7**
TOTAL	**20.0**	**39.6**	**34.3**	**95.2**	**90.2**	**43.3**

Capital IT expenditures respond to the needs of three general business drivers and are undertaken as projects or programs:

- Software Refresh and Maintenance Program ensures continued operations of the installed IT application infrastructure
- Minor Fixed Assets (MFA) program ensures the continued operations of the installed IT hardware infrastructure. Expenditures in this category address equipment needs which are generated by the growth in demand for IT services, in addition to the replacement of end-of-life and under-capacity assets in IT and in the Business Telecom network.
- Development Projects replace or upgrade older and end-of-life applications or develop new applications or processes, including those:

- that have become inadequate for current functional needs;
- that require new applications to improve Business operations
- that result from legislative or market driven initiatives

Software Refresh and Maintenance includes costs related to upgrading existing operating systems.

MFA includes desktop computing equipment, field tablet computers, mainframe and storage systems, servers, and peripherals and telecommunication infrastructure including PBX's, computerized telephony interfaces etc. Other capital items include systems applications and operating systems required to operate the IT and telecommunication infrastructure hardware.

Development projects include the cost for new applications or the replacement of exiting applications which are at end of life.

The following architecture principles underlie IT strategy and planning and as such will guide the required application upgrades that will take place over the next 5 years:

- Applications will be "off the shelf" with built-in protocols (tested and generally used throughout like industries).
- The system architecture will be on an open standards platform allowing systems to run on any hardware platform.
- Middleware, interfaces and hubs, will be used as appropriate to facilitate application interconnectivity.
- Systems architecture and chosen applications will be:
    - robust (generally understood to mean unlikely to fail, but rapid response if it does)

  - secure (generally understood to mean 3-tiered, fire-walled and password protected)
  - flexible service oriented architecture (generally accepted as the most appropriate and efficient IT strategy).
- System hardware will be upgraded as required to support the new application.
- Costs will be managed on a total cost of operations basis.

In support of new and planned applications the current hardware infrastructure will be upgraded and designed to:

- improve disaster recovery processes;
- improve system security;
- facilitate the increased application of mobile technologies;
- continue the transition to storage area networks that benefit from generally accepted industry practices;
- secure improved functionality from new and expected technology.

IT capital project spending increases significantly from 2002 through 2008 and beyond as existing enterprise applications are upgraded and replaced. The larger number of smaller projects which had been undertaken in 2003 through 2006 will decline and be replaced by a phased series of large projects.

The major planned capital projects that will be funded in 2007 and 2008 are described below.

2.2 Software Refresh and Maintenance Program Capital Expenditures

Table 4 lists the capital expenditures for the software refresh and maintenance program.

Table 4
Software Refresh and Maintence Program Capital Expenditure
($ Millions)

	Historic			Bridge	Test	
Description	**2004**	**2005**	**2006**	**2007**	**2008**	**2008 DX**
Software Refresh & Maintenance	**1.7**	**2.6**	**1.0**	**11.9**	**7.1**	**3.3**
Windows (O/S)	**1.4**	**11.6**	**7.6**	**0.0**	**0.0**	**0.0**
TOTAL	**3.0**	**14.2**	**8.6**	**11.9**	**7.1**	**3.3**

Hydro One utilizes just over 700 commercial software programs in order to equip its employees with the required technologies to perform their tasks efficiently and safely. The software refresh and maintenance program provides the needed software vendors' releases, periodic version upgrades, and replacements of applications that meet the total capital threshold of $2 million aggregated.

Applications are replaced or upgraded with the line of business involvement to address their business needs and to ensure that applications remain compatible with current IT platforms and other interfacing applications. In this manner, vendor support is maintained to help fix breakdowns or other issues that may occur with the applications. Funding decisions are made based on software lifecycles, vendor schedules, reliability requirements, and experience with similar initiatives/projects.

In 2005-2006 work was undertaken to upgrade the Microsoft Windows operating system technology from Windows NT and Windows/Office 98 to Windows XP and Office 2003 for all users operating on the Hydro One system. In addition to upgrading the desktop operating system and e-mail application the platform was simplified and consolidated to improve system reliability, redundancy and to ensure better security. Coincident with the XP software investment in 2005/2006 a significant increase in MFA investments for computers, servers and storage was required to replace those operating on the old Windows NT/98 platform to retain functionality in the XP/2003 environment.

Software refresh and maintenance expenditures identified for 2007 and 2008 include an upgrade to the Open Market Systems to utilize the functionality of the existing Company hub technology, increased use of Citrix solutions, virtualization of the Storage Area Network to improve data retention and stabilize storage costs, collaboration technology investments using Windows Sharepoint, and a number of other technology investments related to intrusion detection, firewalls, enhanced security and to a greater use of portal technologies.

In 2007, application investment was undertaken in the area of security related to intrusion detection and network access controls; upgrades to oracle database versions and database management tools; upgrades to the middleware application , the informatica tool and to the mainframe operating systems.

2.3 Minor Fixed Assets

Table 5 lists the capital expenditures for IT Minor Fixed Assets.

Table 5
IT Minor Fixed Assets Programs Capital Expenditures
($ Millions)

	Historic			Bridge	Test	
	2004	2005	2006	2007	2008	2008 DX
IT Mainframe, Servers and Strorage Program	1.8	5.9	4.7	11.5	5.9	3.4
IT Desktops, Laptops, Tablets, Printers & Plotters	5.0	6.9	5.9	4.8	7.1	4.0
Telecom Networks & PBX/Voicemail	2.1	1.7	2.5	1.2	1.6	0.9
TOTAL	8.8	14.6	13.2	17.5	14.6	8.3

Minor Fixed Asset investments are for IT hardware and include specific programs to refresh older hardware such as computers. Equipment refresh is planned to ensure that if system upgrades or applications are added over the life of the hardware that the system will continue to be functional with only a minimal upgrade being required. This strategy minimizes the costs of ownership, ensures operational risk is kept at an acceptable level, and maintains functionality. Planned funding is based on equipment lifecycles. This work is broken down into the categories discussed below for the expenditures shown in Table 5.

2.3.1 MFA: IT Mainframe, Servers and Storage Sustainment program

This investment in servers and mainframe computing capability is an ongoing infrastructural obligation for Hydro One information technology.
The majority of the costs in the MFA category in 2006 were spent on replacement of UNIX servers and on Windows servers. The UNIX server replacement cost has been brought forward from future years to ensure improved system reliability and to respond to and manage projected annual growth in demand for additional IT processing and storage capacity. The replacement of the UNIX servers with more modern and efficient equipment addresses the end of life issues, which the Company would face with some of the existing UNIX servers.

Included in the 2006 and 2007 work program are improvements to the current Disaster Recovery (DR) strategy and processes. In 2007 costs included upgrading the mainframe computer and the associated operating system. The DR program allows for the recovery of critical Hydro One systems in the event of a major technology disruption. The DR project will take advantage of the replacement of a number of existing UNIX servers and storage devices by transferring the replaced units to the recovery and back-up role.

UNIX and Windows servers are used to run business applications, networks, web services and email. Data storage devices are used by business applications and email to store and retrieve data. In assessing when to replace or add additional servers and storage devices vendor's end-of-support-life, capacity requirements, maintenance costs, and systems criticality are assessed. Hardware upgrades are ongoing costs and are needed to maintain reliable service for business applications.

The funding for the mainframe, servers and storage refresh program varies year to year depending upon hardware lifecycles, capacity management, and business requirements for increased processing capacity. In 2005 and 2006 the spend increased to address end of life issues with a number of e-mail exchange and file servers which were replaced coincident with the Windows XP/2003 project. In 2007 costs, as noted, include server upgrades to the DR site and the consolidation of and replacement of servers at the main data centre. In 2008 costs in this category include servers and infrastructure which are undergoing refresh at the Grid Operations Data Centre. Distribution applications supported at the operations centre include distribution outage and reporting applications.

2.3.2 MFA: IT Desktops, Laptops, Tablets, Printers, and Plotters Sustainment Program

Desktop and laptop computers are used by most Hydro One staff for office productivity applications (email, word processing, spreadsheet, presentation, and personal databases) and for business applications such as PassPort, ArcFM and PeopleSoft among many others. Rugged tablet computers are used by field staff using Geographical Information System (GIS) based applications for doing system design and asset condition assessments. Printers and Plotters are used by most Hydro One staff throughout the company.

Hardware upgrades are required to accommodate new software processing requirements, to replace end of life equipment and to maintain reliability. Properly programmed equipment refreshes can maintain or reduce maintenance costs. Hardware maintenance and capability costs tend to increase with aging hardware that is no longer under vendor warranty. Hydro One’s intent is to replace desktop computers every four years, laptops every three years, and printers and plotters every four to five years. This is consistent with industry practice and ensures that spares which are maintained by service technicians are consistent with the computer population at Hydro One.

Hardware and support service pricing combinations are compared in the market regularly and at times of major purchases in line with corporate procurement policies.

The funding for desktops, laptops, tablets, printers, and plotters varies year to year depending upon hardware lifecycles, business needs and projected requirements to meet forecast work programs. Funding costs in 2005 and 2006 reflect the acceleration in the laptop and desktop refresh program and tied back to the XP upgrade, whereby obsolescence caused by the added application requirements caused 2,100 and 2,382 desktop/laptop units respectively to be replaced.

Tests using XP applications on existing laptop computers, which had been enhanced with additional memory, did not result in acceptable performance. The cost of enhancing the existing equipment combined with the still suboptimal performance of the equipment when XP software was installed, and then combined with the hardware's end of life issues, negated any business benefit that might have been achieved by delaying the full replacement of the equipment. Therefore, the decision was made to purchase new hardware that met current needs and standards. Ongoing sustainment funding for laptop and desktop equipment and peripheral replacement consistent with the refresh objectives noted above, is reflected in the cost projections for 2007. Costs for 2008 include additional equipment which will be purchased for new staff.

2.3.3 MFA: Telecom Networks and PBX/Voicemail Sustainment Program

The telecom assets of Hydro One are many and have a large variety of install dates, lifecycles, and capacities. Data and voice hardware is improved or replaced over time as part of ongoing program management. Continuous initiatives are undertaken to improve data and voice communication efficiency across the wide area networks, the local area networks, the virtual private networks. These upgrades are also necessary to ensure systems are supported by third party vendors.

The telecom MFA program includes the work to rewire local area networks, replace end of life data network switches and routers, upgrade telephone PBX switches, and replace un-interruptible power systems (UPS). Work in this category includes the replacement of end of life hardware and software in the Internet Security Node which is used for authenticating Market Open business to business transactions and for internet access to Hydro One Networks Inc. applications.

The Telecom MFA program is needed to maintain reliable telecommunications availability plus capacity as well as network security against intrusions by computer hackers, viruses and worms. IT will replace telecommunications hardware facilities that are at end of life, no longer able to meet changing function, capacity or performance needs, and/or expensive to repair and unreliable because they are no longer supported by vendors.

The telecommunication hardware includes wiring, switches, and routers used to provide local area network (LAN) and wide area network (WAN) services to offices throughout Ontario. The business telecom network is used to transmit data required to run business applications, for email, to perform ongoing systems and information backups and to push new applications or software upgrades to end users in the field.

PBX/Voicemail hardware includes private branch exchange (PBX) and key set telephone switches, and voice mail equipment used to provide business telephone services to Hydro One employees at central and field locations throughout the province.

Within the Hydro One voice and data network there are more than 500 routers/switches and hubs that connect to 70 PBX's and 35 smaller multi-line office sets. A majority of the routers/switches and hubs are reaching end of life.

The investment in business telecommunications Networks and PBX/Voicemail is undertaken to replace end-of-life assets and to maintain service reliability and security. The strategy is again to replace equipment that is no longer supported by vendors. For network equipment the refresh occurs about every five years and about every ten years for PBX/Voicemail equipment.

The funding for business telecommunications Networks and PBX/Voicemail varies year to year depending upon hardware lifecycles, business needs for increased bandwidth and availability of resources. Changes to business applications and work methodologies, the introduction of new applications and new work processes, may require the upgrades to occur more frequently.

2.4 IT Development Projects Capital Expenditures

Table 6 lists the capital development project expenditures of IT.

Table 6
IT Development Projects Capital Expenditures
($ Millions)

	Historic			Bridge	Test	
Description	**2004**	**2005**	**2006**	**2007**	**2008**	**2008 DX**
Cornerstone Project	**0.0**	**0.0**	**0.0**	**60.4**	**63.0**	**28.0**
CIS/CSS Hybrid Upgrade/CRM	**0.0**	**0.0**	**0.4**	**2.9**	**2.0**	**2.0**
CTI Upgrades	**0.0**	**1.5**	**3.3**	**0.7**	**0.0**	**0.0**
ArcFM	**6.3**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**
APCi/WEP	**0.9**	**8.7**	**8.0**	**0.9**	**0.0**	**0.0**
IREIS	**0.3**	**0.0**	**0.0**	**0.0**	**0.3**	**0.1**
PeopleSoft Upgrade	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**
Mobile IT	**0.6**	**0.0**	**0.0**	**0.0**	**3.0**	**1.4**
Asset Data Collection and Data Mart	**0.0**	**0.6**	**0.8**	**0.9**	**0.0**	**0.0**
Asset Information System	**0.0**	**0.0**	**0.0**	**0.0**	**0.4**	**0.2**
TOTAL	**8.2**	**10.8**	**12.5**	**65.8**	**68.6**	**31.7**

The following IT Capital projects are active in the Bridge year 2007 and/or are planned for the Test year, 2008.

2.4.1 Cornerstone Project

The major software applications used by Hydro One consist of Peoplesoft (Finance and HR), Passport (Supply Chain, Procurement, Accounts Payable) and Customer One (CSS: Customer Service System). These systems were implemented in anticipation of the de-merger of Ontario Hydro and to address Y2K concerns. The applications were modified extensively following their implementation to provide the required business functionality. Functionality of these core systems was also enhanced by the addition of some 700 separate applications, which allow the field and head office staff to complete their work.

These core systems are aged and beyond economical maintenance. They no longer efficiently fulfill the Company's growing needs for information management and reporting. The PassPort system has been the daily source of asset and work information since its inception in the de-merger days of the late 1990's. The financial system, Peoplesoft, uses PassPort information and derives financial reporting information. The CSS system is used for billing and collections and by customer service representatives to address customer inquires on a daily basis. The systems have limited interconnectivity, which has resulted in the requirement for manual input duplication or other workarounds. Bridging of data and the development of workflow between systems is costly and complex.

All three of these extremely critical systems have been customized and altered to varying degrees to meet the current needs of the Company, over the past several years. Vendors are unwilling to support these older applications and have been unable to help with add-on customized changes that have been initiated. As software vendors for these applications are moving to new architectures, support for these older applications is being phased out. This leaves the Company with the option of continuing with these applications and developing its own support expertise or migrating to more current versions, or potentially replacing the existing applications with a more integrated and current application platform.

Continuing with these applications however limits the company's ability to employ current technology, to make use of mobile business solutions, and to address evolving business needs and processes. Even if the Company were to support its own legacy applications, the risk with the business systems would increase as the existing hardware would also require replacement with more modern systems. These more modern systems might not be able to operate the older applications.

This investment, which addresses replacement of the core business systems, in a phased approach, positions the company on a robust, secure and flexible enterprise base and will allow the replaced applications to be upgrade on a continual basis, without the cost of a significant one time upgrade.

The Cornerstone name and concept has been adopted inside the company to assist in communicating with every employee the ‘how’ and ‘when’ of changes that will benefit them throughout the conversion.

The Cornerstone Project envisions four staged replacements of core applications which are scheduled to occur between 2008 and 2011. Hydro One intends to retain outside consultants and software application vendors, through a competitive bidding process, to assist it with its replacement program.

The capital work program for Cornerstone commenced in 2007. Work is currently ongoing with Phase 1 of the project (described below) and work has begun on Phase 2 and Phase 3 planning.

The four phases of the Cornerstone Project are:

Phase 1 – EAM (Enterprise Asset Management) Core Functionality (Target In-Service Q2 2008)

As discussed in the project IJD, found in Exhibit D2, Tab2, Schedule 3, the EAM initiative will replace the existing Passport applications with a modern EAM solution. The result will be an integrated EAM application which will allow for more effective information transfer within the Company and provide the basis for connectivity with the other core systems as they are replaced or upgraded.

The first part of Cornerstone is to replace the current installation of PassPort 6. The current version, which supports work management, supply chain and certain asset management processes is old, unsupported, and has been heavily customized since its installation in 1998 and has been in a “locked down” mode and no software code changes have been made since 2004.

The PassPort 6 version is no longer supported by the software vendor, Indus. This means that the vendor will not provide ongoing application fixes for the application and may not be able to fix the application if it breaks. Additionally the continuous customization which was undertaken to extend the life of the Version 6 now significantly complicates upgrading the current application and requires the system be replaced.

Hydro One commenced with Phase 1 after obtaining the Hydro One Board approval in February 2007. Phase 1 will provide similar and enhanced functionality to the existing Passport application, will improve business processes, will put in place governance and structure around data collection and management, will address Bill 198 and other regulatory issues, will change business processes and by turning on or up modules within the application suite will serve as the basis for future phases of the project.

The chosen EAM solution is an SAP suite of applications using SAP 2005 and the SAP netweaver platform. The application will use service oriented architecture principles and the architecture and solution will be overseen and approved by SAP Canada.
The upgrade will be an “off the shelf” “vanilla” solution and implementation. Accenture has been chosen through a competitive RFP process to be the system integrator and will deliver a solution utilizing work practices based on its high performance utility model. The Accenture agreement includes a holdback clause to ensure the solution is delivered.

The Cornerstone project philosophy is to make changes to corporate processes and to utilize the built in functionality of the application tool to support those processes. This enables the application to upgraded and business processes to be continually improved through enhancements provided by the application vendor. Hence, a significant portion of this project relates to change management, streamlining business processes and putting in processes and process measures to ensure ongoing adherence to the new business model and to the business rules embedded in the application.

Inergi is working closely with Hydro One, in its role as outsource business service provider and as an end user of the applications and revised business processes. Inergi and its parent company, Cap Gemini, are working with Accenture to ensure the solution delivered meets Hydro One’s needs. Accenture, SAP and Cap Gemini/Inergi have all committed to delivering the required solution and working in a collaborative and open process. Accenture, SAP and Cap Gemini/Inergi, along with Hydro One staff all have central roles on the project and are active participants in the project governance process.

Governance over the project includes oversight by a sub committee of the Hydro One Board of Directors, Executive and project level reviews and an ongoing Quality Assurance /Quality Control process implemented by Accenture. Hydro One executives have included in their performance compensation a portion of their compensation which is specifically related to the success of the project.

Phase 1 of Cornerstone was undertaken following an exhaustive selection and discovery process completed in 2006 and early 2007 which was used to confirm cost and scope. Costs for Phase 1 represent the current estimate of how the project costs will be incurred in each of 2007 and 2008.

A similar exercise has not been completed for future phases and the costs associated therein are to be reviewed at an appropriate point prior to final approval. Included in 2008 are project start up and initiation costs for subsequent phases.

Value added, beyond the value from a like-for-like replacement, is expected in all phases of Cornerstone.

The benefits from Phase 1 are based upon a fulsome understanding of the benefits from the SAP application. These benefits are derived from three key value levers underpinned by Cornerstone Phase 1 application, process and organizational changes. These value levers are:

1) Centralizing to a single asset registry with a uniform hierarchy and selective integration to legacy databases;
2) Providing greater process transparency, integration and collaboration (enabled through the application and process changes) across Hydro One's lines of business (LOB); and,
3) Enhancing compliance to the underlying processes and data requirements.

Phase 1 corporate savings total $200 million and are based upon 12 areas of identified benefit over the period from mid 2008 to end of 2015. These identified benefits include:

- Enhanced crew productivity due to better materials availability through more efficient forecasting, planning and execution.

- Estimated Benefit – $35.5 million

- Optimized O&M and Capital spend through enhanced asset analysis and maintenance.
  - Estimated Benefit – $50.3 million
- More accessible information from Electronic Asset Management systems through better leverage of IT.
  - Estimated Benefit – $19.9 million
- Improved contract compliance and management through reduction in P-Card and non-PO spend for direct purchase materials and services.
  - Estimated Benefit – $35.0 million
- Improved system reliability through higher quality asset data and avoided emergency “trouble” work.
  - Estimated Benefit – $21.6 million
- Work bundling for routine inspections and Preventive Maintenance work.
  - Estimated Benefit – $6.3 million
- Increased back-office productivity (Designer/Clerical) through reduced costs of tracking work to be scheduled and time prioritizing work.
  - Estimated Benefit – $12.2 million
- Improved inventory performance through reduced expediting, material handling, storage costs, returns and excess/obsolete inventory.
  - Estimated Benefit – $9.5 million
- Improved warehouse shipping processes and payment reconciliation.
  - Estimated Benefit – $1.6 million
- Improved ERS processes through better automation.
  - Estimated Benefit - $7.5 million
- Greater control governance around one-time setup vs. regular AP vendor setup.
  - Estimated Benefit - $0.6 million

- Improve Transmission customer satisfaction through more detailed reporting and improved connection process.
    - Estimated Benefit - intangible

Each of the future phases build on the foundation set by Phase 1 and each of Phases 1 through 3 will utilize the interconnected SAP application platform. Each phase is stand-alone to the extent that each will add its own benefits to the overall Cornerstone program.

As future phases are developed, it is expected that the cumulative benefits of the Cornerstone program will improve; however, the extent is not quantifiable at this time as this is dependent on further refinement of scopes of work for future phases as well as the impacts of such factors as Smart Meters as these become better known.

Phase 2 – Upgrade PeopleSoft – HR and Finance Functionality

The PeopleSoft financial and HR modules were installed in 1998 and the HR module was upgraded in 2002 and subsequently customized. PeopleSoft has been purchased by Oracle, and support for older versions of the PeopleSoft applications will be phased out as PeopleSoft moves to an integrated platform with Oracle applications.

As in Phase 1, the main objective is not only to install an off-the-shelf solution, but also to adopt industry-standard practices that are enabled by the off-the shelf packages. Integration of the new financial and HR application with the modules installed in Phase 1 will enhance financial reporting capabilities.

Recent discussions with Peoplesoft have indicated that the existing applications will not be supported past 2008. The Company will implement a temporary solution utilizing temporary "patch" support from another vendor. However, as these systems are core to the Company's financial reporting and human resource management ability the project timelines may be advanced such that this Phase of the Cornerstone project is commenced prior to starting work on Phase 3. The relatively contained nature of the project allows this to occur without disrupting work on Phase 1.

Phase 3 – Enhanced EAM Functionality

This phase is intended to enhance the functionality and information available to the Asset Manager. Key deliverables for Phase 3 include:

- the release of the additional functionality offered by the system replacement implemented in Phase 1 (EAM-Core)
- replace most of the existing end-user applications with the EAM solution or with specialized packaged point solutions designed to integrate with the EAM, especially focused on Asset Management capabilities
- enhance reporting capabilities
- integrate the asset repository with Geospatial Information Systems (GIS) and technology.

Phase 4 - Replace Customer Information System Functionality

The Customer Service System (CSS) or Customer -1 application was purchased in 1997 from Andersen Consulting. The application has undergone significant modifications in order to address the changes in the Ontario regulatory environment and to meet OEB requirements. This is an extensively customized product which is very costly to maintain and very costly to modify to meet new business needs.

The Hydro One IT strategy is to make modifications to the existing system to extend its useful life and to address known regulatory and business requirements. The system itself is robust but difficult to work with. Improvements to the system, which are discussed below, are intended to stream line work processes, provide additional functionality and to make changes to the application less costly.

To obtain full functionality with the newer systems, and to improve workflow and improve customer satisfaction the intent of Phase 4 is to replace the existing Customer -1 system with a more integrated application which would interface with the application suite implemented in Phases 1-3.

Andersen Consulting no longer supports the application and Hydro One is part of a user group who continue to maintain the core functionality of the Customer -1 application. The number of users in the user group, who support the application, is however declining, as more of the utilities using the Customer-1 application are switching to newer integrated CSS applications.

Inevitably, the Customer -1 application will have to be replaced. No application solution has been chosen at this stage and Hydro One intends to maintain its flexibility to take advantage of business and application solutions as they become available.

2.4.2 CIS/CSS Hybrid Upgrade Project/CRM

Capital spending for this area is for 2 end customer impacting projects – Customer Information System (CIS) application changes and the upgrade of the existing Customer Relationship Management (CRM) applications

The CIS is the term given to a suite of billing and customer applications which includes the Customer-1 application and the Open Market Systems. To improve their existing performance, and prior to their replacement with Phase 4 of the Cornerstone project, Hydro One intends to make a series of investments in the CIS and related applications ($2.9M in 2007 and $2.0M in 2008) to improve current performance and reliability.

Some aspects of previously planned work to update applications in Customer Care will become part of the Cornerstone project.

This project is allocated 100% to distribution account categories. The upgrade is labeled as "hybrid" because some components will be upgraded and others will not, rendering the resultant configuration as a hybrid application, rather than a full replacement or upgrade.

The Customer-1 application is the predominant part of the CIS suite of applications. It provides the technology backbone for billing, customer care, field services, and open market services to customers and key constituents.

Upgrades were made to the CIS platform in 2006 and changes which improve business efficiency will continue in 2007 and 2008.

Undertaking the Hybrid project will enable the CIS application to remain functional until its upgrade or replacement in 2011. It is expected through investment in a Hybrid program, rather than in replacement of the existing CIS application at this time, that Hydro One will maintain flexibility and have a number of options available to it in light of the Government's smart metering program.

Timing as to when this work may occur, or how much work is able to be done is dependent on the Smart Meter project and on any OEB mandated rate changes. The CIS

Hybrid, Smart Metering and rate change projects require access to the same CIS system or elements of the system, and the scheduling and testing of any application code changes, and system maintenance programs requires resource co-ordination.

Customer Relationship Management refers to the applications used by Hydro One to track information, work programs and projects for its large distribution and transmission customers. Hydro One intends to replace the existing applications which are at end of life with an SAP CRM solution. The solution will be implemented initially on a stand alone basis and will be integrated at a later date into the Cornerstone ERP solution.

Data in the current CRM applications will be reviewed prior to its being exported to the new solution. The SAP implementation will follow the same Cornerstone philosophy where no modification or customization will be allowed to the base code. This will enable Hydro One to utilize application upgrades provided by the application vendor.

A Systems Integrator for the project implementation, including business process change and change management will be selected through a competitive RFP process.

2.4.3 CTI Upgrades

In 2007 work will be completed on the upgrade to the contact centre's computer-telecom-interface (CTI) technology and applications. This technology enables contact centre agents to handle customer inquiries in a variety of media, such as telephone calls, emails, faxes and posted letters. These changes will provide for the requisite flexibility to meet growing and changing customer needs going forward. This project is allocated fully to Distribution accounts.

2.4.4 ACPi/WEP Project

This project will complete the IT provisioning for work planning, crew scheduling, dispatching and time recording functions to the Lines of Business users such as Customer Operations, Grid Operations and E&CS. The result will be the Work Planning and Reporting System (WPRS).

This will be achieved by leveraging the system integration tool that is being delivered through the ACPi (ArcFM, CSS, Passport integration) project. The WEP project will add work planning and crew scheduling plus the application to view assigned activities for time capture and job status. New applications will be utilized by field staff in Customer Operations regarding the dispatch of the high-volume of short duration jobs.

There is a wide range of benefits for this project including efficiency in resource utilization by organizing work orders by geographical area and better tracking of resource assignments. There are additional benefits for Finance in the areas of time capture and up front time approval.

The WEP application will interface with the Cornerstone solution through the use of the hub technology solution developed in the ACPi project.

2.4.5 IREIS Project

This project converts and stores geospatial information data, which will be accessed through the Integrated Real Estate Information System.

2.4.6 Mobile IT Project

Mobile IT ($3.0 million in 2008) will equip field forces with the tools required to access current and planned asset data applications when in the field. In 2007, Hydro One is undertaking a study to develop a cohesive IT Mobile strategy.

The strategic review is intended to assess how to best use technology in the field and how to best support what work processes. The study will consider the Cornerstone project as well as the enhanced process functionality provided by the WEP suite of applications to develop a direction that the Company will follow in building mobile applications.

Direction from the strategic review will enable the Company to respond to staff and vehicle location safety needs, mobile computing requirements, consider Smart Network preparedness and optimization of the Smart Metering initiative.

The investment provides additional commercial software products, enhancements to existing software products and the installation, configuration and integration of those products along with associated hardware (database and application servers and upgraded hand-held devices). This project will permit field management and staff access to critical systems and information regarding work crew projects, field assets and optimal scheduling as part of work management processes.

2.4.7 Asset Data Collection and Data Mart Project

Through the use of handheld tablets system information data is being collected on the current state of the Distribution system. The scope of the project provides software to analyze the information and allow it to be transferred and used in the corporate

Geographical Information System (GIS). The information will assist in the efficient expansion, operation, and maintenance of the distribution system.

Costs included in the period 2006 to 2008 relate to systems and applications costs for the data collection work being performed on distribution poles and lines assets. In 2007, $0.9M has been identified for capital items associated with distribution data collection project.

3.0 FACILITIES & REAL ESTATE

This section addresses the capital expenditures that are required to acquire (own or lease) and maintain Hydro One Networks Inc.'s workspace (office space and service centres). The distribution facilities represents approximately $4.4 million of overall capital estimated spending in 2008, as illustrated in Table 7, below.

Table 7
Total Real Estate Capital Expenditures ($ Millions)

	Historic			**Bridge**	**Test**	
	2004	2005	2006	2007	2008	2008 Dx
Major	5.1	2.6	3.0	6.5	9.2	4.0
MFA	0.8	0.0	0.6	3.1	0.6	0.4
Total	5.9	2.6	3.6	9.6	9.8	4.4

3.1 Major Capital

The Real Estate major capital program allows for the provision of workspace of head office facilities, including Ontario Grid Control Centre – Barrie, field administrative & service centre facilities, and other work locations such as the London Call Centre.

The increase in costs over the 2006 to 2008 period reflects the increased operational requirements as a result of the program expansion resulting in the Distribution and Transmission Businesses. Key components of this expanded work program are discussed below.

The capital program focuses on undertaking critical component replacement work on a priority basis (e.g. roof replacement). As a result of the planned and corrective replacement of these critical components, the amount of capital spent varies year over year. Contracted facility service providers conduct regular inspections of administrative and service centre sites across the province to ensure critical building/site components are inspected regularly and major structural and related problems are identified. Maintaining building and site assets in a condition that ensures their longer-term viability, while meeting the workspace needs of employees on a day to day basis, is critical to the successful completion of a variety of corporate work activities. Equally important is ensuring that employee workspaces are consistently maintained to a standard that meets current work requirements and complies with all corporate, legislative and other related safety and environmental regulations. This program also considers the facilities portfolio accommodation strategy in terms of facility improvements, building additions, and new facilities in line with the Company's changing operational requirements.

Key Program work activities include:

- New buildings, buildings additions and major facility renovation as part of facility program accommodation strategy that responds to need to address aged facilities (reaching their end of life) and is in line with current and projected operational and work programs requirements including staff growth at locations across the Province.

- Replacement of major building components including roof structures, windows, heating, ventilating and air conditioning (HVAC) systems and other structural elements and building systems;
- Dealing with environmental issues that may arise such as mould;
- Water treatment upgrades to improve quality and reliability of water supply, including conversions to municipal supply;

The Company in particular is looking for new space standards to meet accommodation needs and achieve their customer, technologies, health and safety initiatives. Forecast expenditures for 2008 for distribution are $4 million.

3.2 Minor Fixed Assets (MFA)

As noted in Table 7, MFA expenditures are based on spent on replacement of furniture or additional furniture due to increased staff levels. Forecast expenditures in this area are $0.4 million for 2008.

4.0 TRANSPORT AND WORK EQUIPMENT (TWE) REPLACEMENT PROGRAM

This section identifies the Transport and Work Equipment (TWE) capital expenditures for the period 2004 to 2008. The increase in capital expenditures is directly related to the increase in work programs and additional staffing required to execute these work programs identified by each of the Lines of Business. Fleet capital requirements are primarily based on industry standards (manufacturer's recommendations) for life cycle expectancy, the remaining capital value, and operating cost drivers which are then linked to the Business Plan and Work Programs. Light vehicles are replaced after 6 years or

180,000 km, service trucks are replaced after 6 years or 200,000 km, and work equipment is replaced after 8 to 10 years or 230,000 km.

Table 8
Capital Expenditures ($ Millions)

	Historic			Bridge	Test	
	2004	**2005**	**2006**	**2007**	**2008**	**2008 Dx**
Total	13.5	40.5	41.2	41.1	51.6	39.2

The objective of the TWE Replacement Program is to promote an orderly system of purchasing and funding a standardized fleet replacement process and to plan for future transportation requirements. The TWE Replacement Program annually analyzes 5-year cycles for capital investment requirements and maintains a safe and efficient fleet. It is critical to evaluate and forecast spending requirements to minimize fluctuating spending patterns and to stabilize long term capital investment. The fleet capital program, on an annual basis, is evaluated against the business plan and is subject to the work program prioritization and forecasting process.

Business cases for the program are prepared and approved and the equipment is strategically procured through a tendering process.

The TWE Replacement Program reviews:

- Equipment capital forecast;
- Equipment productivity, functionality, and future requirements;
- Equipment standards, equipment age, mechanical condition, kilometers traveled and cost per kilometer, downtime, and repair time;
- Safety/risk;

- Work programs, evaluating staff and equipment complement;
- Tendered procurement process;
- Fleet's Original Capital Value and Net Book Value;
- Historical and future utilization;
- Strategic procurement; and
- Cost versus 5-year business plan.

The guidelines for vehicles considered for replacement are based on vehicles meeting predetermined criteria including, but not limited to: manufacturer's life expectancy, average cost per kilometer, regulated maintenance standards, safety/risk, and beneficial purchasing cycles. As vehicles reach the targeted criteria, a vehicle maintenance evaluation is performed and, in some cases, the unit may be reassigned to other functions with "low usage" requirements. The replacement program measures the age and value of the fleet and meets the requirements and due diligence of a typical Utility fleet.

The benefits of our replacement program include:

- Maximum safety, productivity and utilization;
- Minimum downtime, repair time, and fleet complement;
- Reduced operating costs.

Hydro One Networks Inc. Fleet Operations has increased its yearly capital expenditures significantly in order to replace its aging equipment.

Over the 2004 to 2008 period, the Sustainment, Development, and Operations work programs have grown by over 70% and the growth of the TWE replacement program is aligned with this.

$20 million of planned capital was brought forward to 2003 from 2004 based on the substantial increase in the work program for 2004 and 2005.

The actual capital expenditures for new vehicles in 2005 ($40.5 million), 2006 ($41.2 million) and 2007 ($41.1 million), along with the budget in 2008 ($51.6 million) are based on the additional vehicles required to execute the planned work programs. The additional capital identified in 2008 is a direct reflection of the increase in the work programs and additional staffing indentified by all the Lines of Business.

4.1 Capital vs. Operating Leases

The evaluation of leasing as a financial alternative to the approved capital program was evaluated during the 2003 strategic sourcing initiative. The evaluation included the review of both capital and operating leases and the total operating costs. The risks and benefits generated by leasing were evaluated and it was decided the risks outweighed the modest benefits. The results therefore indicated that leasing was not cost effective.

The requirement for short term rentals (as distinct from long term rentals) is recognized and is included with our operating expenses in Exhibit C1, Tab 4, Schedule 1, Attachment A.

4.2 Procurement Initiatives

Fleet Services follow capital procurement objectives for material and service, listed below, to achieve cost reductions over the next five years:

- Profile the commodities, collect and analyze cost drivers;
- Analyze the supply market;

- Develop a strategy for sourcing;
- Select the suppliers through a rigorous RFP process;
- Conduct negotiations.

These procurement initiatives have allowed Hydro One Networks Inc. to control pricing for 3 year terms with preferred vendors.

5.0 SERVICE EQUIPMENT

Table 9 below identifies the expenditures for Service Equipment for the 2004 to 2008 period.

Table 9
MFA Service Equipment ($ Millions)

	Historic			Bridge	Test	
	2004	2005	2006	2007	2008	2008 Dx
Total	4.9	3.1	3.9	7.9	9.3	5.3

Minor fixed assets for service equipment represents capital items ≥ $2,000 required by our staff to carry out the construction and maintenance work programs. Capital items < $2,000 are expensed to OM&A. Minor fixed asset expenditures for service equipment are required to replace end of life service equipment, replace technologically obsolete service equipment when new standards and safer work practices come into effect, and provide for sufficient levels of new service equipment consistent with work program expansion and increased staffing levels.

Purchases in this category include specialized transportation equipment for off-road work sites and mobile equipment required to carry out a variety of work such as all terrain vehicles, boats, barges, snowmobiles and related accessories to transport crews to off-road work sites. It also includes measuring and testing equipment to carry out a variety of work activities including trouble shooting, performance testing of equipment, wood pole density testing, battery testing, etc.; tools; AED devices used by Health & Safety & Environment group to promote more safety and emergency awareness and other miscellaneous equipment.

In order to complete overhaul and maintain large power transformers and manage the related oil requirements over the planning period, the largest portion of the purchases are Mobile equipment such as dryair supply machines, oil filters, oil tankers, mobile degassifiers, heater banks, insulated tanks and Schnabel car upgrades .

Higher year over year spending in 2007 & 2008 is the result of end-of-life replacement of specific large transport equipment and to accommodate planned growth in distribution and transmission work program.

6.0 CONSERVATION AND DEMAND MANAGEMENT

Table 10
Conservation & Demand Management ($ Millions)

	Historic			Bridge	Test	
	2004	**2005**	**2006**	**2007**	**2008**	**2008 Dx**
Total	0.0	0.0	2.9	7.9	0.0	0.0

Capital expenditures are related to load control programs under development and to distribution loss reduction. Board Decision RP-2004-0203 / EB-2004-0461 December 7, 2004 – line 125, relating to the approval of Utility C&DM Plans indicated that any capital projects related to C&DM should be placed in the utility's rate base.

The objective of the "Residential Load Control Program" is to assess residential customer response and the potential load impact of controlling central air conditioning, pool pumps, and electric hot water heating during system peak periods through installation of load control units and interval meters. Air conditioning and water heating are significant contributors to both summer and winter peak loads on Hydro One Network Inc.'s system. Accordingly, potential demand savings from load control could contribute significantly to Hydro One Network Inc.'s demand management effort. Customers will experience reductions in their energy usage without a significant effect on their comfort.

The "Distribution Network Loss Reduction Program" will be beneficial to all Hydro One Network Inc. customers. The program involves identifying and implementing projects where incremental investments will result in an overall economic benefit to customers by reducing system delivery losses.

Work under the loss reduction program was initiated following a study prepared by Kinetrics in 2005 as part of 2006 Distribution Rates proceeding RP-2005-0020/EB-2005-0378. In its Decision with Reasons for Proceeding RP-2005-0020/EB-2005-0378, the Board approved $8M in capital spending on loss reduction initiatives.

7.0 CUSTOMER CARE

Capital investments are required to build or upgrade the major Information Technology (IT) systems used in the delivery of Hydro One Distribution's Customer Care work program. The major IT systems supporting the delivery of the Customer Care service programs are: the Customer Information System (CIS) application suite and the Contact Centre Technology suite.

The CIS is an application suite providing billing, metering, contact, and service order support. The CIS is principally made up of the Customer Service System (CSS), and the Open Market Systems, which interface with the CSS. The Contact Centre Technology includes a suite of applications used at the contact centres, to queue and route calls, manage resources, provide Interactive Voice Response equipment and provide other support to call handling.

Capital expenditures for the Customer Care work program are cyclical in nature. There are years when no capital expenditure is required to be invested to support the IT system infrastructure. In other years, expenditures are required for major development or replacement of existing infrastructure, or to develop new infrastructure to keep pace with industry standards, address regulatory requirements, or address end of life issues.

Renovations to the Customer Information System (CIS) suite of applications began in 2006, with two initiatives: an initiative of data clean-up to update the 911 addresses in CIS and correct other data discrepancies; and, an initiative to implement process efficiencies for bill exception handling. Upgrades to the Contact Centre Technology, initiated in 2005, will be completed in 2007.

The capital expenditures related to these projects are identified in Table 6.

8.0 OTHER SHARED SERVICES

Table 11
Other Shared Services Capital ($ Millions)

	Historic			Bridge	Test	
	2004	**2005**	**2006**	**2007**	**2008**	**2008 Dx**
Total	(2.2)	3.1	6.1	1.8	(14.4)	(14.4)

Other costs are comprised of a variety of minor costing elements.

2004 to 2005 costs represent an (over)/under recovery of burdened rates which were assessed to be attributable to the capital program, but not applied back to specific programs; as well as other adjustments to capital projects.

The 2006 other costs include the Transmission capital contribution refund to Transalta as well as other small adjustments.

Other capital in 2007 includes an adjustment for contributed capital related to the Transmission earnings sharing mechanism, as well as other minor adjustments to capital projects. In 2008 Other capital comprises a credit related to the true-up of capitalized overheads in the Distribution business for 2006, as described in Exhibit C1, Tab 5, Schedule 2.

ALLOWANCE FOR FUNDS USED DURING CONSTRUCTION

The interest rate used for construction work in progress (CWIP), which is referred to as Allowance for Funds Used During Construction (AFUDC) reflects the Board's decision in EB-2006-0117, effective November 28, 2006. This decision prescribed that the interest rate to use for CWIP, effective May 1, 2006, would be the Scotia Capital All-Corporates mid-term Yield, as published on the Bank of Canada website and updated quarterly. As a result the 2008 test year reflects a forecast of the prescribed CWIP rate, respectively, while the historical years reflect CWIP at Hydro One Distribution's previously approved embedded cost of debt.

Table 1
Allowance for Funds Used During Construction

Year	AFUDC Rate %	($ millions)
2004	7.0	4.5
2005	6.8	4.4
2006	6.3	5.4
2007	4.8	8.9
2008	5.1	8.9

HYDRO ONE NETWORKS INC.
DISTRIBUTION
Statement of Utility Rate Base
Forecast Year (2008)
Year Ending December 31
($ Millions)

Line No.	Particulars		2008
	Electric Utility Plant		
1	Gross plant at cost	$	6,450.1
2	Less: accumulated depreciation		(2,364.6)
3	Net plant in service	$	4,085.5
	Working Capital		
5	Cash working capital	$	273.2
6	Materials and Supplies Inventory		23.3
7	Total working capital	$	296.5
8	Total rate base	$	4,382.0

COMPARISON OF CAPITAL EXPENDITURES – HISTORIC, BRIDGE AND TEST YEARS

	2004	2005	2006	2007	2008
Distribution Capital ($ millions)					
Sustaining					
Lines Capital					
Trouble Call and Storm Damage	38.3	51.7	90.6	51.7	53.4
Joint Use & Line Relocations	19.2	22.0	24.0	27.1	23.7
Line Asset Replacement	35.2	33.2	47.5	60.0	62.4
Total Lines Capital	92.7	106.8	162.1	138.8	139.5
Stations Capital					
Spare Transformers	4.8	1.7	2.8	0.6	3.5
Mobile Unit Substation Refurbishment	1.1	0.4	1.0	0.3	1.5
Station Refurbishment & Component Replacement	5.1	7.0	4.7	6.8	5.3
Total Stations Capital	11.0	9.1	8.5	7.7	10.3
Metering Capital					
Retail Meter Replacement	1.2	1.4	1.6	0.4	2.5
Smart Meters			14.1	76.7	164.8
Total Metering Capital	1.2	1.4	15.7	77.1	167.3
Total "Sustaining"	104.9	117.3	186.3	223.6	317.1
Development					
New Customer Connections & Upgrades	94.2	100.3	104.6	105.9	103.9
Distribution Generation Connection	0.0	0.3	1.5	1.8	8.4
Wholesale Revenue Meters	6.8	8.7	11.1	9.7	11.4
System Capability Reinforcement	37.7	32.4	29.7	36.9	44.0
Total "Development"	138.6	141.7	146.8	154.2	167.7
Operations	6.3	4.7	2.1	2.0	3.6
Transport and Work, and Service Equipment	12.0	32.1	33.6	35.7	44.5
Information Technology Capital	10.6	19.5	19.3	46.7	43.3
Facilities Capital	2.8	1.8	2.1	6.4	4.4
Other (including CDM)	(3.2)	0.1	2.4	8.0	(14.4)
Total Distribution Capital	**272.0**	**317.2**	**392.6**	**476.6**	**566.2**

LIST OF CAPITAL EXPENDITURE PROGRAMS/PROJECTS IN EXCESS OF $1M TEST YEAR - 2008

*($Millions)

1.0 SUSTAINING CAPITAL (EXHIBIT D1, TAB 3, SCHEDULE 2)

1.1 STATIONS

S1	Spare Distribution Transformers	3.5
S2	Mobile Substation Refurbishment	1.5
S3	Distribution Station Refurbishment	2.5
S4	Demand and Planned Component Replacement	2.6

1.2 LINES

S5	Trouble Calls & Storm Damage	53.4
S6	Joint Use & Line Relocations	23.7
S7	Wood Strucutre Replacement Program	39.8
S8	Waste Storage Tank Replacement	1.2
S9	Defective Crossarm Replacement Program	1.7
S10	Submarine Cable Replacement Program	1.3
S11	Havelock TS 57M1 Feeder Refurbishment	2.1
S12	Kingsville TS M3 and M6 Feeder Refurbishment	1.5
S13	Lindsay TS D4M7 - Phase 4 of 5	1.2
S14	Longlac TS M1 Feeder Refurbishment	1.1
S15	Minden TS 87M1 - Phase 3 of 4	2.0
S16	Town of Thessalon Re-build Part 2 of 4	1.3
S17	Fort Frances TS M1 Feeder Rehab Phase 3	1.8

1.3 METERS

S18	Metering for Shared Use Distribution Charges	2.0
S19	Smart Metering	164.8

<u>Summary</u>

Total Sustaining projects/programs listed above	309.0
Sustaining projects/programs less than $1M	8.1
Total Sustaining capital (per Exhibit D1-3-1)	317.1

2.0 DEVELOPMENT CAPITAL (EXHIBIT D1, TAB 3, SCHEDULE 3)

2.1 CONNECTIONS

D1	New Connections, Upgrades and Service Cancellations	103.9

2.2 SYSTEM CAPABILITY REINFORCEMENT

D2	2008 Demand Investments	1.1
D3	Subtransmission Feeder Sectionalizing	2.2
D4	Armitage TS M12 Feeder Extension	1.7
D5	Holland Jct TS - 44kV Feeder Development	2.8
D6	Curve Inn DS New T2 and Feeder	2.7
D7	Gardiner TS II - 44 kV Feeders	1.3
D8	Brockville Area Upgrade	2.2
D9	Ingersoll North DS Voltage Conversion	1.9
D10	Kleinburg TS – Feeders to Bolton	3.6

D11	Bell River TS M2 Feeder to Haycroft DS	1.9
D12	Seaforth M5 27.6 kV, 25 MVA Voltage Regulator	1.4
D13	Stayner TS x Blue Mountain - Build 2 New 44kV Feeders	4.6
D14	Timmins TS M9 Feeder Extension	2.1
D15	Timmins Moneta DS Voltage Conversion	2.4

2.3 METERING

D16	Wholesale Metering Upgrades	11.4

Summary

Total Development projects/programs listed above	147.2
Development projects/programs less than $1M	20.5
Total Development capital (per Exhibit D1-3-1)	167.7

3.0 OPERATIONS CAPITAL (EXHIBIT D1, TAB 3 SCHEDULE 4)

O1	System Data Archiving and Management	1.3
O2	NMS Enhancement for Distribution Monitoring and Control	1.0

Summary

Total Operations projects/programs listed above	2.3
Operations projects/programs less than $1M	1.3
Total Operations capital (per Exhibit D1-3-1)	3.6

4.0 SHARED SERVICES (EXHIBIT D1, TAB 3, SCHEDULE 6)

4.1 INFORMATION TECHNOLOGY

		SHARED COST
IT1	Cornerstone Phase I	50.3
IT2	Mobile IT	3.0
IT3	CIS/CSS Hybrid Upgrades	2.0

4.2 SHARED SERVICES AND OTHER

		SHARED COST
C1	Fleet Services	51.6
C2	MFA Service Equipment	9.3
C3	Real Estate Facilities	9.8

Summary

5.0 SHARED DISTRIBUTION COST ALLOCATION

Total Shared Services and Other projects/programs listed above	126.0	74.7
Shared Services and Other projects/programs less than $1M	34.9	3.1
Total Shared Services and Other capital (per Exhibit D1-3-1)	160.9	77.8

Justification for Programs or Projects
In Excess of $1 Million

Date: August 2007

Hydro One Distribution- Investment Justification
Spare Distribution Transformer Investments

Investment Driver: DC108 **Reference #:** **S1**

Investment Name: Spare Distribution Transformer Investments **In-Service:** December, 2008

Need:

This investment is required to maintain the distribution spare transformer population at sufficient levels to respond to equipment failures.

Not proceeding with this investment would result in a lack of spare transformers, a deterioration of overall customer supply reliability and increase the risk of prolonged outages during equipment failures.

Investment Summary:

Hydro One Distribution's system utilizes 1,477 in-service transformers and regulators, ranging in size from 0.5 to 40 MVA in 71 different categories and up to 70 years in age. These devices are made up of several components and sub-systems, which are subject to wear and tear, resulting in occasional failure. The average life of the in-service transformers and regulators is in the range of 30-50 years and the average age is increasing.

Over the last four years the distribution system has averaged about 32 transformer failures per year. Following a failure, a spare transformer is usually moved into service reducing the available spares complement. As the age of transformers increases, it becomes crucial that a sufficient number of replacement transformers be available as functional operating spares, as the number of failures are expected to increase. A comprehensive transformer spare complement strategy has been developed to ensure the correct number and type of spares are available in order to respond to failures.

This investment addresses the current gap and requires the purchase of three transformers and one regulator. The ratings are as follow:

- One 7.5/12.5 MVA, 115.5/8.8 kV transformer
- One 5 MVA, 27.6/8.32-4.16 kV transformer
- One 6 MVA, 44/13.2 kV transformer
- One 10 MVA, 12.47 kV regulator

Results:

- Purchase three (3) step-down transformers and one (1) regulator to meet future failure demand.
- Maintain customer connection reliability by restoring full operating capability through the timely and unencumbered dispatch of operating spare transformers.
- Maintains the availability of mobile substations for failure response and to support the Stations OM&A and Capital programs, as mobile substations would be used in lieu of spare transformers, if spares were not available.

Costs:

	2008 ($M)
Capital* and Minor Fixed Assets (MFA) (A)	3.5
Operations, Maintenance & Administration (OM&A) and Removals (B)	-
Gross Investment Cost (A+B)	**3.5**
Recoverable (C)	-
Net Investment Cost (A+C)	**3.5**

*Includes Overhead and Allowance for Funds Used During Construction (AFUDC) at current rates

Hydro One Distribution– Investment Justification
Mobile Substation Refurbishment

Investment Driver: DC 108 **Reference #**: **S2**

Investment Name: Mobile Substation Refurbishment **In-Service**: December, 2008

Need:
This investment is required to provide for the safe operation of a fleet of 28 mobile substations and to maintain their performance at acceptable levels.

Consequences of not proactively managing the population of mobile substations include increased safety risks during transportation, an inability to restore power in a timely manner and the unavailability of replacement transformers required to complete maintenance programs thereby increasing reliability risks.

Investment Summary:

Hydro One Distribution's spare transformer strategy requires the availability of mobile substations for first-response power restoration**.**

As transportable mobile units, mobile substations must adhere to the requirements of the Highway Traffic Act. They receive annual inspections (time-based) for trailer certifications and power system components, as well as detailed inspections that occur each time units are dispatched for service. Inspection reports are used to track asset condition and to prioritize refurbishment.

This investment provides $1.5 million to complete mobile substation refurbishments to correct equipment deficiencies, and to replace reclosers on Unit # 30 (115/27.6 kV) and to purchase a new 27.6/8 kV transformer for Unit # 02**.**

Results:
- Maintain customer reliability by ensuring the availability of mobile substations to restore power when in-service transformers fail.
- Ensures mobile substations remain in good repair and do not present safety hazards.
- Minimize the life cycle costs of station facilities by reducing operating and maintenance expenditures and outage requirements through an integrated spares and mobile substation utilization.

Costs:

	2008 ($M)
Capital* and Minor Fixed Assets (A)	1.5
Operations, Maintenance & Administration and Removals (B)	-
Gross Investment Cost (A+B)	**1.5**
Recoverable (C)	-
Net Investment Cost (A+C)	**1.5**

*Includes Overhead and Allowance for Funds Used During Construction at current rates

Date: August 2007

Hydro One Distribution– Investment Justification
Distribution Stations Refurbishment

Investment Driver: DC108 **Reference #:** S3

Investment Name: Distribution Stations Refurbishment **In-Service:** December 2008

Need:
This investment is required to maintain customer reliability and performance of distribution stations, as well as ensuring employee safety by addressing end-of-life assets.

Not proceeding with this investment would decrease distribution system reliability and compromise employee safety.

Investment Summary:
Hydro One Distribution's system is designed as a single-element, radial-fed distribution network. Distribution stations are a major element in this chain and are composed of individual components that must function as designed in order to maintain reliability and employee safety.

Stations require refurbishment because equipment and structures loose their capability to perform as intended based on ageing and/or utilization. Investments are prioritized based on ACA results, historical performance, availability of spares and additional criteria that includes, customer satisfaction, safety, and improvement in design standards.

Refurbishment that includes end of life transformer, structure and recloser replacement will be completed at the following stations: Iroquois Dam DS, Sioux Narrows DS, Navan DS, Brockville Parkdale DS, Lindsay Eglington DS and Parkhill South DS. Site expansion and structure egress cable relocation is planned for Durham Elgin DS to allow for the connection of a mobile substation. This will be achieved by separating the three feeders (currently egressing on one pole) onto three difference poles.

Results:
- Maintain customer reliability by replacing end-of life assets and by introducing updated designs and components.
- Replace end of life assets to comply with regulatory requirements.
- Address employee safety issues.

Costs:

	2008 ($M)
Capital* and Minor Fixed Assets (A)	2.5
Operations, Maintenance & Administration and Removals (B)	0.3
Gross Investment Cost (A+B)	**2.8**
Recoverable (C)	-
Net Investment Cost (A+C)	**2.5**

*Includes Overhead and Allowance for Funds Used During Construction at current rates

Date: August 2007

Hydro One Distribution– Investment Justification
Demand and Planned Component Replacement

Investment Driver: DC108 **Reference #:** S4

Investment Name: Demand and Planned Component Replacement **In-Service:** December 2008

Need:
This investment is required to maintain the safe operation and acceptable performance of Distribution Stations by addressing emergency situations and replacing end of life components

Not proceeding with this investment would decrease customer reliability and compromise employee safety.

Investment Summary:

Demand Work – $1.8M
This investment provides $1.8 million to repair equipment when it fails, or when there is a need to repair equipment in a timely manner to secure reliability or safety. These failures are difficult to predict, but must be repaired quickly because they generally result in customer interruptions or present significant safety risks. Funding levels are based on historical trends and adjusted to reflect recent experience.

Planned Component Replacement – $0.8M
Components are replaced when their condition has deteriorated to a point where there is a risk of failure and the component has reached end of life, or where the performance has reached unacceptable levels. Component replacements are identified through ACA, routine station inspections and safety investigations, and can include reclosers, switches, fences and gates, surge arrestors, and transformer components.

Part of the component replacement program will address end of life breakers and reclosers by replacing these with new vacuum reclosers. This is a new technology that provides cost savings through improved performance, reduced maintenance and these reclosers provide added protection flexibility.

Results:
- Respond to outages in an expedient manner and address immediate reliability and safety risks.
- Improve system reliability by replacing end of life components.
- Replace end-of-life assets to comply with regulatory requirements.

Costs:

	2008 ($M)
Capital* and Minor Fixed Assets (A)	2.6
Operations, Maintenance & Administration and Removals (B)	-
Gross Investment Cost (A+B)	**2.6**
Recoverable (C)	-
Net Investment Cost (A+C)	**2.6**

*Includes Overhead and Allowance for Funds Used During Construction at current rates

Date August 2007

Hydro One Distribution – Investment Justification
Trouble Calls and Storm Damage

Investment Driver: DC106 **Reference #**: **S5**

Investment Name: Trouble Calls and Storm Damage **In-Service:** December, 2008

Need:

This demand program funds the repair of assets where there has been a power interruption, or where situations pose reliability or safety risks that require immediate attention. The facilities covered under this program include all distribution line assets.

Failure to respond to trouble calls and storm damage, and situations where components or equipment are near failure would result in unacceptable safety and reliability risks to Hydro One Distribution.

Investment Summary:

Hydro One Distribution's system services about 1.2 million customers that place a high value on both reliability and quality of power. This is a demand program needed to restore power, maintain reliability and safety, and respond to customer needs in a manner that meets regulatory requirements. It includes:

- Emergency pole replacements
- Emergency equipment and component replacements
- Response to power quality issues
- Submarine and underground cable failures/problems
- Storm Damage response
- Damage claims

Hydro One Distribution is obligated to provide this service in accordance with good utility practice and the requirements of the Distribution System Code.

Trouble call response affects the company's performance on a number of OEB-specified service quality requirements; specifically, SAIDI and CAIDI reliability indices.

The funding of this program is based on historical accomplishments where the average volume of work and expenditures over the last 4 years is the primary consideration in setting forecast levels, although other mitigating factors may be considered (e.g. discounting extraordinary storm years).

The funding of this program is based on historical accomplishments as follows:

	2004	2005	2006	2007 Projected	2008 Proposed
Poles Replaced (units)	890	1,428	1,393	1,150	1,250
Equipment Replaced (units)	2,806	3,091	2,877	2,800	2,900
Storm Damage ($M)	14.0	26.3	62.0	26.0	26.0

Results:

- Ensures Hydro One Distribution promptly meets its obligation to provide customers with safe and reliable service.
- Comply with regulatory requirements.

Costs:

- The costs for forestry and premium time incurred as part of storm damage restoration are captured as part of OM&A Trouble Calls.
- Includes $2.5M that is recovered through damage claims.

	2008 ($M)
Capital * and MFA (A)	55.9
Operating, Maintenance & Administration and Removals (B)	4.2
Gross Investment Cost (A+B)	**60.1**
Capital Contribution (C)	(2.5)
Net Capital (A+C)	**53.4**

*Includes overhead and Allowance for Funds During Construction at current rates

Date: August 2007

Hydro One Distribution – Investment Justification
Joint Use and Line Relocations

Investment Driver: DC103 **Reference #:** **S6**

Investment Name: Joint Use and Line Relocations **In-Service:** December, 2008

Need:

This is a demand program that covers joint-use work that Hydro One Distribution is obligated to provide in order to meet its contractual obligations to joint use partners in accordance with existing Joint Use Agreements.

This program also covers line relocation work that must be carried out at the request of Municipal and Provincial road authorities as per the requirements of the Public Service Work on Highways Act and associated Ministry of Transportation guidelines. It also includes relocation work requested by customers in accordance with Hydro One Distribution's Conditions of Service.

Investment Summary:

Investment details for the two components of this program are provided below:

Joint Use

This work covers changes/upgrades to Hydro One Distribution assets to accommodate the use of the assets by joint use partners such as telecommunication or cable companies (communication circuits), municipalities (street lighting) or local distribution companies (power circuits). The cost sharing provisions in joint use agreements allow Hydro One Distribution to recover its costs resulting from requests to add new attachments to poles. Costs recovered include those to increase pole class to accommodate changes in pole loading, increased height to obtain appropriate ground clearances for public safety, as well as costs associated with premature retirement of in-service assets.

Line Relocations

The Line Relocation component of this program covers the work required in response to road modifications initiated by Provincial or Municipal Road Authorities, or by individuals who require assets relocated for the purpose of developing their property. Hydro One Distribution occupies road allowances at no cost and in return is required, on occasion, to install, relocate or reconstruct its facilities in order to accommodate the specific requirements of the road authorities. Most commonly, this involves relocating lines to accommodate changes to roads, highways and bridges. The cost of the plant relocation is either fully or partially recoverable, depending on the specific circumstances of each project.

The number of relocation projects can vary significantly from year to year depending on the number of government infrastructure projects and economic conditions influencing individual 3rd party development projects.

This program involves the management and construction of 400 to 600 line projects on an annual basis.

Projected spending is based on historical costs taking into account any observed trending and identified joint-use and relocation work scheduled for 2008.

Results:

Hydro One Distribution will meet its contractual and legal obligations, and maintain property rights for Hydro One Distribution lines located on road allowances.

Costs:

	2008 ($M)
Capital* and Minor Fixed Assets (A)	32.7
Operating, Maintenance & Administration and Removals (B)	1.2
Gross Investment Cost (A+B)	**33.9**
Capital Contribution (C)	(9.0)
Net Capital (A+C)	**23.7**

*Includes overhead and Allowance for Funds Used During Construction at current rate

Hydro One Distribution – Investment Justification
Wood Structure Replacement Program

Investment Driver: DC102 **Reference #: S7**

Investment Name: Wood Structure Replacement Program **In-Service**: December, 2008

Need:
This program is needed to ensure that sub-standard wood poles that have reached their end-of-life are replaced on a timely and economic basis.

Not proceeding with this investment would increase the risk of failure under adverse conditions, leading to reduced reliability, as well as increasing public and employee safety risks.

Investment Summary:
Hydro One Distribution's system includes about 1.65 million wood poles that support approximately 113,500 kilometers of overhead circuits. This program funds the replacement of poles that have been determined to be at end-of-life as established through pole assessment techniques based on industry standards. Wood poles deteriorate over time and when their strength is reduced to the point that there is a risk of failure under adverse weather conditions, they are deemed to be at end of life. Planned replacement of poles costs much less than "emergency" or reactive replacement and will be much less disruptive to customers. As such, over the long term, there is a compelling business need to replace poles in a proactive manner, consistent with good utility practice.

Pole replacements are determined through Hydro One Distribution's pole assessment program. As of the end of 2006 approximately 50% of the pole population will have been tested, tagged with barcodes and had their respective geographic coordinates identified and recorded. Annual testing targets are to remain at about 300,000 poles. Historically, about 4% of those inspected have been found to be substandard. Based on the 2007 pole testing program and deducting substandard poles that will be replaced under other programs, it is projected that 7,000 poles will need replacement during 2008. The replacement of these poles will remove substandard poles from the system thereby maintaining reliability, and ensuring compliance with Canadian Standards Association requirements for end of life pole replacement.

Aside from this program, poles are also replaced under other programs including those dealing with trouble calls and storm damage, system capability reinforcement, sustainment projects, line relocations and joint use modifications. It is estimated that an additional 9,000 to 13,000 poles will be replaced under these other programs.

Results:
- Replace end-of-life assets to comply with utility standards, and regulatory and legal requirements.
- Maintain customer reliability by replacing end of life wood pole structures.

Costs:

	2008 ($M)
Capital* and Minor Fixed Assets (A)	39.8
Operating, Maintenance & Administration and Removals (B)	4.3
Gross Investment Cost (A+B)	**44.1**
Recoverable (C)	-
Net Investment Cost (A+C)	**39.8**

*Includes overhead at current rates. No Allowance for Funds Used During Construction is included due to monthly capitalization.

Date: August 2007

Hydro One Distribution – Investment Justification
Waste Storage Tank Replacement

Investment Driver: DC104 **Reference #:** **S8**

Investment Name: Waste Storage Tank Replacement **In-Service Date:** December 2008

Need:

This investment is required to fund the replacement of Hydro One Distribution's end-of-life PCB storage tanks (shipping containers) to prevent oil leaks and spills and to comply with legislative requirements.

Not proceeding with this investment will potentially harm the environment and place Hydro One Distribution in non-compliance with Environmental Regulations should oil and waste leak from the existing deteriorated containers.

Investment Summary:

As part of operations, Hydro One Distribution manages activities (e.g. clean up, notification, documentation, storage transportation, containment, security, inventory, inspection, reporting) related to PCBs and other wastes. The wastes, which may be in the form of liquid (e.g. oil) or solid (i.e. spill remnants, discarded contaminated equipment - pole transformers, capacitors, reclosers), are collected at numerous sites throughout the province and placed in storage tanks (for liquids) and containers (for solids). Once economical quantities of a particular waste class are gathered in these units, disposal is arranged through third party facilities.

For Hydro One Distribution waste management, the current inventory of tanks and containers is distributed at 90 sites in the province. The vast majority of waste storage tanks and containers are on average more than 20 years old. The ageing population includes a number of units that are at end-of-life and need to be replaced, i.e. corroded and developing cracks. This investment covers the replacement of PCB and waste storage tanks at 29 service centers. This investment is the second year of a 4 year program.

The deteriorated and end-of-life shipping containers pose a high risk of leakage and are very difficult to inspect or maintain due to their enclosed and compartmentalized nature. These units cannot be repaired and must be replaced to ensure environmental compliance.

Results:

- The replacement of PCB and other waste product storage tanks that are approaching end-of-life so that Hydro One Distribution can prevent spills and damage to the environment.
- The prudent management of environment risks and compliance with regulatory requirements.

Costs:

	2008 ($M)
Capital* and Minor Fixed Assets (A)	1.2
Operating, Maintenance & Administration and Removals (B)	-
Gross Investment Cost (A+B)	**1.2**
Recoverable (C)	-
Net Investment Cost (A+C)	**1.2**

*Includes overhead and Allowance for Funds Used During Construction at current rates

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Hydro One Distribution – Investment Justification
Defective Crossarm Replacement Program

Investment Driver: DC107 Reference #: **S9**

Investment Name: Defective Crossarm Replacement Program **In-Service:** December, 2008

Need:

This investment is required to address defective wood crossarms on the Hydro One Distribution system. Having been identified as defective, these crossarms must be replaced on a planned basis to address safety and reliability risks and to comply with the requirements of the Distribution System Code.

Not replacing defective crossarms would lead to reduced feeder reliability, potential safety hazards and violation of the Distribution System Code.

Investment Summary:

Distribution lines' equipment deteriorates over time and must be replaced when it reaches end-of-life. Crossarms are a major component on the distribution system as they are fastened to poles and support the insulators and conductors. Once these components have reached end-of-life (i.e. wood rot, severely cracked, twisted or burnt) the likelihood of their failure increases and safety and customer reliability risks reach unacceptable levels.

Each defective wood crossarm that is identified through visual inspections as part of the patrol program is given a defect rating. Crossarms that are found to be in extremely poor condition are scheduled for emergency replacement under the trouble call program. The remainder of the defective crossarms are recorded and are scheduled for replacement in order to prevent failures and address reliability issues..

In 2008, 2,000 cross-arms are expected to be replaced, from those identified during line patrols from previous years.

Results:

- Replace approximately 2,000 defective wood crossarms during 2008 to eliminate known safety hazards to the public and to Hydro One Distribution staff
- Replace defective wood crossarms before failure and thereby address customer reliability risks.
- Replace end of life components to comply with regulatory requirements.

Costs:

	2008 ($M)
Capital* and Minor Fixed Assets (A)	1.7
Operations, Maintenance & Administration and Removals (B)	0.2
Gross Investment Cost (A+B)	**1.9**
Recoverable (C)	-
Net Investment Cost (A+C)	**1.7**

*Includes Overhead at current rates. No Allowance for Funds During Construction is charged due to monthly capitalization.

Date: August 2007

Hydro One Distribution – Investment Justification
Submarine Cable Replacement Program

Investment Driver: DC107 Reference #: **S10**

Investment Name: Submarine Cable Replacement Program **In-Service**: December, 2008

Need:
This investment is required replace sections of submarine cables at the shoreline, whose neutral/armour wires have corroded and pose safety and reliability risks, and to replace deteriorated submarine cables that have experienced a high rate of failure.

If this work is not completed, there is a likelihood of serious injury to the public as a result of fault current from damaged cables at the shoreline. Furthermore, customer reliability expectations may not be met.

Investment Summary:
There are approximately 2,200 circuit kilometers (single-phase) of submarine cable that are used mainly to supply seasonal island dwellings. These cables lie in rocky terrain and cross small and larger lakes, where it is difficult and expensive to build overhead lines. As a result, submarine cables provide the most cost effective solution by which to serve customers in these areas.

Asset condition assessments and past failures have shown that many of the cables, particularly at the shoreline are exposed to the elements. The ice and rocks abrade the protective armour wire allowing corrosion of the steel. This results in a loss of mechanical strength and creates a discontinuity in the grounding of the cable. The sheathing on the cable may also crack allowing water to migrate into the insulation causing an electrical failure. The problem occurs predominantly in rocky cottage locations, where it can expose the public to voltage hazards at the shoreline.

The cables to be repaired or replaced are identified during line patrols and through outage monitoring. The locations are normally identified at least a year in advance of the work being completed, allowing adequate time for planning. The cable sections proposed for replacement are prioritized based either on the condition of the armor wire where exposed at the shoreline, or based on the historical failure rate.

It is more cost effective to splice in new sections of cable at the shoreline where the damage to the cable has occurred rather than replace the entire cable. Splicing in new sections of replacement cable reinstates the mechanical protection required to protect the cable from ice and public interference. An entire cable is replaced when it reaches end-of-life, as determined by the number of failures the cable has experienced, and the length of corroded or missing neutral.

Results:
- Address end of life Submarine Cables.
- Maintain customer reliability with reduced outage frequency and duration.
- Eliminate known safety hazards to the public associated with damaged submarine cables.

Costs:

	2008 ($M)
Capital* and Minor Fixed Assets (A)	1.3
Operations, Maintenance & Administration and Removals (B)	0.2
Gross Investment Cost (A+B)	**1.5**
Recoverable (C)	-
Net Investment Cost (A+C)	**1.3**

*Includes overhead and Allowance for Funds Used During Construction at current rates

Date: August 2007

Hydro One Distribution – Investment Justification
Havelock TS 57M1 Feeder Refurbishment

Investment Driver: DC 107 **Reference#: S11**

Investment Name: Havelock TS 57M1 Feeder Refurbishment **InService:** December, 2008

Need:

This investment is required to address the end-of-life condition of poles, crossarms and insulators on the 44 kV Havelock TS 57M1 Feeder, specifically the 3.2 km line section south of Bancroft DS.

Not proceeding with this investment risks prolonged outages, reliability issues, and increased public and employee safety risks due to the likelihood of wood pole and component failures.

Investment Summary:

This investment identifies section refurbishment work that is required on the Havelock TS 57M1 feeder line section located in the Bancroft area. This is a radial feeder, roughly 90 km in length that supplies about 7,500 customers with a winter peak load of roughly 15 MVA. Annual load growth is expected to be in the 1% to 1.5 % range over the planning period.

In 2003, an asset condition assessment of this feeder indicated that 23 km of the line section between Eels Lake RS and Bancroft DS had reached end-of-life. The poles in this line section are of 1948 vintage. The plan was to re-establish this section in phases, from 2004 to 2008, as a new 44 kV circuit on road allowance underbuilt with a rural 12.48 kV circuit. Poor feeder performance (long outages) stems from the fact that the section of feeder proposed for relocation is in poor condition and is difficult to access.

By the end of 2007, about 20 km of line section will have been addressed. The investment of $2.1M in 2008 is required to complete the final 3 km of rehabilitation of this feeder.

Results:

- Maintain system security and customer delivery reliability.
- Improved accessibility and outage response time.
- Reduce safety hazards to the public and employees by replacing end of life components.
- Replace end of life components to comply with regulatory requirements.

Costs:

	2008 ($M)
Capital* and Minor Fixed Assets (A)	2.1
Operations, Maintenance & Administration and Removals (B)	0.2
Gross Investment Cost (A+B)	**2.3**
Recoverable (C)	-
Net Investment Cost (A+C)	**2.1**

*Includes overhead and Allowance for Funds Used During Construction at current rates

Date: August 2007

Hydro One Distribution – Investment Justification
Kingsville TS M3 & M6 Feeder Refurbishment

Investment Driver: DC107 **Reference #: S12**

Investment Name: Kingsville TS M3 & M6 Refurbishment **In-Service:** December, 2008

Need:

This investment is required for section refurbishment work on the Kingsville TS 27.6 kV M3 and M6 feeders.

Not proceeding with this investment risks prolonged outages, reliability issues, and increased public and employee safety risks due to the likelihood of wood pole and component failures.

Investment Summary:

These are radial feeders that together supply about 7,000 Hydro One Distribution, Chatham-Kent Hydro, and Essex Power customers. The M3 feeder supplies about 2500 Hydro One customers and embedded distributor – Chatham-Kent Hydro. The M6 feeder is used almost exclusively to supply embedded distributor Essex Power. Both feeders have a history of poor performance in terms of both outage duration and frequency. Annual load growth is expected to be about 1.5% over the planning period.

The M3 and M6 feeders supply over 40 MW of load with limited back-up supply during the peak summer months. This investment is required to address the end-of-life condition of poles and cross-arms on the two 27.6 kV feeders.

The main line section to be addressed is the 5 km M3/M6 double-circuit line section between Town Line Road (near switch B99X) and Hwy 77 (north of the former Town of Leamington). The other section to be addressed is the 2.5 km single-circuit M3 line section from Hwy 77 to Wheatley RS. Both line sections are within a high lightning strike area.

An asset condition assessment of the line sections has been completed, indicating that 130 poles should be replaced due to inadequate pole height and end-of-life pole condition.

The plan is to complete 130 pole replacements, addressing pole condition and correct clearance deficiencies. In addition, lightning protection will be installed in those sections where pole replacements are being completed.

Results:

- Maintain system security and customer delivery reliability by replacing end of life components.
- Improve feeder lightning performance in a high lightning strike area.
- Reduce potential safety hazards to the public and Hydro One employees by replacing end of life components
- Replace end of life components to comply with regulatory requirements.

Costs:

	2008 ($M)
Capital* and Minor Fixed Assets (A)	1.5
Operations, Maintenance & Administration and Removals (B)	0.2
Gross Investment Cost (A+B)	**1.7**
Recoverable (C)	-
Net Investment Cost (A+C)	**1.5**

*Includes overhead and Allowance for Funds Used During Construction at current rates

Date: August 2007

Hydro One Distribution– Investment Justification
Lindsay TS D4M7 Phase 4 of 5

Investment Driver: DC107 **Reference #: S13**

Investment Name: Lindsay TS D4M7 Phase 4 of 5 **In-Service Date:** December, 2008

Need:

This investment is required to address the end-of-life condition of poles and crossarms on the 44 kV Lindsay TS D4M7 feeder; specifically the 3.7 km line section between Bulmer's Road and Fairburn Road, in the Fenelon Falls area.

Not proceeding with this investment risks prolonged outages, reliability issues and increased public and employee safety risks due to continuing feeder deterioration.

Investment Summary:

This investment consists of section refurbishment work that is required on the Lindsay TS D4M7 feeder. This is a 36 km long line supplying approximately 4,200 customers. Annual load growth is expected to be in the 1% to1.5% range over the planning period. The section proposed for rehabilitation is more than 50 years old.

An Asset Condition Assessment study of this feeder and other rural feeders in the area has been completed. Findings of this study identified that about 65% of the poles on the 16.5 km line section between Bobcaygeon Duke DS and Switch D406-2 have reached, or are very near to end-of-life. The study also revealed that the neighbouring F1 and F2 rural feeders, located on the road allowance would require refurbishment within the next 5-10 years.

In order to address these issues, a number of possible alternatives were analysed and compared. The preferred plan is to relocate the entire 16.5 km section of feeder onto road allowance in the same location as the rural feeders also nearing end-of-life, and in the process transfer the rural feeders onto the new 44 kV structures. This solution would address both component end-of-life and improve reliability by providing improved access to the 44 kV feeder by relocation to road allowance from off-road.

This is the fourth phase of a five year plan. Under this phase, a 3.7 km section of new line will be built, with provisions for underbuild circuits (rural and Joint Use) from Bulmer's Road to Fairburn Road.

An investment of $1.2 million is required to complete Phase 4 of 5 phases to rehabilitate this feeder.

Results:

- Replace end-of-life assets to comply with regulatory requirements.
- Address public and employee safety risks by replacing end of life assets.
- Improved customer reliability by relocation from off road to road allowance and by replacing end of life assets.
- Reduce vegetation management costs by relocating onto road allowance.
- A reduction of losses of 3.1 kW during peak periods.

Costs:

	2008 ($M)
Capital* and Minor Fixed Assets (A)	1.2
Operations, Maintenance & Administration and Removals (B)	0.1
Gross Investment Cost (A+B)	**1.3**
Recoverable (C)	-
Net Investment Cost (A+C)	**1.2**

*Includes overhead and Allowance for Funds Used During Construction at current rates

Date: August 2007

Hydro One Distribution – Investment Justification
Longlac TS M1 Feeder Refurbishment

Investment Driver: DC 107 **Reference #**: **S14**

Investment Name: Longlac M1 Feeder Refurbishment **In-Service:** Dec, 2008

Need:

This investment is required to address the end-of-life condition of poles, crossarms and insulators on the 44 kV Longlac S M1 Feeder, specifically the 4.3 km section starting at Longlac West DS to Picnic Point Road.

Not proceeding with this investment risks prolonged outages, reliability issues, and increased public and employee safety risks due to the likelihood of wood pole and component failures.

Investment Summary:

This investment is part of a multi-year plan started in 2003 to refurbish a 22 km section of Hydro One Distribution's Longlac TS 16M1 feeder. The Longlac TS 16M1 feeder is a 44 kV circuit supplying all load east of Geraldton including the town of Longlac and the area's lumber industry. This feeder is a radial supply to this area, with a main trunk roughly 36 km in length and approximately 50 years old. This feeder supplies about 1,220 customers with a winter peak load of roughly 18.3 MVA. Load growth is expected to be between 1% and 4%, with the likely need for a 2^{nd} 44 kV circuit by 2014.

An ACA study of the feeder identified that the majority of poles had components that had reached end of life. In the past several years the town of Longlac had experienced several long duration outages, primarily related to end of life crossarm and insulator failures that needed to be addressed. A number of alternatives were considered in determining the most cost effective solution to provide an acceptable level of security to customers and replace end of life, or near end of life components. The alternative selected was to rebuild the entire 22 km line section in poor condition and re-establish the feeder as a new 44 kV circuit with a rural underbuilt 7.2/12.48 kV circuit, as well as provisions for a future 2^{nd} 44 kV circuit.

This investment represents the final 4.3 km on the main line of the Longlac TS M1 feeder to be rehabilitated.

Results:

- Maintain system security and customer delivery reliability by replacing end of life assets.
- Reduce potential safety hazards to the public and Hydro One employees.
- Replace end of life components to comply with regulatory requirements.
- A reduction in line losses of 10 kW at peak periods.

Costs:

	2008 ($M)
Capital* and Minor Fixed Assets (A)	1.1
Operations, Maintenance & Administration and Removals (B)	0.1
Gross Investment Cost (A+B)	**1.2**
Recoverable (C)	-
Net Investment Cost (A+C)	**1.1**

*Includes overhead and Allowance for Funds Used During Construction at current rates

Date: August 2007

Hydro One Distribution – Investment Justification
Minden TS 87M1 Phase 3 of 4

Investment Driver: DC 107 **Reference #: S15**

Investment Name: Minden TS 87M1 – Phase 3 of 4 **In-Service:** December 2008

Need:

This investment is required to address the end-of-life condition of poles, crossarms and insulators on the 44 kV Minden TS 87M1 Feeder, specifically 4.5 km of the line section between Haliburton and Tory Hill, located in the Minden area.

Not proceeding with this investment risks continued prolonged outages, reliability issues, and safety concerns for the public and employees.

Investment Summary:

This investment identifies refurbishment work that is required on a section of the Minden TS 87M1 feeder located in the Minden area. This radial feed, roughly 40 km in length, supplies about 5,000 customers with a peak load of roughly 10 MVA. Annual load growth is expected to be in the 1% to 1.5 % range over the planning period.

An assessment of the condition of the line has indicated that 11 km of the 24 km line section between Haliburton DS and Tory Hill DS has reached end-of-life. The poles in this line section have tested poorly, with the majority identified as substandard.

After assessing alternatives, it was identified that the preferred plan was to re-establish this section as a new 44 kV circuit on road allowance with a rural 12.48 kV underbuild circuit, in phases, over a number of years. Poor feeder performance stems from the fact that the section of feeder proposed for relocation is in poor condition and is difficult to access, being located in extremely rugged terrain.

A cost of $2.0M is required to complete phase 3 of 4 for the rehabilitation of this feeder. The remaining 2.5 km of new overhead line section will be completed in phase 4.

Results:

- Improve system security and customer delivery reliability by replacing end lf life components
- Improved accessibility and outage response time.
- Reduce potential safety hazards to the public and Hydro One employees.
- Replace end of life components to comply wirh regulatory requirements.
- Reduce vegetation management costs by relocating onto road allowance.
- A reduction in line losses of 28 kW.

Costs:

	2008 ($M)
Capital* and Minor Fixed Assets	2.0
Operations, Maintenance & Administration and Removals	0.2
Gross Investment Cost	**2.2**
Recoverable	0
Net Investment Cost	**2.0**

*Includes overhead and Allowance for Funds Used During Construction at current rates

Hydro One Distribution – Investment Justification
Town of Thessalon Rebuild – Part 2 of 4

Investment Driver: DC107 **Reference #: S16**

Investment Name: Town of Thessalon Rebuild – Part 2 of 4 **In-Service:** December, 2008

Need:
This investment is required to address the end-of-life condition of poles, conductor, and associated overhead line components operating at 2.4 kV in the Town of Thessalon.

Not proceeding with this investment would present reliability and safety risks to residents of Thessalon associated with overhead line assets that are at end of life.

Investment Summary:
The Town of Thessalon is an acquired Municipal Electric Utility that has a 2.4 kV delta distribution network supplied from two 25kV/2.4 kV Distribution Stations with a total load of about 4.0 MVA.

An ACA has concluded that the majority of the 2.4 kV system in Thessalon is at end-of-life and in need of replacement. Specifically;
- more than 50% of the poles are at end-of-life.
- there are numerous sections of frayed and/or "suspect" conductor.
- numerous instances of substandard clearances, including clearances to joint-use tenants and street lights.
- substandard conductor ground clearances.

In addition, an ungrounded 2.4 kV delta distribution network is not a common North American electric utility installation. Hydro One Distribution Standards do not cover a 2.4 kV delta system, and as such there are no approved work methods, materials, or construction standards for this system.

A review of the options for addressing the end-of-life assets and non-standard system in Thessalon concluded that the preferred alternative is to re-build the Town's distribution network and convert it to 25/14.4 kV operation in four stages This voltage is consistent with the existing Hydro One Distribution system supplying the area around Thessalon. Completion of this work will allow the elimination of two Distribution Stations.

Phase 1 of this plan will be completed in 2007. This investment covers phase 2 of the recommended plan.

Results:
- Replace end-of-life distribution line assets and bring the distribution network in the Town of Thessalon up to present-day Hydro One Distribution Standards.
- Mitigate reliability and safety risks associated with end-of-life distribution line assets.
- Replace end of life assets to comply with regulatory requirements.

Costs:

	2008 ($M)
Capital* and Minor Fixed Assets	1.3
Operations, Maintenance & Administration and Removals	0.2
Gross Investment Cost	**1.5**
Recoverable	-
Net Investment Cost	**1.3**

*Includes overhead and Allowance for Funds Used During Construction at current rates

Date: August 2007

Hydro One Distribution – Investment Justification
Fort Frances TS M1 Feeder Rehab Phase 3

Investment Driver: DC107 **Reference** #: **S17**

Investment Name: Fort Frances TS M1 Rehab **In-Service:** December, 2008

Need:

This investment is required to address the end-of-life condition of poles and crossarms on the 44 kV Fort Frances TS M1 feeder, specifically the 14 km line section between Straton and Pinewood.

Not proceeding with this investment risks prolonged outages, reliability issues, and leads to continuing feeder deterioration.

Investment Summary:

Hydro One Distribution's Fort Frances 22M1 feeder is a 44kV line emanating from Fort Frances TS that feeds 7 Hydro One Distribution stations as well as a major customer, Abitibi Paper. It supplies the communities that are situated along the Rainy River west from Fort Frances.

This investment is the third phase of a multi-year plan that includes refurbishment work on a 14 km line section of the Fort Frances TS M1 between Straton and Pine River DS. The M1 feeder is a 94 km long line supplying approximately 3,500 customers. Annual load growth is expected to be less than 1% over the planning period.

An Asset Condition Assessment study of this feeder has been completed. Findings of this study identified that there is a need to address deteriorated line sections of this feeder. The sections proposed for rehabilitation are 50 plus years old and represent about 30% of the total feeder length. The preferred plan is to rehabilitate the feeder over a number of years, replacing poles and insulators, but not the conductor. The conductor is adequate to meet future customer load requirements and has a remaining life of at least 20 years. This solution would address both component end-of-life and the reliability issues.

Results:

- Improved customer reliability and address safety issues by replacing end of life components
- Replace end-of-life assets to comply with regulatory requirements.

Costs:

	2008 ($M)
Capital* and Minor Fixed Assets	1.8
Operations, Maintenance & Administration and Removals	0.2
Gross Investment Cost	**2.0**
Recoverable	-
Net Investment Cost	**1.8**

*Includes overhead and Allowance for Funds Used During Construction at current rates

Hydro One Distribution - Investment Justification
Metering for Shared Use Distribution Charges

Investment Driver: DC109 **Reference #**: **S18**

Investment Name: Metering for Shared Use Distribution Charges **In-Service Date**: December 2008

Need:

This investment is required for metering which is used to determine Local Distribution Companies' (LDCs') shared use of Hydro One owned distribution stations.

Investment Summary:

In situations where LDCs consume power at Hydro One owned distribution stations, the LDC's energy consumption is measured,to allow the determination of the LDC's shared use of the distribution station. The 2008 spending will install new meters at 20 sites at the cost of approximately $0.1 million at each location.

Results:

- Charge the approved OEB Shared Use Distribution Charge to those LDCs using Hydro One distribution stations.
- Recover the capital cost of the investment through the application of the approved OEB rate.

Costs:

	2008 ($M)
Capital* and Minor Fixed Assets (A)	2.0
Operations, Maintenance & Administration and Removals (B)	-
Gross Investment Cost (A+B)	**2.0**
Recoverable (C)	-
Net Investment Cost (A+C)	**2.0**

*Includes Overhead and Allowance for Funds Used during Construction at current rates

Date: August, 2007

Hydro One Distribution – Investment Justification
Smart Metering - 2008

Investment Driver: CC851 **Reference #: S19**

Investment Name: Smart Metering **In-Service: January, 2010**

Need:

The Provincial Government has mandated the installation of smart meters in 800,000 homes by 2008 and installations in all homes by 2010. These meters must be capable of being read daily and of providing energy consumption data to the customer by the next business day. This investment is required to meet these requirements.

Provincial regulations provide the authorization for Hydro One Distribution to proceed with this initiative.

Investment Summary:

Meeting this mandate requires a new communication/IT infrastructure that encompasses Advanced Metering Infrastructure ("AMI") capable electronic meters, supporting telecommunications, back office integration and business process re-design, customer information system ("CIS") upgrades and other supporting IT software/hardware systems.

Hydro One will rely on the IESO as the Data Company (DataCo) appointed by the Ontario Ministry of Energy to provide the meter data management/repository ("MDM/R") functionality. Accordingly, no costs have been included in Hydro One's plan for the processing and storage of consumers' consumption information and data received from other LDCs. Only expenditures required to interface between Hydro One's AMI system and the MDM/R and the MDMR and Hydro One's CIS have been included.

Hydro One is accountable for owning and installing the smart meters ("AMCD"), collecting customer metering data over a telecommunications network ("AMRC" and "WAN") to a computer application ("AMCC"), and passing the data to DataCo's data warehouse, and receiving the data back for customer billing purposes.

Hydro One Networks Distribution Business' share of the Provincial target is forecast to be about 1.3 million meter installations by 2010, with about 240,000 installations by 2008. The company is on track to meet these targets.

This project carries risks. Smart meters are a relatively new technology without significant deployment to date. Evolving directions regarding specifications, accountabilities and timelines also remain a risk. For example, until a smart meter entity (SME) -- the data warehouse that is inserted in the middle of the meter-to-bill process – is created, and plans developed, Hydro One cannot finalize its plan to integrate its AMR to provide hourly data or develop TOU billing capability. It has done extensive work to identify these risks and mitigate them to the extent possible, however.

Capital expenditures in 2008 will be focused on:

- The installation of additional smart meters and related advanced metering communications devices ("AMCDs");
- Building and expanding the advanced metering regional collector ("AMRC") and underlying networks to accommodate an increasing number of meters coming on-stream;
- Commissioning and placing into service, hardware and software for the AMCC to enable it to communicate and transmit quality meter data to/from the MDM/R and the company's CIS
- Upgrades to our CIS system to provide for TOU biliing and related required settlement changes
- Integration of the end to end systems including business process redesign, and
- Project management and the expertise required to accomplish the above tasks.

Operating expenditures in 2008 will be focused on:

- Maintaining and operating hardware, software and software licenses associated with the AMCC;
- Telecommunication charges associated with operating the LANs and WAN;
- Maintaining smart meters that have been placed into service;

- Managing, developing and implementing business process redesign, change management (including staff training) and customer communication related work; and
- Responding to higher customer inquiries pre- and post-installation of smart meters on customer premises.

Results:

- 370,000 incremental meter installations in 2008 (for a total of 610,000).
- Communications network required to support the installed meters, also in place.
- Core systems modified/built to support limited commencement of time of use billing.
- Business proceses re-engineered to support smart metering.
- Limited cost savings in the areas of meter reading, meter sampling and reverification.

Costs:

	2008($M)
Capital* and Minor Fixed Assets (A)	164.8
Operations, Maintenance & Administration and Removals (B)	9.7
Gross Investment Cost (A+B)	**174.5**
Recoverable (C)	-
Net Capital Cost (A+C)	**164.8**

*Includes Overhead and Allowance for Funds Used During Construction at current rates

Date: August 2007

Hydro One Distribution – Investment Justification
New Connections, Upgrades and Service Cancellations - 2008

Investment Driver: DC201 **Reference #: D1**

Investment Name: New Connections, Upgrades and Service Cancellations **In-Service:** December, 2008

Need:

These investments are required to meet the on-going demand to connect new customers to Hydro One Distribution's network, upgrade services of existing customers, and the cancellation of service.

Not proceeding with these investments would result in non-compliance with Distribution license requirements and with obligations under the Distribution System Code. This work is therefore a regulatory requirement.

Investment Summary:

Each year, Hydro One Distribution connects new customers to the distribution network, upgrades services for existing customers and removes facilities when customers cancel services.

As part of the obligations in Hydro One's electricity distribution license and the distributor's responsibilities in the Distribution System Code (DSC), Hydro One Distribution is required to make an offer to connect all distribution customers on a non-discriminatory basis, upon written request for connection.

A service upgrade occurs when a customer requires a larger service entrance. A service upgrade normally requires the preparation of a service layout and replacement of secondary service wires. Transformers may also have to be upgraded, meters replaced and possibly additional transformation installed.

For cancellations of existing service, Hydro One Distribution is required to remove the idle assets (transformers, poles, service wires, meters, etc.) for safety and security reasons. The cost for this work is charged to depreciation, where most other costs associated with new connections and upgrades are capitalized.

Individual investments within these programs are managed on a project basis. Projects include design (service layouts), labour, material and other costs associated with actual physical connection or removal.

A standard connection consisting of a service layout, overhead transformation, 30 m of overhead conductor, and standard retail metering (including smart meters) is provided free of charge to new customers that "lie along" the existing network, as per the DSC requirements. For customers that require expansion of the network in order to be connected, a discounted cash-flow calculation is used to determine customer contributions. The capital contribution is based on any shortfall between future revenues and the cost of connection, network expansion and reinforcement. Customer contributions for system expansions, plus other recoverable costs beyond the standard connection, are forecast at $23.7M for the year.

Projected cost for these programs are primarily based on historic demand and forecast load growth that takes into consideration the Ontario Gross Domestic Product and Ontario Building Permits.

Results:

- Connect new customers.
- Upgrade the services of existing customers.
- Remove assets when services are cancelled.
- Satisfy the requirements of the Distribution System Code and Distribution License.

Costs:

	2008($M)
Capital* and Minor Fixed Assets (A)	127.6
Operations, Maintenance & Administration and Removals (B)	6.7
Gross Investment Cost (A+B)	**134.3**
Recoverable (C)	(23.7)
Net Capital Cost (A+C)	**103.9**

*Includes Overhead and Allowance for Funds Used During Construction at current rates

Date: August 2007

Hydro One Distribution – Investment Justification
2008 Demand Investments

Investment Driver: DC202 **Reference #:** **D2**

Investment Name: 2008 Demand Investments **In Service:** December 2008

Need:
This investment is required to provide a capability for the Customer Operations' function to resolve lower cost critical issues identified by customers or system impact assessments on a short lead-time basis.

Not proceeding with this investment would result in deteriorated service reliability and quality causing decreased customer satisfaction and substandard supply. Damage to distribution system assets could result.

Investment Summary:
Minor distribution system modifications are required to address system needs identified by customer power quality complaints, reliability concerns, system impact assessments and customer connection requests. Responding to these needs ensures an adequate supply of electricity to customers.

Technical criteria are used in assessing system/customer needs. Minor system modifications/betterments addressed by this plan include items such as protection coordination, and installing new equipment or equipment upgrades. Modifications that will cost over $0.1M are assessed individually and are subject to a separate approval.

Results:

- Maintain reliability and quality of service within supply standards.
- Address customer and reliability issues in an expedient manner.

Cost:

	2008($M)
Capital* and Minor Fixed Assets (A)	1.1
Operations, Maintenance & Administration and Removals (B)	0.1
Gross Investment Cost (A+B)	**1.2**
Recoverable (C)	-
Net Capital Cost (A+C)	**1.1**

*Includes Overhead and Allowance for Funds Used During Construction at current rates

Date: August 2007

Hydro One Distribution – Investment Justification
Subtransmission Feeder Sectionalizing - 2008

Investment Driver: DC202 **Reference #:** **D3**

Investment Name: Subtransmission Feeder Sectionalizing **In-Service :** December, 2008

Need:

This investment is required to achieve a corporate goal to move Hydro One Distribution reliability to upper-quartile.

If this investment is cancelled, customers would not receive the benefits of improved reliability on the worst performing subtransmisison feeders. As well, not proceeding with this investment would present customer and reputation risks as a result of not having targeted system modifications that cost effectively improve the reliability of supply to distribution customers.

Investment Summary:

Feeder sectionalizers automatically isolate a portion of the feeder for downstream faults, reducing the number of customers affected. Subtransmission feeders (27.6 kV & 44 kV feeders supplied from Transformer Stations (TSs)) offer the greatest opportunities to improve reliability since they supply large amounts of load, and historically have not employed automatic sectionalizing for faults. Since 2005, the approved Business Plan has included funding for installing mid-feeder sectionalizers on the worst performing feeders over the period 2005-2007. The program has been extended to 2008 to complete the program, as not all feeders were completed during the 2005 to 2007 period due to the need to complete other higher priority work.

This investment is to provide mid-feeder sectionalizing on 32 subtransmission feeders in 2008, bringing the total number of feeders provided with sectionalizing to 86, with 30 feeders completed in 2005-2006 and 24 planned for 2007. The feeders have been selected based on having the highest number of customer interruptions and interruption hours (highest contributions to provincial SAIDI & SAIFI), plus the suitability for sectionalizer application.

This investment represents the final phase of the provincial program to install subtransmission feeder sectionalizing on the poorest performing subtransmission feeders.

Results:

- Individual sub-transmission feeders will see customer outages and outage durations reduced on average by about 25%.
- Feeder sectionalizing will improve reliability. On average, this investment will reduce provincial SAIFI and SAIDI by 1.5% and 1.8% respectively bringing the total expected improvement at the end of the program to 4.5% and 5.5% respectively.

Costs:

	2008($M)
Capital* and Minor Fixed Assets (A)	2.2
Operations, Maintenance & Administration and Removals (B)	0.2
Gross Investment Cost (A+B)	**2.4**
Recoverable (C)	-
Net Capital Cost (A+C)	**2.2**

*Includes Overhead and Allowance for Funds Used During Construction at current rates

Hydro One Distribution – Investment Justification
Armitage TS M12 Feeder Extension

Investment Driver: DC202 **Reference #:** D4

Investment Name: Armitage TS M12 Feeder Extension **In Service:** June 1, 2008

Need:

This investment is required to provide adequate 44 kV feeder capacity in the southern area of Whitchurch-Stouffville.

Not proceeding with this investment would lead to overloaded assets and the inability to serve new load presenting reliability, customer, regulatory and reputation risks as a result.

Investment Summary:

Whitchurch-Stouffville is a high-growth suburban community north of the City of Markham. Significant load growth is occurring in the southern part of the town, including several large commercial loads. The expected growth rate is 3.2 % per year. The existing 44 kV feeders in the area are unable to supply the additional load.

Two existing 44 kV feeders supplying the southern part of Whitchurch-Stouffville had exceeded their planning criteria in 2006. The situation is expected to worsen as additional load is added.

Various alternatives were analyzed and compared to address the situation. The preferred plan is to extend Armitage TS M12 by 6km and reconfigure it to supply the southern part of the town and relieve existing feeders. The work is consistent with the feeder development recommendations of the Whitchurch-Stouffville supply study.

Results:

- Provide adequate 44 kV feeder capacity to supply southern Whitchurch-Stouffville.
- Relieve overloaded feeders.
- Line losses will be reduced by 740 kW.
- Implement a cost effective life cycle plan.

Costs:

	2008 ($M)
Capital* and Minor Fixed Assets (A)	1.7
Operations, Maintenance & Administration and Removals (B)	0.2
Gross Investment Cost (A+B)	1.9
Recoverable (C)	-
Net Investment Cost (A+C)	1.7

*Includes Overhead and Allowance for Funds Used During Construction at current rates

Date: August 2007

Hydro One Distribution – Investment Justification
Holland Junction TS Feeder Development

Investment Driver: DC202 **Reference #: D5**

Investment Name: Holland Junction TS Feeder Development **In-Service:** December, 2008

Need:

This investment is required to provide adequate 44 kV feeder capacity in northern York Region.

Not proceeding with this investment would lead to overloaded assets and the inability to serve new load presenting reliability, customer, regulatory and reputation risks as a result.

Investment Summary:

Northern York Region, including the areas of Newmarket, Aurora, Bradford, East Gwillimbury and Whitchurch-Stouffville, is largely supplied from Armitage TS. Significant load growth is occurring in all of these areas due to increases in population as well as commercial and industrial developments. The load growth for the Hydro One Distribution area is expected to be 3.1 % per year for the next several years.

Armitage TS has exceeded its LTR rating and requires relief. Hydro One Networks has been directed by the Ontario Energy Board to construct a new transformer station in the vicinity of Holland Junction in King Township. The anticipated in-service date for the transformer station is prior to the 2009 summer peak.

Various alternatives were analyzed and compared to address the situation. The preferred plan is for Hydro One Distribution and Newmarket Hydro to each construct four 44kV feeders from the new TS. This project is for Hydro One Distribution to construct two 44 kV feeders from Holland Junction TS to Hwy 11.

Results:

- Transfer load from Armitage TS to Holland Junction TS.
- Provide adequate 44 kV feeder capacity to supply Northern York Region at least cost.
- Line losses will be reduced by 74kW
- Implement life cost cycle plan

Costs:

	2008 ($M)
Capital* and Minor Fixed Assets (A)	2.8
Operations, Maintenance & Administration and Removals (B)	0.3
Gross Investment Cost (A+B)	3.1
Recoverable (C)	-
Net Investment Cost (A+C)	2.8

*Includes Overhead and Allowance for Funds Used During Construction at current rates

Hydro One Distribution – Investment Justification
Curve Inn DS new T2 and feeder

Investment Driver: DC202 **Reference #:** **D6**

Investment Name: Curve Inn DS T2 and Feeder **In Service:** December, 2008

Need:

This investment is required to provide adequate 27.6 kV transformation capability in the southwestern part of the Municipality of Clarington.

Not proceeding with this investment would present reliability, customer, reputation and regulatory risks as the result of overloading assets

Investment Summary:

The southwestern part of the Municipality of Clarington is a high-growth suburban area adjacent to City of Oshawa. Significant load growth is occurring in this area, including several large commercial and residential developments. The existing facilities in the area are unable to supply the additional load.

The load growth in Clarington southwest is projected to be 3.8% per year for the next 5 years. The areas are largely supplied by Park Road DS which has a station capacity of 35.7MVA. This capacity will be exceeded in year 2008 when the load on the station is expected to reach 36.8MVA.

Various alternatives were analyzed and compared to address the situation. The preferred plan is to add a new 12 MVA transformer at the existing Curve Inn DS and provide load relief to Park Road DS by transferring Wilmot Creek community load to Curve Inn DS. This investment will address the growing loads in the Municipality of Clarington for the next 5 years, The load relief will also improve the supply reliability to the Wilmot Creek community, as the new feeder will be about 5 km shorter.

Results:

- Provide additional transformation capability.
- Relieve overloading of Park Road DS.

Costs:

	2008 ($M)
Capital* and Minor Fixed Assets (A)	2.7
Operations, Maintenance & Administration and Removals (B)	0.2
Gross Investment Cost (A+B)	2.9
Recoverable (C)	-
Net Investment Cost (A+C)	2.7

*Includes Overhead and Allowance for Funds Used During Construction at current rates

Date: August 2007

Hydro One Distribution – Investment Justification
Gardiner TS II 44 kV Feeders

Investment Driver: DC202 **Reference #: D7**

Investment Name: Gardiner TS II – 44 kV Feeders **In Service:** June 2008

Need:
This investment is required to relieve loading on Gardiner TS and Frontenac TS that supply Hydro One Distribution. Transferring load to a new TS is the least cost option for maintaining adequate capacity and supply reliability.

Not proceeding with this investment would result in an inability to relieve the existing overloaded Gardiner TS and Frontenac TS thereby resulting in decreased customer satisfaction and substandard quality of supply.

Investment Summary:
Based on the results of system studies and an analysis of alternatives, the preferred solution is the construction of a new transformer station (Gardiner TS II) on the site of the existing Gardiner TS. This will require Hydro One Distribution to build new feeder egresses from 3-44 kV feeder positions. This will enable Gardiner TS and Frontenac TS loads to be reduced below their rating (136.6 MVA and 105.9 MVA respectively) for at least the next 10 years.

This investment funds a capital contribution to Hydro One Transmission as stipulated in the Transmission System Code for building the new TS in the amount of $1.0 million, as well as the cost of installing IESO compliant metering at a cost of $0.3 million.

Results:
- Provide adequate transformation capacity to supply Hydro One Distribution's load growth.
- Optimize transformer and feeder utilization and balance by transferring load to the new TS.

Costs:

	2008 ($M)
Capital* and Minor Fixed Assets (A)	1.3
Operations, Maintenance & Administration and Removals (B)	-
Gross Investment Cost (A+B)	1.3
Recoverable (C)	-
Net Investment Cost (A+C)	1.3

*Includes Overhead and Allowance for Funds Used During Construction at current rates

Date: August 2007

Hydro One Distribution – Investment Justification
Brockville Area Upgrade

Investment Driver: DC202 **Reference #: D8**

Investment Name: Brockville Area Upgrade **In Service:** December 2008

Need:

This investment is required to meet growing loads in the Brockville area, ensure that system protection criteria are met, and address failed distribution system components.

Not doing the proposed work will lead to overloading of feeders, inability to serve additional loads in some parts of the municipality, increasing customer dissatisfaction with power quality, reducing the ability to provide timely service restoration following outages, risk that system protection criteria are not being met and reducing reliability.

Investment Summary:

The Brockville "City" area requires supply capacity reconfiguration at the distribution voltage level. Distribution customers are supplied either directly at 44 kV from the transformer station, or at 4.16 or 8.32 kV from distribution stations. An assessment of the supply to Brockville shows heavy/imbalanced feeder loading and aged/failed underground conductors have been identified. One 44 kV line is loaded beyond Hydro One's planning criteria (loading is 27 MVA compared to 25 MVA which initiates a capability review).

Limited capability to supply new loads or provide satisfactory outage restoration exists. Brockville's total load is 61 MVA with 1.5% growth.

This investment will improve feeder loading and balance, provide improved alternate supply capability, and satisfy the need to ensure that distribution protection criteria are observed. Failed distribution system components will be replaced and upgraded to be capable of handling future demands. System protection will be reviewed and modified as required on the eight DSs in the Brockville area to ensure safe and reliable operation of the system.

Results:

- Distribution Station and feeder capacity will be adequate to serve loads in Brockville over the next 5 to 10 years.
- Voltage and power quality will be within CSA and industry standards.
- Deterioration of reliability will be avoided.
- Due diligence regarding protection settings will be satisfied.
- Losses will be reduced by 30 kW.

Costs:

	2008 ($M)
Capital* and Minor Fixed Assets (A)	2.2
Operations, Maintenance & Administration and Removals (B)	0.2
Gross Investment Cost (A+B)	2.4
Recoverable (C)	-
Net Investment Cost (A+C)	2.2

*Includes Overhead and Allowance for Funds Used During Construction at current rates

Date: August 2007

Hydro One Distribution – Investment Justification
Ingersoll North DS Voltage Conversion

Investment Driver: DC202 **Reference #**: **D9**

Investment Name: Ingersoll North DS Voltage Conversion **In Service:** December, 2008

Need:

This investment is needed to address end-of-life conditions at the 27.6/8.32 kV Ingersoll North DS, and to supply forecast new loads in the Hwy. 19 & Hwy. 401 area near Ingersoll.

Not proceeding with this investment would present customer, regulatory and reputation risks as a result of deteriorating performance of assets that are at end-of-life, and insufficient system capacity for forecast loads.

Investment Summary:

Ingersoll North DS is a 3.6 MVA, 27.6/8.32 kV station that currently supplies 3.2 MVA of load via a 8.32 kV feeder (the F2 feeder). The station is 55 years old and has been deemed to be at end-of-life based on a detailed condition assessment\. The F2 feeder supplies load along Hwy. 19 south of Ingersoll towards Hwy. 401 and then the surrounding rural areas to the south of the Hwy 401. Along Hwy. 19, two developments are planned, a new residential subdivision and a new auto parts plant. Both developments will "lie-along" the existing F2 feeder.

To address the end-of-life conditions at Ingersoll North DS, as well as supply the new load connections in the area, the preferred plan is to eliminate Ingersoll North DS through a combination of 27.6/16 kV voltage conversion and the installation of step-down transformers at strategic locations. In order to achieve this, a new metered 27.6/16 kV Supply Point is required, and approximately 25 km of insulation upgrades, protection changes and removals are required.

Results:

- Replace DS assets that are at end-of-life.
- Provide sufficient distribution feeder capacity to serve forecast new loads along Hwy. 19, south of Ingersoll.
- Reduce peak Line Losses by 130 kW.

Costs:

	2008 ($M)
Capital* and Minor Fixed Assets (A)	1.9
Operations, Maintenance & Administration and Removals (B)	0.2
Gross Investment Cost (A+B)	2.1
Recoverable (C)	-
Net Investment Cost (A+C)	1.9

*Includes Overhead and Allowance for Funds Used During Construction at current rates

Date: August 2007

Hydro One Distribution – Investment Justification
Kleinburg TS Feeders to Bolton

Investment Driver: DC202 **Reference #: D10**

Investment Name: New Kleinburg TS Feeders to Bolton **In Service:** December, 2008

Need:

This investment is required to provide adequate 44 kV and 27.6kV feeder capacity in the Bolton area.

Not proceeding with this investment will continue to present reliability, customer, regulatory and reputation risks as a result of overloaded assets.

Investment Summary:

Bolton is a high-growth suburban community in the town of Caledon, north of Brampton and west of the City of Vaughan. Bolton is experiencing significant load growth that includes several large commercial and industrial developments. The expected growth rate is 3.3 % per year. The existing 27.6 kV and 44 kV feeders in the area are unable to supply the additional future load.

Two existing 44 kV feeders and three 27.6kV feeders supplying the Bolton area exceeded their planning criteria in 2006. The situation is expected to worsen as additional load is added.

Various alternatives were analyzed and compared to address the situation. The preferred plan is to build two new feeders, one 44 kV and one 27.6 kV from Kleinburg TS for about 12 km on the same pole line and reconfigure the supply in the northern part of Bolton, thereby relieving the existing overloaded feeders.

Results:

- Provide adequate 44 kV and 27.6 kV feeder capacity to supply Bolton area.
- Line losses will be reduced by 47 kW.

Costs:

	2008 ($M)
Capital* and Minor Fixed Assets (A)	3.6
Operations, Maintenance & Administration and Removals (B)	0.2
Gross Investment Cost (A+B)	**3.8**
Recoverable (C)	-
Net Investment Cost (A+C)	**3.6**

*Includes Overhead and Allowance for Funds Used During Construction at current rates

Date: August 2007

Hydro One Networks – Investment Justification
Belle River TS M2 Feeder to Haycroft DS

Investment Driver: DC202 **Reference #:** **D11**

Investment Name: Belle River TS M2 Line to Haycroft DS **In Service:** December, 2008

Need:

This investment is needed to address the overloading of 115/27.6 kV Tilbury West HV DS.

Not proceeding with this investment would present customer, reliability, regulatory and reputation risks as the result of overloading assets.

Investment Summary:

Tilbury West HV DS supplies the Town of Tilbury (Chatham-Kent Hydro service territory) and the Hydro One service territory surrounding the town. The Town of Tilbury is located along Hwy 401 about 45 km east of the City of Windsor.

Tilbury West HV DS is a 15/25 MVA 115/27.6 kV station. Load in the HV DS exceeds its rated capacity by 3 MVA. The preferred (least cost) plan to transfer part of the station's load on to the new Belle River TS was placed into service in May 2006.

This investment covers the extension of the Belle River TS M2 feeder by about 7.5 km to Haycroft DS. Haycroft DS will be transferred from the Tilbury West HV DS F1 feeder to the Belle River TS M2 feeder, thereby reducing the load on Tilbury West HV DS to within acceptable standards.

Results:

- Improve reliability by providing adequate load relief for Tilbury West HV DS for the next 10 years, at least cost.

Costs:

	2008 ($M)
Capital* and Minor Fixed Assets (A)	1.9
Operations, Maintenance & Administration and Removals (B)	0.1
Gross Investment Cost (A+B)	2.0
Recoverable (C)	-
Net Investment Cost (A+C)	1.9

*Includes Overhead and Allowance for Funds Used During Construction at current rates

Date: August 2007

Hydro One Distribution – Investment Justification
Seaforth M5 27.6 kV, 25 MVA Voltage Regulation

Investment Driver: DC202 **Reference #:** **D12**

Investment Name: Seaforth M5 27.6 kV, 25 MVA Voltage Regulation **In-Service :** December, 2008

Need:

This investment is required to maintain supply voltage within Distribution System Code requirements on the Seaforth M5 feeder.

Not proceeding with the proposed improvement will lead to unacceptably low voltage, inability to connect additional customers in some parts of the municipality and increasing customer dissatisfaction as a result of power quality issues.

Investment Summary:

As recent as November 2006, Festival Hydro identified a new customer (8-10 MVA ethanol plant) to be located within Festival Hydro's service area in the town of Hensal. The Town of Hensal is supplied from the Seaforth M5 feeder at 27.6kV and is approximately 22 km from Seaforth TS. The total line length is 25 km.

Load flow studies indicate that by 2008 that there will be substandard voltage starting at a point approximately half way along the feeder (12 km). Hydro One customers connected to the furthest 12 km and Festival Hydro (Town of Hensal) will experience low voltage if remedial action is not taken. This condition can be avoided with the installation of a new 27.6kV, 25 MVA regulator approximately 10 km from Seaforth TS.

Load in the area is expected to continue to grow at 1.5 % per year. The installation of a new regulator as proposed will ensure that voltage levels on the Seaforth M5 will remain within acceptable standards for a period of 5 years.

Results:

- Avoid substandard voltage problems when the new ethanol plant connects in 2008.
- Improve voltage regulation.
- Reduce line losses by 46 kW.

Costs:

	2008 ($M)
Capital* and Minor Fixed Assets (A)	1.4
Operations, Maintenance & Administration and Removals (B)	-
Gross Investment Cost (A+B)	1.4
Recoverable (C)	-
Net Investment Cost (A+C)	1.4

*Includes Overhead and Allowance for Funds Used During Construction at current rates

Date: August 2007

Hydro One Distribution – Investment Justification
Stayner TS x Blue Mountain – Build 2 New 44 kV Feeders – Stage 1

Investment Driver: DC202 **Reference #: D13**

Investment Name: Stayner TS x Blue Mountain - Build 2 New 44 kV Feeders **In-Service:** December, 2008

Need:

This investment is required to maintain acceptable supply conditions to customers in the Blue Mountain area, meet load growth in the area and avoid the risk of unsupplied load due to feeder loading beyond protection limits.

Not proceeding with this investment will result in substandard voltage and protection conditions on the existing 44 kV feeders supplying the Blue Mountain area.

Investment Summary:

Load in the Blue Mountain and Collingwood area is supplied at 44 kV from Meaford TS and Stayner TS. The two most heavily loaded feeders are the Meaford TS M1 at 37 MVA, and the Stayner TS M1 at 32 MVA. Load on these two feeders is expected to grow at a rate of 2-2 ½ % over the next several years due to new residential and tourist developments. By winter 2008/2009, the voltage at the end of both feeders is projected to be below CSA standard of 94% of nominal unless relief is provided.

In 2006, the OPA issued a report recommending that additional transmission capacity be provided to the Southern Georgian Bay area by converting Stayner TS from 115 kV to 230 kV and installing 230-115 kV auto-transformation at this location. The additional capacity at Stayner TS will consist of 75/125 MVA transformers replacing existing 50/83 's, plus 3 new 44 kV feeder positions.

This investment covers Stage 1 of a plan to extend two new 44 kV feeders from Stayner TS to the Blue Mountain area in order to relieve the existing Meaford TS M1 and Stayner TS M1 feeders. Stage 1 involves 10 km of new double-circuit 44 kV wood pole line, overbuilding existing rural distribution circuits, and connected to existing M1 & M3 feeders out of Stayner TS. A separate investment will be issued for Stage 2, for 2009 construction, which will extend the 2 new feeders to Stayner TS to co-incide with the in-service date of the station upgrade.

Results:

- Maintain supply conditions within CSA standards in the Blue Mountain area.
- Provide new feeders to utilize new transmission capacity at Stayner TS.

Costs:

	2008 ($M)
Capital* and Minor Fixed Assets (A)	4.6
Operations, Maintenance & Administration and Removals (B)	0.5
Gross Investment Cost (A+B)	**5.1**
Recoverable (C)	-
Net Investment Cost (A+C)	**4.6**

*Includes overhead and Allocated Funds Used During Construction at current rates

Date: August 2007

Hydro One Distribution – Investment Justification
Timmins TS M9 Feeder Extension

Investment Driver: DC202 **Reference #:** **D14**

Investment Name: Timmins TS M9 Feeder Extension **In-Service:** December, 2008

Need:

This investment is needed to address forecast overloading of Hoyle DS. It also addresses replacement of 4 kV line assets that are nearing end-of-life and reduces system losses.

Not proceeding with this investment would present reliability, customer, regulatory and reputation risks as the result of overloading assets.

Investment Summary:

Customers located east & south-east of Timmins are supplied by Hoyle DS, a 115-27.6 kV HVDS. Hoyle DS is a single-bank station and as a result its' firm load capability is limited to the 115 kV Mobile Substation rating of 15 MVA. Hoyle DS is currently loaded at about 12 MVA and is forecast to increase to 18 MVA by the end of 2007 due to a number of new and re-developing mines being connected in this area.

Prior to the mid-1990's, a portion of the load supplied from Hoyle DS was fed from the Timmins TS M9 feeder. This load was transferred to Hoyle DS when construction of Placer Domes' open-pit gold mine forced the relocation of the roadway on which the M9 was located. A review of alternatives for addressing the forecast overloading of Hoyle DS has concluded that the preferred plan is to re-establish the M9 supply eastwards through South Porcupine and transfer load in this area from Hoyle DS to Timmins TS.

This project involves extending the Timmins TS M9 feeder for approximately 1.3 km through South Porcupine by converting the South Porcupine DS F2 feeder from 4.16 kV to 27.6 kV. An additional 2.5 km of associated single-phase line taps will also be converted from 2.4 kV to 16 kV and approximately 1800 KVA of load, or about half the total load on South Porcupine DS, will be converted to 27.6 kV. This work addresses near end-of-life condition of the existing 4 kV feeder, which will otherwise require replacement in about 5 years. Also included are 2 new 27.6 kV load break switches and a new 3-phase electronically-controlled unit.

Results:

- Relieve overloading of Hoyle DS to maintain customer supply.
- Replace near end-of-life 4 kV assets fed from South Porcupine DS.
- Reduce peak Line Losses by 200 kW.

Costs:

	2008 ($M)
Capital* and Minor Fixed Assets (A)	2.1
Operations, Maintenance & Administration and Removals (B)	0.2
Gross Investment Cost (A+B)	**2.3**
Recoverable (C)	-
Net Investment Cost (A+C)	**2.1**

*Includes overhead and Allocated Funds Used During Construction at current rates

Date: August 2007

Hydro One Distribution – Investment Justification
Timmins Moneta DS Voltage Conversion

Investment Driver: DC202 **Reference #:** **D15**

Investment Name: Timmins Moneta DS Voltage Conversion **In-Service:** December, 2009

Need:

To address the condition of an existing 4.16 kV distribution station and associated line assets that are at, or approaching, end-of-life.

Not proceeding with this work will result in deterioration of existing station & line equipment resulting in supply interruptions, negative environmental impacts and the reduced safety for Hydro One staff and the general public.

Investment Summary:

Prior to 2003, load in the central core of the City of Timmins was supplied via a 4.16 kV distribution network fed from four 27.6-4.16 kV Distribution Stations – Pine DS, Ninth DS, Vimy DS #2, and Moneta DS. The total load on this system was 17 MVA, about 15% of the total load in the City. The remainder of the load in Timmins is supplied directly at 27.6/16 kV via feeders emanating from Timmins TS and Laforest Road and Hoyle high voltage distribution stations (HVDS).

A condition assessment was conducted on the entire 4.16 kV network in 2001 and 2002, which concluded that the four stations were in need of extensive rehabilitation work including new circuit breakers and associated control systems, plus replacement of most structural support components. In addition, an assessment of the associated 4.16 kV feeders fed from these stations concluded that 60-70 % of the existing wood poles are at end-of-life, and there are numerous instances of substandard primary and secondary conductor which are prone to mechanical failure and/or electrical overloading.

The preferred solution is to eliminate the existing 4.16 kV system through conversion of the operating voltage to 27.6 kV supplied directly from Timmins TS, over a multi-year period. Elimination of Timmins Pine DS, Ninth DS, and Vimy DS #2 was completed in 2003, 2004, and 2006 respectively.

This investment covers the work necessary for the elimination of Timmins Moneta DS, which is the final station supplying load at 4.16 kV in the City core. This investment is planned to be carried out over a 2-year period (2008-2009). The voltage conversion work involves replacing approximately 150 end–of-life wood poles, 80 transformers and removal of Moneta DS.

Results:

- Eliminate DS assets that are at end-of-life thereby securing customer reliability.
- Replace 4.16 kV line assets that are at end-of-life with new 27.6/16 kV assets to secure customer reliability, safety and comply with regulatory requirements.
- Reduce peak Line Losses by 50 kW.

Costs:

	2008 ($M)
Capital* and Minor Fixed Assets	2.4
Operations, Maintenance & Administration and Removals	0.2
Gross Investment Cost	**2.6**
Recoverable	-
Net Investment Cost	**2.4**

*Includes overhead and Allocated Funds Used During Construction at current rates

Date: August 2007

Hydro One Distribution – Investment Justification
Wholesale Metering Upgrades

Investment Driver: DC205 **Reference #:** **D16**

Investment Name: Wholesale Metering Upgrades **In-Service:** December, 2008

Need:

This investment is needed to upgrade or replace Hydro One Distribution wholesale meter points at the earliest seal expiry date of any meter or recorder of the metering installation to ensure compliance with the required Wholesale Revenue Metering Hardware Standards.

Not proceeding with this investment would expose metering not in compliance with the Market Rules to sanctions and delivery point penalties of up to 1.8 times the line capacity or transformer bank rating. As well, this would result in customer disputes concerning sales and revenues.

Investment Summary:

- The Market Rules stipulate that the earliest expiry date of any seal period of any meter forming part of a metering installation (MI), the Metered Market Participant (MMP) for the MI "shall make such alternative arrangement as may be necessary to comply with the provisions" of Chapter 6 of the Market Rules, "and of any policy or standard established by the IESO pursuant to this chapter".

- Hydro One Distribution has 50 distribution wholesale metering points where seals have or will expire in 2008. In compliance with Market Rules and to meet Measurement Canada requirements, the 50 meter installations will be upgraded as a combination of 45 full upgrades, 1 meter only upgrade and 4 meter cabinet only upgrades.

Results:

- Upgrade 50 Hydro One Distribution wholesale metering points due in 2008 at the most economical cost
- Ensuring compliance with the Market Rules and Measurement Canada requirements.

Costs:

	2008 ($M)
Capital* and Minor Fixed Assets	11.4
Operations, Maintenance & Administration and Removals	-
Gross Investment Cost	11.4
Recoverable	-
Net Investment Cost	11.4

*Includes overhead and Allocated Funds Used During Construction at current rates

Date: August 2007

Hydro One Distribution - Business Case Summary
System-Data Archiving and Management

Investment Driver: DC 308 **Reference #:** **O1**

Investment Name: System-Data Archiving and Management **In-Service Date:** Sept, 2009

Need:

This investment is required to develop long term storage for distribution system data captured by ORMS and other operations systems. Effective analysis of distribution system performance trends and management of the asset sustaining programs requires the ability to store, access and evaluate data about past outages over a period of 15 years and therefore increased storage capabilities are needed.

Funding is required to prevent situations where effective analysis of performance trends, asset life and outage restoration could be impaired by the absence of historical distribution information.

Investment Summary:

In order to evaluate trends in operating performance, asset life cycle performance and forestry program effectiveness, operating data needs to be retained for up to about a 15 year time horizon. The current historical databases are oriented to the needs of operating and yearly statistical performance reporting and hence have storage capacity limited to about 5 years. Requests by planners for information have to be dealt with by operating staff who devise the appropriate queries for the request objective. As the volume of data increases, greater storage capacity and improved retrieval and analysis tools are needed to allow planners to harvest maximum benefit from this data asset.

This investment will provide long term storage of operating data from ORMS, NMS and other systems (such as weather data feeds) integrated into one archive. It will also provide extraction and analysis tools to allow planners to perform various data mining and correlation studies needed to guide optimum decisions on Distribution System investments.

Results:
- Improved targeting of the distribution system investments.
- Reduced labour cost for extracting and analysis of historical data.

Costs:

	2008 ($M)
Capital* and Minor Fixed Assets	1.3
Operations, Maintenance & Administration and Removals	-
Gross Investment Cost	1.3
Recoverable	-
Net Investment Cost	1.3

*Includes overhead and AFUDC at current rates

Hydro One Distribution - Investment Justification
NMS Enhancements for Distribution Monitoring and Control

Investment Driver: DC308 **Reference #:** **O2**

Investment Name: NMS Enhancements for Distribution Monitoring and Control **In-Service Date:** December 2008

Need:

This investment is needed to allow maximum benefit to be obtained from the development program to install Distribution Stations Monitoring (DSM) systems and remotely controllable sectionalizers (D1T3Sch3 section 2.2.2).

Not completing this work will result in no real-time monitoring of the Distribution Stations (DS's) and no monitoring and control of Sectionalizers from the OGCC. This means that response to events at DS's with DSM systems and on feeders with sectionalizers will be unnecessarily delayed. Further, the ability to use the NMS Information System to store DS loading data will not be possible and a separate system will have to be developed for this.

Investment Summary:

This investment will enhance the NMS and supporting telecom infrastructure at the OGCC and Hub sites to allow the real time monitoring of DS equipped with DSM systems and monitoring and control of feeder sectionalizers.

Monitoring of DSs will allow for faster identification and response to distribution outages and product quality issues (e.g. voltage sag, flicker and momentary outages). It will also allow for better management of heavily loaded DSs. The ability to identify momentary outages (such as may result from momentary tree contact or broken insulator) will allow these to be addressed in a planned fashion at lower cost rather than when they deteriorate to an unplanned outage which results in customer interruption and higher cost emergency response.

Monitoring and control of sectionalizers will also allow for faster identification and response to distribution outages. The location of the fault will be narrowed down to a section of the feeder thereby reducing the time to locate the fault. Also, power restoration will take less time through remote switching of the sectionalizers.

The NMS has an information system which stores all SACDA information for later analysis. Connecting the DMS systems and the sectionalizers to the NMS will allow the NMS information system to be used to store the data concerning operation and loading of DS's avoiding the need and cost for a separate storage system.

Results:

- Faster response to outages and product quality problems.
- Improved management of vegetation or insulator problems.
- Integrated and low cost storage of data.

Costs:

	2008 ($M)
Capital* and Minor Fixed Assets	1.0
Operations, Maintenance & Administration and Removals	-
Gross Investment Cost	1.0
Recoverable	-
Net Investment Cost	1.0

*Includes Overhead and Allowance for Funds Used During Construction at current rates

Date: August, 2007

Hydro One Networks – Investment Justification
Cornerstone Phase 1

Investment Name: Cornerstone Phase 1 – EAM Core ($144M); **Reference #: IT1**

In Service: Q2, 2008 (Phase 1)

Need:

The current installation of Indus PassPort is no longer eligible for vendor support. It has been heavily customized to adapt to current requirements. It does not provide full work management and supply chain functionality, nor does it provide a single asset registry "system of record." Therefore, a significant investment is required or else technology and process solutions will not be available to support the achievement of our business goals and completion of the upcoming capital work program. Moreover, significant internal control and business continuity risks would remain unaddressed.

Investment Summary:

PassPort 6 was installed in Hydro One in 1998 and is currently being utilized for supply chain, work management, asset management, and accounts payable. The 1998 installation was compromised due to two key changes in direction: the decision to include the Distribution side of the business in what had previously been a Transmission-only solution; and the decision to have all Y2K products in place certified and tested a year early, by year-end 1998. In order to make the scope achievable in the available time, much of the functionality that was available within the Passport tool was not "turned on" for the business, and the solution was heavily customized during and after go-live to meet business needs. As a legacy, there now exist numerous bolt-ons and custom solutions that interface with PassPort and attempt to overcome the business limitations of that initial solution. These limitations will hinder the ability of the company to meet its aggressive capital program and continuing to maintain the heavily customized PassPort system is costly and complex.

Phase One proposes to replace the Passport functionality with SAP functionality. The scope consists of and is restricted to doing what is required to "turn on" the SAP product and make it work as designed in the business, with no SAP software customizations. In a business context, "what is required" consists of:

- Changing business processes that currently touch PassPort, to maintain or improve business performance. We will not customize the product to accommodate current business processes; rather, we will replace current business processes with industry standard practices.
- We will reconnect to SAP, replace within SAP, or decommission applications in the interest of three criteria:
  - Mitigate project risk (complexity and cost)
  - Enable future Cornerstone phases
  - Minimize life cycle cost to the business
- Migration or replication of data needed to execute the SAP solution
- Establishment of an effective change management capability within the project to minimize disruption, maximize adoption, and reduce the overall cost and risk of implementation.

Results:

Phase One will bring the following business benefits to Hydro One:

- Improved Asset Lifecycle Decision-Making
- Enhanced Work-Program Planning & Execution
- Set the stage for subsequent phases of the Hydro one System Replacement Strategy.

Costs[1]:

	2006 ($M)	**2007** ($M)	**2008** ($M)	**Total** ($M)
Capital* and MFA	0.0	76.7	50.3	127
OM&A and Removals	4.0	7.0	6.0	17
Gross Investment Cost	4.0	83.7	56.3	144
Capital Contribution				
Net Investment Cost	4.0	83.7	56.3	144

1 Costs for Phase 1 including overhead and AFUDC at current rates. .

Date: August, 2007

Hydro One Networks – Investment Justification

Mobile IT

Investment Name: Mobile IT **Reference #:** IT2

In Service: Q4 2008

Need:

This investment is required to permit field managers' access to critical systems and information regarding work crew projects, field assets and optimal scheduling as part of work management processes.

If this investment is not undertaken there is an ongoing risk of delayed information and/or errors and omissions being encountered with data entry from field notes. Hydro One's overall strategy of a properly equipped mobile work force will be delayed.

Investment Summary:

Significant resources are used to both manage and report on field-based activities and to respond to changes driven by events encountered in-process. Project reporting and activity planning based on timely and accurate scheduling of information for both goods and services as well as manpower and equipment require access to critical information using mobile computing tools. Field staff and managers require field utilization of technologies currently accessible only in offices. Current applications require upgrades to effectively manage and control the maintenance activities within Hydro One Distribution.

After consideration of alternatives, the preferred plan is to provide mobile application tools to field staff. This investment will provide tools in the areas of dispatch, work management, time sheets, switch orders and inspections that deliver data to support business processes from Grid Operations to Asset Management, among others. This investment provides additional commercial software products, enhancements to existing software products and the installation, configuration and integration of those products along with associated hardware (database and application servers and hand-held computers).

Results:

- *Improved Asset Decision Quality:* Provide immediate access to more comprehensive and integrated asset data in corporate systems, contributing to consistency and timeliness in asset decisions.
- *Increased Throughput:* With the ability to capture more data at source using mobile devices, enable one-time data entry and workflow approval as part of normal business processes.
- *Prevention of rework:* Asset condition assessment surveys on occasion require some rework or a revisit to the site. There is an anticipated general reduction in such rework as this initiative is implemented.
- *Timely investments: A*bility to make good decisions regarding field assets and their replacement scheduling will be assisted by additional and available information. With increased volumes of asset condition information, investment planners can utilize and analyze this information to strengthen decisions that replace assets at the right time, not sooner than required nor too late, avoiding undue risks to service levels.

Shared Costs:

	2008 ($M)
Capital* and MFA (A)	3.0
Operating, Maintenance & Administration and Removals (B)	0.3
Gross Investment Cost (A+B)	**3.3**
Capital Contribution (C)	-
Net Investment Cost (A+C)	**3.0**

*Includes overhead and AFUDC at current rates and Minor Fixed Assets include servers and hand-held computers.

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Hydro One Networks – Investment Justification
CSS- CIS Hybrid

Reference #: IT 3

Investment Name: Customer Information System – Hybrid

In Service: Q4 2008

Need:

This investment is required to address end-of-life application issues with Customer-1 and other Customer Information Systems and to improve the CIS platform to meet increased service level requirements. The customer contact centres need to update the systems capability to deal with billing and service inquiries stemming from service levels, metering, demand management, LDC rationalization, improved customer satisfaction initiatives, and billing / tariff modifications. Upgrades must be made in advance of consumer demand for information and service.

The solution proposed is to make renovations to some systems and replace portions of other systems as applicable in light of the Cornerstone Strategy. If these selected initiatives are not undertaken the useful life of the current CIS applications will be limited, impact the Smart Meter project, and possibly accelerate the timeframe to fully replace the entire CIS application suite.

Investment Summary:

The CIS application suite provides the technology backbone that enables Hydro One Distribution to provide billing, customer contact and care, field services, and open market services to its customers and key constituents. The CIS applications impact the Customer Service Operations and the Field Operation areas of the organization. The CIS system serves as the basis for customer interaction. Currently Hydro One Distribution utilizes 13 applications to provide the following functions for the organization: full customer care for all types of distribution customer billing, service order management, marketing, meter management and contact management, as well as facilitating retail competition for all customers.

The costs for CIS are included in Shared Services capital with the costs allocated 100% to Distribution.

A CIS assessment was conducted to determine the best strategy for Hydro One to utilize its CIS application suite to meet its business needs. Hydro One's specific requirements were compared to an internal solution and to other solutions in the marketplace. The recommendation is to make renovations to some systems and replace portions of other systems where such enhancements would be commercially appropriate or have continuing value. Renovations will be undertaken when resources are available and with due consideration to required regulatory changes and for Smart Metering requirements.

Results:

- Updated and enhanced CIS application suite with greater access provided to customer data.
- Lower costs for enhancement projects.

Shared Costs:

	2008 ($M)	**Total ($M)**
Hybrid Option	2.0	2.0
Total Capital * and MFA		

Date: August, 2007

Operating, Maintenance & Administration and Removals		
Gross Investment Cost	2.0	2.0
Recoverable		
Net Investment Cost	2.0	2.0

*Includes overhead and AFUDC at current rates

Date: August, 2007

Hydro One Networks – Investment Justification
Fleet Services 2008 Capital Requirements

Investment Driver: Fleet Services 2008 Capital Requirements **Reference #:** C1

In-Service Date: Late 2008

Need:

This investment is required to meet vehicle and fleet capital requirements arising from increased work programs and staff growth.

Not proceeding or delaying this investment would lead to lower-than-required fleet levels and mix and a shift to more expensive rental units. Extending the life of the vehicles past their optimum level of economic and reliable operations will result in increased equipment and user operating costs, reduced reliability and unsafe operating conditions.

Investment Summary:

Hydro One controls and manages 4,522 fleet units which support the various lines of business (LOBs) including Provincial Lines, Stations, Forestry and Engineering and Construction Services (E&CS). Fleet vehicles must be maintained at an optimum level to comply with various regulations (Highway Traffic Act, CVOR regulations, etc.) and to maintain LOB productivity by minimizing downtime and travel time and taking advantage of technology improvement opportunities.

Present replacement criteria are based on manufacturers' recommendations and repair history. Light vehicles are replaced after 6 years or 170,000 km, service trucks are replaced after 6 years or 200,000 km, and work equipment is replaced after 8 – 10 years or 230,000 km. This is used as a guideline and ultimately it is used in combination with break even analysis, including replacement cost, depreciation, operating cost and potential life expectancy.

Of the capital required in 2008, $35M is required to replace units which have reached their end of life cycle.

Other key elements of the 2008 capital program include:

- supporting the Forestry Mechanical Brushing Program.
- replacement of a second aging helicopter (over 2007 requirements) which supports the Tx Work Program.
- replacement of an additional 50 rental pickups (over 2007 requirements) with 50 Hydro One-owned units. Analysis has determined that the rental units, which are used for approximately 9 months per year, are more expensive than owned units due to Hydro One’s lower borrowing costs.
- additional fleet required for new hires.

Results:

- Reduced operating costs and increased reliability

Shared Costs:

	2008 ($M)
Capital* and MFA	51.6
Operating, Maintenance & Administration, and Removals	0.0
Gross Investment Cost	51.6
Capital Contribution	0.0
Net Investment Cost	51.6

*Includes overheads and AFUDC at standard rates.

Date: August, 2007

Hydro One Networks – Investment Justification
MFA Service Equipment 2008

Investment Driver: MFA Service Equipment **Reference #:** C2

In-Service Date: Late 2008

Need:
Minor fixed asset expenditures for service equipment are required to replace end of life and obsolete equipment, and to provide sufficient levels of new equipment consistent with work program and staffing expansions.

Service equipment is used by field staff to carry out day-to-day work activities including specialized transportation equipment to and from the work site. This equipment must be maintained at appropriate levels such that work can be executed in a safe and cost effective manner. Inadequate investment will result in equipment breakdowns or increased labour time. Overall this would adversely impact job costs, outage duration, and work program accomplishments.

Investment Summary:
Minor fixed asset (MFA) spending for service equipment represents items > $2000 each exclusive of general computer MFA requirements, real estate MFA requirements and fleet MFA requirements, addressed elsewhere, which are necessary to replace end of life equipment used by field staff to execute the work program in a cost effective manner.

Purchases in this category include:
- Minor specialized transportation equipment such as snowmobiles, all terrain vehicles, boats, barges, and related accessories to transport crews to off-road work sites,
- measuring and testing equipment to carry out a variety of work activities including trouble shooting, performance testing of equipment, wood pole density testing, battery testing, relay test systems, moisture analyzers, circuit breaker testers, resistance testers, etc.,
- tools and a wide range of other miscellaneous equipment such as PCB waste bins, portable generators, cabling trailers and equipment, hand held meter reading devices, satellite equipment for mobile emergency preparedness, insulator power washing equipment to describe a few.
- Relatively large tanker units utilised in the service of transformers including degassifiers used to remove impurities from insulating oil, heated oil tankers, oil filters and dry air machines.

MFA service equipment requirements will vary year to year depending on a number of factors including the overall asset condition, the number of large cost "one-time" items that occur from year to year, the size of the work program and associated staffing levels projected in the business plan, random equipment failures, unanticipated system impacts, weather severity and trends which affect the intensity and use of certain types of equipment particularly related to storm and trouble call programs.

Spending in 2008 is focused on additional service equipment required to accommodate the growth in the work program. It is also the result of end of life replacement of specific large equipment such as oil tankers, degassifiers, and air supply equipment used to overhaul and maintain large power transformers and manage the related oil requirements. Such purchases are a part of long term replacement plans to replace end of life equipment that are expected to extend to 2010 and beyond.

Results:
- Maintain equipment and tool fleets at required levels to execute the 2008 transmission OM&A and capital program

Shared Costs:

	2008 ($M)
Capital* and MFA	9.3
Operating, Maintenance & Administration, and Removals	0.0
Gross Investment Cost	9.3
Capital Contribution	0.0
Net Investment Cost	9.3

*Includes overheads and AFUDC at standard rates.

Date: August, 2007

Hydro One Networks – Investment Justification
Real Estate Facilities 2008

Investment Driver: Real Estate Facilities Capital for 2008 **Reference #:** C3
In-Service Date: Late 2008

Need:

This investment provides for facilities improvements, resulting from assessments of aging facilities infrastructure across the Province. The facilities infrastructure base is comprised mainly of aged buildings, legacy building systems and components, many of which are reaching the end of their asset life cycle. This program also considers the facilities portfolio accommodation strategy in terms of facility improvements, building additions and new facilities in line with the Company's changing operational requirements.

Not proceeding with this investment would present risks related to health & safety (related to mould, drinking water quality, and potentially unsafe building structures) that could result in non-compliance with legislative and regulatory requirements.

Investment Summary:

Key program work activities include:

- Replacement of major building components including roof structures, windows, heating, ventilating and air conditioning (HVAC) systems and other structural elements and building systems.
- Dealing with environmental issues that may arise such as mould.
- Treatment upgrades to improve quality and reliability of water supply, including conversions to municipal supply.
- Facilities Improvements: Service, Administrative Centres
- HQ & Admin Facilities - new/ additional workspace demand – accommodation planning.
- Purchase of MFA at Centres (e.g., office furniture)

There are 92 Administrative Centres and Service Centres throughout the province. Administrative Centres include the Ontario Grid Control Centre in Barrie, London Call Centre, and GTA facilities (Trinity, Clegg Road and Torbram Road). Service Centres provide accommodation for Line of Business field staff, such as Provincial Lines and Forestry.

Contracted facility service providers conduct regular inspections of administrative and service centre sites across the province to ensure critical building/site components are inspected regularly and major structural and related problems are identified.
This capital program focuses on undertaking the critical component replacement work on a priority basis.

Capital spending of $9.8M is required for 2008 to replace major building components, ensure facility water well standards are met, secure and protect facilities that house critical equipment, and provide space to support work programs.

Results:

- Improved Administrative and Service Centre facilities through replacement of roof structures, windows, HVAC systems and other structural elements.
- Reduced potential environmental hazards to Hydro One employees with a focus on mould removal and water quality.
- Specific Service Centres will meet Security Standard 1300 and NERC Physical Security of Substations.

Shared Costs:

	2008 ($M)
Capital* and MFA	9.8
Operating, Maintenance & Administration, and Removals	0.0
Gross Investment Cost	9.8
Capital Contribution	0.0
Net Investment Cost	9.8

*Includes overheads and AFUDC at standard rates.

HYDRO ONE NETWORKS INC.
DISTRIBUTION
Mapping In-Service Additions to Grouped USofA Accounts for years 2006 - 2008
As at December 31
($ Millions)

Line No.	Minimum USoA Grouping	Account Numbers	2006	2007	2008
1	Land and Buildings	1805, 1806, 1808, 1810, 1905, 1906	0.5	0.3	0.3
2	TS Primary Above 50	1815	4.1	4.3	4.3
3	Distribution Station Equipment	1820	18.8	21.8	21.7
4	Poles, Wires	1830, 1835, 1840, 1845	201.6	181.2	169.9
5	Line Transformers	1850	76.9	112.9	107.9
6	Services and Meters	1555, 1855, 1860	4.7	5.9	6.3
7	General Plant	1908, 1910	2.7	4.5	3.8
8	Equipment	1915, 1930, 1935, 1940, 1945, 1950, 1955, 1960	34.0	41.8	47.9
9	IT Assets	1920, 1925	26.8	53.6	117.0
10	Other Distribution Assets	1608, 1615, 1620, 1665, 1675, 1680, 1685, 1970,1975, 1980, 1990, 2005, 2010, 2050	0.3	2.9	3.9
11	Smart Meters	1565	9.5	84.4	112.8
12	**Total In-Service Assets**		**379.9**	**513.7**	**595.9**

HYDRO ONE NETWORKS INC.
DISTRIBUTION
Continuity of Property, Plant and Equipment
Year Ending December 31
Historical (2004, 2005, 2006), Bridge (2007) & Test (2008) Years
Total - Gross Balances
($ Millions)

Fixed Assets

Line No.	Year	Opening Balance	Additions	Retirements	Sales	Transfers In/Out	Closing Balance	Average
		(a)	(b)	(c)	(d)	(e)	(f)	(g)
Historic								
1	2004	4,941.9	285.1	(31.8)	(16.3)	45.9	5,224.8	5,083.4
2	2005	5,224.8	290.7	(23.2)	(3.6)	4.0	5,492.7	5,358.8
3	2006	5,492.7	379.9	(10.9)	(10.3)	15.1	5,866.5	5,679.6
Bridge								
4	2007	5,866.5	513.7	(210.1)	-	7.2	6,177.3	6,021.9
Test								
5	2008	6,177.3	595.9	(50.8)	-	0.6	6,723.0	6,450.1

HYDRO ONE NETWORKS INC.
DISTRIBUTION
Continuity Accumulated Depreciation
Year Ending December 31
Historical (2004, 2005, 2006), Bridge (2007) & Test (2008) Years
Total - Gross Balances
($ Millions)

Fixed Assets

Line No.	Year	Opening Balance (a)	Additions (b)	Retirements (c)	Sales (d)	Transfers In/Out (e)	Other (f)	Closing Balance (g)	Average (h)
Historic									
1	2004	1,912.0	153.0	(31.2)	(14.2)	26.5	-	2,046.1	1,979.1
2	2005	2,046.1	155.3	(18.2)	(8.9)	1.4	0.2	2,175.9	2,111.0
3	2006	2,175.9	159.2	(10.3)	(9.8)	13.8	-	2,328.7	2,252.3
Bridge									
4	2007	2,328.7	168.9	(210.1)	-	3.9		2,291.4	2,310.1
Test									
5	2008	2,291.4	196.9	(50.8)	-	0.3		2,437.9	2,364.6

HYDRO ONE NETWORKS INC.
DISTRIBUTION
Continuity of Property, Plant and Equipment - Construction Work in Progress
Year Ending December 31
Historical (2004, 2005, 2006), Bridge (2007) & Test (2008) Years
Total - Gross Balances
($ Millions)

Fixed Assets

Line No.	Year	Opening Balance	Capital Expenditures	Transfers to Plant	Other Adjustments	Closing Balance
		(a)	(b)	(c)	(d)	(e)
Historic						
1	2004	64.4	272.0	(283.2)	-	53.2
2	2005	53.2	317.2	(290.7)	-	79.7
3	2006	79.7	392.6	(379.9)	(5.4)	87.0
Bridge						
4	2007	87.0	515.7	(513.7)	5.4	94.4
Test						
5	2008	94.4	566.1	(595.9)	-	64.6

HYDRO ONE NETWORKS INC.
DISTRIBUTION
Statement of Working Capital
Annual Average
Test Year (2008)
($ Millions)

Line No.	Particulars		2008
1	Cash Working Capital	$	273.2
2	Materials and Supplies		23.3
3	Total	$	296.5

REVENUE REQUIREMENT

1.0 SUMMARY OF REVENUE REQUIREMENT

Hydro One Distribution follows standard regulatory practice and has calculated revenue requirement consistent with the principles of the 2006 Electricity Distribution Rate Handbook as follows:

Sum of:

Table 1
($ Millions)

OM&A	478	Exhibit C1, Tab 2, Schedule1
Depreciation and Amortization	239	Exhibit C1, Tab 6, Schedule 1
Capital Taxes	11	Exhibit C2, Tab 4, Schedule 1
Income Taxes	39	Exhibit C2, Tab 6, Schedule 1, Att A
Return on Capital	300	Exhibit B1, Tab 1, Schedule 1
Total Revenue Requirement	**$1,067**	**Exhibit E2, Tab 1, Schedule 1**

The resultant Revenue Requirement of $1,067 million is the amount required by Hydro One Distribution to ensure the most appropriate, cost-effective solution to respond to corporate objectives mainly related to public and employee safety, electricity market and regulatory requirements.

2.0 CALCULATION OF REVENUE REQUIREMENT

The details of the Revenue Requirement components are as follows:

2.1 OM&A Expense

Sustaining	$280.0
Development	9.1
Operations	13.4
Customer Care	103.8
Shared Services and Other Costs	66.9
Taxes Other Than Income Tax	4.5
Total OM&A	**$477.7**

2.2 Depreciation and Amortization Expense

Depreciation	$207.4
Amortization	$31.6
Total Expense	**$238.9**

2.3 Capital Taxes

Capital Tax	$11.3
Total Capital Taxes	**$11.3**

2.4 Payments in Lieu of Corporate Income Taxes

Income Before Payments in Lieu of Corporate Income Taxes	$115.8
Tax Rate	34.50%
Total Payments in Lieu of Corporate Income Taxes	**$38.8**[1]

2.5 Return on Capital

Return on Capital	$299.9

[1] Calculated on the basis of regulatory taxes payable, as per 2006 Electricity Distribution Rate Handbook; adjusted for R&D ITC ($0.3 million) and Ontario Education Credit ($0.8) see Exhibit C2, Tab 6, Schedule 1 for detailed calculation.

3.0 REVENUE REQUIREMENT – COMPARISON OF YEAR 2006 TO YEAR 2008

Table 2 below compares, by element, the Year 2006 approved Revenue Requirement (as per RP-2005-0020/EB-2005-0378) against the Year 2008 proposed Revenue Requirement.

Table 2
Comparison of Revenue Requirements: 2006 vs. 2008 ($ Millions)

Line No	Description	Year 2006 OEB Approved	Year 2008	Difference
1	OM&A	423	478	55
2	Depreciation	202	239	37
3	Capital Taxes	10	11	1
4	Income Taxes	69	39	(30)
5	Return	261	300	39
	Total Revenue Requirement	**965**	**1,067**	**102**

There are a number of key operational and financial factors contributing to the increased revenue requirement that have an impact across the cost components in Table 2. The increase in Total Revenue Requirement is largely attributable to the increase in OM&A costs ($45 million), Smart Meters ($10 million OM&A, $12 million rate base) and the net impact of rate base growth ($63 million) offset by lower cost of debt and lower income tax rates.

Table 3 illustrates the value of the key impacts of the increase in the Revenue Requirement.

Table 3
Components of Change to Revenue Requirement
Previously OEB-Approved (2006) vs. Proposed (2008)

Description	**Amount ($ millions)**
Impact of increased rate base	63
Increase in OM&A	45
Impact of Smart Meters	22
Change in Common Equity	8
Impact of lower statutory tax rate	(9)
Decrease in asset removal costs	(9)
Lower ROE as per OEB formula	(8)
Decrease in cost of debt	(6)
Other	(4)
Total Change	**102**

HYDRO ONE NETWORKS INC.
DISTRIBUTION

Revenue Deficiency/(Sufficiency)
Year Ending December 31, 2008
($ Millions)

Line No.	Particulars		2008
1	Revenue requirement (excl. riders)	$	1,066.8
2	Recovery of deferral accounts		12.3
3	Total revenue requirement (incl. riders)		1,079.1
4	Revenue at prior-year rates (incl. riders)		1,056.6
5	Revenue deficiency/(sufficiency)	$	22.5

HYDRO ONE NETWORKS INC.
DISTRIBUTION
Calculation of Revenue Requirement
Year Ending December 31, 2008
($ Millions)

Line No.	Particulars		2008
	Cost of Service		
1	Operating, maintenance & administrative	$	477.7
2	Depreciation & amortization		238.9
3	Capital taxes		11.3
4	Income taxes		38.8
5	Cost of service excluding return (Note 1)	$	766.9
6	Return on capital		299.9
7	Total revenue requirement	$	1,066.8

Note 1: Per Exhibit C2, Tab1, Schedule 1

EXTERNAL REVENUES

1.0 STRATEGY

Hydro One Distribution’s strategy is to focus on core work and continue to be responsive to external work requests and accommodate customer needs where Hydro One Distribution can provide value and have the resources and/or assets to do so.

Over 96% of Hydro One Distribution’s revenues are earned through its distribution tariff. External revenues account for the remaining 4% [$42.0 million in 2008] and are earned through the provision of services to third parties and through joint use of Hydro One Distribution’s assets by third parties. These revenues are used to offset the revenue requirement from Hydro One distribution tariff and thereby reduce the required revenue to be collected from distribution ratepayers. External revenues are categorized into regulated and non-regulated categories.

2.0 COSTING AND PRICING

The costing of external work is determined on the basis of cost causality with estimates calculated in the same way as internal work estimates using the standard labor rates, equipment rates, material surcharge, and overhead rates (see Exhibit C1, Tab 4, Schedule 1 for a description of costing for internal work and section 5 of Exhibit C1, Tab 2, Schedule 6 for a description of the costing of external work). For unregulated work an appropriate margin is added to cover, as a minimum, the risk of non-payment by third parties in order to ensure there is an overall benefit for the distribution ratepayers.

3.0 DESCRIPTION

Regulated external revenues for 2008 ($31.3M) account for about 75% of external distribution revenues. These revenues, shown in table 1, cover a wide range of miscellaneous services (e.g. joint use of poles for attachment of Telecommunications, sentinel light services) based on rates and underlying costs per the 2006 Electricity Distribution Rate Handbook issued May 2005 .

Table 1
Regulated Revenues
($M)

$M	2004	2005	2006	2007	2008
Joint Use	5.3	5.6	5.8	6.0	6.2
Sentinel Lights	4.9	3.5	3.6	3.3	4.0
Retail Service Revenue	N/A	N/A	N/A	0.9	1.1
Other Regulated Misc. Services	16.3	15.2	17.2	19.7	20.0
Totals	26.5	24.3	26.6	29.9	31.3

Unregulated external revenues (e.g. competitive new connection and upgrade work, and emergency support to other North American utilities), as shown in Table 2, account for the remaining $10.7M or about 25% of 2008 external distribution revenues.

Table 2
Unregulated Revenues
($M)

$M	2004	2005	2006	2007	2008
Joint Use	2.5	2.2	3.2	3.3	3.3
New Connects/Upgrades	5.3	5.2	4.3	4.9	4.0
Generation Studies	0.1	0.1	0.7	1.5	0.5
Other External Work	23.3	9.9	2.4	3.1	2.2
Non-Regulated Misc. Rev.	1.0	0.6	0.9	0.8	0.7
Totals	32.2	18.0	11.6	13.5	10.7

3.1 Regulated Revenues

3.1.1 Joint Use Revenues

Joint Use revenues are generated from third parties who jointly use Hydro One Distribution's poles by stringing various attachments to the poles, mostly wire cables, and in return Hydro One Distribution charges a per pole attachment fee. At the end of 2006, there were approximately 800,000 joint use poles being used by 535 customers including Bell Canada, Telecommunications companies, independent telephone companies, and others including LDCs, fiber companies and municipalities. About 90% of the revenue in this segment come from Bell Canada and Telecommunications companies. The Ontario Energy Board sets the rates for joint use service, for Telecommunications companies. Other joint use rates/contracts are negotiated and include other considerations such as reciprocal pole sharing arrangements and vegetation management services are unregulated and discussed in Section 3.2. Table 3 below is a summary of the volumes (# of pole attachments) for the regulated segment of joint use.

Table 3
Volume of Joint Use permits by Customer Category

	2004 volume	2005 volume	2006 volume	2007 volume	2008 volume
Telecommunications	234,734	237,623	265,399	272,415	280,588
Street Lighting	70,000	74,000	77,678	78,843	80,008

As can be seen from the table, the number of attachments is increasing over the 5-year period. The increase is due to new Telecommunications companies attaching to poles and existing companies expanding their service areas.

3.1.2 Sentinel Light Revenues

The sentinel light rental program is designed to provide rural customers with low-cost security lighting. The service is provided primarily to rural residential, farm, and cottage customers, for whom street lighting is not available.

Exhibit A, Tab 5, Schedule 1, section 3, provides reference to the legislation that allows the sentinel light program to continue for existing Hydro One Distribution customers.

Table 4 summarizes the historical volumes of sentinel lights and poles owned and maintained by Hydro One Distribution. The decrease over the five-year period reflects the fact that there is no new customers added and there is a continuing decrease in the number of existing customers as discussed in Exhibit C1, Tab2, Schedule 2.

Table 4
Year-End Volume of Sentinel Lights in service

	2004 volume	2005 volume	2006 volume	2007 volume	2008 volume
Sentinel Lights	40,603	40,029	38,754	37,812	36,870
Sentinel Light Poles	2,490	2,513	2,377	2,319	2,261
Total	43,093	42,542	41,131	40,131	39,131

3.1.3 Other Regulated Miscellaneous Services

Hydro One Distribution provides a number of other regulated miscellaneous services as identified in Table 5 below. The rates for these services are approved and regulated by the Ontario Energy Board. A description for items 1 through 7 can be found in the "2006 Electricity Distribution Rate Handbook, Chapter 11". The associated volumes of items 1 through 7 (as identified in Table 5) are shown in Table 6 along with the 2008 revenues. Brief descriptions for items 8 and 9 follow the tables.

Table 5

Service Description
1. Dispute Meter Test
2. Collection of Account, Disconnect/load Limiter/Reconnect Trips
3. Account Set-up Charge
4. Arrears Certificate
5. NSF Cheque Charge
6. Easement Charge for Unregistered Rights
7. Late Payment Charge
8. Tingle Voltage Test
9. Standby Rate

Table 6
Other Regulated
Miscellaneous Services
2004 - 2008 Volumes

	2004 volume	2005 volume	2006 volume	2007 volume	2008 volume	2008 Revenue (k$)
Dispute Meter Test	135	140	193	182	184	$6
Collection of Account	N/A	2,585	2,300	2,300	2,300	$69
Disconnect/load Limiter/Reconnect Trips	4,544	9,750	10,511	10,722	10,839	$760
Account Set-up Charge	149,345	144,437	141,778	140,392	144,800	$4,256
Non Sufficient Funds (NSF) Cheque Charge	11,159	9,781	9,240	9,330	9,429	$189
Easement Charge for Unregistered Rights (approx)	N/A	N/A	N/A	N/A	N/A	$265
Late Payment Charge applied to number of distinct accounts	N/A	N/A	N/A	N/A	N/A	$14,491
Total 2008 Revenue						$20,035

3.1.3.1 Tingle Voltage Test

Tingle voltage (also known as high neutral voltage) is undesirable as it may have an adverse effect on dairy cattle, and in extreme cases may be noticeable by humans. Hydro One Distribution strives to limit neutral voltage to 10V. In cases where customers deem the voltage to be excessive, a voltage test is conducted to determine the cause of the abnormality. Usually, there is no charge to the customer for this type of analysis; however, should the customer request further testing, the additional costs are recovered from the customer. Historically, the number of times that additional testing is required is approximately 30 per year.

3.1.3.2 Standby Charges

A standby charge is a monthly fee that is applied to a customer that has their own generation facilities and addresses those instances when the customer is dependent on Hydro One Distribution for their electricity supply whenever their own generation facilities are out of service. The monthly charge marginally offsets the cost to Hydro One of having facilities available to ensure emergency supply whenever the customer's facilities are out of service. The charge is only applicable when electricity is not supplied by Hydro One Distribution. The 2006 Electricity Distribution Rate Handbook allows standby administration charge to cover the incremental cost of monitoring, billing and administration. The Board approved this charge on an Interim basis as part of the Generic Decision on 2006 EDR issues in proceeding RP-2005-0020/EB-2005-0529. In its decision in EB-2005-0378, the OEB directed Hydro One to establish such a variance account which it has done. Hydro One will place any revenues received from the application of this rate into this variance account and will be credited back to the customers of this province, as part of the next distribution rate hearing process. To-date there have been no such charges and it is expected that there will be none in 2008.

3.2 Unregulated Revenue

3.2.1 Joint Use Revenue

As noted in section 3.1.1 above, the rates for Bell Canada and Local Distribution Company (LDC) attachments are based on a negotiated price rather than rates approved by the OEB due to other considerations such as reciprocal pole sharing arrangements and vegetation management services.

Table 9
Volume of Joint Use permits – Unregulated

	2004 volume	2005 volume	2006 volume	2007 volume	2008 volume
Bell Canada	479,232	479,232	479,232	479,232	479,232
LDCs	7,244	7,295	7,236	9,615	9,903

3.2.2 New Connections/Upgrades

Hydro One Distribution connects approximately 17,500 new customers to its distribution system each year consisting primarily of subdivision and rural residential customers along with farms, cottages, and industrial customers. Approximately 6,500 upgrade services are also completed each year that involves increasing a customer's existing supply capacity to meet their increased electricity requirements.

Both the new connection service and the upgrade service have elements of work that must be done by Hydro One Distribution under its Distribution License. This includes: working within Limits of Approach [working within pre-determined boundaries of live equipment which is voltage level dependent but nominally for distribution equipment is 3 metres or 10 feet] of the distribution equipment to install any required equipment; connect the customer to Hydro One's distribution system; and connect the meter at the customer site.

The remainder of the new connection/upgrade work may be performed by a qualified contractor of the customer's choice. As required by the Distribution System Code, Hydro One Distribution will carry out this work, if requested by the customer at Hydro One's fully burdened cost, since crews are usually on-site and set up. For an above ground new connection, this work would include the installation of poles, conductor, and related equipment to run from the distribution line to the meter at the customer site. Similarly, for an underground connection, this would include digging the trench and laying the cable and related equipment. This type of project is known as contestable or competitive work and is what contributes to the external revenues for this segment.

Table 10 represents the number of New Connections and Upgrades Hydro One Distribution provides to customers each year.

Table 10
Volume of New Customer Connections & Upgrades

	2004 volume	2005 volume	2006 volume	2007 volume	2008 volume
New Connections & Upgrades	24,083	23,647	22,898	24,059	24,194

Into the future, it is expected that the volumes will remain relatively flat, as discussed in Exhibit D1, Tab 3, and Schedule 1.

3.2.3 <u>Distribution Generation Studies</u>

The external revenue shown is for undertaking connection impact assessments in response to requests from generation proponents. Hydro One does assessments based on the customer request that includes the proposed size of the generator and where it will be located. Connection impact assessments are technical studies that determine the impact of the new generation facility on the Distribution System and ensure the generator will comply with the technical requirements. The technical requirements generators must meet to connect to Hydro One distribution system are outlined in “Technical Requirements for Generators Connecting to Hydro One's Distribution System”. These requirements are in place to ensure public and employee safety, protect the integrity of Hydro One’s system and guarantee reliable and quality service to our customers. For more information about these studies, refer to Exhibit C1, Tab 2, and Schedule 3. The volume is expected to decline in 2008 due to the best area's for generation would have been developed first and remaining areas would not be as economical.

Table 11
Volume of Generation Studies Completed

	2004 volume	2005 volume	2006 volume	2007 volume	2008 volume
Distribution Generation Studies	30	30	70	300	225

3.2.4 Other External Work

Revenues from external work in this segment include minor amounts of forestry line clearing and brush control work; training related to health, safety & environment; streetlight maintenance; and subdivision redesign.

External training covers a wide range of practical and classroom delivered courses. These include courses like Electrical Safety Awareness, a mandatory course for anyone working in the proximity of live electrical apparatus regardless of trade or occupation. Packaged delivery of technical courses for numerous trade and professional types are delivered for Lines, Forestry, Power Electricians, Metering technicians, Protection engineers and technicians. Customers include large (Toronto Hydro) and small utilities (Peninsula West Utilities Limited), large (INCO) and small (Wardrop Engineering) companies including Non Utility Generators (Trans Alta, Brighton Beach) that send trainees to a cross section of courses in various trades/disciplines.

Hydro One Distribution will provide an initial subdivision design and will recover this cost through the staking fee charged to the developer. When the developer revises the subdivision plan, a redesign of the subdivision is needed. The cost of the redesign is borne by the developer.

If a subdivision design has been completed but construction has not commenced for a period of 12 months or more, a review of the subdivision design is necessary. This review includes a field visit and is necessary to determine if the original design is still viable or if a revised design is needed to supply the subdivision. The cost to do this additional work is also covered by the developer.

Table 12
Number of Subdivision Redesigns

	2004 volume	2005 volume	2006 volume	2007 volume	2008 volume
Subdivision Redesign	37	40	44	45	45

Other external work also includes, from time to time, emergency services provided by Hydro One Distribution crews to restore power to neighboring Canadian and U.S. utilities affected by natural disasters such as ice storms and hurricanes.

3.2.5 Non-Regulated Miscellaneous Revenues

3.2.5.1 Under density Billing

Under density Billing revenues for Northwest part of the province are generated through annual fees levied upon five large companies that utilize dedicated under density distribution lines operated and maintained by Hydro One Distribution. The load on these under density lines does not cover the annual costs of maintenance and therefore an annual fee is charged and is designed to recover maintenance costs for servicing these lines. The revenues collected by Networks represent the recovery of costs for maintenance and forestry work on the underdensity distribution lines.

Table 13
Volume of Underdensity Billings

	2004 volume	2005 volume	2006 volume	2007 volume	2008 volume
Underdensity Billings (# of customers)	6	5	5	5	5

3.2.5.2 Inergi Royalties

As a result of the outsourcing agreement with Inergi LP royalty revenue is received by Hydro One Networks Inc. to compensate it for the use of Hydro One resources by Inergi LP to service other third party customers.

Please refer to Exhibit C1, Tab 2, Schedule 6 for more information on Inergi agreement.

External Revenues Historic, Bridge Year and Test Year
Hydro One Networks Inc.

$'s

	2004	2005	2006	2007	2008
Regulated Revenues					
Joint Use Revenue	**5.3**	**5.6**	**5.8**	**6.0**	**6.2**
Telecommunications	5.1	5.4	5.6	5.8	6.0
Street Lighting	0.2	0.2	0.2	0.2	0.2
Sentinel Revenue*	**4.9**	**3.5**	**3.6**	**3.3**	**4.0**
Retail Service Revenue	**N/A**	**N/A**	**N/A**	**0.9**	**1.1**
Miscellaneous Charges	**16.3**	**15.2**	**17.2**	**19.7**	**20.0**
Late Payment Charges	11.1	11.8	12.4	14.2	14.5
Other Miscellaneous Charges	5.2	3.4	4.8	5.5	5.5
Total Regulated	26.5	24.3	26.6	29.9	31.3
Unregulated Revenues					
Joint Use Revenue	**2.5**	**2.2**	**3.2**	**3.3**	**3.3**
Bell Canada	2.2	2.2	3.0	3.0	3.0
LDC's	0.3	0.0	0.2	0.3	0.3
DX Generation Studies	**0.1**	**0.1**	**0.7**	**1.5**	**0.5**
New Connects/Upgrades & Other Contestable Work	**28.6**	**15.1**	**6.7**	**7.9**	**6.2**
New Connects & Upgrades	5.3	5.2	4.3	4.9	4.0
Lines - Other Contestable Work	22.3	8.9	1.1	2.0	1.0
Forestry Contestable Work	0.0	0.0	0.1	0.0	0.1
Health, Safety & Environment Training	1.0	1.0	1.2	1.1	1.1
Non-Regulated Miscellaneous Revenue	**1.0**	**0.6**	**0.9**	**0.8**	**0.7**
Total Unregulated	32.2	18.0	11.6	13.5	10.7
Total External Revenue	**58.7**	**42.3**	**38.1**	**43.3**	**42.0**

*****Revenue 2004 was excluded from the regulated Distribution business, Exhibit A, Tab 5, Schedule 1

REGULATORY ASSETS

1.0 INTRODUCTION

The purpose of this evidence is to provide a description of the Distribution Regulatory Assets and a detailed account of their balances.

All of the Regulatory Assets reported by Hydro One Distribution have been established consistent with the Board's requirements as set out in the Accounting Procedures Handbook, subsequent Board direction, or per specific requests initiated by Hydro One Distribution.

The Distribution Regulatory Asset balances are summarized in Table 1 below:

Table 1
Distribution
Summary of Regulatory Asset Balances for Approval
$ million

Description	May 1, 2006	Dec 31, 2006	Dec 31, 2007	April 30, 2008
Total Regulatory Assets for Approval	**8.4**	**(1.7)**	**(30.0)**	**(48.7)**

Hydro One Distribution is forecasting Regulatory Asset values up to April 30, 2008. It is expected that new Distribution rates will be implemented at the start of May 2008. Details on the forecast basis will be described for each account.

Disposition of the following accounts is discussed in Exhibit F1, Tab 2, Schedule 1.

2.0 REGULATORY ASSETS REQUESTED FOR APPROVAL

The following table provides a summary of the Regulatory Asset requested for approval:

Table 2
Distribution
Regulatory Assets Requested for Approval
$ million

Description	May 1, 2006	Dec 31, 2006	Dec 31, 2007	April 30, 2008
OEB Costs Account	(0.8)	(0.9)	(0.9)	(0.9)
Tax Changes Account	0.0	(2.8)	(4.7)	(5.0)
Smart Meter Minimum Functionality Under-recovery to May 31, 2007	0	3.6	5.8	6.9
Smart Meter Exceeding Minimum Functionality Under-recovery	0	0.6	3.4	5.7
Smart Meter Minimum Functionality Under-recovery between June 1, 2007 and April 30, 2008	0	0.0	3.7	9.4
Retail Settlement Variance Accounts	9.2	(2.2)	(37.3)	(64.8)
Total Regulatory Assets for Approval	**8.4**	**(1.7)**	**(30.0)**	**(48.7)**

In the Board's December 9, 2004 *Decision with Reasons* in the Review and Recovery of Regulatory Assets Phase 2 (RP-2004-0117/0118), Hydro One was directed to use a fixed rate of 7.71% for all Regulatory Asset accounts. Accordingly, simple interest at 7.71% was applied to the monthly opening principal balance in these accounts from May 1, 2006 to November 30, 2006.

In a letter dated November 28, 2006, the Board directed Electricity LDC's to implement a new prescribed interest rate. This new rate was to be effective May 1, 2006. On December 12, 2006 Hydro One wrote to the Board saying that Hydro One would be implementing this new interest rate effective December 1, 2006 since retroactive application of the interest rates could result in financial impacts different from those included in Hydro One's previously published financial statements. Accordingly, the interest rate for these accounts was changed to 4.59% (the OEB prescribed rate effective at that time) effective December 1, 2006. Hydro One has applied the OEB prescribed rate of 4.59% since December 1, 2006 for all Regulatory Asset accounts.

2.1 Ontario Energy Board Costs Account

In a letter dated December 20, 2004 the Board announced an amendment to the Accounting Procedures Handbook and the Uniform System of Accounts to establish a deferral account to record Ontario Energy Board Cost Assessments.

The intent of this account was to record Ontario Energy Board cost assessments incremental to the 1999 base year for the Board's fiscal year 2004 and subsequent fiscal year(s) determined in accordance with the following Board requirements.

In the Board's April 12, 2006 Decision with Reasons (RP-2005-0020 / EB-2005-0378) regarding Hydro One's 2006 Distribution Rates, the Board approved Hydro One Distributions OEB Costs Deferral Account amounts as submitted. Those amounts were forecast to April 30, 2006 based on the 2005/2006 OEB Q2 Invoice to Hydro One Distribution.

The 2005/2006 OEB Q3 and Q4 Invoices to Hydro One Distribution were lower than the 2005/2006 OEB Q2 Invoice, therefore the amount approved for recovery in the Board's April 12, 2006 Decision with Reasons was higher than the actual value in the OEB Costs Regulatory Asset account on May 1, 2006.

Hydro One Distribution transferred the approved value of the account into the Regulatory Asset Recovery account on May 1, 2006 leaving the excess of the approved amount over the actual amount as a credit in the OEB Costs Regulatory Asset account. No additional principal amounts have been added to this account since May 1, 2006.

Table 3 provides a summary of Ontario Energy Board Cost Assessments related deferral balances for the Hydro One Distribution business:

Table 3
Distribution
OEB Costs Deferral Account Balances
$ million

Description	USofA Account Ref	May 1, 2006	Dec 31, 2006	Dec 31, 2007	April 30, 2008
OEB Costs Account	1508	(0.8)	(0.9)	(0.9)	(0.9)

After approval by the Board, this account will be closed.

2.2 Tax Changes Account

In the Board communique of December 2005 (to LDC's), and the Board's April 12, 2006 Decision with Reasons (RP-2005-0020 / EB-2005-0378) regarding Hydro One's 2006 Distribution Rates, the Board authorized the creation of an account to capture the tax impact of the following differences:

- differences that result from a legislative or regulatory change to the tax rates or rules, and
- differences that result from a change in, or a disclosure of, a new assessing or administrative policy that is published in the public tax administration or interpretation bulletins by relevant federal or provincial tax authorities

Hydro One Distribution has been charging the amount related to the reduction of the Capital Tax rate to this account since May 1, 2007. The amount related to the elimination of the Large Corporation Tax was charged to this account from May 1, 2006 to April 30, 2007.

The balance in Hydro One Distribution's Tax Rate Changes Account is summarized in Table 4 below:

Table 4
Distribution
Tax Rate Changes Account Balances
$ million

Description	USofA Account Ref	May 1, 2006	Dec 31, 2006	Dec 31, 2007	April 30, 2008
Tax Rate Changes	1592	0	(2.8)	(4.7)	(5.0)

2.3 Smart Metering Minimum Functionality Expenditures incurred before May 31, 2007

As part of the RP-2005-0020/EB-2005-0378 Proceeding the OEB approved an incremental fixed monthly charge of $0.27 per metered customer, applicable as of May 1, 2006, to start collecting funds for the deployment of Smart Meters. Subsequently, as part of the EB-2007-0542 Proceeding, the monthly amount was increased to $0.93 per metered customer as of May 1, 2007. The revenues collected per the above are recorded in a variance account set up for Smart Meter revenue.

On May 2, 2007, the Board issued a notice of combined proceeding (EB-2007-0063) to determine the prudence and recovery of costs associated with smart metering activities for 13 licensed distributors, including Hydro One Networks

.

The issues considered in the combined proceeding included:

1. Costs recovery relating to minimum functionality pursuant to Ontario Reg. 426/06.
2. Prudence of costs incurred.
3. The mechanism for re-setting rates for smart meter costs that are found to be prudent through this proceeding.
4. Accounting Procedures.
5. Regulatory treatment of stranded meter costs and recovery through rates.
6. The mechanisms for re-setting rates for smart meter costs incurred on a go forward basis.
7. Mechanism for dealing with costs not part of this proceeding.

The Board's Decision was released on August 8, 2007. The Board determined that the purchasing decisions of the thirteen utilities involved in this proceeding were implemented with the necessary due diligence and the terms of the contracts are prudent. The Board agreed with the overall costs incurred to May 31, 2007 related to the minimum functionality of all installed meters. These approved amounts were OM&A costs of $8.366 million, and Capital costs of $21.799 million. The approved amounts include only one half of the $1.348 million of project management capital costs incurred to May 31, 2007, and the Board requested Hydro One to include the remainder, or $0.674 million, in this application with a further explanation of these costs. This is included in Section 2.5 below. The Board also requested that the $70,000 of costs for repairing or replacing meter bases incurred to date and in the future be tracked in a variance account. This is included in Section 2.4 below.

Table 5 below details the revenue requirement (net of revenue received) related to smart meter minimum functionality up to May 31, 2007 that Hydro One is requesting recovery for in this proceeding. The revenue requirement was calculated based on the approach illustrated in Appendix E of the decision for proceeding EB-2007-0063.

Table 5
Distribution
Smart Meter Minimum Functionality Under-Recovery to May 31, 2007
$ million

Description	Dec 31, 2006	Dec 31, 2007	April 30, 2008
Revenue Requirement	6.1	10.6	11.7
Less: Revenue	(2.5)	(4.8)	(4.8)
Net Revenue Requirement to be Recovered	**3.6**	**5.8**	**6.9**

2.4 Smart Metering Expenditures Exceeding Minimum Functionality

The Smart Metering Expenditures Exceeding Minimum Functionality primarily includes TOU capability as well as some costs for outage detection capability as described below:

Meter Outage Detection Capability

Super capacitors are being installed in the meters so they have the power to communicate outage event information after loss of electrical supply. In cases where meters can notify Hydro One of “nested” outages, this will enable Hydro One to become aware of outages in our rural areas in a timely manner, resulting in increased customer satisfaction and efficiency. Currently Hydro One has to rely on customer calls to be made aware of initial and remaining power outages.

Collector Outage Detections Capability

Battery backup for the collectors is included to ensure the meter outage events can be communicated through the collectors even when power supply to them has been interrupted. This capability is important as it ensures that the outage capability in the meter described above follows through to our central control offices.

TOU (Time of Use) Capability and Integration

The ultimate benefit of smart meters is to provide proper price signals to customers based on when they use electricity. TOU functionality is therefore an imperative element of the smart meter program. The TOU functionality will be provided through the communication network work as discussed in Exhibit C1, Tab 2, Schedule 2 and Exhibit D1, Tab 3, Schedule 2. This will integrate the meter information into the format needed for the IESO to use in the meter data management and meter data repository (MDMR).

The review of these costs were not part of the Combined Smart Metering Hearing (EB-2007-0063) since the proceeding only reviewed costs associated with minimum functionality.

The $70,000 of costs for repairing or replacing meter bases incurred to date were initially included in minimum functionality. The Board in their decision for EB-2007-0063 directed that these costs be separated out and tracked in a variance account. These costs and future repair costs through April 2008 are included in the table below and are being split between OM&A and capital as requested in the decision in EB-2007-0063.

The Hydro One Smart Meter revenue requirement associated with these elements is summarized in Table 6 below:

Table 6
Distribution
Smart Meter Exceeding Minimum Functionality Under-Recovery
$ million

Description	Dec 31, 2006	Dec 31, 2007	April 30, 2008
Revenue Requirement	0.6	3.4	5.7

2.5 Smart Metering Minimum Functionality Expenditures between June 1, 2007 and April 30, 2008

The final area of Smart Meter expenditures include elements that were reviewed and approved in the Combined Smart Meter Proceeding (EB-2007-0063) but are related to the period June 1, 2007 to April 30, 2008 and therefore not part of the Decision delivered on August 8, 2007. These expenditures include the cost of meters that were included in the Smart Meter proceeding but were not yet installed. All of these meters will be installed by April 30, 2008.

The total number of meters that will be installed during this period is 522,086 for a total number of meters of 610,000. Using the Board's unit cost methodology, the unit cost in this time period has decreased from $479.47 to $428.00.

The Project management costs of $0.674 million that were not approved in the Smart Meter proceeding, as discussed in Section 2.3 above, have also been included in the costs below.

Due to the scope, complexity and specialized nature of this work, Hydro One selected Capgemini as its systems integrator, which includes providing the project management function. Capgemini was selected in 2005 as the systems integrator through a competitive RFP process. Hydro One's smart meter program has established detailed requirements to design, build, test, and commission the end to end solution to provide customers the tools and systems needed to take advantage of a smart meter system. Much of this work requires long lead times and is tied to external party timelines such as the IESO's implementation of the MDMR.

The Program Management function provides full Project Management Office (PMO) services and tools for a project that includes 12 work streams:

- Meter installation and field services
- Commissioning of head-end systems (advanced metering control computer, or "AMCC", for 1.2 million meter points)
- Network Engineering
- Integration of AMCC to MDMR to Hydro One's customer information system (CIS)
- Billing and customer care
- Settlements (retail and wholesale impact assessment)
- Customer Contact Centre (call centre to handle meter installation and TOU customer enquiries)
- CIS upgrade for TOU rates
- New systems – data and synchronization gateway and exception management for transactions exceeding 30 million per day upon full implementation
- Integrated business process design for moving from manual meter reading to an advanced metering regional collector (AMRC), including all related service orders, managing a network that encompasses over one million communication nodes, TOU billing, etc.
- Infrastructure Management (managing the procurement and implementation of computer hardware required for AMCCs, Integration, and TOU upgrades, this includes all required environments, e.g. for development, testing and production)
- Project management and tracking, which includes the following activities;
    - tracking cost and schedule performance; management of issues, risks, assumptions and change logs and associated action plans for all workstreams;

- the development and operation of a quality management program for the project;
- the development and operation of a project governance plan; and
- the development and maintenance of the integrated project plan.

The services above are the project related functions typically provided by the systems integrator. Although Hydro One is providing overall project management and direction to Capgemini, the competitively tendered role of PMO described above is not a role that Hydro One is able to resource internally. As noted in Exhibit D1, Tab 3, Schedule 2, the total project management costs on a per installed smart meter unit are forecast to drop from $21.7 per unit, based on costs and units installed to the end of May 2007, to $7.2 per unit based on total costs and units installed to the end of 2008.

The total Minimum Functionality net revenue requirement between June 1, 2007 and April 30, 2008 is summarized in Table 7 below:

Table 7
Distribution
Smart Meter Minimum Functionality Under-Recovery between
June 1, 2007 and April 30, 2008
$ million

Description	**Dec 31, 2006**	**Dec 31, 2007**	**April 30, 2008**
Revenue Requirement	0.0	11.3	21.4
Less: Revenue	0.0	(7.6)	(12.0)
Net Revenue Requirement to be Recovered	**0.0**	**3.7**	**9.4**

2.6 Retail Settlement Variance Accounts (RSVA)

The RSVA accounts have been established pursuant to Article 490 which requires that all distributors establish Retail Settlement Variance Accounts to record the differences between the amount owed to the IESO / host distributors and the amount billed to customers and retailers.

The vast majority of the balance in the RSVA accounts is related to Wholesale Market Services (WMS). The purpose of the WMS account is to capture the net of the amounts charged by the IESO, host distributors, and embedded generators (based on the settlement invoices for the operation of the IESO administered markets and the IESO – controlled grid) and the revenue accrued for customers using the Board approved Wholesale Market Service Rate.

The RSVA accounts were previously reviewed and approved by the Board in RP-2004-0117/0118 and RP-2005-0020 / EB-2005-0378. The balance of the RSVA account has been filed with the Board on a quarterly basis per the Electricity Reporting and Record Keeping Requirements and is included in the Board's annual review of deferral account balances.

Pursuant to the Board's October 29, 2007 letter to Electricity Distributors re: "Ontario Uniform Transmission Rate Order, EB-2007-0759: Effect on Distributor Retail Transmission Rates", which directs Distributors to incorporate the disposition of variance account balances relating to retail transmission rates in their 2008 Cost of Service application, Hydro One is requesting disposition of RSVA balances in this submission.

The total Retail Settlement Variance Accounts balance is summarized in Table 8 below:

Table 8
Distribution
Retail Settlement Variance Accounts
$ million

Description	May 1, 2006	Dec 31, 2006	Dec 31, 2007	April 30, 2008
RSVA Wholesale Market Services	0.6	(23.8)	(60.3)	(72.6)
RSVA Tx Network & Tx Network Aggregation	1.4	7.6	12.5	1.4
RSVA Tx Connection & Tx Connection Aggregation	1.6	5.4	7.5	2.5
RSVA Provincial Benefit	5.6	7.8	0.0	0.0
RSVA Low Voltage	0.0	0.8	3.0	3.8
Total RSVA	9.2	(2.2)	(37.3)	(64.8)

2.7 Accounts Not Being Requested For Recovery

2.7.1 RCVA and RRRP Accounts

RCVA and RRRP deferral accounts are currently being tracked by Hydro One Distribution but are not being requested for recovery as part of this proceeding. Balances in these accounts will continue to be filed with the Board on a quarterly basis per the Electricity Reporting and Record Keeping Requirements and included in the Board's annual review of deferral account balances.

2.7.2 Regulatory Asset Recovery Account – Phase I

Ontario's local electricity distribution companies (LDCs or distributors) incurred costs in preparation for the competitive market which opened in May 2002. In addition to these transition costs, utilities incurred other costs associated with regulatory directives related to market restructuring and the ongoing competitive market.

On January 10, 2005, the Board issued an *Order* (RP-2004-0117/0118) granting Hydro One approval for its regulatory asset account balance of $155 million as filed on December 20, 2004.

Simple interest is applied to the monthly opening principal balance in this account.

The Recovery of Regulatory Asset Balances – Phase I account (USofA 1590) is monitored and reported on a quarterly basis to the Board per the Electricity Reporting and Record Keeping Requirements. A final reconciliation (and true up adjustment) will be done at the end of the three year duration of the rate rider (April 30, 2008 for Distribution customers with volumetric rate riders, and March 31, 2008 for Embedded LDCs and Directs with fixed dollar amount rate riders).

2.7.3 Regulatory Asset Recovery Account – Phase II

On August 17, 2005, Hydro One Distribution filed an application with the Board for an order approving or fixing just and reasonable rates for the distribution of electricity effective May 1, 2006. On April 12, 2006, the Board issued a *Decision with Reasons* (RP-2005-0020 / EB-2005-0378) granting Hydro One approval for its regulatory asset account balances of $100 million as approved for Rate Rider recovery under that application.

Simple interest is applied to the monthly opening principal balance in this account.

The Recovery of Regulatory Asset Balances – Phase II account (USofA 1590) is monitored and reported on a quarterly basis to the Board per the Electricity Reporting and Record Keeping Requirements. A final reconciliation (and true up adjustment) will be done at the end of the four year duration of the rate rider (April 30, 2010).

PLANNED DISPOSITION OF REGULATORY ASSETS

1.0 INTRODUCTION

The purpose of this evidence is to outline the planned disposition of Regulatory Assets.

2.0 PLANNED DISPOSITION OF REGULATORY ASSETS

Hydro One Distribution is requesting approval to reduce the annual revenue requirements over a four year period by the Regulatory Asset total balance of $(48.7) million, or $(12.2) million per year.

Hydro One Distribution is requesting disposition of Regulatory Asset balances up to April 30, 2008. Balances as of April 30, 2008 are reasonably predictable. Allowing disposition of balances up to April 30, 2008 is more efficient as it provides the opportunity to close out certain deferral accounts. For the purposes of this filing, April 30, 2008 was chosen as it is assumed approved Distribution rates will be in place at the beginning of May 2008.

Hydro One Distribution's requested reduction to the Revenue Requirement of $(48.7) million is detailed in Table 1:

Table 1
Distribution
Disposition of Regulatory Asset Balances ($ Millions)

Description	Balance April 30, 2008
OEB Costs Account	(0.9)
Tax Changes Account	(5.0)
Smart Meter Minimum Functionality Under-recovery to May 31, 2007	6.9
Smart Meter Exceeding Minimum Functionality Under-recovery	5.7
Smart Meter Minimum Functionality Under-recovery between June 1, 2007 and April 30, 2008	9.4
Retail Settlement Variance Accounts	(64.8)
Total Requested for Disposition	**(48.7)**

Hydro One Distribution is requesting a reduction to the Revenue Requirement by the amounts detailed in Table 1 over a four year period to maintain consistency with previous recovery periods approved for Regulatory Accounts within the Electricity Transmission and Distribution Businesses, such as the 2006 Distribution Rate Proceeding (RP-2005-0020 / EB-2005-0378) and the 2004 Regulatory Assets Review Proceeding (RP-2004-0117/0118).

A Regulatory Asset Recovery Account will be established for any difference between the amount of Regulatory Assets approved and the actual value of the Regulatory Assets detailed above as at April 30, 2008. This variance will continue to be tracked and will be interest improved on a monthly basis (using a simple interest calculation) at the OEB approved rate. This account will be reported to the Board on a quarterly basis consistent with the Electricity Reporting and Record Keeping Requirements and subject to the Board's annual Regulatory Asset Review.

VARIANCE ACCOUNTS REQUESTED

This exhibit requests approval to establish new variance accounts for Hydro One Distribution as follows:

- Pension Cost Differential
- OEB Cost Differential
- Bill Impact Mitigation

The need for these accounts and the accounting and control process is described in further detail in the remainder of this exhibit.

1.0 PENSION COST DIFFERENTIAL

Hydro One Distribution proposes to track the difference between actual pension costs booked using the actuarial assessment, provided by Mercer Human Resource Consulting, and the estimated pension costs used in this rate filing. Hydro One's actuarial valuation was prepared as at December 31, 2006 and was filed with FSCO in September 2007.

2.0 OEB COST DIFFERENTIAL

This account will track the difference between the annual OEB Cost Assessments, intervenor cost awards, and costs associated with OEB-initiated studies and the amount for these expenditures approved by the OEB as part of the 2008 Distribution Rates until these rates are rebased.

3.0 BILL IMPACT MITIGATION

This account will record the difference between Hydro One's requested revenue requirement and distribution rates resulting from the Application of the Cost Allocation for Electricity Distributors report issued by the Board on November 28, 2007. In this report the Board indicated that Distributors should endeavor to move their revenue-to-cost ratios within an acceptable range which is closer to one but should not move them away from one and be cognizant of customer bill impacts. To comply with these requirements, Hydro One Distribution proposed rates will result in a revenue differential of $2.5 million. The establishment of the Bill Impact Mitigation variance account will enable this balance to be recorded and submitted for recovery at a future proceeding. The intent of this account is similar in nature to the MEU Rate Mitigation account approved by the Board in their RP-2005-0014/EB-2005-0099 to 0185 decision At that time, the Board directed Hydro One to limit the rate increase to no more than 10 percent on the average customer's total bill and recognized that Hydro One would have a revenue shortfall. The Board wrote that they would allow for the recovery of this deferred revenue in future years.

4.0 ACCOUNTING AND CONTROL PROCESS

The variance accounts requested above will be managed in the same manner as existing Hydro One Distribution variance accounts. Accounts will be updated monthly and interest applied consistent with the Board approved rate. Balances will be reported to the Board as part of the quarterly reporting process. The outstanding balance whether in a debit or credit position will be submitted for approval by the Board as part of Hydro One Distribution's next rate filing.

HYDRO ONE NETWORKS INC.
DISTRIBUTION

Regulatory Assets for Approval
As at April 30, 2008
($ Millions)

Line No.	Particulars	Principal (a)	Interest (b)	Total (c)
1	OEB Costs	(0.8)	(0.1)	(0.9)
2	Tax Rate Change	(4.7)	(0.3)	(5.0)
3	Smart Meter Minimum Functionality to May 31, 2007	6.5	0.4	6.9
4	Smart Meter Costs Exceeding Minimum Functionality	5.5	0.2	5.7
5	Smart Meter Minimum Functionality after May 31, 2007	9.2	0.2	9.4
6	Retail Settlement Variance Accounts	(63.3)	(1.5)	(64.8)
7	**Total Regulatory Assets for Approval**	$ **(47.6)**	$ **(1.1)**	$ **(48.7)**

HYDRO ONE NETWORKS INC.
DISTRIBUTION
Schedule of Annual Recoveries*
Year Ending December 31
($ Millions)

Line No.	Particulars	2008	2009	2010	2011	2012	Total
		(a)	(b)	(c)	(d)	(e)	(f)
1	Requested Recovery of Pending Assets	(8.1)	(12.2)	(12.2)	(12.2)	(4.1)	(48.7)

* Note: above figures do not include interest improvement

INTRODUCTION TO COST ALLOCATION AND RATE DESIGN

This exhibit provides a road map to the evidence associated with cost allocation and rate design, which Hydro One Distribution proposes in this submission in respect of its Legacy, Acquired LDCs and Embedded (Low Voltage) customers.

The G1 exhibits describe Hydro One's proposal in a number of cost allocation and rate design areas, including: establishing new customer classes into which all current customer classes will be mapped; use of the OEB-recommended cost allocation methodology to allocate costs to the new customer classes; the harmonization process that is used to integrate existing customers into the new rate classes; use of the OEB-approved rate design methodology for setting the rates for the new customer classes; the proposals for mitigating customer bill impacts; and a number of other cost allocation and rate design issues as detailed in the following Sections of this Exhibit.

The G2 exhibits provide the 2008 rate schedules for all customers, including: rate schedules for the Legacy customers, which can be found in Exhibit G2, Tab 5, Schedule 1; rate schedules for the Acquired LDCs , which are provided in Schedule 1 of Exhibits G2, Tab 6, through Exhibit G2, Tab 93; and finally, the rate schedule for the Sub-Transmission customers, including current Embedded customers, which can be found in Exhibit G2, Tab 94, Schedule 1. The G2 exhibits also provide some miscellaneous exhibits (e.g. Miscellaneous rates, Conditions of Service) as detailed in the following Sections of this Exhibit.

1.0 COST ALLOCATION STUDY

Hydro One is using the Cost Allocation methodology recommended by the Board in its September 29, 2006 report, Proceeding EB-2005-0317, to allocate the revenue requirement by customer group. Hydro One modified the methodology to deal with its unique circumstances, such as the provision of Sub-Transmission service to Embedded customers and the numerous number of customer classes. The modifications are described in Exhibit G2, Tab 1, Schedule 1.

2.0 CUSTOMER CLASSIFICATION

The current customer classification is presented in Exhibit G1, Tab 2, Schedule 2. Hydro One is proposing to adopt 12 new customer classes into which all of its Legacy and Acquired customers will be mapped. The proposed 12 customer classes are shown below.

1. Urban Residential (High Density)
2. R1 Residential (Medium Density)
3. R2 Residential (Low Density)
4. Seasonal
5. Urban General Service energy billed
6. Urban General Service demand billed
7. General Service energy billed
8. General Service demand billed
9. Sub-Transmission
10. Street Light
11. Sentinel Light
12. Distributed Generation

More details on the proposed new 12 customer classes are presented in Exhibit G1, Tab 2, Schedule 3.

As part of the process for mapping Acquired customers to the 12 new customer classes Hydro One undertook a review of customers that meet the Urban Density criteria. The results of the review are presented in Exhibit G1, Tab 2, Schedule 4 and Exhibit G2, Tab 3, Schedule 1.

3.0 HARMONIZATION OF RATE CLASSES

Hydro One proposes to harmonize the rate classes for the customers of the 88 Acquired Utilities, including Terrace Bay, into six of the 12 new customer classes: Urban Residential, R1 Residential, Urban General Service energy billed, Urban General Service demand billed, General Service energy billed, and General Service demand billed customer classes. Hydro One also proposes to map and harmonize the rate classes for existing Legacy customers to the 12 new proposed classes. The purpose of the mapping and harmonization processes is to reduce the current 281 rate classes to a more manageable level in order to simplify the rate structures, facilitate customer understanding and achieve administrative efficiencies.

The evidence in support of this proposal is provided in Exhibit G1, Tab 2, Schedule 5 and Exhibit G2, Tab 2, Schedule 1.

4.0 APPORTIONMENT OF REVENUE REQUIREMENT

The revenue requirement by customer class and corresponding revenue to cost ratios that result from the application of the cost allocation methodology provide a guide on over or under-contribution by rate group. The allocated revenue requirement for each of the new 12 customer classes is shown in Exhibit G1, Tab 3, Schedule 1.

5.0 RATE DESIGN CONSIDERATIONS

The rate design is not changing for any customer classes other than for Sentinel and Street Lights, and for Sub-transmission customers, for whom a fixed service charge is proposed in addition to a variable charge as supported by feedback received during stakeholdering. A description of Hydro One's proposal with respect to rate design issues for 2008 Distribution rates is presented in Exhibit G1, Tab 4, Schedule 1.

The proposed 2008 target rates for the 12 new customer classes is presented in Exhibit G1, Tab 4, Schedule 2, rate considerations for Acquired customers is presented in Exhibit G1, Tab 4, Schedule 3, and rate considerations for Sub-Transmission customers are presented in Exhibit G1, Tab 4, Schedule 4. These exhibits provide a summary of the proposed 2008, 2009, 2010 and 2011 Distribution rates. The rates for Acquired LDCs are harmonized using a 4 year phase-in approach to deal with the wide variation of rates in the Acquired LDCs .

Hydro One's proposal with respect to Low Use Secondary Service customer rates is presented in Exhibit G1, Tab 2, Schedule 6.

Exhibit G1, Tab 4, Schedule 5 explains the development of the fixed service charge credit for unmetered scattered load and Exhibit G1, Tab 4, Schedule 6 explains the proposal with respect to the Transformer Ownership Allowance.

6.0 REGULATORY ASSET RATE RIDER # 3

Exhibit G1, Tab 5, Schedule 1, provides a description of the methodology applied by Hydro One Distribution in respect to allocating the balance accrued in the five Regulatory Asset accounts to April 30, 2008 to the various customer classes.

Exhibit G1, Tab 5, Schedule 2 provides a description of the allocators and charge determinants that Hydro One Distribution proposes to use in respect of recovering the accumulated Regulatory Asset balances from the various customer classes.

Rate Riders # 3 that will apply in respect of the recovery of the Regulatory Asset balances are derived in Exhibit G1, Tab 5, Schedule 3.

7.0 RETAIL TRANSMISSION SERVICE RATES

Hydro One Distribution proposes to revise its Retail Transmission Service Rates (RTSR) for 2008, and Exhibit G1, Tab 6, Schedule 1 provides the corresponding evidence in terms of the methodology used and the resultant rates that would apply for the 12 new proposed rate classes. Additional supporting details are presented in Exhibit G2, Tab 4, Schedule 1.

The corresponding 2008 RTSR for the proposed new 12 customer classes is included in Exhibits G2, Tabs 5 to 94 that contain all the applicable rates.

8.0 CUSTOMER BILL IMPACTS AND MITIGATION

An assessment of customer bill impacts is provided in Exhibit G1, Tab 7, Schedule 1 for the Legacy customers, in Exhibit G1, Tab 7, Schedule 2 for Acquired LDC customers, and in Exhibit G1, Tab 7, Schedule 3 for the Sub-Transmission customers.

Hydro One Distribution believes it is necessary to propose an approach which mitigates bill impacts for Legacy and Acquired LDCs customers. Evidence in this respect is provided in Exhibit G1, Tab 8, Schedule 1 and Exhibit G1, Tab 8, Schedule 2.

9.0 PROPOSAL FOR CUSTOMERS CURRENTLY ON THE INTERIM TIME-OF-USE RATE PILOT

Exhibit G1, Tab 9, Schedule 1 provides information on Hydro One Distribution proposal for the three customers currently enrolled in the Interim Time-of-Use rate pilot.

10.0 DISTRIBUTION LOSS FACTORS

An assessment of Hydro One Distributions loss factor is included in Exhibit A, Tab 15, Schedule 3. A description of the proposed Total Loss Factors are included in Exhibit G1, Tab 10, Schedule 1, and are also included in the corresponding Rate Schedules for Legacy, Acquired and Sub-Transmission customers in Exhibit G2, Tabs 5 to 94.

11.0 MISCELLANEOUS RATES

The proposed rates for Miscellaneous charges can be found in Exhibit G2, Tab 95, Schedule 1 and in the corresponding Rate Schedules for Legacy, Acquired and Sub-Transmission customers in Exhibits G2, Tabs 5 to 94.

12.0 TERMS AND CONDITIONS OF SERVICE

The Terms and Conditions of Service applicable to all Hydro One customers are provided in Exhibit G2, Tab 96, Schedule 1.

CUSTOMER CLASSIFICATION

In order to set the context for the allocation of Hydro One's revenue requirement to customer classes, Exhibits G1, Tab 2, Schedule 2 to Schedule 6 provide a review of the current and proposed customer classes.

1.0 CATEGORIES OF SERVICE

Within the Hydro One Distribution business there are two categories of service provided to customers. The first category entails distribution service to over one million Retail customers. Retail customers consist of Legacy customers (customers of the former Ontario Hydro and its successor companies) and Acquired customers (customers of the LDCs acquired by Hydro One, excluding Brampton Hydro which is a subsidiary of Hydro One and whose customers are not part of this Application). Retail customers currently fall into rate classes designated for residential, seasonal, general service and farm customers.

The second category entails distribution service to Sub-Transmission customers that are directly connected to the Hydro One Distribution Sub-Transmission (ST) system. ST customers consist of all Embedded LDCs, all Embedded Direct delivery points with demands above 5 MW, and large customers with demands above 500 kW that provide their own transformation facilities and are connected to Hydro One's distribution system at voltages of 13.8 kV or above.

2.0 REDUCING THE NUMBER OF CUSTOMER CLASSES

One of the main objectives of this Application is to simplify the structure of Hydro One Distribution's current rate classes to better reflect utilization of assets and services which impact cost causality. The simplified rate classes are also designed to be more consistent with the number, and categorization of rate classes typically used in other Ontario distribution companies (LDCs), and are expected to reduce customer confusion and be significantly easier to manage from an administrative perspective.

As described in Exhibit G1, Tab 2, Schedule 2 Hydro One currently has over 280 rate classes to administer its Retail and ST customers. With the implementation of time-of-use rates, and assuming not all customers within a rate class will want to adopt time-of-use, the number of rate classes to be administered can potentially expand to a value of close to 600 if action is not taken to reduce the number of rate classes. Hydro One is concerned that this vast array of distribution tariffs has the potential to create significant customer confusion and increase the overall cost of administrating the rates and the customer interface.

Hydro One discussed the possibility of reducing the number of rate classes applicable to its customers at a stakeholder session held September 5th, 2007. The discussion with stakeholders included Hydro One's intent of creating customer classes that reflect the type of customer served, consumption level, types of assets used to provide the service, and customer density. As detailed in Exhibit A, Tab 16, Schedule 1, Stakeholders were actively engaged in this discussion and provided valuable input that was used to shape the 12 new customer classes discussed in Exhibit G1, Tab 2, Schedule 3.

3.0 MAPPING EXISTING RATE CLASSES TO PROPOSED RATE CLASSES

All of the existing Legacy rate classes and Acquired utility rate classes will be mapped to the 12 new proposed rate classes using the harmonization process described in Exhibit G1, Tab 2, Schedule 5.

CURRENT CUSTOMER CLASSIFICATION

This exhibit describes Hydro One's current customer classification.

1.0 CURRENT CUSTOMER CLASSES

Hydro One Distribution currently has three basic distribution customer groups that have 281 customer classes and their own distinct rate structures:

- Legacy Retail customers,
- Acquired Utility customers, and
- Embedded customers.

1.1 Legacy Retail Rate Classes:

Hydro One Distribution has 13 Retail rate classes for its Legacy customers to reflect its diverse customer and geographical base, while each of the Acquired LDCs have three to four rate classes that are more typical of urban-based utilities.

Table 1 summarizes the existing Legacy Retail rate classes with a brief description. A more detailed description of the rate classes follows the table.

Table 1
Existing Legacy Retail Rate Classes

Symbol	Description
UR2	Residential Year Round Class – Urban Density
R1	Residential Year Round Class - High Density
R2	Residential Year Round Class - Normal Density
R3	Seasonal Class - High Density
R4	Seasonal Class - Normal Density
F1	Farm Class - Single Phase
F3	Farm Class - Three Phase
UG2	General Service Class – Urban Class
G1	General Service Class - Single Phase
G3	General Service Class – Three Phase
T	Transmission Class
Light	Street Lighting Sentinel Light

Existing Density Criteria:

Urban Density: areas containing 3,000 or more customers with a line density of at least 60 customers per kilometer

High Density: areas containing 100 or more customers with a line density of at least 15 customers per kilometer.

Normal Density: areas that are neither High Density nor Urban Density.

Existing Legacy Retail Customer Classes

Residential - Year-Round: This classification applies to a customer's main place of residence and may include additional buildings served through the same meter, provided they are not rental income units. To be classified as year-round residential, all of the following criteria must be met:

a. Occupants must state that this is their principle residence for purposes of the *Income Tax Act.*
b. The occupant must live in this residence for at least 8 months of the year.
c. The address of this residence must appear on the occupant's electric bill, driver's license, credit card invoice, property tax bill, etc
d. Occupants who are eligible to vote in Provincial or Federal elections must be enumerated for this purpose at the address of this residence.

Residential – Seasonal: This classification is comprised of cottages, chalets, and camps, any residential service not meeting the Residential - Year-Round criteria.

Farm: This classification is applicable to properties actively engaged in agricultural production as defined by Statistics Canada. It does not include tree, sod, or pet farms. Services to year-round pumping stations or other ancillary services remote from the main farm shall be classed as farm. It includes single-phase and three-phase customers that can be energy or demand billed.

General Service: This classification is applicable to any service that does not fit the description of the Residential or Farm classes. Generally, it is comprised of commercial, industrial, educational, administrative, auxiliary and government services. It also includes combination services where a variety of uses are made of the service by the owner of one property, and all multiple services except residential. It includes single-phase and three-phase customers that can be energy or demand billed.

Transmission: This classification is applicable for General class customers supplied by the sub-transmission system up to 5,000 kW.

Street Lighting: Classification for street lighting service only.

Sentinel Lighting: Classification for sentinel lighting service only.

1.2 Existing Acquired LDCs Customer Classes

The Acquired LDCs customer classes consist of: Residential customer class, General Service energy billed for customers with average demands below 50 kW, General Service demand billed for customers with average demands above 50 kW, and Large User for Acquired LDCs with customers that have average demand exceeding 5,000 kW. In 2006, Unmetered Scattered Load rates for Acquired General Service customers were developed following the 2006 EDR guidelines.

Currently each Acquired LDC has separate and distinct rates as derived from the Board's Rate Unbundling and Design (RUD) model. Therefore, Hydro One Distribution is currently maintaining approximately 270 rates for the approximately 160,000 Acquired LDC customers.

One of the goals of this Submission is to harmonize the Acquired LDCs' more than 270 rate classes into Hydro One's new proposed customer classes to achieve a smaller and more manageable set of rates. This manageable set is achieved through the Harmonization process described in Exhibit G1, Tab 2, Schedule 5.

<u>Special Subclasses</u>:

Low Use Secondary Services: Applicable only for low use secondary services located on the same property as the main service, supplied from the same transformer, with the same owner and consumes less than annual threshold levels. There is no service charge applicable for consumption not exceeding the following thresholds per rate class:

Residential year-round	<1,500 kWh / annum
Residential – seasonal	< 500 kWh / annum
General Service & Farm	< 2,500 kWh / annum

There are 2,500 customers with these accounts in 2007. Their consumption is included within the rate classes where they reside to derive total revenues per rate class. However, to derive revenues the customer counts need to be reduced to reflect that this sub-class of customers pays no monthly service charge.

Unmetered Scattered Loads: This category captures services to phone booths, bill boards, cable boxes, etc., but excludes street and sentinel lighting, which are separate classes. Unmetered loads reside in rate classes G1, G3 and UG2. The analysis of these classes included these customers to derive the total revenues for each rate class.

1.3 Embedded (LV) Rate Classes:

The LV rates consist of the following rate structures that were approved by the OEB in proceeding RP-2000-0023:

Shared LV line – line used by more than one embedded customer, LDC or Direct
HVDS hi – provides transformation service from above 50 kV to 44 kV or above 24.9 kV

Shared LVDS - provides transformation service from above 44 kV or 24.9 kV to lower voltages

HVDS low - provides transformation service from above 50 kV to 13.8 kV or lower voltage

Specific LV line – LV line used by one embedded customer and the line is located in their territory

Specific DX line – DX line used by one embedded customer and the line is located in their territory

Currently only the Shared LV line charge applies to Direct customers due to the fact that these are the only facilities that Direct customers utilize. Embedded LDCs are subject to all of the above LV rates depending on the facilities they use.

PROPOSED CUSTOMER CLASSIFICATION

This exhibit presents Hydro One's proposed customer classification.

1.0 PROPOSED CUSTOMER CLASSES

In order to simplify rates, provide similar customer classes as other LDCs, reduce customer confusion, improve administrative efficiency and to better reflect asset utilization and cost causality, Hydro One is proposing 12 new customer classes:

1. Urban Residential (High Density)
2. R1 Residential (Medium Density)
3. R2 Residential (Low Density)
4. Seasonal
5. Urban General Service energy billed
6. Urban General Service demand billed
7. General Service energy billed
8. General Service demand billed
9. Sub-Transmission
10. Street Light
11. Sentinel Light
12. Distributed Generation

Based on Stakeholder feedback received on September 5, 2007 Urban General Service energy billed and Urban General Service demand billed customer classes have been included in our proposal. Also based on Stakeholder feedback at the same session, Hydro One will change the current definitions used for Residential customers Urban, High and Normal density. The current description of Urban Residential, R1 Residential High density and R2 Residential Normal density will be changed to Urban Residential (high density), R1 Residential (medium density) and R2 Residential (low density) to minimize potential customer confusion.

Urban Residential (High Density)

This customer class will include all existing Legacy residential, farm and Acquired LDCs residential customers that meet the Urban Density Criteria. The Urban Density criteria is unchanged and is defined as areas containing 3,000 or more customers with a line density of at least 60 customers per kilometer. The proposed Urban Residential customer class has 155,840 customers in 2006 some of which are mapped from the other original Legacy classes and the Acquired residential classes, as shown in the Table below.

Table 1
Proposed Urban Residential (High Density) customers 2006 Data

Current Customer Class	Number of Customers
Urban Legacy	82,519
R1 Legacy	11,753
R2 Legacy	293
Farm single-phase	128
Acquired LDCs Residential	61,147
	155,840

R1 Residential (Medium Density)

This customer class will include all R1 Legacy customers that have not been reclassified to Urban class and all remaining Acquired Residential customers that have not been reclassified as Urban class. The proposed R1 Residential customer class in 2006 has 365,190 customers as shown in the Table below.

Table 2
Proposed R1 Residential (Medium Density) customers 2006 Data

Current Customer Class	Number of Customers
R1	292,508
Acquired LDCs Residential	72,682
	365,190

R2 Residential (Low Density)

This customer class includes all current R2 customers that have not been reclassified to Urban and all energy billed Farm customers that are currently single-phased or three-phased Farms. These groups of customers receive Rural or Remote Electricity Rate Protection, (RRRP). This group also includes one Caledon residential class. The proposed R2 Residential customer class has 358,328 customers in 2006 as shown in the Table below.

Table 3
Proposed Rural Residential (Low Density) customers 2006 Data

Current Customer Class	Number of Customers
R2	272,111
Caledon OH-06	7,266
Farms single phase	78,720
Farms three-phase	231
	358,328

Seasonal Residential

This customer class will include all current R3 and R4 and Caledon OH-07 customers. This customer class in 2006 has 154,437 customers as shown in the Table below:

Table 4
Proposed Seasonal Residential customers 2006 Data

Current Customer Class	Number of Customers
R3	70,750
R4	83,477
Caledon OH-07	210
	154,437

Urban General Service Energy Billed

This customer class will include all existing Legacy General Service, Farms and Acquired General Service customers that meet the Urban Density Criteria and are energy billed. The Urban Density criteria is unchanged and is defined as areas containing 3,000 or more customers with a line density of at least 60 customers per kilometer. The proposed Urban General Service energy billed customers class has 12,427 customers in 2006 as show in the Table below.

Table 5
Proposed Urban General Service energy billed customers 2006 Data

Current Customer Class	Number of Customers
Urban General Service Legacy customers energy billed	5,309
General Service single phase	425
General Service three-phase	432
Farm single-phase	18
Acquired LDCs General Service	6,243
	12,427

Urban General Service Demand Billed

This customer class will include all existing Legacy General Service and Acquired General Service customers that meet the Urban Density Criteria, are demand billed, and are supplied at voltages below 13.8 kV. The Urban Density criteria is unchanged and is defined as areas containing 3,000 or more customers with a line density of at least 60 customers per kilometer. The proposed Urban General Service energy billed customers class has 1,375 customers in 2006 as show in the Table below.

Table 6
Proposed Urban General Service demand billed customers 2006 Data

Current Customer Class	Number of Customers
Urban General Service Legacy customers demand billed	593
General Service single phase	8
General Service three-phase	119
Acquired LDCs General Service	655
	1,375

General Service Energy Billed

This customer class will include: all energy billed customers that are currently single–phase General Service customers, three-phase General Service customers, Acquired General Service customers, all energy billed Farm customers that are currently single-phased or three-phased Farms that do not receive RRRP, and energy billed T-class customers. All these customers are customers with average demands below 50 kW and do not meet the Urban Density criteria. The proposed General Service energy billed customer class in 2006 has 92,225 customers as show in the Table below. This class will also include all unmetered scattered load connections.

Table 7
Proposed General Service Energy Billed customers 2006 Data

Current Customer Class	Number of Customers
General Service single-phase energy billed	55,032
General Service three-phase energy billed	10,318
T-Class customers energy billed	14
Farm single phase energy billed and no RRRP	8,723
Farm three phase energy billed and no RRRP	589
Acquired LDCs General Service customers energy billed	12,632
Unmetered Scattered Load	4,917
Total Number of Customers	**92,225**

General Service Demand Billed

This customer class will include: all demand billed single–phase General Service customers, three-phase General Service customers, Acquired General Service customers, all demand billed Farm customers that are currently single-phased or three-phased Farms, and T-Class customers below 500 kW of demand. All these are customers with average demands above 50 kW, supplied at voltages below 13.8 kV, and do not meet the Urban Density criteria. The proposed General Service energy billed customer class in 2006 has 6,849 customers, as shown in the Table below.

Table 8
Proposed General Service Demand Billed customers 2006 Data

Current Customer Class	Number of Customers
General Service single-phase demand billed	579
General Service three-phase demand billed	4,044
Farm single phase demand billed	495
Farm three-phase demand billed	389
T-Class customers demand billed and with demands below 500 kW	175
Acquired LDCs General Service customers demand billed	1,167
Total Number of Customers	**6,849**

Distributed Generator

As per the Board's direction in the EB-2005-0528 proceeding, Hydro One has created a new customer class consisting of all 81 active Distributed Generators located within its territory in 2006. The current customer classification for these customers is 48 T-class Customers, 1 Acquired General Service customer, and 32 General Service three-phase customers.

Street Lighting

Classification for street lighting service only

Sentinel Lighting

Per the requirements of Regulation 116/02 made under the *Electricity Act, 1998* Hydro One Networks includes the provision of sentinel lighting service as part of its regulated business. This rate classification is applicable for sentinel lighting service only, and includes the cost of providing distribution service to the sentinel lights. The cost for providing this service is determined using the cost allocation methodology recommended by the Board as part of proceeding EB-2005-0317, and is net of the miscellaneous revenues associated with charges for providing the sentinel lights themselves.

Sub-Transmission (ST) Customer Class

This customer class will include all three-phase customers with demands above 500 kW that provide their own transformation facilities and are connected at voltages of 13.8 kV or above. The class will also include all Embedded LDC supply points, some of which are connected at voltages below 13.8 kV. This ST class will include some customers from the following groups: T-class customers, Acquired General Service customers, Urban General Service customers, three-phase General Service customers, three-phase Farms, all Acquired Large Users, all Direct customers and all Embedded LDC supply points. The proposed Sub-Transmission customer class in 2006 has 670 Delivery Points as show in Table 9.

Table 9
Proposed Sub-transmission Delivery Points 2006 Data

Current Delivery Points	Number of Delivery Points
Urban General Service above 500 kW	10
General Service three-phase above 500 kW	57
Acquired LDCs General Service customers above 500 kW	72
T-Class customers above 500 kW	124
Farm three-phase above 500 kW	1
Acquired Large Users	6
Embedded Direct	42
Embedded LDCs	358
Total Number of Delivery Points	**670**

The above mentioned 12 customer classes have been used in Hydro One’s Cost Allocation Study to allocate the 2008 proposed Revenue Requirement amongst the customer classes.

DENSITY REVIEW

This exhibit presents a description of the Density Review undertaken by Hydro One to identify customers that qualify for Urban Density classification.

1.0 INTRODUCTION

Hydro One undertook a review of Urban areas to update the classification of Residential and General Service customers. This review entailed identifying areas in the Province that meet the Urban Density criteria and using 2006 data gathered from maps, operating diagrams and customer connectivity information to identify all Residential and General Service Legacy and Acquired customers served within the areas that meet the Urban Density criteria.

This review identified 11,753 current R1 customers, 293 current R2 customers, and 128 current single-phase Farm customers that meet the Urban Density criteria and will be re-classified from their current customer classification. In addition, 61,147 current Acquired LDCs Residential customers meet the Urban Density criteria and are proposed to be grouped as part of the new Urban Residential customer class. All existing Urban customers will also be included in this new Urban class. The remaining 72,682 Acquired Residential customers, excluding Caledon Residential OH-06 and OH-07 customer classes, will be grouped with the R1 customer class.

The review also identified 425 current single–phase General Service customers, 432 current three-phase General Service customers, and 18 current single-phase Farms that meet the Urban Density criteria and will be re-classified from their current customer classification. In addition, 6,243 current Acquired General Service customers and 5,309 current Urban General Service customers that meet the Urban Density criteria are proposed to be grouped as part of the new Urban General Service energy billed customer class. Finally, the review also identified 8 current single–phase General Service customers, and 119 current three-phase General Service customers that meet the Urban Density criteria and will be re-classified from their current customer classification. In addition,, 655 current Acquired General Service customers and 593 current Urban General Service customers that meet the Urban Density criteria are proposed to be grouped as part of the new Urban General Service demand billed customer class.

Results of the Density review for Urban areas are included in Exhibit G2, Tab 3, Schedule 1.

HARMONIZATION OF ACQUIRED LDC CUSTOMERS AND CONSOLIDATION OF LEGACY CUSTOMER CLASSES

This exhibit discusses the proposal to harmonize the rate classes for the customers of the Acquired Utilities and to consolidate the rate classes for Hydro One Distribution's Legacy customers with the 12 new proposed customer classes.

Terrace Bay, whose purchase by Hydro One has been approved by the OEB is also included in this harmonization plan for a total of 88 Acquired utilities to be harmonized. Brampton Hydro is a separate business, and not part of Hydro One Distribution submission for distribution rates. Since the initial unbundling of distribution rates, each of the 88 Acquired Utilities have maintained their own individual distribution rates as developed via the Board's Rate Unbundling Design (RUD) Model.

The purpose of the plan presented herein for both Legacy and Acquired customers is to reduce the numerous existing rate classes to a more manageable level in order to minimize the degree of customer confusion over the numerous rates and to improve administrative efficiencies.

1.0 INTRODUCTION TO HARMONIZATION

Hydro One Distribution proposed to harmonize the rates for its Acquired LDCs as part of the 2006 Distribution Rate submission RP-2005-0020/EB-2005-0378. The 2006 proposal was intended to harmonize rates only amongst the Acquired LDCs, The Board Decision with Reasons dated April 12, 2006, indicated that the then proposed harmonization was premature and that there was no evidence to determine that the proposed rate would be fair and reasonable because the proposed harmonized rates were not based on a cost allocation study.

Hydro One believes that the concerns raised by the Board in the 2006 proposal have been addressed in the current harmonization plan.

1. A Cost Allocation Study Methodology has been recommended by the Board and the results of this cost allocation study now provide support for the target distribution rates that are the basis of the harmonization plan. Given the impact on customer bills resulting from the harmonization plan a multiple year phased-in approach is being proposed by Hydro One. The relevant statistics for the Acquired LDC customer groups in terms of current rates and customer numbers are provided in Tables 1 to 3 in Exhibit G2, Tab 2, Schedule 1.

2. The current plan entails harmonization of all of the Acquired LDCs residential rate classes into the two new Residential rate classes proposed by Hydro One: Urban or R1. Density for each Acquired LDC customer determines if the Acquired LDC's Residential customer is to be harmonized with the Urban or the R1 residential group.

3. Three of Caledon's Residential customer classes, OH 01, OH 06 and OH 07 are being harmonized with the Urban (UR), Rural (R2) and Seasonal customer class respectively. Caledon Residential OH 01 was based on the previous Ontario Hydro Urban Residential customer class, Caledon Residential OH 06 was based on the previous Ontario Hydro Residential R2 customer class and Caledon Residential OH 07 was based on the previous Ontario Hydro R4 Seasonal customer class.

4. The Acquired General Service customer classes are proposed to be harmonized into the four new General Service classes: Urban General Service energy billed, Urban General Service demand billed, General Service energy billed, or General Service demand billed. Density for each Acquired LDC customer determines if the Acquired

LDC's General Service customer is to be harmonized with the Urban General Service or the General Service group.

5. Acquired Large Users are proposed to be grouped as part of the new Sub-Transmission customer class which is described in Exhibit G1, Tab 2, Schedule 3.

2.0 HARMONIZATION OF RESIDENTIAL AND GENERAL SERVICE RATES

The proposed harmonization plan entails merging some of the customers in Acquired Residential classes with the Urban Residential customer class. All the remaining residential customers of the 88 Acquired LDCs will be merged with the R1 Residential customer class. Similarly, some of the Acquired General Service customers are proposed to be harmonized into either Urban General Service, or General Service, depending on meeting the Urban Density criteria, and further grouped into energy, or demand billed customer classes. As stated in Exhibit G1, Tab 2, Schedule 1, one of the benefit of harmonizing the customer classes would be the elimination of over 270 Acquired rate classes.

The proposed harmonization plan would entail combining all Residential and General Service Acquired customers into six new customer classes that include Hydro One's Legacy customers. The results in terms of the number of customers in the Acquired LDCs moving to the six new rate classes are shown in Table 1 below.

Table 1
Acquired Rate Classes

Customer class	Number of Acquired customers affected based on 2006 data	Number of Acquired LDCs affected
Urban Residential	61,147	12
R1 Residential	72,682	88
Urban General Service energy billed	6,243	11
Urban General Service demand billed	655	11
General Service energy billed	12,632	88
General Service demand billed	1,167	88

The plan proposed to harmonize Acquired customer rates is described in section 2.1 below. The plan was presented at the second Stakeholder session on September 5th, 2007 and Stakeholders generally supported the proposed approach as noted in Exhibit A, Tab 16, Schedule 1. The starting point of the harmonization plan is the current service charge in the Acquired LDCs and the target of the harmonization plan is the corresponding service charge in the proposed rate class. The two principles applied are to group Acquired LDCs customers according to the proposed service charges and to ensure that the distribution revenues allocated to the group are recovered from all customers in the groups. An example on how these two principles are applied is provided in the following section.

2.1 Description of Process to Harmonize Acquired Rates

Starting with the harmonization of Residential customer classes of Acquired LDCs that moved to the new Urban Residential customer class, the proposed harmonization plan would entail the following step:

1. Current Acquired fixed service charges are truncated downward into rounded dollar amounts, (e.g. $3.60 becomes $3.00).
2. Determine the target fixed and volumetric rates that would be applicable to the Acquired Residential customers. The target rates would be the new Urban Residential distribution rates
3. Determine the incremental increase, or reduction required to bring the service charge to the target service charge
4. Divide the increment into four, (based on a four year phase-in plan)
5. Apply the increment calculated in step 4 above to the truncated service charge to determine year one service charge
6. Year two service charge is the service charge for year one calculated in step 5 above plus the increment calculated in step 4 above
7. Year three service charge is the service charge for year two calculated in step 6 above plus the increment calculated in step 4 above
8. Year four service charge is the target service charge for the new Urban Residential class
9. A common volumetric charge is determined for all customers in the group to recover the balance of Distribution revenue not collected through fixed charges in each year of the four year-plan
10. Three of Caledon's Residential rate classes would be moved to Urban, R2 Residential, and Seasonal residential classes since they are similar to the Legacy Urban, R2 Residential, and Seasonal rate classes proposed.

A numerical example of the above steps is provided in Table 2 below.

Table 2
Development of Harmonized group rates for the Residential Urban Customer Class

Residential Urban	LDC 1	LDC 2
Target rates (fixed and volumetric)	$9.45/month & 0.89 ¢/kWh	$9.45/month & 0.89 ¢/kWh
May 2007 Rates (fixed and volumetric)	$3.94/month & 0.62 ¢/kWh	$11.46/month & 1.17 ¢/kWh
LDC truncated fixed service charge	$3.00/month	$11.00/month
LDC increase/(decrease) to achieve target fixed service charge	$5.51/month	$(2.01)/month
LDC year 1 rates	$3.00 + $5.51/4 = $4.38/month & 0.92*¢/kWh	$11.00 - $2.01/4 = $10.50/month & 0.92* ¢/kWh
LDC year 2 rates	$4.38 + $5.51/4 = $5.76/month & 0.91*¢/kWh	$10.50 - $2.01/4 = $10.00/month & 0.91* ¢/kWh
LDC year 3 rates	$5.76 + $5.51/4 = $7.14/month & 0.90*¢/kWh	$10.00 - $2.01/4 = $9.50/month & 0.90* ¢/kWh
LDC year 4 rates	$9.45 & 0.89 ¢/kWh	$9.45 & 0.89 ¢/kWh

*Calculation of the volumetric charge is not shown, but it is adjusted to ensure recovery of the required distribution revenue from customers in the group.

The same process as described above is followed for Acquired Residential classes that are being moved to the R1 Residential customer class and for General Service customers of Acquired LDCs that are being moved to Urban General Service energy billed, Urban General Service demand billed, General Service energy billed, or General Service demand billed classes.

Tables 6 and 7 in Exhibit G2, Tab 2, Schedule 1, provide examples of the derivation of rates for acquired customers that have the lowest and highest service charges in Urban Residential, R1 Residential, General Service energy billed, General Service demand billed, Urban General Service energy billed and Urban General Service demand billed. The Large users of the Acquired LDCs are being mapped to the new Sub-Transmission class in 2008.

2.2 Impacts due to Harmonization of Acquired Residential and General Service Customer Rates

The range of impacts on total bill resulting from the harmonization of Acquired Residential and General Service customer rates before bill impact mitigation are summarized in Table 3 below, where percentage changes compared to approved 2007 rates are shown. The complete set of impacts can be found in Tables 8, 9, and 10 of Exhibit G2, Tab 2, Schedule 1. Commodity, Wholesale Market Service and Debt Retirement charges are based on current, 2007 applicable charges and kept constant before and after harmonization. Retail Transmission Service Rates (RTSR) for 2008 are based on the new proposed RTSR, as described in Exhibit G1, Tab 6, Schedule 1. Losses for 2008 are based on the proposed loss factors described in Exhibit G1, Tab 10, Schedule 1.

Table 3
Range of impacts for Acquired Residential and General Service customers of Harmonization

Customer Class	Number of customers in 2006	Range of impacts on total bill (percent)
Residential	141,305	1.6 to 30.9
General Service	20,697	-3.0 to 36.2

Impacts are being mitigated to all Acquired Residential and General Service customers by phasing-in the harmonization plan over four years.

3.0 MAPPING OF LEGACY CUSTOMER CLASSES

Currently, Hydro One Distribution has 15 rate classes for Residential, General Service and Embedded LDCs and Direct customers. The proposed consolidation plan results in 12 new customer classes into which the Acquired LDC customer classes will be harmonized.

A similar process as described in Section 2 above is also used to consolidate Hydro One existing Legacy customer classes to the 12 new proposed customer classes.

As described in Exhibit G1, Tab 8, Schedule 1, a four-year plan can be implemented such that all Legacy customers would, on average have a total yearly bill impact of less than 10 percent, including the impact of the 2008 revenue requirement increase.

4.0 CONCLUSION

Currently, Hydro One Distribution has 88 Acquired LDCs and each LDC has 3 or 4 individual rate classes for Residential, General Service energy billed, General Service demand billed, and in some cases Large User rates.

The Hydro One Distribution harmonization plan for the Acquired LDCs ensures that the resultant bill impact for Acquired LDC customers are kept within prescribed thresholds in accordance with the 2006 Electricity Distribution Rate Handbook.

The harmonization plan covers a four year period at the end of which Acquired LDC customers will be part of the Urban, R1 Residential, Urban General Service energy billed, Urban General Service demand billed, General Service energy billed or General Service demand billed customer classes.

As described in Exhibit G1, Tab 8, Schedule 2, a four-year plan can be implemented such that all Acquired customers would, on average, have a total yearly bill impact of less than 10 percent, including the impact of the 2008 revenue requirement increase.

At the end of the four-year harmonization plan, rates for Acquired and legacy customers would be harmonized into the 12 new proposed customer classes.

LOW USE SECONDARY CUSTOMER RATE CONSIDERATION

This exhibit describes the proposal to eventually eliminate the Low Use Secondary customer rates.

1.0 LOW USE SECONDARY SERVICE

Hydro One is proposing to eventually eliminate its Low Use Secondary Service rates. This rate design was introduced in 1996 as a mitigation measure when Ontario Hydro changed the rate structure used to bill end-use customers from a declining block rate structure to a fixed monthly charge and a volumetric charge. For customers with very low consumption, the introduction of a fixed charge would have resulted in substantial bill impacts. For 2008, Hydro One proposes to introduce a fixed monthly charge for this rate design and bill the low use secondary service customer consumption at the General Service energy billed customer classification consumption using the corresponding applicable distribution rates. To mitigate large rate impacts the fixed charge is being phased-in over 5 years. The target fixed charge is the General Service energy billed service charge.

COST ALLOCATION OF REVENUE REQUIREMENT

This exhibit presents an overview of the process to allocate Hydro One Distribution related revenue requirement costs to Legacy, Acquired, and Sub-Transmission customer groups (including current Embedded LV customers).

1.0 INTRODUCTION

The 2008 revenue requirement of $1,067 million for Hydro One Distribution was derived in Exhibit E1, Tab 1, Schedule 1, and is attributed to the Retail, (Legacy and Acquired), and Sub-Transmission customers.

This revenue requirement is allocated to the proposed customer groups using the Cost Allocation methodology issued by the OEB on September 29, 2006 in the RP-2005-0317 proceeding. Hydro One modified the OEB methodology to reflect its unique circumstances related to the provision of an LV system and a very large number of rates. The modifications are detailed in Exhibit G2, Tab 1, Schedule 1, and are similar to the modifications applied in Hydro One's Cost Allocation Information Filing of January 15, 2007 as part of Proceeding RP-2007-0001.

2.0 APPORTIONMENT OF REVENUE REQUIREMENT

Hydro One used the OEB Cost Allocation Methodology to allocate the proposed $1,067 million revenue requirement to customer classes. The allocated revenue requirement was compared to the revenues that would be collected from customers at adjusted 2007 Distribution rates. The adjustment consisted of increasing the 2007 approved rates proportionally to recover the 2008 Revenue Requirement of $1,067 million. Revenue to cost ratios were then calculated. Revenue to cost ratios above 1 mean that the customer class is over-contributing and revenue to cost ratios below 1 mean that the customer class is under-contributing. The results of the cost allocation study are summarized in the Table below.

Table 1
Hydro One Cost Allocation Study Results

	UR	R1	R2	Seasonal	UGSe	UGSd	GS e	GS d	ST	DG	Street Light	Sent. Light	Total
Rev Req $M	66.0	240.2	390.3	83.6	9.3	16.8	111.1	105.4	27.4	0.4	8.1	8.0	1,066.6
Revenue at current rates $M	57.7	197.1	404.6	77.0	12.1	16.0	119.6	107.9	64.2	0.6	4.9	4.9	1,066.6
Rev/cost ratio	**0.87**	**0.82**	**1.04**	**0.92**	**1.29**	**0.95**	**1.08**	**1.02**	**2.35**	**1.63**	**0.60**	**0.62**	**1.00**

More details on the results of the cost allocation study can be found in Exhibit G2, Tab 1, Schedule 1.

3.0 TARGET REVENUE TO COST RATIO

Hydro One is proposing to use the revenue to cost ratio ranges recommended in the Board's report issued November 28, 2007 under proceeding EB-2007-0667, "Application of Cost Allocation for Electricity Distributors". The Board recommended revenue to cost ratios range from 0.7 for street lights to 1.8 for large commercial customers. Given that this is the first time that the OEB's cost allocation methodology is being used as a basis for determining distribution rates, the wider range of revenue to cost ratios proposed by the Board will reduce the potential bill impacts on customers whose distribution rates have to increase to closer reflect cost causality. The proposed range of revenue to cost ratios will result in those customer classes with a revenue to cost ratio above 1 continuing to cross-subsidize those customer classes with a revenue to cost ratio below 1.

Hydro One is proposing the following revenue to cost ratios for the various new proposed customer classes.

For the R2 Residential, General Service energy billed, and General Service demand billed customer classes, the current revenue to cost ratio is proposed to be maintained:

For the Distributed Generation customer class, the revenue to cost ratio is proposed to be set at 1.0 rather than the current 1.63 in support of Government policy to promote Distributed Generation in Ontario.

For Street Light and Sentinel Light classes it is proposed to increase the revenue to cost ratio from about 0.6 to 0.7. This is the lower end of the revenue to cost ratio proposed by the Board for this class of customers.

For the Urban General Service energy billed class it is proposed to reduce the revenue to cost ratio from 1.29 to 1.2. This is the higher end of the revenue to cost ratio proposed by the Board for small commercial customers.

For the Sub-Transmission class it is proposed to reduce the revenue to cost ratio from 2.35 to 1.15. This is the higher end of the revenue to cost ratio proposed by the Board for large users.

In order to recover almost all of the 2008 Revenue Requirement based on the revenue to cost ratios described above, the revenue to cost ratio for Urban Residential, R1 Residential, Seasonal Residential and Urban General Service demand billed customer classes will have to increase. The revenue to cost ratios for the Urban Residential, Seasonal Residential, and Urban General Service demand billed customer classes are proposed to be set to 1.0. For the R1 Residential customer class, the proposed revenue to cost ratio is 0.88, which results in bill impacts that are considered to be the maximum that Acquired residential customers being harmonized to this customer class can sustain.

The proposed revenue to cost ratios result in Hydro One not being able to fully recover its 2008 proposed Revenue Requirement. The shortfall is estimated to be $2.5 million per year, which is the difference in the total proposed revenue requirement shown in Table 2 as compared to Table 1. Hydro One proposes to establish a variance account, as described in Exhibit F1, Tab 3, Schedule 1 to record this revenue shortfall for recovery at a future date from all customers.

Table 2
Proposed Revenue/Cost Ratio by Customer Class

	UR	R1	R2	Seasonal	UGSe	UGSd	GS e	GS d	ST	DG	Street Light	Sent. Light	Total
Proposed Revenue Requirement $M	66.0	211.4	404.6	83.6	11.2	16.8	119.6	107.9	31.5	0.4	5.7	5.6	1,064.1
Proposed revenue to cost ratio	**1.0**	**0.88**	1.04	**1.0**	**1.2**	**1.0**	1.08	1.02	**1.15**	**1.00**	**0.7**	**0.7**	1.0

*Revenue to cost ratios in bold show the proposed change

4.0 REVENUE TO COST RATIO EQUAL TO ONE

In response to feedback received during the stakeholdering process, Hydro One explored the impact of moving all customer classes to a revenue to cost ratio of 1. Table 3 shows the average impacts that would result from making this change. As shown in Table 3, the resulting average total bill impacts under a revenue to cost ratio of 1 is generally greater and could be as much as three times the impact under the proposed revenue to cost ratios. As a result, using a revenue to cost ratio of 1 for all customer classes would result in either unacceptable bill impacts or the need for an excessively long impact mitigation period.

Table 3
Impact to Customer Classes of Revenue/Cost Ratios

	Proposed R/C	Average impact %	R/C = 1	Average impact %
UR	1.0	3.4	1	3.4
R1	0.88	3.0	1	8.3
R2	1.04	1.0	1	(0.8)
Seasonal	1.0	9.7	1	9.7
UGe	1..2	(2.3)	1	(6.3)
UGd	1.0	0.3	1	0.3
GSe	1.08	0.5	1	(2.2)
GSd	1.02	(2.1)	1	(2.7)
DG	1	(29.0)	1	(29.0)
Street Light	0.7	5.0	1	21.7
Sentinel Light	0.7	25.0	1	118.1
ST	1.15	(4.7)	1	(5.0)

RATE DESIGN CONSIDERATIONS

This exhibit presents the rate design structure that Hydro One Distribution proposes for 2008 distribution rates. More details are provided in Exhibits G1, Tab 4, Schedule 2 to Schedule 6.

1.0 RETAIL RATE CONSIDERATIONS

Hydro One Distribution proposes to follow the direction in the 2006 EDR Handbook with respect to the design of its retail distribution rate structure. This means continuing with the use of a combination of a monthly service charge and a volumetric charge.

The cost allocation methodology determines the revenue requirement by customer class that is fixed and variable. These results provide the basis for determining the proposed fixed and variable distribution charges. The OEB Cost Allocation Methodology also determines the fixed charges based on three methods: a) Avoided costs, b) Directly Related customer costs and c) Minimum System with PLCC Adjustment. The Board recommended that the fixed charge be set at a range between the Avoided costs and method c). Hydro One is proposing fixed charges that are consistent with the Board's recommended range with the exception for the gross fixed charge for R2 Residential customers.. The proposed fixed charges are the service charge determined by method c) using the cost allocation methodology, or the service charge of the predominant class in the new customer groups, whichever is the lower. For customers in the R2 Residential class that receive Rural or Remote Electricity Rate Protection, (RRRP), the gross service charge before RRRP has been set at 10% above method c. The service charge for R2 customers net of RRRP falls within the Board's recommended range for setting service charges. In cases were the service charge is proposed to be set at the level of the current service charge of the predominant customer class in the new groups, the lower service charge is chosen to mitigate bill impacts on low use consumers as a result of being mapped into the new groups. For Street Lights and Sentinel Lights, Hydro One Distribution proposes to introduce a nominal fixed charge of $1 per account per month consistent to how other LDCs charge for this type of service.

2.0 SUB-TRANSMISSION (ST) RATE CONSIDERATIONS

As recommended by Hydro One and supported by Stakeholder feedback received at the session on September 5th, 2007, Hydro One Distribution proposes to expand its current Low Voltage (LV) rates from a volumetric charge to a fixed and volumetric charge. This new rate structure will be applicable to all customers in the new ST customer group that includes Embedded customers currently being billed based on LV rates. The cost allocation study provides a basis for determining a fixed charge by delivery point that will recover the fixed costs that Hydro One incurs in delivering electricity to ST customers. The proposed ST rates include:

- Fixed monthly charge by delivery point
- Meter Charge if Hydro One, rather than the customer, owns the meters
- Volumetric charge for the use of common lines
- Volumetric charges for the use of High Voltage Distribution Stations (provides transformation service from above 50 kV to under 50 kV)
- Volumetric charge for the use of Low Voltage Distribution Stations (provides transformation service from above 50 kV to 13.8 kV, or lower voltage)
- Volumetric charge for the use of Low Voltage Distribution Stations (provides transformation service from above 44 kV to 12.5 kV or lower voltages)
- Specific ST line – ST line section (44kv to 13.8 kV) used by solely one embedded customer and located in their territory

- Specific Primary line – Primary line section (below 13.8 kV) used by solely one embedded customer and located in their territory.

TARGET RATES FOR RETAIL CUSTOMERS

This exhibit presents numerical information in support of the target rates that Hydro One Distribution proposes for the proposed 12 new rate classes described in Exhibit G1, Tab 2, Schedule 3.

1.0 INTRODUCTION

Hydro One Distribution derives its Retail distribution rates consistent with the Board's 2006 Electricity Distribution Rate (EDR) Handbook guidelines that propose a fixed and a volumetric distribution charge. The level of the charges has been determined based on the results of the Cost Allocation methodology using the 2008 Revenue Requirement.

2.0 DISTRIBUTION RATES

Using the information from the cost allocation methodology and the allocated Revenue Requirement by customer class, the proposed rates for the Hydro One Distribution new rate classes can be derived.

Table 1 below shows the fixed and volumetric rates that result from the application of the cost allocation methodology and the fixed and volumetric distribution rates, before any mitigation plan to address bill impacts. For Street Lights and Sentinel Lights, Hydro One proposes to introduce a nominal service charge of $1 per account per month. This is consistent to how other LDCs charge for this type of service.

Table 1
Distribution Rates

Rate Class	Fixed Charge [$/Cust] range per Cost Allocation	Proposed Fixed Charge [$/Cust]	Proposed Volumetric Charge [¢/kWh or $/kW]
UR	8.47 to 22.12	14.32	2.29
R1	8.56 to 29.67	19.04	2.60
R2	9.41 to 45.37	49.91 *	3.10
Seasonal	6.34 to 30.58	19.51	6.38
UGe	10.73 to 12.33	12.33	2.09
UGd	29.19 to 39.65	29.19	7.25 **
GSe	10.72 to 30.97	30.97	3.39
GSd	26.49 to 54.46	46.75	9.22 **
Dist Gen	25.26 to 36.66	36.66	7.07 **
Street Lights	5.01 to 12.4	1.00 ***	4.57
Sentinel Lights	2.36 to 32.77	1.00 ***	5.30

* Gross, set at 110% of $45.37
** $/kW
*** per connection

For General Service energy billed customers, the proposed fixed charge has to be increased to recover the revenue shortfall from Unmetered Scattered Load (USL) connection determined in Exhibit G1, Tab 4, Schedule 5. The increase is $0.35/customer/month, based on a revenue shortfall of $404,767 to be recovered from 97,005 General Service energy billed customers per month. The value of the credit was determined by the OEB Cost Allocation Model, Sheet O3.5 USL Metering Credit.

For the GSd, UGd and DGen rate classes, the variable rate has to be increased to recover the proposed $0.60/kW credit for the Customer Supplied Transformer Allowance [CSTA]. The projected CSTA credit is $0.93 million and it will be recovered by an $.07/kW CSTA rate adder to the variable rates.

RATE CONSIDERATIONS FOR ACQUIRED LDC CUSTOMERS

This exhibit presents information in support of the process that Hydro One Distribution proposes for setting the rates of the Acquired LDC customer classes.

1.0 INTRODUCTION

Hydro One Distribution derives its retail distribution rates for the Acquired LDC customer classes using the proposed harmonization plan for Residential and General Service customers of the Acquired LDCs. Hydro One is proposing to phase-in over four years the target distribution rates, so that at the end of the four-year period all Acquired LDCs' customers would have been migrated to Urban, Residential R1, Urban General Service energy billed, Urban General Service demand billed, General Service energy billed or General Service demand billed customer classes. All Acquired Large Users will migrate to the new Sub-Transmission customer group.

The rates per Acquired customer rate classes are derived using the six proposed rates for the customer classes that the Acquired LDCs customers are being migrated to. In addition to the proposed phase-in approach, additional impact mitigation measure as discussed in Exhibit G1, Tab 8, Schedule 2, will be required to keep total average bill impacts at below 10% as per the 2006 EDR Handbook.

2.0 DISTRIBUTION RATES

Using the information on 2008 Revenue Requirement and the harmonized rates for 2008 the proposed Acquired Distribution Rates can be derived.

2.1 Residential and General Service Classes Adjustments.

Table 1 shows how the Acquired rate classes map to the target rates. The proposed target rates are the same as described in Exhibit G1, Tab 4, Schedule 2.

Table 1
Harmonized target rates

Customer Group	Distribution Charge	Target Rates
Acquired Residential migrated to Urban Residential	Fixed service charge ($/customer) Volumetric charge (¢/kWh)	14.32 2.29
Acquired Residential migrated to R1 Residential	Fixed service charge ($/customer) Volumetric charge (¢/kWh)	19.04 2.60
Acquired General Service migrated to Urban General Service energy billed	Fixed service charge ($/customer) Volumetric charge (¢/kWh)	12.33 2.09
Caledon Residential OH 06	Fixed service charge ($/customer) Volumetric charge (¢/kWh)	21.41* 3.10
Caledon OH 07	Fixed service charge ($/customer) Volumetric charge (¢/kWh)	19.51 6.38
Acquired General Service migrated to Urban General Service demand billed	Fixed service charge ($/customer) Volumetric charge ($/kW)	29.19 7.25
Acquired General Service migrated to General Service energy billed	Fixed service charge ($/customer) Volumetric charge (¢/kWh)	30.97 3.39
Acquired General Service migrated to General Service demand billed	Fixed service charge ($/customer) Volumetric charge ($/kW)	46.75 9.22

*Net of $28.50 RRRP

The target rates in Table 1 above were used to derive harmonized rates for Residential and General Service customers, following the methodology described in Exhibit G1, Tab 2, Schedule 5. These target rates are the proposed end-state rates effective May 1, 2011. Table 2 summarizes the harmonized 2008 distribution rates for Acquired LDCs Residential and General Service customer classes.

Rates for the various Residential and General Service customer classes in Caledon follow the same methodology outlined above for other Acquired LDCs that are being harmonized.

The exceptions are for existing Residential OH 06 and OH 07 rate classes of Caledon. The proposed distribution rates for these two classes are based on the R2 and Seasonal Legacy proposed Distribution rates. Table 2 below shows the proposed rates for all Acquired LDC Residential and General Service customer classes prior to the application of any mitigation plan required to keep bill impacts at below 10% of total bill as per the 2006 EDR Handbook.

Table 2
Proposed 2008 Distribution Rates for Acquired Residential and General Service classes

	Res		GS<50		GS>50	
	SrChg	VarChg	SrChg	VarChg	SrChg	VarChg
	[$/month]	[c/kWh]	[$/month]	[c/kWh]	[$/month]	[$/kW]
Ailsa Craig	12.13	2.71	20.41	3.21	24.36	9.22
Arkona	8.30	2.71	9.94	3.21	13.89	9.22
Arnprior	12.88	2.71	23.40	3.21	27.34	9.22
Arran-Elderslie	11.51	2.71	13.53	3.21	17.48	9.22
Artemesia	13.58	2.71	21.84	3.21	25.78	9.22
Bancroft	14.39	2.71	25.64	3.21	29.59	9.22
Bath	14.42	2.71	15.08	3.21	19.03	9.22

	Res		GS<50		GS>50	
	SrChg	VarChg	SrChg	VarChg	SrChg	VarChg
	[$/month]	[c/kWh]	[$/month]	[c/kWh]	[$/month]	[$/kW]
Blandford-Blenheim	12.85	2.71	24.78	3.21	28.73	9.22
Blyth	9.96	2.71	23.33	3.21	27.28	9.22
Bobcaygeon	15.14	2.71	24.94	3.21	28.89	9.22
Brighton	12.86	2.71	24.02	3.21	27.96	9.22
Brockville	13.68	2.71	23.33	3.21	27.28	9.22
Caledon CH 02	15.96	2.71				
Caledon OH 06	30.64	2.67				
Caledon OH 07	33.18	4.69				
Caledon CH			25.69	3.21	29.64	9.22
Caledon GS 05			24.91	3.21	28.85	9.22
Caledon OH			26.35	3.21	30.30	9.22
Campbellford-Seymour	13.69	2.71	19.69	3.21	23.64	9.22
Carleton Place	15.22	2.71	24.83	3.21	28.78	9.22
Cavan-Millbrook-North Monaghan	16.01	2.71	24.17	3.21	28.12	9.22
Centre Hastings	12.84	2.71	21.15	3.21	25.09	9.22
Chalk River	15.25	2.71	23.41	3.21	27.36	9.22
Champlain	12.17	2.71	22.59	3.21	26.54	9.22
Cobden	14.49	2.71	23.26	3.21	27.21	9.22
Deep River	16.61	2.71	24.76	3.21	28.70	9.22
Deseronto	13.54	2.71	15.21	3.21	19.15	9.22
Dryden	15.19	2.71	21.96	3.21	25.91	9.22
Dundalk	15.14	2.71	24.85	3.21	28.80	9.22
Durham	16.67	2.71	25.71	3.21	29.66	9.22

	Res		GS<50		GS>50	
	SrChg	VarChg	SrChg	VarChg	SrChg	VarChg
	[$/month]	[c/kWh]	[$/month]	[c/kWh]	[$/month]	[$/kW]
Eganville	14.30	2.71	23.40	3.21	27.35	9.22
Erin	14.48	2.71	37.65	3.21	41.59	9.22
Exeter	15.99	2.71	15.90	3.21	19.85	9.22
Fenelon Falls	9.24	2.71	21.79	3.21	25.74	9.22
Forest	15.95	2.71	25.51	3.21	29.46	9.22
GBE	11.34	2.71	15.05	3.21	19.00	9.22
Georgina	12.83	2.71	20.39	3.21	24.34	9.22
Glencoe	13.54	2.71	15.90	3.21	19.85	9.22
Grand Bend	14.37	2.71	24.19	3.21	28.14	9.22
Hastings	16.65	2.71	24.02	3.21	27.97	9.22
Havelock	15.97	2.71	24.20	3.21	28.14	9.22
Kirkfield	8.43	2.71	18.07	3.21	22.02	9.22
Lanark Highlands	12.93	2.71	21.13	3.21	25.08	9.22
Larder Lake	15.80	2.71	22.70	3.21	26.64	9.22
Latchford	14.43	2.71	9.02	3.21	12.97	9.22
Lindsay	15.81	2.71	24.76	3.21	28.70	9.22
Lucan Granton	12.83	2.71	19.49	3.21	23.44	9.22
Malahide	12.97	2.71	18.78	3.21	22.69	9.22
Mapleton	14.39	2.71	23.35	3.21	27.30	9.22
Markdale	15.19	2.71	24.99	3.21	28.94	9.22
Marmora	12.86	2.71	15.24	3.21	19.18	9.22
McGarry	13.55	2.71	21.74	3.21	26.64	9.22

	Res		GS<50		GS>50	
	SrChg	VarChg	SrChg	VarChg	SrChg	VarChg
	[$/month]	[c/kWh]	[$/month]	[c/kWh]	[$/month]	[$/kW]
Meaford	13.57	2.71	25.73	3.21	29.68	9.22
Middlesex Centre	15.21	2.71	20.40	3.21	24.35	9.22
Napanee	15.09	2.71	24.20	3.21	28.15	9.22
Nipigon	15.20	2.71	24.91	3.21	28.86	9.22
North Dorchester	10.52	2.71	18.77	3.21	22.72	9.22
North Dundas	12.97	2.71	17.36	3.21	21.31	9.22
North Glengarry	9.83	2.71	20.31	3.21	24.26	9.22
North Grenville	15.16	2.71	22.64	3.21	26.58	9.22
North Perth	15.08	2.71	29.36	3.21	33.31	9.22
North Stormont	8.41	2.71	11.40	3.21	15.35	9.22
Omemee	15.01	2.71	23.42	3.21	27.37	9.22
Perth	15.14	2.71	21.76	3.21	25.71	9.22
Perth East	8.27	2.71	18.08	3.21	22.03	9.22
Prince Edward	15.20	2.71	24.03	3.21	27.98	9.22
Quinte West	9.12	2.71	9.81	3.21	13.75	9.22
Rainy River	16.00	2.71	21.92	3.21	25.87	9.22
Ramara	9.13	2.71	22.50	3.21	26.45	9.22
Red Rock	15.96	2.71	23.33	3.21	27.28	9.22
Rockland	11.41	2.71	12.92	3.21	16.87	9.22
Russell	14.48	2.71	21.93	3.21	25.87	9.22
Schreiber	16.68	2.71	22.57	3.21	26.51	9.22
Severn	12.11	2.71	24.20	3.21	28.15	9.22
Shelburne	15.23	2.71	22.74	3.21	26.69	9.22

	Res		GS<50		GS>50	
	SrChg	VarChg	SrChg	VarChg	SrChg	VarChg
	[$/month]	[c/kWh]	[$/month]	[c/kWh]	[$/month]	[$/kW]
Smiths Falls	13.60	2.71	14.28	3.21	18.23	9.22
South Glengarry	11.40	2.71	20.39	3.21	24.34	9.22
South River	15.21	2.71	24.21	3.21	28.16	9.22
Springwater	12.81	2.71	22.61	3.21	26.56	9.22
Stirling-Rawdon	13.62	2.71	25.71	3.21	29.66	9.22
Terrace Bay	19.56	2.71	38.41	3.21	231.38	9.22
Thedford	13.57	2.71	20.28	3.21	24.23	9.22
Thessalon	15.87	2.71	21.02	3.21	24.96	9.22
Thorndale	7.68	2.71	18.11	3.21	22.06	9.22
Thorold	14.34	2.71	24.08	3.21	28.03	9.22
Tweed	7.64	2.71	13.68	3.21	17.62	9.22
Wardsville	11.35	2.71	16.66	3.21	20.61	9.22
Warkworth	15.95	2.71	23.41	3.21	27.36	9.22
West Elgin	14.44	2.71	18.89	3.21	22.84	9.22
Whitchurch Stouffville	12.13	2.71	23.28	3.21	27.23	9.22
Wiarton	15.80	2.71	24.80	3.21	28.74	9.22
Woodville	6.82	2.71	19.52	3.21	23.47	9.22
Wyoming	12.88	2.71	20.40	3.21	24.35	9.22

2008 Proposed Distribution Rates for Urban Residential and General Service customer classes

Arnprior	11.70	2.40	18.74	2.00	22.95	7.33
Brockville	12.50	2.40	18.67	2.00	22.89	7.33

	Res		GS<50		GS>50	
	SrChg	VarChg	SrChg	VarChg	SrChg	VarChg
	[$/month]	[c/kWh]	[$/month]	[c/kWh]	[$/month]	[$/kW]
Caledon OH 01	16.95	2.40				
Carleton Place	14.04	2.40	20.17	2.00	24.39	7.33
Dryden	14.01	2.40	17.31	2.00	21.52	7.33
GBE	10.16	2.40	10.39	2.00	14.61	7.33
Lindsay	14.63	2.40	20.10	2.00	24.31	7.33
Perth	13.96	2.40	17.10	2.00	21.32	7.33
Quinte West	7.94	2.40	5.15	2.00	9.36	7.33
Smiths Falls	12.42	2.40	9.62	2.00	13.84	7.33
Thorold	13.16	2.40	19.43	2.00	23.64	7.33
Whitchurch Stouffville	10.95	2.40	18.62	2.00	22.84	7.33

2.2 Large User Class

For Acquired Large User customers, the proposed 2008 rates are the Sub-Transmission rates proposed in Exhibit G1, Tab 4, Schedule 4 and shown in Table 3.

Table 3
Proposed 2008 Distribution Rate for Acquired Large User classes

	Fixed Charge $/delivery point/month*	Volumetric charge $/kW/month
Arnprior	188	0.58
Brockville	188	0.58
Caledon	188	0.58
GBE	188	0.58
Quinte West	188	0.58

* Excludes meter charge of $553/delivery point/month if applicable

3.0 2009, 2010 AND 2011 PROPOSED RATES FOR ACQUIRED LDCS

For the Residential and General Service classes of the Acquired LDCs that are being harmonized, the proposed 2011 Distribution rates are the harmonized target distribution rates shown in Table 1 above. These rates would become effective May 1st, 2011 i.e. in the fourth year of the harmonization phase-in process and would be adjusted by the third generation Incentive Rate mechanism yet to be determined by the OEB.

The Distribution rates effective as of May 1, 2009 for Residential and Acquired General Service customers of Acquired LDCs would be the rates shown in Table 4 below. The Distribution rates effective as of May 1, 2010 for Residential and Acquired General Service customers of Acquired LDCs would be the rates shown in Table 5 below. The 2009 and 2010 rates were derived using the harmonization plan described in Exhibit G1, Tab 2, Schedule 5 and will also be adjusted by the third generation Incentive Rate mechanism yet to be determined by the OEB. The rates shown are prior to the application of any required rate impact mitigation plan which keep bill impacts at below 10% of total bill as per the 2006 EDR Handbook.

Table 4
Proposed 2009 Distribution Rates for Acquired Residential and General Service classes to be adjusted for 3rd Generation IRM

	Res		GS<50		GS>50	
	SrChg	VarChg	SrChg	VarChg	SrChg	VarChg
	[$/month]	[c/kWh]	[$/month]	[c/kWh]	[$/month]	[$/kW]
Ailsa Craig	14.27	2.68	23.83	3.27	31.72	9.22
Arkona	11.60	2.68	16.88	3.27	24.78	9.22
Arnprior	14.75	2.68	25.79	3.27	33.69	9.22
Arran-Elderslie	14.01	2.68	19.07	3.27	26.96	9.22

	Res		GS<50		GS>50	
	SrChg	VarChg	SrChg	VarChg	SrChg	VarChg
	[$/month]	[c/kWh]	[$/month]	[c/kWh]	[$/month]	[$/kW]
Artemesia	15.16	2.68	24.67	3.27	32.57	9.22
Bancroft	15.78	2.68	27.28	3.27	35.17	9.22
Bath	15.83	2.68	20.16	3.27	28.05	9.22
Blandford-Blenheim	14.71	2.68	26.56	3.27	34.45	9.22
Blyth	12.93	2.68	25.67	3.27	33.56	9.22
Bobcaygeon	16.29	2.68	26.88	3.27	34.78	9.22
Brighton	14.72	2.68	26.03	3.27	33.93	9.22
Brockville	15.36	2.68	25.66	3.27	33.55	9.22
Caledon CH 02	16.93	2.68				
Caledon OH 06	27.28	2.82				
Caledon OH 07	28.37	5.29				
Caledon CH			27.38	3.27	35.27	9.22
Caledon GS 05			26.81	3.27	34.71	9.22
Caledon OH			27.70	3.27	35.60	9.22
Campbellford-Seymour	15.37	2.68	23.39	3.27	31.28	9.22
Carleton Place	16.44	2.68	26.66	3.27	34.55	9.22
Cavan-Millbrook-North Monaghan	17.02	2.68	26.34	3.27	34.24	9.22
Centre Hastings	14.69	2.68	24.29	3.27	32.19	9.22
Chalk River	16.51	2.68	25.82	3.27	33.71	9.22
Champlain	14.34	2.68	25.19	3.27	33.08	9.22
Cobden	15.99	2.68	25.52	3.27	33.41	9.22
Deep River	17.21	2.68	26.51	3.27	34.41	9.22
Deseronto	15.08	2.68	20.41	3.27	28.31	9.22

	Res		GS<50		GS>50	
	SrChg	VarChg	SrChg	VarChg	SrChg	VarChg
	[$/month]	[c/kWh]	[$/month]	[c/kWh]	[$/month]	[$/kW]
Dryden	16.38	2.68	24.93	3.27	32.82	9.22
Dundalk	16.29	2.68	26.70	3.27	34.60	9.22
Durham	17.35	2.68	27.42	3.27	35.32	9.22
Eganville	15.59	2.68	25.81	3.27	33.70	9.22
Erin	15.96	2.68	35.29	3.27	43.19	9.22
Exeter	16.97	2.68	20.80	3.27	28.70	9.22
Fenelon Falls	12.48	2.68	24.58	3.27	32.47	9.22
Forest	16.89	2.68	27.03	3.27	34.92	9.22
GBE	13.68	2.68	20.10	3.27	27.99	9.22
Georgina	14.66	2.68	23.78	3.27	31.68	9.22
Glencoe	15.07	2.68	20.80	3.27	28.69	9.22
Grand Bend	15.73	2.68	26.38	3.27	34.28	9.22
Hastings	17.30	2.68	26.04	3.27	33.93	9.22
Havelock	16.94	2.68	26.39	3.27	34.29	9.22
Kirkfield	11.85	2.68	22.14	3.27	30.03	9.22
Lanark Highlands	14.87	2.68	24.27	3.27	32.16	9.22
Larder Lake	16.60	2.68	25.39	3.27	33.29	9.22
Latchford	15.87	2.68	16.04	3.27	23.94	9.22
Lindsay	16.62	2.68	26.51	3.27	34.41	9.22
Lucan Granton	14.66	2.68	22.99	3.27	30.88	9.22
Malahide	14.94	2.68	22.56	3.27	30.38	9.22
Mapleton	15.79	2.68	25.71	3.27	33.60	9.22
Markdale	16.37	2.68	26.98	3.27	34.88	9.22

	Res		GS<50		GS>50	
	SrChg	VarChg	SrChg	VarChg	SrChg	VarChg
	[$/month]	[c/kWh]	[$/month]	[c/kWh]	[$/month]	[$/kW]
Marmora	14.73	2.68	20.47	3.27	28.37	9.22
McGarry	15.10	2.68	24.49	3.27	33.29	9.22
Meaford	15.15	2.68	27.46	3.27	35.35	9.22
Middlesex Centre	16.43	2.68	23.81	3.27	31.70	9.22
Napanee	16.17	2.68	26.40	3.27	34.29	9.22
Nipigon	16.41	2.68	26.82	3.27	34.72	9.22
North Dorchester	13.04	2.68	22.54	3.27	30.44	9.22
North Dundas	14.94	2.68	21.72	3.27	29.62	9.22
North Glengarry	12.65	2.68	23.62	3.27	31.52	9.22
North Grenville	16.32	2.68	25.27	3.27	33.17	9.22
North Perth	16.16	2.68	29.72	3.27	37.62	9.22
North Stormont	11.81	2.68	17.80	3.27	25.69	9.22
Omemee	16.03	2.68	25.84	3.27	33.74	9.22
Perth	16.29	2.68	24.52	3.27	32.42	9.22
Perth East	11.55	2.68	22.16	3.27	30.05	9.22
Prince Edward	16.40	2.68	26.06	3.27	33.95	9.22
Quinte West	12.23	2.68	16.61	3.27	24.51	9.22
Rainy River	17.00	2.68	24.84	3.27	32.73	9.22
Ramara	12.26	2.68	25.00	3.27	32.89	9.22
Red Rock	16.92	2.68	25.66	3.27	33.56	9.22
Rockland	13.82	2.68	18.85	3.27	26.74	9.22
Russell	15.97	2.68	24.85	3.27	32.75	9.22
Schreiber	17.36	2.68	25.13	3.27	33.03	9.22

	Res		GS<50		GS>50	
	SrChg	VarChg	SrChg	VarChg	SrChg	VarChg
	[$/month]	[c/kWh]	[$/month]	[c/kWh]	[$/month]	[$/kW]
Severn	14.22	2.68	26.40	3.27	34.29	9.22
Shelburne	16.45	2.68	25.48	3.27	33.37	9.22
Smiths Falls	15.21	2.68	19.56	3.27	27.46	9.22
South Glengarry	13.79	2.68	23.78	3.27	31.67	9.22
South River	16.41	2.68	26.43	3.27	34.32	9.22
Springwater	14.63	2.68	25.22	3.27	33.11	9.22
Stirling-Rawdon	15.25	2.68	27.42	3.27	35.32	9.22
Terrace Bay	19.12	2.68	35.81	3.27	169.76	9.22
Thedford	15.15	2.68	23.57	3.27	31.46	9.22
Thessalon	16.74	2.68	24.03	3.27	31.93	9.22
Thorndale	11.36	2.68	22.22	3.27	30.12	9.22
Thorold	15.68	2.68	26.17	3.27	34.06	9.22
Tweed	11.28	2.68	19.35	3.27	27.25	9.22
Wardsville	13.70	2.68	21.32	3.27	29.22	9.22
Warkworth	16.90	2.68	25.83	3.27	33.72	9.22
West Elgin	15.87	2.68	22.78	3.27	30.68	9.22
Whitchurch Stouffville	14.25	2.68	25.56	3.27	33.45	9.22
Wiarton	16.61	2.68	26.59	3.27	34.49	9.22
Woodville	10.63	2.68	23.04	3.27	30.93	9.22
Wyoming	14.76	2.68	23.80	3.27	31.70	9.22

2009 Proposed Distribution Rates for Urban Residential and General Service customer classes

	Res		GS<50		GS>50	
	SrChg	VarChg	SrChg	VarChg	SrChg	VarChg
	[$/month]	[c/kWh]	[$/month]	[c/kWh]	[$/month]	[$/kW]
Arnprior	12.39	2.38	16.48	2.04	24.91	7.31
Brockville	13.00	2.38	16.34	2.04	24.77	7.31
Caledon OH 01	15.90	2.38				
Carleton Place	14.08	2.38	17.34	2.04	25.77	7.31
Dryden	14.02	2.38	15.61	2.04	24.04	7.31
GBE	11.32	2.38	10.78	2.04	19.21	7.31
Lindsay	14.26	2.38	17.20	2.04	25.63	7.31
Perth	13.93	2.38	15.21	2.04	23.64	7.31
Quinte West	9.87	2.38	7.30	2.04	15.73	7.31
Smiths Falls	12.85	2.38	10.25	2.04	18.68	7.31
Thorold	13.32	2.38	16.85	2.04	25.28	7.31
Whitchurch Stouffville	11.89	2.38	16.24	2.04	24.67	7.31

Table 5
Proposed 2010 Distribution Rates for Acquired Residential and General Service classes to be adjusted for 3rd Generation IRM

	Res		GS<50		GS>50	
	SrChg	VarChg	SrChg	VarChg	SrChg	VarChg
	[$/month]	[c/kWh]	[$/month]	[c/kWh]	[$/month]	[$/kW]
Ailsa Craig	16.40	2.65	27.24	3.34	39.08	9.22
Arkona	14.90	2.65	23.83	3.34	35.66	9.22
Arnprior	16.63	2.65	28.19	3.34	40.03	9.22
Arran-Elderslie	16.52	2.65	24.60	3.34	36.44	9.22

	Res		GS<50		GS>50	
	SrChg	VarChg	SrChg	VarChg	SrChg	VarChg
	[$/month]	[c/kWh]	[$/month]	[c/kWh]	[$/month]	[$/kW]
Artemesia	16.73	2.65	27.51	3.34	39.35	9.22
Bancroft	17.17	2.65	28.92	3.34	40.76	9.22
Bath	17.25	2.65	25.24	3.34	37.08	9.22
Blandford-Blenheim	16.56	2.65	28.34	3.34	40.18	9.22
Blyth	15.89	2.65	28.00	3.34	39.84	9.22
Bobcaygeon	17.43	2.65	28.83	3.34	40.66	9.22
Brighton	16.57	2.65	28.05	3.34	39.89	9.22
Brockville	17.03	2.65	27.99	3.34	39.83	9.22
Caledon CH 02	17.89	2.65				
Caledon OH 06	23.92	2.97				
Caledon OH 07	23.55	5.89				
Caledon CH			29.07	3.34	40.91	9.22
Caledon GS 05			28.72	3.34	40.56	9.22
Caledon OH			29.06	3.34	40.89	9.22
Campbellford-Seymour	17.06	2.65	27.08	3.34	38.92	9.22
Carleton Place	17.65	2.65	28.49	3.34	40.33	9.22
Cavan-Millbrook-North Monaghan	18.02	2.65	28.52	3.34	40.35	9.22
Centre Hastings	16.53	2.65	27.44	3.34	39.28	9.22
Chalk River	17.76	2.65	28.23	3.34	40.07	9.22
Champlain	16.51	2.65	27.78	3.34	39.62	9.22
Cobden	17.48	2.65	27.78	3.34	39.62	9.22
Deep River	17.82	2.65	28.27	3.34	40.11	9.22
Deseronto	16.61	2.65	25.62	3.34	37.46	9.22

	Res		GS<50		GS>50	
	SrChg	VarChg	SrChg	VarChg	SrChg	VarChg
	[$/month]	[c/kWh]	[$/month]	[c/kWh]	[$/month]	[$/kW]
Dryden	17.57	2.65	27.89	3.34	39.73	9.22
Dundalk	17.43	2.65	28.56	3.34	40.39	9.22
Durham	18.02	2.65	29.14	3.34	40.97	9.22
Eganville	16.89	2.65	28.21	3.34	40.05	9.22
Erin	17.43	2.65	32.94	3.34	44.78	9.22
Exeter	17.96	2.65	25.71	3.34	37.54	9.22
Fenelon Falls	15.71	2.65	27.37	3.34	39.21	9.22
Forest	17.84	2.65	28.54	3.34	40.38	9.22
GBE	16.02	2.65	25.15	3.34	36.99	9.22
Georgina	16.49	2.65	27.18	3.34	39.01	9.22
Glencoe	16.61	2.65	25.70	3.34	37.54	9.22
Grand Bend	17.10	2.65	28.58	3.34	40.41	9.22
Hastings	17.95	2.65	28.06	3.34	39.90	9.22
Havelock	17.90	2.65	28.59	3.34	40.43	9.22
Kirkfield	15.28	2.65	26.21	3.34	38.05	9.22
Lanark Highlands	16.80	2.65	27.40	3.34	39.24	9.22
Larder Lake	17.40	2.65	28.09	3.34	39.93	9.22
Latchford	17.30	2.65	23.07	3.34	34.90	9.22
Lindsay	17.42	2.65	28.27	3.34	40.11	9.22
Lucan Granton	16.49	2.65	26.48	3.34	38.32	9.22
Malahide	16.90	2.65	26.35	3.34	38.07	9.22
Mapleton	17.18	2.65	28.06	3.34	39.90	9.22
Markdale	17.56	2.65	28.98	3.34	40.81	9.22

	Res		GS<50		GS>50	
	SrChg	VarChg	SrChg	VarChg	SrChg	VarChg
	[$/month]	[c/kWh]	[$/month]	[c/kWh]	[$/month]	[$/kW]
Marmora	16.59	2.65	25.71	3.34	37.55	9.22
McGarry	16.64	2.65	27.23	3.34	39.93	9.22
Meaford	16.72	2.65	29.19	3.34	41.03	9.22
Middlesex Centre	17.64	2.65	27.21	3.34	39.05	9.22
Napanee	17.26	2.65	28.60	3.34	40.44	9.22
Nipigon	17.61	2.65	28.74	3.34	40.57	9.22
North Dorchester	15.55	2.65	26.32	3.34	38.15	9.22
North Dundas	16.90	2.65	26.09	3.34	37.92	9.22
North Glengarry	15.48	2.65	26.94	3.34	38.77	9.22
North Grenville	17.48	2.65	27.91	3.34	39.75	9.22
North Perth	17.23	2.65	30.09	3.34	41.92	9.22
North Stormont	15.22	2.65	24.20	3.34	36.04	9.22
Omemee	17.04	2.65	28.27	3.34	40.10	9.22
Perth	17.43	2.65	27.29	3.34	39.12	9.22
Perth East	14.82	2.65	26.24	3.34	38.08	9.22
Prince Edward	17.59	2.65	28.09	3.34	39.93	9.22
Quinte West	15.35	2.65	23.42	3.34	35.26	9.22
Rainy River	18.00	2.65	27.76	3.34	39.60	9.22
Ramara	15.39	2.65	27.50	3.34	39.34	9.22
Red Rock	17.87	2.65	28.00	3.34	39.83	9.22
Rockland	16.22	2.65	24.77	3.34	36.61	9.22
Russell	17.45	2.65	27.78	3.34	39.62	9.22
Schreiber	18.04	2.65	27.70	3.34	39.54	9.22

	Res		GS<50		GS>50	
	SrChg	VarChg	SrChg	VarChg	SrChg	VarChg
	[$/month]	[c/kWh]	[$/month]	[c/kWh]	[$/month]	[$/kW]
Severn	16.33	2.65	28.60	3.34	40.44	9.22
Shelburne	17.68	2.65	28.22	3.34	40.06	9.22
Smiths Falls	16.81	2.65	24.85	3.34	36.68	9.22
South Glengarry	16.19	2.65	27.17	3.34	39.01	9.22
South River	17.62	2.65	28.64	3.34	40.48	9.22
Springwater	16.44	2.65	27.83	3.34	39.67	9.22
Stirling-Rawdon	16.87	2.65	29.14	3.34	40.97	9.22
Terrace Bay	18.67	2.65	33.22	3.34	108.13	9.22
Thedford	16.72	2.65	26.85	3.34	38.69	9.22
Thessalon	17.61	2.65	27.05	3.34	38.89	9.22
Thorndale	15.04	2.65	26.34	3.34	38.17	9.22
Thorold	17.02	2.65	28.25	3.34	40.09	9.22
Tweed	14.92	2.65	25.03	3.34	36.87	9.22
Wardsville	16.05	2.65	25.99	3.34	37.82	9.22
Warkworth	17.84	2.65	28.24	3.34	40.08	9.22
West Elgin	17.31	2.65	26.68	3.34	38.51	9.22
Whitchurch Stouffville	16.38	2.65	27.84	3.34	39.68	9.22
Wiarton	17.41	2.65	28.39	3.34	40.23	9.22
Woodville	14.45	2.65	26.56	3.34	38.40	9.22
Wyoming	16.64	2.65	27.21	3.34	39.04	9.22

2010 Proposed Distribution Rates for Urban Residential and General Service customer classes

	Res		GS<50		GS>50	
	SrChg	VarChg	SrChg	VarChg	SrChg	VarChg
	[$/month]	[c/kWh]	[$/month]	[c/kWh]	[$/month]	[$/kW]
Arnprior	13.09	2.36	14.21	2.07	26.86	7.28
Brockville	13.49	2.36	14.01	2.07	26.66	7.28
Caledon OH 01	14.85	2.36				
Carleton Place	14.11	2.36	14.51	2.07	27.16	7.28
Dryden	14.03	2.36	13.92	2.07	26.56	7.28
GBE	12.48	2.36	11.17	2.07	23.82	7.28
Lindsay	13.88	2.36	14.29	2.07	26.94	7.28
Perth	13.89	2.36	13.31	2.07	25.95	7.28
Quinte West	11.81	2.36	9.44	2.07	22.09	7.28
Smiths Falls	13.27	2.36	10.87	2.07	23.51	7.28
Thorold	13.48	2.36	14.28	2.07	26.92	7.28
Whitchurch Stouffville	12.84	2.36	13.86	2.07	26.51	7.28

RATE CONSIDERATIONS FOR SUB-TRANSMISSION CUSTOMERS

This exhibit provides information in support of the derivation of Sub-Transmission (ST) rates replacing the existing Low Voltage (LV) rates. These rates will be applicable to all customers grouped in the new ST customer class.

1.0 ST CLASS DESCRIPTION

The proposed ST class consists of all supply points to Embedded LDCs, plus other accounts whose supply from Hydro One Distribution assets is three-phase, between 44 kV and 13.8 kV inclusive, for whom Hydro One does not have the responsibility for the local customer-site transformation and whose load is over 500 kW.

2.0 ST RATE DERIVATION

2008 proposed ST rates are developed using the results of the Cost Allocation Methodology. Exhibit G2, Tab 1, Schedule 1, includes more details on the results of the Cost Allocation and the basis for the proposed ST rates. As recommended by Hydro One and supported by Stakeholder feedback received at the session on September 5th, 2007, the proposed ST rates have a fixed monthly charge, and also various volumetric charges to be applied based on the types of asset used. The charges for the use of ST line, High Voltage Distribution Stations, Low Voltage Distribution Stations with Secondary voltages of 12.5 kV or below, Specific ST line and Specific Primary Line, were derived using the Cost Allocation Methodology and replace the corresponding LV charges. In addition a fixed charge for customers that do not own their meters is proposed.

For consistency with billing of RTSR charges, addressed in Exhibit G1, Tab 6, Schedule 1, the ST line and HVDS charges are proposed to be billed to customers supplied from multiple feeders connected to the same TS or HVDS based on their aggregated billing demand.

For customers with Load Displacement generation above 1 MW, or 2 MW for renewable generation installed after October 1998, it is proposed that the ST volumetric charges be billed on a gross load basis, consistent with the methodology used to bill for Retail Transmission Service Rates connections.

The following Table shows the current LV charges and the proposed 2008 ST charges.

Table 1

ST Proposed 2008 monthly charges

LV		ST	
Asset Type Utilized	Current Volumetric Rate*	Asset Type Utilized	Proposed Volumetric Rate**
Shared LV Line	$0.633/kW	Common ST Line	$0.58/kW
HVDS-high	$1.678/kW	HVDS-high	$1.42/kW
HVDS-low	$3.797/kW	HVDS-low	$2.66/kW
Shared LVDS	$2.12/kW	LVDS-low	$1.24/kW
Specific LV Line	$526/km	Specific ST Line	$729/ km
Specific Distribution Line	$358/km	Specific Primary Line	$565/ km

*No applicable Service Charge

** Fixed Charge of $188 and a meter charge of $553 will also apply

HVDS-High Rate

For consistency purposes, it is proposed that the HVDS-high rate be set equivalent to the Retail Transmission Service Rate (RTSR) – transformation. Customers in the ST group can obtain transformation from above 50 kV to a voltage between 44 kV and 13.8 kV either through the use of an HVDS–high, or through a TS owned by Hydro One Transmission. Customers that obtain supply through a TS are charged the RTSR – transformation.

HVDS-low rate

It is proposed, that consistent with the current rate structure, the HVDS-low rate be set to be the sum of the HVDS-high rate and LVDS-low rate. HVDS-lows supply voltage at or below 12.5 kV.

LVDS-low rate

LVDS-lows transform power from between 44 kV and 13.8 kV, to under 13.8 kV. The rate is set to recover the portion of the Cost Allocation Methodology dollars attributable to LVDS-low.

Specific ST Line and Specific Primary Line rates

A line section is “Specific” if it supplies solely one LDC and is within that LDC’s territory. ST lines are between 44 kV and 13.8 kV, while Primary lines are between 12.5 kV and 4.16 kV. These Specific Line rates are set at values which would recover the Cost Allocation Methodology dollars attributable to ST and Primary lines, and also reflect the relationship in unit costs between ST and Primary lines. Specific Line rates are charged by km rather than by kW.

Meter Charge for Hydro One Owned Meter

Most of the customers in the ST group provide their own metering facilities. To reflect this, Hydro One is proposing an additional fixed charge applicable only to customers for whom Hydro One provides metering facilities.

Fixed charge

Hydro One is proposing to introduce a fixed charge per delivery point in cases where a customer uses common ST lines, or uses HVDSs and the customer owns the lines emanating from the HVDS. The fixed charge is intended to recover costs that do not vary with consumption. All other customer groups have a distribution rate structure that includes both a fixed and a volumetric charge. The level of the fixed charge is proposed to be $188 per account. This value is lower than the fixed charge that would be determined using the fixed Revenue Requirement estimated by the Cost Allocation Methodology. The $188 charge is based on the OEB Cost Allocation method c) of determining fixed charges: Minimum System with PLCC Adjustment, adjusted to exclude Low Voltage meter costs. A lower fixed charge results in a higher volumetric charge than estimated by the Cost Allocation Methodology, to enable Hydro One to recover the revenue requirement allocated to the ST group.

UNMETERED SCATTERED LOAD FIXED SERVICE CHARGE

This exhibit explains the development of a fixed service charge credit for unmetered scattered load customers based on the results of the Cost Allocation Study.

1.0 INTRODUCTION

Currently, Hydro One Distribution Legacy General Service class rate schedules include a separate and lower fixed service charge that is applicable to unmetered scattered load connections.

In 2006 Hydro One Distribution established a fixed service charge applicable to unmetered scattered load (USL) customers within the Acquired LDC General Service customers. The charge was set at half of the fixed service charge applicable to the corresponding Acquired General Service customer class. This was consistent with the 2006 EDR Handbook guidelines.

2.0 PROPOSAL

Hydro One has completed a Cost Allocation Study which enables a proper fixed charge credit to be established for USL customers. This credit reflects the nature of USL customers, that is, no meter or meter reading costs should be recovered from USL customers.

The fixed service charge credit will be applied to the proposed General Service energy billed fixed service charge for Legacy and Acquired customers.

3.0 CALCULATIONS

The following table illustrates the development of the fixed service charge for unmetered scattered load based on the results of the Cost Allocation Study.

Table 1
General Service Energy Billed Fixed Service charge

	Fixed Service charge ($/customer/month)
Fixed charge as per Cost Allocation Study	30.97
Credit for USL customers (Sheet O3.5 USL Metering Credit)	6.86
Net Fixed Charge for USL customers	24.11

The number of unmetered scattered load connections and the revenue shortfall are shown in Table 2 below, based on the unmetered service charge credit in Table 1 above.

Table 2
General Service number of 2006 Unmetered connections and revenue shortfall

	Number of Unmetered connections in 2006	Revenue shortfall ($)
General Service	4,917	404,767

This revenue shortfall is re-allocated to the General Service energy billed customer class when determining Distribution fixed charges to ensure that Hydro One recovers the Revenue Requirement allocated to the General Service energy billed group.

TRANSFORMER OWNERSHIP ALLOWANCE

This exhibit presents a description of the Transformer Ownership Allowance proposed for 2008.

1.0 CUSTOMER SUPPLIED TRANSFORMER ALLOWANCE

There are circumstances under which, Hydro One Distribution does not supply customers with transformation equipment, but rather the customer provides its own equipment. This occurs usually when the customer has unique consumption characteristics that require the use of special equipment not usually provided by Hydro One Distribution or the level of consumption is above a certain threshold. Since the rates developed for some customer classes assume that Hydro One Distribution provides transformation to the customer, customers that provide their own transformation should be entitled to receive a credit equivalent to the costs of transformation included in customer rates.

Hydro One is proposing to maintain the current Transformer Ownership Allowance of $0.60/kW and establish a Transformer Ownership Allowance based on ¢/kWh basis. Some customers that provide their own transformation are energy billed, therefore, in order to be able to provide them with a Transformer Ownership Allowance, a rate based on ¢/kWh is required. Hydro One used 2006 billing data to determine the equivalent Transformer Ownership Allowance in ¢/kWh. The 2008 proposed Transformer Ownership Allowance for energy billed customers is 0.14 ¢/kWh. The proposed Transformer Ownership Allowance will also apply to current single-phase customers that provide their own transformation equipment.

The projected cost based on the proposed $0.60/kW credit is $0.93 million resulting in a $.07/kW CSTA rate adder to the variable charges

REGULATORY ASSET RECOVERY ALLOCATION TO CUSTOMER GROUPS

This exhibit describes Hydro One Distribution proposed methodology to allocate the costs in respect of the Regulatory Assets identified in Exhibit F1, Tab 1, Schedule 1, to the various customer classes.

1.0 METHODOLOGY

The methodology proposed to allocate the Regulatory Asset balances to the various customer classes follows the methodology principles reviewed and approved by the Board in proceeding RP-2004-0117/RP-2004-0118.

The five new Regulatory Asset accounts, described in Exhibit F1, Tab 1, Schedule 1, are:

- OEB Costs
- Tax Change
- Smart Meter Minimum Functionality Under-recovery to May 31, 2007
- Smart Meter Exceeding Minimum Functionality Under-recovery
- Smart Meter Minimum Functionality Under-recovery between June 1, 2007 and April 30, 2008

The four current Regulatory Asset account balances that are also proposed to be cleared as of April 30, 2008 are:

- o RSVA Wholesale Market Service Charge
- o RSVA Retail Transmission Network Charges
- o RSVA Retail Transmission Connection Charges

- RSVA Low Voltage Charges

2.0 ALLOCATION PRINCIPLES

Cost causality is the basic principle applied in determining how costs should be allocated to customer groups. There are three main mechanisms by which Regulatory Asset costs may be allocated and which Hydro One Distribution has used in the context of this submission. These are as follows:

- If costs were incurred for the benefit of all customers irrespective of their energy consumption, number of customers would be the recommended allocator for this group of costs.
- If costs have been included in the Revenue Requirement, for example as OM&A costs, now that Hydro One conducted a Cost Allocation Study, these costs can be allocated to the various customer groups based on the results of the Cost Allocation Study, and in particular how OM&A costs are allocated to customer groups.
- If costs are allocated in the Cost Allocation Study based on a specific composite allocator, for example Net Fixed Assets, then these costs can be allocated to the various customer groups based on the results of the Cost Allocation Study, and in particular how Net Fixed Assets are allocated to customer groups.

3.0 PROPOSED ALLOCATION OF REGULATORY ASSET ACCOUNTS TO CUSTOMER GROUPS

The amounts accumulated in the Regulatory Asset accounts are described in Exhibit F1, Tab 1, Schedule 1. The proposed method of recovering these costs from customer groups is consistent with the OEB decision in RP-2004-0017/RP-2004-0018 and the following sub-sections describe the approach taken.

3.1 OEB costs ($(0.9) million)

OEB costs are included in Hydro One Distribution revenue requirement as OM&A costs. Exhibit C1, Tab 2, Schedule 6 describes these costs. The amount in the Regulatory Asset variance account, were originally included as OM&A costs. Using the Cost Allocation Study, OM&A costs is the proposed allocator amongst customer classes.

3.2 Tax Change ($(5.0) million)

Tax costs are included in Hydro One Distribution revenue requirement. In the Cost Allocation Study, Tax costs are allocated to the customer groups based on allocation of Net Fixed Assets, therefore, Net Fixed Assets is the proposed allocator amongst customer classes.

3.3 Smart Meters Minimum Functionality Expenditures incurred before May 31, 2007 ($6.9 million)

Smart meter costs are included in Hydro One Distribution revenue requirement as OM&A costs and are related to customers, regardless of customer consumption. Number of customers is the proposed allocator for this account amongst customer classes.

3.4 Smart Meter Expenditures Exceeding Minimum Functionality ($5.7 million)

Smart meter costs are included in Hydro One Distribution revenue requirement as OM&A costs and are related to customers, regardless of customer consumption. Number of customers is the proposed allocator for this account amongst customer classes.

3.5 Smart Meter Minimum Functionality Expenditures between June 1, 2007 and April 30, 2008 ($9.4 million)

Smart meter costs are included in Hydro One Distribution revenue requirement as OM&A costs and are related to customers, regardless of customer consumption. Number of customers is the proposed allocator for this account amongst customer classes.

3.6 RSVA Wholesale Market Service Charge ($(72.6) million)

Wholesale Market Service charges are billed by Hydro One to customers that are not market participants. Energy for non-market participants is the allocator proposed for this account amongst customer classes.

3.7 RSVA Retail Transmission Service Charges Network ($1.4 million)

Hydro One proposes to use energy consumed as an allocator of this variance account amongst customer classes.

3.8 RSVA Retail Transmission Service Charges Connections ($2.5 million)

Hydro One proposes to use energy consumed as an allocator of this variance account amongst customer classes.

3.9 RSVA Low Voltage ($3.8 million)

Hydro One proposes to use energy consumed as an allocator of this variance account amongst customer classes.

4.0 DETAILS OF ALLOCATION OF COSTS

Table 1 below shows the details of the allocation of Regulatory Asset account costs to the various customer classes. Columns show the various customer groups and rows show each individual Regulatory Asset account. The top part of Table 1 shows the various allocators to be used for the different accounts. The last rows show the amount that will need to be recovered for the various customer classes and the average class total bill impact.

Table 1

See attachment

5.0 CUSTOMER CLASS AMOUNTS

As shown in Table 1, based on balances to April 30, 2008 of the Regulatory Asset accounts, using cost causality principles, and 2008 data, the estimated amounts allocated to the various customer groups are as follows:

Customer Class	Amount ($ million)
UR	(1.49)
R1	(6.55)
R2	(10.98)
Seasonal	0.48
Urban General Service energy	(1.0)
Urban General Service demand	(2.40)
General Service energy	(5.22)
General Service demand	(9.58)

Customer Class	**Amount ($ million)**
Distributed Generator	(0.01)
Street Light	(0.39)
Sentinel Light	(0.07)
Sub-Transmission	(11.47)
Total	**(48.68)**

Exhibit G1, Tab 5, Schedule 2, provides the allocators and charge determinants to be used to derive the Regulatory Asset Rate Rider # 3 and Exhibit G1, Tab 5, Schedule 3, calculates the Rate Riders # 3 proposed for the period May 2008 to April 2012 by customer class.

Table 1

Regulatory Asset Recovery

Stats for Allocation			UR	R1	R2	Seasonal	GSe	GSd	UGe	UGd	St Lgt	Sen Lgt	Dgen	ST
Customers	1,177,552		162,058	376,430	364,938	155,177	97,005	7,015	12,744	1,429	-	-	84	673
GWh	38,411		1,494	4,407	5,624	707	2,299	3,237	424	831	121	22	3	19,240
GWh excl WMP	24,267		1,494	4,407	5,624	707	2,299	3,237	424	831	121	22	3	5,096
Billing kWs	56,293,509							11,019,445		2,203,297			48,843	43,021,924
Dx Rev excl Riders [$M]	1,024		53.9	186.5	392.6	74.8	113.9	105.5	11.6	15.7	4.8	0.9	0.6	63.4
Est of Total Bill [$M]	3,797		181.1	527.3	700.9	129.6	276.4	360.9	48.4	122.8	14.1	2.6	1.0	1,431.8
OMA	100%		6.76%	24.04%	38.79%	8.06%	10.48%	7.19%	0.93%	0.96%	0.64%	0.18%	0.01%	1.96%
NFA	100%		5.78%	21.57%	35.38%	7.62%	10.52%	12.37%	0.90%	2.13%	0.89%	0.19%	0.01%	2.64%
Balances	$ 1000s	Allocator												
RSVA Wholesale Market Service Charges	$ (72,590)	GWh excl WMP	$ (4,469.60)	$ (13,184.11)	$ (16,824.68)	$ (2,114.04)	$ (6,878.01)	$ (9,684.03)	$ (1,268.81)	$ (2,485.24)	$ (360.75)	$ (67.06)	$ (10.14)	$ (15,243.54)
RSVA Tx Network	1430	GWh	$ 55.63	$ 164.08	$ 209.39	$ 26.31	$ 85.60	$ 120.52	$ 15.79	$ 30.93	$ 4.49	$ 0.83	$ 0.13	$ 716.30
RSVA Tx Connection	2540	GWh	$ 98.80	$ 291.45	$ 371.93	$ 46.73	$ 152.05	$ 214.07	$ 28.05	$ 54.94	$ 7.97	$ 1.48	$ 0.22	$ 1,272.30
RSVA LV Wheeling	3840	GWh	$ 149.37	$ 440.61	$ 562.28	$ 70.65	$ 229.86	$ 323.64	$ 42.40	$ 83.06	$ 12.06	$ 2.24	$ 0.34	$ 1,923.48
OEB Costs	$ (900)	OMA	$ (60.83)	$ (216.40)	$ (349.11)	$ (72.56)	$ (94.34)	$ (64.69)	$ (8.34)	$ (8.68)	$ (5.74)	$ (1.62)	$ (0.05)	$ (17.64)
Tax Change	$ (5,000)	NFA	$ (289.15)	$ (1,078.38)	$ (1,769.17)	$ (380.87)	$ (525.84)	$ (618.52)	$ (44.99)	$ (106.59)	$ (44.67)	$ (9.60)	$ (0.31)	$ (131.91)
Smart Meter Minimum Functionality to May 31, 2007	$ 6,900	Cust #	$ 949.60	$ 2,205.73	$ 2,138.39	$ 909.28	$ 568.41	$ 41.10	$ 74.68	$ 8.37	$ -	$ -	$ 0.49	$ 3.94
Smart Meter Costs Exceeding Minimum Functionality	$ 5,700	Cust #	$ 784.45	$ 1,822.13	$ 1,766.50	$ 751.14	$ 469.56	$ 33.96	$ 61.69	$ 6.92	$ -	$ -	$ 0.40	$ 3.26
Smart Meter Minimum Functionality after May 31, 2007	$ 9,400	Cust #	$ 1,293.66	$ 3,004.91	$ 2,913.18	$ 1,238.73	$ 774.36	$ 56.00	$ 101.73	$ 11.40	$ -	$ -	$ 0.67	$ 5.37
Total Regulatory Assets for Approval	$ (48,680)													
	$ (48,680.0)		$ (1,488.1)	$ (6,550.0)	$ (10,981.3)	$ 475.4	$ (5,218.4)	$ (9,577.9)	$ (997.8)	$ (2,404.9)	$ (386.6)	$ (73.7)	$ (8.2)	$ (11,468.4)
Assuming a 4 year recovery	$ (12,170.0)		$ (372.0)	$ (1,637.5)	$ (2,745.3)	$ 118.8	$ (1,304.6)	$ (2,394.5)	$ (249.4)	$ (601.2)	$ (96.7)	$ (18.4)	$ (2.1)	$ (2,867.1)
	Rider 3	c/kWh	(0.02)	(0.04)	(0.05)	0.02	(0.06)	(0.07)	(0.06)	(0.07)	(0.08)	(0.08)	(0.06)	Note 1
		$/kW						(0.22)		(0.27)			(0.04)	Note 1
	Impacts		-0.21%	-0.31%	-0.39%	0.09%	-0.47%	-0.66%	-0.52%	-0.49%	-0.69%	-0.70%	-0.22%	-0.20%

Note 1:		$/kW
Rider # 3 for ST customers		**$/kW**
	Rider # 3 for all ST customers	**0.02**
	Plus Rider # 3 for non-Market Participant customer	**-0.29**

BILLING PARAMETERS FOR RECOVERY OF REGULATORY ASSET COSTS

1.0 INTRODUCTION

This exhibit describes the allocators and charge determinants that are necessary to develop Regulatory Rate Riders # 3 to recover accumulated Regulatory Asset balances. These charge determinants will be used in Exhibit G1, Tab 5, Schedule 3, to calculate Rate Rider # 3 by customer class.

Exhibit G1, Tab 5, Schedule 1, explains how the Regulatory Assets amounts are proposed to be allocated to the various customer classes.

2.0 REGULATORY ASSET ALLOCATORS

The allocators used to allocate the costs to the various customer groups are number of customers, OM&A by customer class, Net Fixed Assets by customer class, energy for non-market participants, and energy for all customers. The data is derived from the sales forecast data for 2008 on a customer class by customer class basis and from the Cost Allocation Study results. The aggregate sales forecast methodology explained in Exhibit A, Tab 14, Schedule 3, is predicated on a more detailed customer class forecast and this customer class forecast is used for rate design purposes. Table 1 below provides the 2008 customer numbers, OM&A, and Net Fixed Assets by customer class data that will be used in these calculations.

Table 1
2008 Allocator Data

Rate Class	Number of Customers	OM&A ($M)	Net Fixed Assets ($M)	Energy non-market participant (GWh)	Energy (GWh)
UR	162,058	25.68	217.05	1,494	1,494
R1	376,430	91.36	809.49	4,407	4,407
R2	364,938	147.38	1,328.04	5,624	5,624
Seasonal	155,177	30.63	285.91	707	707
Urban General Service energy	12,744	3.52	33.77	424	424
Urban General Service demand	1,429	3.66	80.02	831	831
General Service energy	97,005	39.83	394.73	2,299	2,299
General Service demand	7,015	27.31	464.29	3,237	3,237
Distributed Generation	84	0.02	0.23	3	3
Street Lights	0	2.42	33.54	121	121
Sentinel Light	0	0.68	7.21	22	22
Sub-Transmission	673	7.45	99.02	5,098	19,240
Total	1,177,552	379.95	3,753.29	24,267	38,411

3.0 RATE RIDER CHARGE DETERMINANTS

The charge determinants used to calculate Rate Rider # 3 are energy or demand by customer class. The data is derived from the sales forecast data for 2008 and is derived on a customer class by customer class basis. The sales forecast methodology is explained in Exhibit A, Tab 14, Schedule 3. The charge determinants for Rate Rider # 3 are shown in the Table below.

Table 2
2008 Charge Determinants

Rate Class	Energy GWh	Demand kW
UR	1,494	N/A
R1	4,407	N/A
R2	5,624	N/A
Seasonal	707	N/A
Urban General Service energy	424	N/A
Urban General Service demand	N/A	2,203,297
General Service energy	2,299	N/A
General Service demand	N/A	11,019,445
Distributed Generation	N/A	48,843
Street Lights	121	N/A
Sentinel Light	22	N/A
Sub-Transmission	N/A	43,021,924

DEVELOPMENT OF REGULATORY ASSET RATE RIDER # 3

This exhibit presents the process for calculating the Rate riders in respect of recovery of the Regulatory Assets, which is comprised of the following steps:

a) isolate the amounts to be collected
b) determine the class allocators and charge determinants
c) derive initial rates as the ratio of the amounts to be collected divided by the respective class charge determinants

1.0 INTRODUCTION

Hydro One Distribution proposes to derive the Regulatory Rate riders consistent with the approach approved by the Board to develop Rate Riders #1 to recover the Regulatory Assets in proceeding RP-2004-0117/RP-2004-0118. The resultant Rate riders provided herein are consistent with the Board's guidelines and approval under that same proceeding.

2.0 RATE DESIGN

Hydro One Distribution proposes in this submission that the Rate riders developed to recover the costs of the Regulatory Assets from the various rate classes should be based on 2008 forecast sales information to make it consistent with the data used to establish 2008 Distribution rates. It is also proposed that the rate adjustments be made to the volumetric charge only, consistent with the decision in RP-2004-0117/RP-2004-0118, and that the Regulatory Asset Account balances be recovered from customers over a four year period.

Hydro One Distribution proposes to use the same mechanism as was previously used to recover the Regulatory Asset account balances as per RP-2004-0117/RP-2004-0118 to recover the new Regulatory Asset account balances.

For all the Acquired customer classes that are being harmonized as per Exhibit G1, Tab 2, Schedule 5, it is proposed that the Regulatory Riders developed for the corresponding customer classes, be used for the Acquired LDCs' customer classes. For example, if an Acquired Residential customer group is being harmonized with the Urban Residential customer class, it is the Urban Residential customer class Regulatory Rate Rider # 3 that would be applied to the Residential customers of this Acquired LDC.

2.1 Rate Rider Design Steps

The initial rate riders per rate class are derived by apportioning to customer classes the amounts to be recovered, arrived at through the same allocation process approved as part of RP-2004-0117/ RP-2004-0118 and described in Exhibit G1, Tab 5, Schedule 1, using the allocators described in Exhibit G1, Tab 5, Schedule 2.

2.2 Class Amounts To Be Recovered

The amounts to be recovered for each customer group were determined in Exhibit G1, Tab 5, Schedule 1. Table 1 below re-states the annual amounts to be recovered from customer classes in column 2 assuming a four year recovery period.

2.3 Charge Determinants

The charge determinants to be used are described in Exhibit G1, Tab 5, Schedule 2. Table 1 below re-states the charge determinants to be used by customer class in column 3.

3.0 RATE RIDER # 3

Using the class amounts in column 2 and the corresponding charge determinants in column 3, Rate Rider # 3 can be derived. Table 1 below provides the rate rider for each customer class.

Table 1
Customer Class Rate Rider

Customer Class	Amount Allocated (A) $000's	Consumption (B) GWhs or MWs	Rate Rider (C)=(A)/(B) ¢/kWh or $/kW
Urban Residential (UR)	(372)	1,494	(0.02)
R1 Residential (R1)	(1,638)	4,407	(0.04)
R2 Residential (R2)	(2,745)	5,624	(0.05)
Seasonal	119	707	0.02
Urban General Service energy	(249)	424	(0.06)
Urban General Service demand ($/kW)	(601)	2,203.3	(0.27)
General Service energy	(1,305)	2,299	(0.06)
General Service demand ($/kW)	(2,395)	11,019.4	(0.22)
Distributed Generator ($/kW)	(2)	48.8	(0.04)
Street Lights	(97)	121	(0.08)
Sentinel Lights	(18)	22	(0.08)
Sub-Transmission ($/kW)	(2,867))	43,021.9	Note 1
Total	(12,170)	N/A	N/A

Note 1. For ST customers the value of Rider # 3 will depend if the customer is market participant or not

Acquired LDC Customers

To provide consistency in approach with the proposed harmonization plan, rate riders will be developed for each harmonized Acquired LDC customer class based on the customer class that they are being harmonized to.

Table 2, 3 and 4 below show the Regulatory assets by Acquired LDC.

Table 2
Regulatory Rate Rider # 3 by Residential class for Acquired LDCs

LDC	Residential Rate Rider # 3 ¢/kWh
Ailsa Craig	(0.04)
Arkona	(0.04)
Arnprior to R1	(0.04)
Arnprior to Urban	(0.02)
Arran-Elderslie	(0.04)
Artemesia	(0.04)
Bancroft	(0.04)
Bath	(0.04)
Blandford-Blenheim	(0.04)
Blyth	(0.04)
Bobcaygeon	(0.04)
Brighton	(0.04)
Brockville to R1	(0.04)
Brockville to Urban	(0.02)
Caledon CH 01	(0.02)
Caledon CH 02	(0.04)
Caledon CH 06	(0.05)
Caledon CH 07	0.02
Carleton Place to R1	(0.04)
Carleton Place to Urban	(0.02)
Cavan-Millbrook-North Monaghan	(0.04)
Centre Hastings	(0.04)
Chalk River	(0.04)
Champlain	(0.04)
Cobden	(0.04)
Deep River	(0.04)
Deseronto	(0.04)
Dryden to R1	(0.04)
Dryden to Urban	(0.02)
Dundalk	(0.04)
Durham	(0.04)
Eganville	(0.04)
Erin	(0.04)
Exeter	(0.04)
Fenelon Falls	(0.04)

LDC	**Residential Rate Rider # 3 ¢/kWh**
Forest	(0.04)
GBE to R1	(0.04)
GBE to Urban	(0.02)
Georgina	(0.04)
Glencoe	(0.04)
Grand Bend	(0.04)
Hastings	(0.04)
Havelock	(0.04)
Kirkfield	(0.04)
Lanark Highlands	(0.04)
Larder Lake	(0.04)
Latchford	(0.04)
Lindsay to R1	(0.04)
Lindsay to Urban	(0.02)
Lucan Granton	(0.04)
Malahide	(0.04)
Mapleton	(0.04)
Markdale	(0.04)
Marmora	(0.04)
McGarry	(0.04)
Meaford	(0.04)
Middlesex Centre	(0.04)
Napanee	(0.04)
Nipigon	(0.04)
North Dorchester	(0.04)
North Dundas	(0.04)
North Glengarry	(0.04)
North Grenville	(0.04)
North Perth	(0.04)
North Stormont	(0.04)
Omemee	(0.04)
Perth to R1	(0.04)
Perth to Urban	(0.02)
Perth East	(0.04)
Prince Edward	(0.04)
Quinte West to R1	(0.04)
Quinte West to Urban	(0.02)
Rainy River	(0.04)

LDC	Residential Rate Rider # 3 ¢/kWh
Ramara	(0.04)
Red Rock	(0.04)
Rockland	(0.04)
Russell	(0.04)
Schreiber	(0.04)
Severn	(0.04)
Shelburne	(0.04)
Smiths Falls to R1	(0.04)
Smiths Falls to Urban	(0.02)
South Glengarry	(0.04)
South River	(0.04)
Springwater	(0.04)
Stirling-Rawdon	(0.04)
Terrace Bay	(0.04)
Thedford	(0.04)
Thessalon	(0.04)
Thorndale	(0.04)
Thorold to R1	(0.04)
Thorold to Urban	(0.02)
Tweed	(0.04)
Wardsville	(0.04)
Warkworth	(0.04)
West Elgin	(0.04)
Whitchurch Stouffville to R1	(0.04)
Whitchurch Stouffville to Urban	(0.02)
Wiarton	(0.04)
Woodville	(0.04)
Wyoming	(0.04)

Table 3
Regulatory Rate Rider # 3 for General Service energy billed class for Acquired LDCs

LDC	General Service Rate Rider # 3 ¢/kWh
Ailsa Craig	(0.06)
Arkona	(0.06)
Arnprior to General Service	(0.06)

LDC	**General Service Rate Rider # 3 ¢/kWh**
Arnprior to Urban General Service	(0.06)
Arran-Elderslie	(0.06)
Artemesia	(0.06)
Bancroft	(0.06)
Bath	(0.06)
Blandford-Blenheim	(0.06)
Blyth	(0.06)
Bobcaygeon	(0.06)
Brighton	(0.06)
Brockville to General Service	(0.06)
Brockville to Urban General Service	(0.06)
Caledon CH	(0.06)
Caledon GS 05	(0.06)
Caledon OH	(0.06)
Campbellford-Seymour	(0.06)
Carleton Place to General Service	(0.06)
Carleton Place to Urban General Service	(0.06)
Cavan-Millbrook-North Monaghan	(0.06)
Centre Hastings	(0.06)
Chalk River	(0.06)
Champlain	(0.06)
Cobden	(0.06)
Deep River	(0.06)
Deseronto	(0.06)
Dryden to General Service	(0.06)
Dryden to Urban General Service	(0.06)
Dundalk	(0.06)
Durham	(0.06)
Eganville	(0.06)
Erin	(0.06)
Exeter	(0.06)
Fenelon Falls	(0.06)
Forest	(0.06)
GBE to General Service	(0.06)
GBE to Urban General Service	(0.06)
Georgina	(0.06)
Glencoe	(0.06)
Grand Bend	(0.06)

LDC	**General Service Rate Rider # 3 ¢/kWh**
Hastings	(0.06)
Havelock	(0.06)
Kirkfield	(0.06)
Lanark Highlands	(0.06)
Larder Lake	(0.06)
Latchford	(0.06)
Lindsay to General Service	(0.06)
Lindsay to Urban General Service	(0.06)
Lucan Granton	(0.06)
Malahide	(0.06)
Mapleton	(0.06)
Markdale	(0.06)
Marmora	(0.06)
McGarry	(0.06)
Meaford	(0.06)
Middlesex Centre	(0.06)
Napanee	(0.06)
Nipigon	(0.06)
North Dorchester	(0.06)
North Dundas	(0.06)
North Glengarry	(0.06)
North Grenville	(0.06)
North Perth	(0.06)
North Stormont	(0.06)
Omemee	(0.06)
Perth to General Service	(0.06)
Perth to Urban General Service	(0.06)
Perth East	(0.06)
Prince Edward	(0.06)
Quinte West to General Service	(0.06)
Quinte West to Urban General Service	(0.06)
Rainy River	(0.06)
Ramara	(0.06)
Red Rock	(0.06)
Rockland	(0.06)
Russell	(0.06)
Schreiber	(0.06)
Severn	(0.06)

LDC	**General Service Rate Rider # 3 ¢/kWh**
Shelburne	(0.06)
Smiths Falls to General Service	(0.06)
Smiths Falls to Urban General Service	(0.06)
South Glengarry	(0.06)
South River	(0.06)
Springwater	(0.06)
Stirling-Rawdon	(0.06)
Terrace Bay	(0.06)
Thedford	(0.06)
Thessalon	(0.06)
Thorndale	(0.06)
Thorold to General Service	(0.06)
Thorold to Urban General Service	(0.06)
Tweed	(0.06)
Wardsville	(0.06)
Warkworth	(0.06)
West Elgin	(0.06)
Whitchurch Stouffville to General Service	(0.06)
Whitchurch Stouffville to Urban General Service	(0.06)
Wiarton	(0.06)
Woodville	(0.06)
Wyoming	(0.06)

Table 4
Regulatory Rate Rider # 3 for General Service demand billed class for Acquired LDCs

LDC	**General Service Rate Rider # 3 $/kW**
Ailsa Craig	(0.22)
Arkona	(0.22)
Arnprior to General Service	(0.22)
Arnprior to Urban General Service	(0.27)
Arran-Elderslie	(0.22)
Artemesia	(0.22)
Bancroft	(0.22)
Bath	(0.22)

LDC	**General Service Rate Rider # 3 $/kW**
Blandford-Blenheim	(0.22)
Blyth	(0.22)
Bobcaygeon	(0.22)
Brighton	(0.22)
Brockville to General Service	(0.22)
Brockville to Urban General Service	(0.27)
Caledon CH	(0.22)
Caledon GS 05	(0.22)
Caledon OH	(0.22)
Campbellford-Seymour	(0.22)
Carleton Place to General Service	(0.22)
Carleton Place to Urban General Service	(0.27)
Cavan-Millbrook-North Monaghan	(0.22)
Centre Hastings	(0.22)
Chalk River	(0.22)
Champlain	(0.22)
Cobden	(0.22)
Deep River	(0.22)
Deseronto	(0.22)
Dryden to General Service	(0.22)
Dryden to Urban General Service	(0.27)
Dundalk	(0.22)
Durham	(0.22)
Eganville	(0.22)
Erin	(0.22)
Exeter	(0.22)
Fenelon Falls	(0.22)
Forest	(0.22)
GBE to General Service	(0.22)
GBE to Urban General Service	(0.27)
Georgina	(0.22)
Glencoe	(0.22)
Grand Bend	(0.22)
Hastings	(0.22)
Havelock	(0.22)
Kirkfield	(0.22)
Lanark Highlands	(0.22)
Larder Lake	(0.22)

LDC	**General Service Rate Rider # 3 $/kW**
Latchford	(0.22)
Lindsay to General Service	(0.22)
Lindsay to Urban General Service	(0.27)
Lucan Granton	(0.22)
Malahide	(0.22)
Mapleton	(0.22)
Markdale	(0.22)
Marmora	(0.22)
McGarry	(0.22)
Meaford	(0.22)
Middlesex Centre	(0.22)
Napanee	(0.22)
Nipigon	(0.22)
North Dorchester	(0.22)
North Dundas	(0.22)
North Glengarry	(0.22)
North Grenville	(0.22)
North Perth	(0.22)
North Stormont	(0.22)
Omemee	(0.22)
Perth to General Service	(0.22)
Perth to Urban General Service	(0.27)
Perth East	(0.22)
Prince Edward	(0.22)
Quinte West to General Service	(0.22)
Quinte West to Urban General Service	(0.27)
Rainy River	(0.22)
Ramara	(0.22)
Red Rock	(0.22)
Rockland	(0.22)
Russell	(0.22)
Schreiber	(0.22)
Severn	(0.22)
Shelburne	(0.22)
Smiths Falls to General Service	(0.22)
Smiths Falls to Urban General Service	(0.27)
South Glengarry	(0.22)
South River	(0.22)

LDC	**General Service Rate Rider # 3 $/kW**
Springwater	(0.22)
Stirling-Rawdon	(0.22)
Terrace Bay	(0.22)
Thedford	(0.22)
Thessalon	(0.22)
Thorndale	(0.22)
Thorold to General Service	(0.22)
Thorold to Urban General Service	(0.27)
Tweed	(0.22)
Wardsville	(0.22)
Warkworth	(0.22)
West Elgin	(0.22)
Whitchurch Stouffville to General Service	(0.22)
Whitchurch Stouffville to Urban General Service	(0.27)
Wiarton	(0.22)
Woodville	(0.22)
Wyoming	(0.22)

Regulatory Rate Rider # 3 Large Users Acquired LDCs

Regulatory Rate Rider # 3 for Large Users of Acquired LDCs will be the Regulatory Rate Rider # 3 applicable to the Sub-Transmission customer class.

RETAIL TRANSMISSION SERVICE RATES

1.0 INTRODUCTION

This exhibits describes the proposal to revise the Retail Transmission Service Rates (RTSR) to reflect the proposed new customer classes and also to take into account the impact on RTSR of aggregation of demand for purposes of determining RTSR charges for customers supplied by multiple feeders emanating from the same TS. The proposed RTSR also reflects the new Uniform Transmission rates effective November 1, 2007, resulting from the Rate Order on proceeding EB-2007-0759.

Aggregation for purposes of billing RTSR charges was approved by the Board in Proceeding EB-2004-0451. For customers that are being aggregated for purposes of RTSR, the aggregated demand is arrived at by applying losses to the measured quantities, in situations where different loss factors are being applied to individual delivery points.

Hydro One Distribution developed its initial RTSR following the guidelines set out in Chapter 11 of the 2000 Distribution Rate Handbook. In this submission, Hydro One is proposing new customer classes and the corresponding RTSR have been developed using the methodology outlined in Chapter 11 of the 2000 Distribution Rate Handbook.

Supporting detail for the derivation of the new RTSR is presented in Exhibit G2, Tab 4, Schedule 1.

1.1 Hydro One Distribution Situation

Hydro One Distribution as a Host Utility is billed at each of its transmission delivery points for the transmission of power to its Retail (Legacy and Acquired) customers, its

Embedded LDCs and its Embedded Direct customers. Its total transmission charges are the sum total of all the transmission charges at these delivery points. The charges at each transmission delivery point are based on the loads of the customers downstream of the delivery point and their contribution to the delivery point's total loading.

1.2 Approved Transmission Rates

The Ontario Uniform Transmission Rates which result from the proceeding EB-2007-0759, effective November 1, 2007 comprise the following charges:

- A Transmission Network charge of $2.31/kW, to be applied to the demand at each transmission delivery point based on billed demand which is defined to be the larger of: a) 85% of non-coincident peak from 7 a.m. to 7 p.m. or b) the peak coincident with the transmission system peak.

- Line and transformation connection charges of $0.59/kW and $1.61/kW, respectively, which are applied to the non-coincident peak at each transmission delivery point.

These rates apply to the load at the deemed transmission delivery point which is set to be on the high side of the transformation station. Metering is typically on the low voltage side at the station, so appropriate loss factors have been applied to uplift the meter readings to the high side of the transformation station.

2.0 ESTIMATING RETAIL TRANSMISSION SERVICE CHARGES FROM IESO

2.1 Method

To estimate the charges from IESO for Transmission, Hydro One estimated the 2008 load at each of its transmission connections and applying the currently approved Transmission rates. This resulted in a total estimated charge of $166.2 million for Network services, $114.8 million for Transformation charges and $36.6 million for Line Connection Charges for a total of $317.6M.

The estimated 2008 charges from the IESO need to be recovered from all Hydro One customers. For the proposed ST customer group, sufficient connectivity data exists to allow Hydro One to allocate the appropriate cost based on each customer's coincident peak with the IESO billing time per month per their transmission delivery point. This resulted in 46% of the $317.6M being allocated to the ST customer class with the residual 54% being recovered from the other Retail (Legacy and Acquired) customers. Within the Retail customer classes, Hourly Load Shape data was used to allocate to each individual customer classes consistent with the methodology of Chapter 11 of the 2000 Electricity Distribution Rate Handbook.

The following Table shows the estimated 2008 IESO charges allocated to the proposed customer classes.

Table 1
2008 IESO charges

	Tx Network	Tx Line	Tx Transformation	Total IESO Bill	Share
IESO Bill	$ 166,226,978	$ 36,611,777	$ 114,776,007	$ 317,614,762	
ST	$ 76,899,232	$ 16,207,183	$ 51,593,835	$ 144,700,250	46%
Retail	$ 89,327,746	$ 20,404,594	$ 63,182,172	$ 172,914,512	54%
UR	$ 7,570,443	$ 1,769,046	$ 5,477,795	$ 14,817,285	
R1	$ 22,697,678	$ 5,351,517	$ 16,570,801	$ 44,619,996	
R2	$ 28,517,822	$ 6,467,960	$ 20,027,830	$ 55,013,611	
Seasonal	$ 3,374,629	$ 809,307	$ 2,505,993	$ 6,689,929	
Uge	$ 1,674,964	$ 370,818	$ 1,148,225	$ 3,194,007	
Ugd	$ 3,289,432	$ 727,263	$ 2,251,945	$ 6,268,640	
GSe	$ 8,807,534	$ 1,967,457	$ 6,092,168	$ 16,867,159	
GSd	$ 12,932,797	$ 2,841,350	$ 8,798,148	$ 24,572,294	
Lighting	$ 449,148	$ 96,938	$ 300,166	$ 846,252	
Dgen	$ 13,298	$ 2,939	$ 9,101	$ 25,338	

In total, Hydro One Distribution needs to collect $166.2 million for RTSR Network and $151.4 million for RTSR Connection and Transformation.

3.0 PROPOSED 2008 RTSR RATES

Using the available Load Research data, the amounts allocated to each customer class divided by the corresponding billing parameters resulted in the proposed 2008 RTSR Rates by customer class shown in Table 2 below. Table 2 below also shows the currently approved RTSR. Customers billed based on energy will be charged these RTSR applied to meter quantities uplifted for losses. Customers billed on demand will be charged the rates below uplifted for losses. For customers that install load displacement generation after October 1998, RTSR connection is billed at the gross demand level consistent with the guidelines in the Distribution Rate Handbook, section 11.3.2.5. The proposed RTSR rates are included in the rate Schedules for Legacy, Acquired, and ST customer groups shown in Exhibits G2, Tabs 5 to 94, Schedule 1.

Table 2
Proposed 2008 RTSR

	Current rates		**Proposed rates**		
	¢/kWh or $/kW	**¢/kWh or $/kW**	**¢/kWh or $/kW**	**¢/kWh or $/kW**	
RATE CLASS	Network	Connection	Network	Line Con.*	Tran.
Urban	0.52-0.55	0.42-0.47	0.47	0.45	N/A
R1	0.52-0.55	0.42-0.47	0.47	0.46	N/A
R2	0.52	0.42	0.46	0.43	N/A
Seasonal	0.41	0.40	0.44	0.43	N/A
Urban General Service energy	0.50 – 0.52	0.33 – 0.43	0.36	0.33	N/A
Urban General Service demand ($/kW)	1.584 – 1.94	0.998 – 1.61	1.41	1.27	N/A
General Service energy	0.48-0.52	0.33-0.39	0.35	0.32	N/A
General Service demand ($/kW)	1.584-1.8	0.998-1.329	1.11	1.00	N/A
Distributed Generator ($/kW)	0.52	0.34	0.25	0.23	N/A
Street and Sentinel Lights	0.3	0.23	0.29	0.25	N/A
ST ($/kW)	1.734-2.52	1.083-2.09	2.01	0.50	1.38

* For customer classes that do not have separate proposed Line and Transformation charges, the Line Connection charges shown include Transformation charges

The current RTSR for all Acquired LDC customers are based on the default value guidelines for RTSR established by the Board. The same rates apply to all Acquired LDCs. The proposed RTSR for Acquired LDCs are the rates shown above and will depend on what customer classes the Acquired Customers are being mapped into.

As in the case for Legacy customers, Acquired customers billed based on energy will be charged these RTSR applied to meter quantities uplifted for losses. Customers billed on demand will be charged the above RTSR uplifted for losses.

BILL IMPACTS LEGACY CUSTOMERS

This exhibit presents the results of the assessment of customer total bill impacts using average levels of consumption by customer class. As per the guidelines in the 2006 Electricity Distribution Rate Handbook, impacts are also shown for Distribution rate increases. Finally, impacts are shown including the impact of Regulatory Asset Rate Rider # 3 as derived in Exhibit G1, Tab 5, Schedule 3, changing Retail Transmission Service Rates (RTSR) as described in Exhibit G1, Tab 6, Schedule 1 and Total Loss Factors as described in Exhibit G1, Tab 10, Schedule 1.

Impacts are derived using the applicable May 1, 2007 rates, the ending of Regulatory Rate Rider # 1, and the proposed initial distribution rates, Regulatory Asset Rate Rider # 3 and 2008 RTSR.

1.0 INTRODUCTION

The total bill impacts are derived for the current average Legacy rate class customer. The rates are assessed on the basis of moving to the proposed distribution rates derived in Exhibit G1, Tab 4, Schedule 2, including Regulatory Asset Rate Rider # 3 derived in Exhibit G1, Tab 5, Schedule 3, RTSR derived in Exhibit G1, Tab 6, Schedule 1, and Total Loss Factors shown in Exhibit G1, Tab 10, Schedule 1 from their current rates as of May 1, 2007. The total bill impacts are premised on the distribution rates arising from the new revenue requirement and moving customer classes towards a target revenue to cost ratio determined by using the cost allocation study methodology and also taking into account the end of Regulatory Rate Rider # 1. All other non-distribution charges, except RTSR, are kept unchanged. Commodity price for eligible customers is based on the Regulated Price Plan for conventional meters, i.e. 5.0 ¢/kWh for the first 600 kWh and 5.9 ¢/kWh for consumption above 600 kWh for Residential customers. For General

Service customers, the consumption threshold is 750 kWh. For non-eligible customers, commodity costs were assumed to be 5.2 ¢/kWh when calculating the class average impact.

Bill impacts are calculated as a change in customer bills in relation to their existing bills that are based on distribution rates and other charges in effect as of May 1, 2007.

The Legacy customers that meet the Urban density criteria will be re-classified as Urban customers in 2008.

2.0 RECAP PROPOSED RETAIL CUSTOMER RATES

At the conclusion of Exhibit G1, Tab 4, Schedule 2, Hydro One Distribution summarized the proposed set of distribution rates for Legacy Retail customers. Table 1 below recaps the proposed rates.

Table 1
Proposed Target Distribution Rates

Rate Class	Service Charge [$/month]	Volumetric Charge [¢/kWh or $/kW]
Urban Residential (High Density)	14.32	2.29
R1 Residential (Medium Density)	19.04	2.60
R2 Residential (Low Density)	21.41*	3.10
Seasonal	19.51	6.38
Urban General Service energy billed (UGS e)	12.33	2.09
Urban General Service demand billed (UGS d) $/kW	29.19	7.25****
General Service energy billed (GS e)	30.97***	3.39
General Service demand billed (GS d) $/kW	46.75	9.22****
Distributed Generator ($/kW)	36.66	7.07****
Street Lights	1.00**	4.57
Sentinel Light	1.00**	5.30

* Net of RRRP ** Per Connection *** Excludes $0.35 adder for USL credit

****Excludes $0.07/kW adder for CSTA

At the conclusion of Exhibit G1, Tab 5, Schedule 3, Hydro One Distribution summarized a set of proposed Regulatory Asset Rate Rider # 3. Table 2 below recaps those riders.

Table 2
Proposed Regulatory Asset Rate Rider # 3

	Rate Rider # 3 ¢/kWh or $/kW
Urban Residential (High Density)	(0.02)
R1 Residential (Medium Density)	(0.04)
R2 Residential (Low Density)	(0.05)
Seasonal	0.02
Urban General Service energy billed (UGS e)	(0.06)
Urban General Service demand billed (UGS d) $/kW	(0.27)
General Service energy billed (GS e)	(0.06)
General Service demand billed (GS d) $/kW	(0.22)
Distributed Generator	(0.04)
Street Lights	(0.08)
Sentinel Light	(0.08)

At the conclusion of Exhibit G1, Tab 6, Schedule 1, Hydro One Distribution summarized a set of proposed RTSR for Legacy Retail customers. Table 3 below recaps those RTSR.

Table 3
Proposed RTSR

	RTSR Network ¢/kWh or $/kW	RTSR Connection ¢/kWh or $/kW
Urban Residential (High Density)	0.47	0.45
R1 Residential (Medium Density)	0.47	0.46
R2 Residential (Low Density)	0.46	0.43
Seasonal	0.44	0.43
Urban General Service energy billed (UGS e)	0.36	0.33
Urban General Service demand billed (UGS d) $/kW	1.41	1.27
General Service energy billed (GS e)	0.35	0.32
General Service demand billed (GS d) $/kW	1.11	1.00
Distributed Generator	0.25	0.23
Lights (Street and Sentinel)	0.29	0.25

3.0 IMPACT BY CUSTOMER CLASSES

Combining the proposed Distribution rates in Table 1, Regulatory Asset Rate Rider # 3 in Table 2 and RTSR rates in Table 3 with other applicable charges including loss factors, the customer bill can be calculated for all customer classes based on average consumption. Table 4 provides the impacts of the Distribution revenue increase only on the distribution portion of the bill, total bill impacts including Rate Rider # 3 and excluding RTSR changes and the impacts of all rate changes on total bill.

The third column from the left in Table 4 shows the impact of 2008 distribution Revenue Requirement on the distribution portion of the bill, excluding Regulatory Rate riders. The impacts reflect moving the various customer classes to revenue to cost ratios that closer reflect cost causality and the reclassification of certain customers to Urban Density. The fourth column in Table 4 shows the impact of the 2008 distribution

Revenue Requirement on the distribution portion of the bill including Regulatory Rate rider # 3. The variability in the results reflects the different amounts for regulatory rate riders recovered from each customer class. The fifth column on Table 4 shows the impact of the 2008 distribution Revenue Requirement on total customer bill. The variability in the results reflects the fact that distribution revenues and regulatory rate riders comprise a different proportion of the total bill for each customer class. The sixth column in Table 4 shows the impact of the 2008 distribution Revenue Requirement, Rate Rider # 3, total loss factors, and the new RTSR on total customer bill. The variability in the results reflects the fact that distribution revenues and RTSR comprise a different proportion of the total bill for each customer class. The impact shown below excludes the effect of the $0.07/kW rate adder for CSTA.

Table 4
Impacts by Customer classes

New Class	Existing Class	Basic Distribution Bill Only	Distribution Bill incl Riders	Total Bill incl Distribution and Riders	Total Bill incl Distribution and Riders plus RTSR
UR	UR	14.2%	6.8%	1.3%	1.0%
	R1	-13.0%	-16.7%	-6.5%	-6.9%
	R2	-23.4%	-26.6%	-10.8%	-11.1%
	F1 wRRA	-26.9%	-29.0%	-11.9%	-11.8%
R1	R1	5.2%	0.8%	0.0%	-0.2%
R2	R2	7.7%	4.0%	1.5%	1.1%
	F1 wRRA	2.6%	0.1%	0.0%	0.0%
	F3 wRRA	-11.3%	-12.5%	-4.1%	-3.3%
Seasonal	R3	47.8%	40.8%	20.9%	21.3%
	R4	2.3%	-0.8%	-0.5%	-0.1%
UGe	F1 nRRA	-48.8%	-51.0%	-20.0%	-21.6%
	G1	-45.1%	-47.6%	-18.0%	-19.3%
	G3	-50.0%	-51.2%	-19.2%	-20.1%
	UG	-22.8%	-24.9%	-7.4%	-8.9%
UGd	G1	-24.2%	-29.8%	-10.0%	-10.2%

New Class	Existing Class	Basic Distribution Bill Only	Distribution Bill incl Riders	Total Bill incl Distribution and Riders	Total Bill incl Distribution and Riders plus RTSR
	G3	-27.2%	-30.3%	-8.9%	-9.1%
	UG	-12.6%	-16.6%	-5.7%	-5.9%
GSe*	F1 nRRA	-6.5%	-8.7%	-3.4%	-5.2%
	F3 nRRA	-11.6%	-13.0%	-4.0%	-5.0%
	G1	0.3%	-2.6%	-1.0%	-2.5%
	G3	-8.7%	-10.0%	-2.7%	-3.8%
	T	-68.2%	-68.4%	-44.1%	-44.7%
	Unmtr	54.2%	47.2%	14.6%	13.1%
GSd	F1 nRRA	27.3%	19.5%	3.1%	0.4%
	F3 nRRA	-15.1%	-17.5%	-5.4%	-8.4%
	F1 wRRA	31.6%	23.2%	3.8%	1.1%
	F3 wRRA	-13.8%	-16.2%	-5.0%	-7.9%
	G1	-2.9%	-7.4%	-3.6%	-5.5%
	G3	-6.7%	-9.4%	-2.8%	-4.7%
	T	-5.5%	-7.9%	-2.3%	-4.4%
DGen	G3d	-28.3%	-28.9%	-7.1%	-12.7%
	Td	-23.4%	-23.9%	-14.8%	-30.9%
	G3e	32.2%	32.3%	17.4%	15.1%
	Te	-22.0%	-21.6%	-17.6%	-15.9%
	GS Eganville	110.0%	111.7%	109.3%	111.9%
Street Lgts	Street Lgts	17.1%	14.6%	4.9%	5.0%
	Terrace Bay	89.4%	48.8%	17.8%	21.9%
Sentinel Lgts	Sentinel Lgts	74.5%	70.9%	25.0%	25.0%

* Excludes impact of $0.35 adder for USL credit,

4.0 CONCLUSION

Based on the results shown in the tables above, to mitigate customer class impacts to less than 10% of total bill per year, using the 2006 EDR guidelines, Hydro One proposes to phase-in basing Distribution rates on the target fixed and volumetric charges calculated using the Cost Allocation Study over a period of four years. The phase-in process is similar to the harmonization plan described in Exhibit G1, Tab 2, Schedule 5.

The total bill impact to Sentinel Lights is estimated to be less than $1.80 per connection per month.

Exhibit G1, Tab 8, Schedule 1, describes the mitigation plan proposed for Legacy customer classes.

BILL IMPACTS ACQUIRED LDC CUSTOMERS

This exhibit presents the results of the assessment of customer total bill impacts by rate class for Acquired LDC customers. Impacts are derived by comparing the applicable May 1st, 2007 rates with the proposed harmonized distribution rates described in Exhibit G1, Tab 2, Schedule 5. As per the guidelines in the 2006 Electricity Distribution Rate Handbook, impacts are also shown for Distribution rate increases excluding Rate Rider # 3. Finally, impacts are shown including the impact of Regulatory Asset Rate Rider # 3 derived in Exhibit G1, Tab 5, Schedule 3 and RTSR changes described in Exhibit G1, Tab 6, Schedule 1.

1.0 INTRODUCTION

The total bill impacts are derived for the average customer per Acquired LDC rate class. The impacts are assessed on the basis of moving to the proposed distribution rates derived in Exhibit G1, Tab 4, Schedule 3, that include the effect of harmonization, Regulatory Asset Rate Rider # 3 derived in Exhibit G1, Tab 5, Schedule 3 and the RTSR derived in Exhibit G1, Tab 6, Schedule 1, from their current rates as of May 1st, 2007. The total bill impacts are premised on the distribution rates arising from the 2008 revenue requirement, Regulatory Rate Rider # 3 and harmonization of distribution rates. All other non-distribution charges, except RTSR and ending of Regulatory Rate Rider # 1, are kept unchanged. Commodity price for eligible customers is based on the Regulated Price Plan for conventional meters, i.e. 5.0 ¢/kWh for the first 600 kWh and 5.9 ¢/kWh for consumption above 600 kWh for Residential customers. For General Service customers, the consumption threshold is 750 kWh. For non-eligible customers, commodity costs were assumed to be 5.2 ¢/kWh when calculating the class average impact.

Bill impacts are calculated as a change in customer bills in relation to their existing bills that are based on distribution rates and other charges in effect as of May 1st, 2007.

2.0 PROPOSED ACQUIRED LDC CUSTOMERS RATES

To recap, Table 1 in Exhibit G1, Tab 4, Schedule 3, include the proposed set of target harmonized distribution rates for Acquired LDC customers.

Tables 2, to 4 in Exhibit G1, Tab 5, Schedule 3, include the proposed Regulatory Asset Rate Rider # 3.

Table 2 of Exhibit G1, Tab 6, Schedule 1, includes the proposed RTSR for Acquired LDC customers.

Combining the proposed Distribution rates, Regulatory Asset Rate Rider # 3, and RTSR rates with other applicable charges including loss factors, the customer bill can be calculated for all customer classes. Table 1 provides the impacts of the Distribution revenue increase only on the distribution portion of the bill, total bill impacts including Rate Rider # 3 and excluding RTSR changes and the impacts of all rate changes on total bill. This table provides a snapshot summary of the average impacts. Schedules 3 through Schedule 6 of Exhibits G2, Tab 5 show the results of the bill impact analysis for each Acquired customer class broken down by levels of consumption. Schedule 3 provides the impacts due to Distribution revenue increase only on the distribution portion of the bill. Schedule 4 shows the impact of the Distribution rate changes due to revenue requirement increase and Regulatory Rate Rider # 3 only on the Distribution portion of the bill. Schedule 5 shows total bill impacts that include Regulatory Rate Rider # 3 and 2008 revenue increase, but exclude RTSR changes. Schedule 6 shows total bill impacts due to all rate changes.

Each column in Table 1 below is sub-divided into three parts to provide the results for the Residential, General Service energy billed and General Service demand billed customer classes. For Residential customers, the second column in Table 1 below shows the average impact of 2008 Distribution revenue increase on the distribution portion of the bill, excluding Regulatory Rate Rider # 3. The third column in Table 1 shows the average impact of the 2008 Distribution revenue increase including Regulatory Rate Rider # 3 on the distribution portion of the bill including current Regulatory Rate riders. The fourth column in Table 1 shows the average impact of the 2008 Distribution revenue increase and proposed Regulatory Rate Rider # 3 on total customer bill. The fifth column in Table 1 shows the average impact of the 2008 distribution revenue increase, the proposed Regulatory Rate Rider # 3 and the RTSR change on total customer bill. The impact shown below excludes the effect of the $0.07/kW rate adder for CSTA.

Table 1
Bill Impacts by Acquired LDC Customer classes

	Residential					**GS<50***					**GS>50**			
Acquired LDC	Basic Distribution Bill Only	Distribution Bill incl Riders	Total Bill incl Distribution and Riders	Total Bill incl Distribution and Riders plus RTSR		Basic Distribution Bill Only	Distribution Bill incl Riders	Total Bill incl Distribution and Riders	Total Bill incl Distribution and Riders plus RTSR		Basic Distribution Bill Only	Distribution Bill incl Riders	Total Bill incl Distribution and Riders	Total Bill incl Distribution and Riders plus RTSR
Ailsa Craig	140.9%	96.5%	23.3%	22.8%		125.8%	103.2%	25.7%	23.6%		121.5%	88.3%	14.9%	10.1%
Arkona	434.0%	158.9%	31.4%	30.9%		383.8%	177.2%	35.3%	33.1%		377.6%	128.6%	19.2%	14.4%
Arnprior	71.8%	41.2%	13.5%	13.1%		120.4%	100.8%	25.3%	23.2%		147.9%	109.5%	16.8%	11.9%
Arran-Elderslie	143.4%	96.4%	23.4%	22.9%		235.4%	186.9%	34.8%	32.5%		186.0%	130.7%	18.5%	13.6%
Artemesia	104.6%	53.5%	16.5%	16.1%		81.4%	47.0%	16.0%	14.1%		69.8%	26.2%	6.7%	2.3%
Bancroft	96.1%	66.4%	18.5%	18.1%		105.6%	87.1%	23.3%	21.2%		146.5%	105.7%	16.5%	11.7%
Bath	105.1%	48.9%	15.6%	15.2%		146.4%	102.1%	26.1%	24.0%		148.6%	84.5%	15.0%	10.2%
Blandford-Blenheim	118.5%	58.8%	17.6%	17.1%		111.6%	80.6%	22.5%	20.5%		151.3%	86.3%	15.2%	10.4%
Blyth	176.7%	94.3%	23.5%	23.1%		131.5%	96.0%	25.1%	23.0%		170.9%	100.2%	16.6%	11.8%
Bobcaygeon	86.5%	63.4%	17.9%	17.5%		94.3%	76.8%	21.6%	19.5%		111.5%	79.1%	13.9%	9.2%
Brighton	102.0%	68.9%	18.9%	18.5%		97.8%	78.7%	21.9%	19.8%		116.9%	80.8%	14.1%	9.4%
Brockville	108.4%	65.2%	18.4%	18.0%		165.0%	142.0%	30.3%	28.1%		260.8%	197.7%	22.0%	16.9%
Caledon OH 01														
Caledon CH 02	77.5%	57.0%	16.6%	16.2%										
Caledon OH 06	31.4%	21.9%	9.4%	8.8%										
Caledon OH 07	69.5%	53.7%	23.5%	22.8%										
Caledon CH						63.9%	53.5%	17.0%	15.1%		61.9%	45.1%	9.5%	5.0%

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Exhibit G1
Tab 7
Schedule 2

	Residential					**GS<50***					**GS>50**			
Acquired LDC	Basic Distribution Bill Only	Distribution Bill incl Riders	Total Bill incl Distribution and Riders	Total Bill incl Distribution and Riders plus RTSR		Basic Distribution Bill Only	Distribution Bill incl Riders	Total Bill incl Distribution and Riders	Total Bill incl Distribution and Riders plus RTSR		Basic Distribution Bill Only	Distribution Bill incl Riders	Total Bill incl Distribution and Riders	Total Bill incl Distribution and Riders plus RTSR
Caledon OH						65.7%	54.2%	17.2%	15.2%		72.7%	52.5%	10.6%	6.0%
Caledon Large User														
Campbellford-Seymour	96.0%	62.2%	17.7%	17.3%		146.8%	122.0%	28.1%	25.9%		145.9%	107.4%	16.5%	11.7%
Carleton Place	40.5%	23.6%	9.0%	8.6%		72.4%	61.6%	18.7%	16.7%		74.4%	56.2%	11.1%	6.5%
Cavan-Millbrook-North Monaghan	58.6%	24.2%	9.4%	9.0%		88.8%	60.4%	18.9%	16.9%		97.8%	51.5%	10.9%	6.4%
Centre Hastings	111.9%	81.2%	21.0%	20.5%		161.2%	136.4%	29.8%	27.6%		198.3%	147.6%	19.5%	14.5%
Chalk River	62.5%	28.6%	10.6%	10.2%		72.8%	45.5%	15.7%	13.8%		63.3%	27.7%	7.0%	2.6%
Champlain	135.2%	81.0%	21.3%	20.9%		154.4%	114.0%	27.4%	25.3%		215.4%	125.5%	18.5%	13.6%
Cobden	47.0%	17.4%	7.4%	7.0%		53.0%	33.2%	12.5%	10.6%		43.8%	17.7%	4.8%	0.5%
Deep River	14.0%	3.0%	2.5%	2.1%		42.8%	33.9%	12.5%	10.6%		30.0%	18.5%	4.8%	0.5%
Deseronto	87.1%	58.5%	17.0%	16.6%		165.7%	141.9%	30.3%	28.1%		143.8%	112.1%	16.9%	12.0%
Dryden	46.4%	26.1%	9.7%	9.3%		148.5%	129.2%	28.9%	26.7%		178.7%	140.5%	18.9%	14.0%
Dundalk	78.4%	51.0%	15.5%	15.1%		75.1%	58.3%	18.1%	16.1%		79.0%	51.3%	10.5%	5.9%
Durham	56.8%	32.5%	11.3%	10.9%		91.6%	77.3%	21.6%	19.5%		113.1%	85.1%	14.5%	9.7%
Eganville	54.6%	38.0%	12.6%	12.2%		45.7%	35.9%	13.0%	11.1%		27.4%	15.3%	4.1%	-0.2%
Erin	40.3%	9.6%	4.8%	4.5%		79.5%	64.2%	19.2%	17.2%		259.4%	174.1%	21.1%	16.1%
Exeter	82.5%	50.5%	15.5%	15.0%		164.2%	137.6%	29.9%	27.7%		128.1%	95.9%	15.5%	10.7%
Fenelon Falls	187.3%	139.6%	28.3%	27.8%		154.3%	128.4%	29.0%	26.8%		202.0%	147.3%	19.6%	14.6%
Forest	82.0%	52.2%	15.8%	15.4%		103.5%	86.7%	23.1%	21.1%		143.7%	106.5%	16.5%	11.7%
GBE	135.0%	83.4%	21.4%	20.9%		194.0%	160.1%	32.2%	30.0%		157.2%	116.8%	17.3%	12.5%
Georgina	109.4%	78.7%	20.5%	20.1%		98.2%	81.6%	22.4%	20.3%		83.0%	60.3%	11.7%	7.0%

	Residential					**GS<50***					**GS>50**			
Acquired LDC	Basic Distribution Bill Only	Distribution Bill incl Riders	Total Bill incl Distribution and Riders	Total Bill incl Distribution and Riders plus RTSR		Basic Distribution Bill Only	Distribution Bill incl Riders	Total Bill incl Distribution and Riders	Total Bill incl Distribution and Riders plus RTSR		Basic Distribution Bill Only	Distribution Bill incl Riders	Total Bill incl Distribution and Riders	Total Bill incl Distribution and Riders plus RTSR
Glencoe	118.8%	45.0%	14.8%	14.4%		258.0%	188.7%	35.2%	32.9%		263.2%	160.1%	20.7%	15.7%
Grand Bend	102.3%	65.6%	18.4%	17.9%		110.9%	90.3%	23.8%	21.7%		135.3%	96.1%	15.6%	10.8%
Hastings	50.5%	31.7%	11.1%	10.7%		74.1%	57.5%	17.9%	15.9%		74.3%	47.9%	10.0%	5.4%
Havelock	69.6%	48.1%	14.9%	14.5%		87.7%	72.6%	20.8%	18.8%		91.9%	67.1%	12.6%	7.9%
Kirkfield	193.8%	108.0%	25.4%	24.9%		83.8%	42.4%	15.1%	13.2%		58.7%	14.7%	4.2%	0.0%
Lanark Highlands	109.5%	56.5%	17.3%	16.9%		69.5%	33.1%	12.7%	10.9%		77.3%	22.6%	6.0%	1.7%
Larder Lake	73.8%	32.3%	11.6%	11.2%		90.6%	51.4%	17.1%	15.2%		115.0%	46.7%	10.3%	5.8%
Latchford	103.9%	32.9%	11.8%	11.4%		324.0%	152.1%	32.1%	29.9%		288.8%	96.6%	16.0%	11.2%
Lindsay	74.0%	46.8%	14.7%	14.2%		91.5%	77.2%	21.6%	19.5%		110.8%	82.8%	14.3%	9.5%
Lucan Granton	73.9%	48.1%	15.0%	14.6%		112.8%	92.2%	24.1%	22.1%		102.0%	73.4%	13.3%	8.6%
Malahide	126.8%	54.8%	16.8%	16.4%		78.0%	31.8%	12.3%	10.5%		72.7%	13.2%	3.8%	-0.4%
Mapleton	98.8%	47.0%	15.2%	14.8%		77.0%	48.6%	16.3%	14.4%		71.5%	32.3%	7.8%	3.4%
Markdale	96.8%	60.2%	17.5%	17.0%		153.1%	129.8%	29.0%	26.8%		252.8%	184.6%	21.4%	16.4%
Marmora	116.8%	81.8%	21.1%	20.6%		218.2%	181.5%	34.1%	31.8%		181.1%	134.6%	18.6%	13.7%
McGarry	103.5%	45.8%	15.0%	14.6%		64.5%	32.2%	12.5%	10.6%		64.1%	19.0%	5.2%	1.0%
Meaford	100.8%	66.0%	18.4%	18.0%		102.9%	85.8%	23.0%	21.0%		134.5%	99.6%	15.9%	11.1%
Middlesex Centre	105.0%	49.9%	15.9%	15.4%		120.6%	72.7%	21.5%	19.5%		179.8%	80.4%	14.8%	10.1%
Napanee	81.0%	50.7%	15.5%	15.1%		106.6%	89.3%	23.6%	21.5%		127.5%	93.9%	15.4%	10.6%
Nipigon	58.5%	7.4%	4.1%	3.8%		122.7%	84.0%	23.2%	21.1%		169.2%	89.1%	15.5%	10.8%
North Dorchester	156.5%	72.3%	20.3%	19.9%		191.3%	123.0%	29.0%	26.9%		222.3%	107.4%	17.5%	12.7%
North Dundas	116.0%	66.0%	18.5%	18.1%		227.7%	188.3%	34.6%	32.3%		279.6%	200.3%	22.1%	17.0%
North Glengarry	151.2%	85.1%	21.9%	21.5%		176.3%	136.2%	30.0%	27.8%		224.1%	141.6%	19.5%	14.5%

	Residential					**GS<50***					**GS>50**			
Acquired LDC	Basic Distribution Bill Only	Distribution Bill incl Riders	Total Bill incl Distribution and Riders	Total Bill incl Distribution and Riders plus RTSR		Basic Distribution Bill Only	Distribution Bill incl Riders	Total Bill incl Distribution and Riders	Total Bill incl Distribution and Riders plus RTSR		Basic Distribution Bill Only	Distribution Bill incl Riders	Total Bill incl Distribution and Riders	Total Bill incl Distribution and Riders plus RTSR
North Grenville	45.9%	27.9%	10.1%	9.7%		80.7%	68.0%	20.0%	17.9%		72.0%	53.3%	10.7%	6.1%
North Perth	78.6%	46.8%	14.7%	14.3%		99.3%	86.6%	23.1%	21.0%		183.0%	144.9%	19.2%	14.3%
North Stormont	208.3%	97.8%	24.3%	23.9%		370.7%	206.1%	37.2%	34.9%		273.8%	123.6%	18.8%	14.0%
Omemee	50.3%	31.8%	11.1%	10.7%		94.7%	77.2%	21.6%	19.6%		99.4%	71.2%	13.1%	8.4%
Perth	69.0%	38.9%	12.9%	12.5%		157.6%	135.8%	29.6%	27.4%		216.9%	166.1%	20.5%	15.4%
Perth East	227.8%	167.3%	30.7%	30.3%		144.0%	118.6%	27.8%	25.7%		128.4%	93.2%	15.4%	10.6%
Prince Edward	82.1%	53.6%	16.1%	15.6%		92.6%	75.7%	21.3%	19.3%		107.1%	76.3%	13.6%	8.9%
Quinte West	185.6%	120.4%	26.3%	25.9%		298.9%	243.6%	38.6%	36.2%		185.8%	139.0%	18.9%	14.0%
Rainy River	78.6%	31.7%	11.6%	11.2%		81.1%	48.2%	16.4%	14.5%		66.9%	26.2%	6.7%	2.4%
Ramara	181.3%	92.6%	23.5%	23.1%		134.0%	79.2%	22.8%	20.8%		172.9%	72.4%	14.1%	9.5%
Red Rock	25.5%	2.2%	2.2%	1.9%		63.3%	44.9%	15.4%	13.5%		51.6%	27.5%	6.8%	2.4%
Rockland	142.2%	68.0%	19.5%	19.0%		261.9%	190.7%	35.8%	33.5%		261.9%	165.0%	21.2%	16.2%
Russell	63.8%	45.8%	14.4%	14.0%		54.1%	42.8%	14.7%	12.7%		32.1%	18.7%	4.8%	0.5%
Schreiber	29.8%	6.9%	3.9%	3.5%		39.2%	18.7%	8.3%	6.5%		27.3%	2.6%	1.0%	-3.0%
Severn	130.0%	66.9%	19.1%	18.7%		127.6%	88.9%	24.0%	21.9%		172.2%	93.6%	16.0%	11.2%
Shelburne	64.3%	40.8%	13.3%	12.9%		163.8%	146.1%	30.6%	28.4%		226.6%	183.3%	21.3%	16.2%
Smiths Falls	68.0%	40.1%	13.2%	12.8%		220.0%	189.0%	34.6%	32.4%		181.2%	141.7%	19.0%	14.1%
South Glengarry	165.8%	87.5%	22.8%	22.3%		204.5%	126.1%	29.6%	27.4%		282.7%	122.8%	19.0%	14.1%
South River	68.7%	31.5%	11.4%	11.0%		83.8%	53.4%	17.5%	15.5%		90.0%	43.2%	9.7%	5.2%
Springwater	125.5%	63.8%	18.5%	18.1%		135.4%	99.0%	25.4%	23.3%		167.8%	99.5%	16.3%	11.5%
Stirling-Rawdon	97.3%	64.8%	18.2%	17.8%		96.9%	77.1%	21.6%	19.6%		123.0%	83.5%	14.5%	9.7%
Terrace Bay	27.6%	-0.7%	1.8%	6.0%		52.0%	19.9%	9.4%	11.7%		54.3%	10.4%	3.7%	4.5%

	Residential					**GS<50***					**GS>50**			
Acquired LDC	Basic Distribution Bill Only	Distribution Bill incl Riders	Total Bill incl Distribution and Riders	Total Bill incl Distribution and Riders plus RTSR		Basic Distribution Bill Only	Distribution Bill incl Riders	Total Bill incl Distribution and Riders	Total Bill incl Distribution and Riders plus RTSR		Basic Distribution Bill Only	Distribution Bill incl Riders	Total Bill incl Distribution and Riders	Total Bill incl Distribution and Riders plus RTSR
Thedford	116.2%	45.7%	15.1%	14.7%		152.9%	97.9%	25.7%	23.6%		172.4%	83.1%	15.2%	10.6%
Thessalon	73.0%	52.7%	15.9%	15.4%		97.8%	85.4%	23.0%	20.9%		184.7%	154.5%	19.9%	14.9%
Thorndale	243.5%	112.7%	26.2%	25.8%		182.6%	101.0%	26.2%	24.1%		184.9%	71.4%	13.9%	9.2%
Thorold	58.8%	36.1%	12.2%	11.8%		87.5%	73.8%	21.0%	18.9%		94.1%	70.9%	12.9%	8.2%
Tweed	222.4%	103.5%	25.2%	24.7%		256.8%	144.4%	31.8%	29.6%		201.7%	87.6%	15.7%	11.0%
Wardsville	133.0%	90.9%	22.4%	22.0%		205.4%	154.8%	31.8%	29.6%		194.2%	122.4%	17.9%	13.0%
Warkworth	66.6%	29.1%	10.8%	10.4%		90.9%	54.0%	17.7%	15.7%		106.7%	46.2%	10.3%	5.8%
West Elgin	63.9%	29.2%	10.7%	10.3%		235.7%	189.4%	34.8%	32.6%		311.5%	210.9%	22.8%	17.7%
Whitchurch Stouffville	117.3%	79.7%	20.8%	20.3%		144.0%	126.4%	28.6%	26.4%		209.3%	165.3%	20.4%	15.4%
Wiarton	43.9%	26.5%	9.8%	9.4%		60.3%	47.9%	15.8%	13.9%		55.1%	36.8%	8.2%	3.7%
Woodville	239.4%	125.5%	27.5%	27.1%		104.4%	50.3%	17.1%	15.2%		114.3%	34.9%	8.5%	4.1%
Wyoming	129.7%	88.3%	22.1%	21.6%		112.9%	94.2%	24.3%	22.3%		103.6%	75.8%	13.5%	8.8%
Bill Impacts for Urban Residential and General Service Customer Classes														
Arnprior	42.0%	17.8%	6.4%	5.8%		20.7%	10.0%	4.4%	2.5%		93.6%	62.3%	9.7%	6.8%
Brockville	72.3%	37.8%	11.0%	10.3%		45.1%	32.1%	8.5%	6.5%		181.7%	130.0%	14.6%	11.6%
Caledon OH 01	53.9%	28.6%	9.0%	8.4%										
Carleton Place	16.2%	3.1%	2.1%	1.6%		-5.6%	-11.4%	-1.1%	-2.9%		36.2%	21.1%	4.4%	1.6%
Dryden	21.1%	5.2%	2.8%	2.2%		36.1%	25.1%	7.3%	5.4%		117.6%	85.9%	11.7%	8.8%
GBE	94.3%	52.8%	13.8%	13.1%		61.0%	42.4%	10.2%	8.1%		100.8%	67.9%	10.2%	7.3%
Lindsay	43.8%	22.3%	7.5%	6.8%		4.9%	-3.0%	1.3%	-0.6%		64.6%	41.6%	7.3%	4.5%
Perth	39.7%	16.0%	5.9%	5.3%		41.1%	28.7%	8.0%	6.0%		147.5%	105.6%	13.1%	10.2%
Quinte West	136.1%	83.4%	18.4%	17.7%		118.5%	88.2%	15.4%	13.3%		123.2%	85.0%	11.7%	8.8%
Smiths Falls	38.9%	16.9%	6.1%	5.5%		75.3%	57.7%	12.1%	10.1%		119.5%	86.8%	11.8%	8.9%

	Residential					**GS<50***					**GS>50**			
Acquired LDC	Basic Distribution Bill Only	Distribution Bill incl Riders	Total Bill incl Distribution and Riders	Total Bill incl Distribution and Riders plus RTSR		Basic Distribution Bill Only	Distribution Bill incl Riders	Total Bill incl Distribution and Riders	Total Bill incl Distribution and Riders plus RTSR		Basic Distribution Bill Only	Distribution Bill incl Riders	Total Bill incl Distribution and Riders	Total Bill incl Distribution and Riders plus RTSR
Thorold	31.3%	13.4%	5.1%	4.5%		2.7%	-4.8%	0.8%	-1.1%		51.6%	32.4%	6.1%	3.3%
Whitchurch Stouffville	79.7%	49.6%	13.2%	12.5%		33.7%	23.6%	7.1%	5.1%		141.5%	105.1%	13.1%	10.2%
Simple Ave	98.7%	54.7%	15.4%	15.0%		122.0%	89.0%	21.8%	19.7%		141.1%	88.2%	13.7%	9.2%
Min	14.0%	-0.7%	1.8%	1.6%		-5.6%	-11.4%	-1.1%	-2.9%		27.3%	2.6%	1.0%	-3.0%
Max	434.0%	167.3%	31.4%	30.9%		383.8%	243.6%	38.6%	36.2%		377.6%	210.9%	22.8%	17.7%

* Excludes impact of $0.35 adder for USL credit

3.0 CONCLUSION

The results in Table 1 above show that prior to mitigation some customer classes would see an average impact higher than 10 percent on total bill as a result of the target Distribution rates. To mitigate impacts Hydro One is proposing to phase-in the target fixed and volumetric charges calculated using the Cost Allocation Methodology for Acquired customers over a period of four years.

Exhibit G1, Tab 8, Schedule 2, describes the mitigation plan for customer classes that would have seen an impact higher than 10 percent prior to mitigation.

BILL IMPACTS SUB-TRANSMISSION CUSTOMERS

This schedule presents an assessment of the Sub-Transmission (ST) customer bill impacts. The impacts are due to both the change in Revenue Requirement and the customers' transition from their existing classes to the proposed ST class. The proposed ST rates are described in Exhibits G1, Tab 4, Schedule 4. The existing classes mapped to ST include Urban General Service, Three-Phase General Service, Three-Phase Farms, T-class, Acquired General Service, Acquired Large Users, Embedded Direct and Embedded LDCs. The bill impact assumes no change to other non-ST related charges, except the creation of Regulatory Asset Rate Rider # 3 described in Exhibit G1, Tab 5, Schedule 3, ending Regulatory Rate Rider # 1, and the proposed change to Retail Transmission Service Rates (RTSR) as described in Exhibit G1, Tab 6, Schedule 1. Commodity costs are assumed to be 5.2 ¢/kWh. Total Loss Factor proposed for the ST class is 3.4% as explained in Exhibit G1, Tab 10, Schedule 1. Impacts include the recovery for Regulatory Asset # 2 as approved by the OEB.

1.0 ESTIMATED CUSTOMER BILL IMPACTS

The table below presents estimates of annual bill revenue by customer classification.

Table 1
Bill Impacts for ST Customers

Customer Existing Rate class	Total current Bill with Rate Riders ($M/yr)	2008 Change in DX related charges ($M/yr)	Change in Regulatory Asset Rate Riders ($M)	2008 Change in RTSR and Losses ($M/yr)	Total 2008 Bill ($M/yr)	Total Bill Impact (%)
UGS	6.6	(1.1)	(0.1)	(0.0)	5.3	(18.7)
Acquired General Service	51.2	(2.6)	(1.1)	(0.0)	47.5	(7.3)
Three-phase General Service	41.2	(8.9)	(0.4)	0.3	32.3	(21.7)
T class	92.7	(16.5)	(0.8)	1.2	76.5	(17.5)
Large Users	28.7	(2.8)	(0.4)	0.1	25.6	(10.8)
Embedded LDC (LV)	1,004.1	(2.2)	(8.1)	(19.4)	974.4	(3.0)
Embedded Direct (LV)	229.8	(0.1)	(2.1)	(3.4)	224.1	(2.5)

2.0 DISCUSSION OF CUSTOMER BILL IMPACTS

The total bill impacts for Embedded LDCs and Embedded Direct customers shown in Table 1 takes into account only the load supplied to Embedded customers by Hydro One's ST facilities. Embedded LDCs and Embedded Directs may also be supplied through Transmission connections. For this reason a range of impacts has not been provided in this submission for Embedded LDCs and Embedded Direct customers as it would not represent the impact on the total embedded customer load, only an average group impact is provided.

All customer classes being mapped to the new ST customer class will see estimated average bill impact reductions. The proposed ST rates will be implemented in 2008 and are not proposed to be phased-in over multiple years.

The impact of Regulatory Asset Rate Rider # 3 and the revised RTSR have been included in the total bill impacts.

MITIGATION OF BILL IMPACTS LEGACY CUSTOMERS

This exhibit presents the proposed impact mitigation plan for Legacy customers. As per the guidelines in the 2006 Electricity Distribution Rate Handbook, LDCs have to present a mitigation plan, if as a result of the proposed rate increase, customer classes or group of customers have yearly impacts higher than 10 percent on total bill.

1.0 INTRODUCTION

As was shown in Exhibit G1, Tab 7, Schedule 1, R3 Seasonal customers prior to mitigation would see impacts higher than 10 percent on total bill resulting from the proposed increase in 2008 Revenue Requirement, moving distribution rates to the target distribution rates determined by using the Cost Allocation Study methodology, creating new customer groups, Regulatory Asset Rate Rider # 3, and RTSR changes.

The bill impact mitigation that Hydro One Distribution proposes includes the following approach to address the impacts on the customer class that could see impacts, on average, of over 10 percent on total bill.

1. Average total bill impacts have been limited to a maximum of 10% in 2008, 8% in 2009, and 7% in 2010. These maximums still leave some room to accommodate third generation Incentive Rate Mechanism increases. Increases in 2011 reflect the remaining increases resulting from the multi-year proposed harmonization process and are under 10% on average total bill
2. Regulatory Rate Rider # 3 is being refunded over 4 years, consistent with Hydro One approved past practices for Regulatory Rate Riders and to provide for a smoother bill impact over the 4 year period.

3. The target revenue to cost ratio proposed for the various customer groups is in the range of 0.7 to 1.2, as opposed to using revenue to cost ratio of 1. This is consistent with the Board's Report issued November 28, 2007.
4. The target distribution rates are being phased-in over a period of four years.
5. A deferral account is being set up to recover the shortfall in 2008 proposed Revenue Requirement that results from Hydro One's proposed Revenue to Cost Ratios by customer class. The revenue to cost ratios are consistent with the Board's recommended revenue to cost ratios. Table 1 and 2 do not include the effect of the $0.07/kW CSTA rate adder.

Table 1 below shows the initial 2008 Distribution rates derived in Exhibits G1, Tab 4, Schedule 2, and the adjusted 2008 Distribution rates after taking into account the four year phase-in period for the customer classes.

Table 1
2008 Distribution Rates

	2008 Initial Distribution Rates		2008 Mitigated Distribution Rates	
	Target Fixed Service Charge [$/cust]	Target Volumetric Charge [¢/kWh or $/kW]]	Target Fixed Service Charge [$/cust]	Target Volumetric Charge [¢/kWh or $/kW]]
UR	14.32	2.29	14.00	2.44
R1	19.04	2.60	19.00	2.81
R2	49.91	3.10	26.2* - 30.64*	2.2 - 2.68
Seasonal	19.51	6.38	19 - 33.18	3.2 - 4.7
Uge	12.33	2.09	14.27	2.00
Ugd	29.19	7.25	18.49	7.42
Gse	30.97	3.39	34.74*** - 203.36***	3.38
GSd	46.75	9.22	38.68 - 207.3	9.44
Street Light	1.00	4.57	1.00**	4.57
Sentinel	1.00	5.30	1.00**	5.30
DGen	36.66	7.07	36.66	7.07

*Net of RRRP **Nominal fixed Charge ***Excludes $0.35 adder for USL meter credit

All Legacy customer rate classes, with the exception of Street Lights, Sentinel Lights, and Distributed Generator are being phased-in to the target distribution rates over a four year period, similar to the period over which Acquired customer classes will be harmonized. Street Lights and Sentinel Lights achieve their corresponding target rates in 2008 since the total bill impact is less than 10 percent, or is less than $1.80 per month per connection. Distributed Generator rates are also not being phased in as the majority of these customers see bill decreases. The range in fixed charges provided in Table 1 above reflects the fact that in many instances there are various legacy customer classes being mapped into the new customer classes. It also includes Caledon classes being mapped to R2 and Seasonal groups, Terrace Bay Street lights, and an Acquired General Service customer being mapped to Distributed Generator group.

For USL, Hydro One is proposing to mitigate the impact to these type of customers by setting a volumetric charge that results in annual bill impacts near $10 per month. The fixed charge is being phased-in in a similar fashion as for the other Acquired LDC customers. The shortfall in revenues resulting from this mitigation measure for USL customers is being recovered from the current USL General Service single-phase energy billed customers.

The following table shows the bill impacts for the customer groups using the mitigated Distribution rates. All customer classes have impacts of less than 10% on total bill with the exception of Distributed Generator, Street Light and Sentinel Light. Street Light and Sentinel Light have total bill impacts of less than $1.80 per month per connection. Fifty one Distributed Generators will see bill decreases. Twenty nine Distributed Generators are estimated to have total bill impacts of 15%. One Distributed Generator customer has a total bill impact of 112%, or approximately $25 per month.

Table 2
2008 Customer Class Total Bill Impact after Mitigation Plan

	Bill Impact % increase/(decrease)
UR	(11) to 1.9
R1	1.30
R2	(1.8) to 9
Seasonal	7 to 9.8
Urban General Service energy	(21.5) to (8.8)
Urban General Service demand	(10) to (5.6)
General Service energy	(8.4) to 2.5
General Service demand	(7.7) to 1.5
Street Light	5 to 21.9
Sentinel	25.0
Distributed Generator	(30.9) to 111.9

The range in bill impacts provided in Table 2 above reflects the various legacy customer groups being mapped into the new customer groups. It also includes Caledon classes being mapped to R2 and Seasonal groups, Terrace Bay Street lights, and an Acquired General Service customer being mapped to Distributed Generator group.

Combining the proposed Distribution rates with other applicable charges and using 2008 sales forecast, customer bills can be calculated for all customer classes and groups. Schedule 3 through Schedule 6 of Exhibit G2, Tab 5 show the results of the bill impact analysis for each Legacy customer group broken down by levels of consumption for each customer class. Schedule 3 provides the impacts due to Distribution revenue increase only on the distribution portion of the bill. Schedule 4 shows the impact of the Distribution rate changes due to revenue requirement increase and Regulatory Rate Rider # 3 only on the Distribution portion of the bill. Schedule 5 shows total bill impacts that include Regulatory Rate Rider # 3 and 2008 revenue increase, but exclude RTSR changes. Schedule 6 shows total bill impacts due to all rate changes.

The complete 2008 Rate Schedule is provided in Exhibit G2, Tab 5 Schedule 1.

MITIGATION OF BILL IMPACTS ACQUIRED LDC CUSTOMERS

This exhibit presents the proposed impact mitigation plan for Acquired LDC customers. As per the guidelines in the 2006 Electricity Distribution Rate Handbook, LDCs have to present a mitigation plan if as a result of the proposed rate increase customer classes, or group of customers, have impacts higher than 10 percent on total bill.

1.0 INTRODUCTION

As was shown in Exhibit G1, Tab 7, Schedule 2, customer classes of Acquired LDCs prior to mitigation would see impacts higher than 10 percent on total bill resulting from the proposed increase in 2008 Revenue Rates, harmonization of distribution rates, Regulatory Asset Rate Rider # 3, and RTSR changes.

Hydro One Distribution proposes the following mitigation initiatives to address the impacts on the Acquired LDC customer classes that could see impacts, on average, of over 10 percent on total bill.

1. The target distribution rates are being phased-in over a period of four years. Average total bill impacts have been limited to a maximum of 10% in 2008, 8% in 2009, and 7% in 2010. These maximums leave some room to accommodate third generation Incentive Rate Mechanism increases. Increases in 2011 reflect the remaining increases resulting from the multi-year proposed harmonization process and result in average total bill impacts below 10%. The volumetric charges were adjusted as necessary each year to limit total bill impacts in 2008, 2009 and 2010. Any shortfall in revenues resulting from this mitigation measure is being absorbed first by the Acquired LDC in subsequent years, and if this is not possible, then by the Legacy

customer classes in the same group as the Acquired customer classes requiring mitigation.

2. Regulatory Rate Rider # 3 is being refunded over 4 years consistent with Hydro One approved past practices with respect to Regulatory Rate Riders and to provide for a smoother bill impacts over the 4 year period.
3. The target revenue to cost ratio range proposed is between 0.7 and 1.2 instead of proposing revenue to cost ratio of 1. This is consistent with the Board's Report issued November 28, 2007.
4. Proposed rates in 2010 and 2011 were adjusted to provide for a smoother set of impacts in those years.
5. A deferral account is being set up to recover the shortfall in 2008 proposed Revenue Requirement that results from Hydro One's proposed Revenue to Cost Ratios by customer class. The Revenue to Cost ratios are consistent with the Board's recommended Revenue to Cost ratios.

Table 1, below shows the initial 2008 Distribution rates derived in Exhibits G1, Tab 4, Schedule 3, and the adjusted 2008 Distribution rates after taking into account the rate mitigation initiative above for the customer classes.

The complete 2008 Rate Schedules are provided in Exhibit G2, Tabs 6 to Tab 93.

Table 1
2008 Distribution Rates

	Residential				GS<50				GS>50			
Acquired LDC	**2008 Initial**		**2008 Mitigated**		**2008 Initial**		**2008 Mitigated**		**2008 Initial**		**2008 Mitigated**	
	SrChg	¢/kWh	SrChg	¢/kWh	SrChg*	¢/kWh	SrChg*	¢/kWh	SrChg	$/kW	SrChg	$/kW
Ailsa Craig	12.13	2.71	12.13	1.85	20.41	3.21	20.41	2.34	24.36	9.22	24.36	9.00
Arkona	8.30	2.71	8.30	1.50	9.94	3.21	9.94	1.98	13.89	9.22	13.89	9.22
Arnprior	12.88	2.71	11.70	2.40	23.40	3.21	18.74	2.00	27.34	9.22	22.95	7.33
Arran-Elderslie	11.51	2.71	11.51	1.90	13.53	3.21	13.53	1.90	17.48	9.22	17.48	8.00
Artemesia	13.58	2.71	13.58	2.35	21.84	3.21	21.84	3.21	25.78	9.22	25.78	9.22
Bancroft	14.39	2.71	14.39	2.10	25.64	3.21	25.64	2.30	29.59	9.22	29.59	8.50
Bath	14.42	2.71	14.42	2.35	15.08	3.21	15.08	2.55	19.03	9.22	19.03	9.00
Blandford-Blenheim	12.85	2.71	12.85	2.30	24.78	3.21	24.78	2.40	28.73	9.22	28.73	8.90
Blyth	9.96	2.71	9.96	2.00	23.33	3.21	23.33	2.20	27.28	9.22	27.28	8.50
Bobcaygeon	15.14	2.71	15.14	2.05	24.94	3.21	24.94	2.50	28.89	9.22	28.89	9.22
Brighton	12.86	2.71	12.86	2.20	24.02	3.21	24.02	2.50	27.96	9.22	27.96	9.22
Brockville	13.68	2.71	12.50	2.40	23.33	3.21	18.67	2.00	27.28	9.22	22.89	6.70
Caledon OH 01	-	2.71	16.95	2.15	-	3.21	-	-	-	9.22	-	-

	Residential				GS<50				GS>50			
Acquired LDC	**2008 Initial**		**2008 Mitigated**		**2008 Initial**		**2008 Mitigated**		**2008 Initial**		**2008 Mitigated**	
	SrChg	¢/kWh	SrChg	¢/kWh	SrChg*	¢/kWh	SrChg*	¢/kWh	SrChg	$/kW	SrChg	$/kW
Caledon CH 02	15.96	2.71	15.96	2.10	-	3.21	-	-	-	9.22	-	-
Caledon OH 06	30.64	2.67	30.64	2.20	-	3.21	-	-	-	9.22	-	-
Caledon OH 07	33.18	4.69	33.18	3.20	-	3.21	-	-	-	9.22	-	-
Caledon CH	-	2.71	-	-	25.69	3.21	25.69	2.90	29.64	9.22	29.64	9.22
Caledon OH	-	2.71	-	-	26.35	3.21	26.35	2.90	30.30	9.22	30.30	9.22
Campbellford-Seymour	13.69	2.71	13.69	2.25	19.69	3.21	19.69	2.15	23.64	9.22	23.64	8.50
Carleton Place	15.22	2.71	14.04	2.40	24.83	3.21	20.17	2.00	28.78	9.22	24.39	7.33
Cavan-Millbrook-North Monaghan	16.01	2.71	16.01	2.71	24.17	3.21	24.17	2.80	28.12	9.22	28.12	9.22
Centre Hastings	12.84	2.71	12.84	2.00	21.15	3.21	21.15	1.94	25.09	9.22	25.09	7.70
Chalk River	15.25	2.71	15.25	2.71	23.41	3.21	23.41	3.18	27.36	9.22	27.36	9.22
Champlain	12.17	2.71	12.17	2.00	22.59	3.21	22.59	2.05	26.54	9.22	26.54	8.00
Cobden	14.49	2.71	14.49	2.71	23.26	3.21	23.26	3.21	27.21	9.22	27.21	9.22
Deep River	16.61	2.71	16.61	2.71	24.76	3.21	24.76	3.21	28.70	9.22	28.70	9.22
Deseronto	13.54	2.71	13.54	2.30	15.21	3.21	15.21	2.18	19.15	9.22	19.15	8.50
Dryden		2.71		2.40		3.21		2.00				

	Residential				GS<50				GS>50			
Acquired LDC	**2008 Initial**		**2008 Mitigated**		**2008 Initial**		**2008 Mitigated**		**2008 Initial**		**2008 Mitigated**	
	SrChg	¢/kWh	SrChg	¢/kWh	SrChg*	¢/kWh	SrChg*	¢/kWh	SrChg	$/kW	SrChg	$/kW
	15.19		14.01		21.96		17.31		25.91	9.22	21.52	7.33
Dundalk	15.14	2.71	15.14	2.30	24.85	3.21	24.85	2.85	28.80	9.22	28.80	9.22
Durham	16.67	2.71	16.67	2.60	25.71	3.21	25.71	2.48	29.66	9.22	29.66	9.22
Eganville	14.30	2.71	14.30	2.71	23.40	3.21	23.40	3.21	27.35	9.22	27.35	9.22
Erin	14.48	2.71	14.48	2.71	37.65	3.21	37.65	2.10	41.59	9.22	41.59	7.20
Exeter	15.99	2.71	15.99	2.25	15.90	3.21	15.90	2.18	19.85	9.22	19.85	8.95
Fenelon Falls	9.24	2.71	9.24	1.70	21.79	3.21	21.79	1.98	25.74	9.22	25.74	7.75
Forest	15.95	2.71	15.95	2.20	25.51	3.21	25.51	2.32	29.46	9.22	29.46	8.50
GBE	11.34	2.71	10.16	2.35	15.05	3.21	10.39	2.00	19.00	9.22	14.61	7.33
Georgina	12.83	2.71	12.83	2.05	20.39	3.21	20.39	2.65	24.34	9.22	24.34	9.22
Glencoe	13.54	2.71	13.54	2.55	15.90	3.21	15.90	1.74	19.85	9.22	19.85	7.40
Grand Bend	14.37	2.71	14.37	2.10	24.19	3.21	24.19	2.34	28.14	9.22	28.14	8.75
Hastings	16.65	2.71	16.65	2.65	24.02	3.21	24.02	2.93	27.97	9.22	27.97	9.22
Havelock	15.97	2.71	15.97	2.30	24.20	3.21	24.20	2.60	28.14	9.22	28.14	9.22
Kirkfield	8.43	2.71	8.43	2.00	18.07	3.21	18.07	3.21	22.02	9.22	22.02	9.22
Lanark Highlands		2.71		2.35		3.21		3.21				

	Residential				GS<50				GS>50			
Acquired LDC	**2008 Initial**		**2008 Mitigated**		**2008 Initial**		**2008 Mitigated**		**2008 Initial**		**2008 Mitigated**	
	SrChg	¢/kWh	SrChg	¢/kWh	SrChg*	¢/kWh	SrChg*	¢/kWh	SrChg	$/kW	SrChg	$/kW
	12.93		12.93		21.13		21.13		25.08	9.22	25.08	9.22
Larder Lake	15.80	2.71	15.80	2.70	22.70	3.21	22.70	3.05	26.64	9.22	26.64	9.22
Latchford	14.43	2.71	14.43	2.71	9.02	3.21	9.02	2.32	12.97	9.22	12.97	8.80
Lindsay	15.81	2.71	14.63	2.40	24.76	3.21	20.10	2.00	28.70	9.22	24.31	7.33
Lucan Granton	12.83	2.71	12.83	2.60	19.49	3.21	19.49	2.53	23.44	9.22	23.44	9.22
Malahide	12.97	2.71	12.97	2.40	18.78	3.21	18.78	3.21	22.69	9.22	22.69	9.22
Mapleton	14.39	2.71	14.39	2.40	23.35	3.21	23.35	3.11	27.30	9.22	27.30	9.22
Markdale	15.19	2.71	15.19	2.10	24.99	3.21	24.99	1.82	28.94	9.22	28.94	7.25
Marmora	12.86	2.71	12.86	2.00	15.24	3.21	15.24	1.88	19.18	9.22	19.18	8.00
McGarry	13.55	2.71	13.55	2.50	21.74	3.21	21.74	3.21	26.64	9.22	26.64	9.22
Meaford	13.57	2.71	13.57	2.20	25.73	3.21	25.73	2.32	29.68	9.22	29.68	8.75
Middlesex Centre	15.21	2.71	15.21	2.25	20.40	3.21	20.40	2.70	24.35	9.22	24.35	9.00
Napanee	15.09	2.71	15.09	2.35	24.20	3.21	24.20	2.35	28.15	9.22	28.15	8.90
Nipigon	15.20	2.71	15.20	2.71	24.91	3.21	24.91	2.34	28.86	9.22	28.86	8.80
North Dorchester	10.52	2.71	10.52	2.25	18.77	3.21	18.77	2.08	22.72	9.22	22.72	8.30
North Dundas		2.71		2.25		3.21		1.72				

	Residential				GS<50				GS>50			
Acquired LDC	**2008 Initial**		**2008 Mitigated**		**2008 Initial**		**2008 Mitigated**		**2008 Initial**		**2008 Mitigated**	
	SrChg	¢/kWh	SrChg	¢/kWh	SrChg*	¢/kWh	SrChg*	¢/kWh	SrChg	$/kW	SrChg	$/kW
	12.97		12.97		17.36		17.36		21.31	9.22	21.31	7.00
North Glengarry	9.83	2.71	9.83	2.20	20.31	3.21	20.31	1.95	24.26	9.22	24.26	7.70
North Grenville	15.16	2.71	15.16	2.71	22.64	3.21	22.64	2.79	26.58	9.22	26.58	9.22
North Perth	15.08	2.71	15.08	2.40	29.36	3.21	29.36	2.15	33.31	9.22	33.31	7.70
North Stormont	8.41	2.71	8.41	2.10	11.40	3.21	11.40	1.78	15.35	9.22	15.35	9.22
Omemee	15.01	2.71	15.01	2.71	23.42	3.21	23.42	2.55	27.37	9.22	27.37	9.22
Perth	15.14	2.71	13.96	2.40	21.76	3.21	17.10	2.00	25.71	9.22	21.32	7.15
Perth East	8.27	2.71	8.27	1.60	18.08	3.21	18.08	2.25	22.03	9.22	22.03	8.95
Prince Edward	15.20	2.71	15.20	2.25	24.03	3.21	24.03	2.57	27.98	9.22	27.98	9.22
Quinte West	9.12	2.71	7.94	2.10	9.81	3.21	5.15	2.00	13.75	9.22	9.36	7.33
Rainy River	16.00	2.71	16.00	2.65	21.92	3.21	21.92	3.18	25.87	9.22	25.87	9.22
Ramara	9.13	2.71	9.13	2.10	22.50	3.21	22.50	2.48	26.45	9.22	26.45	9.22
Red Rock	15.96	2.71	15.96	2.71	23.33	3.21	23.33	3.21	27.28	9.22	27.28	9.22
Rockland	11.41	2.71	11.41	2.30	12.92	3.21	12.92	1.80	16.87	9.22	16.87	7.25
Russell	14.48	2.71	14.48	2.50	21.93	3.21	21.93	3.21	25.87	9.22	25.87	9.22
Schreiber		2.71		2.71		3.21		3.21				

	Residential				GS<50				GS>50			
Acquired LDC	**2008 Initial**		**2008 Mitigated**		**2008 Initial**		**2008 Mitigated**		**2008 Initial**		**2008 Mitigated**	
	SrChg	¢/kWh	SrChg	¢/kWh	SrChg*	¢/kWh	SrChg*	¢/kWh	SrChg	$/kW	SrChg	$/kW
	16.68		16.68		22.57		22.57		26.51	9.22	26.51	9.22
Severn	12.11	2.71	12.11	2.25	24.20	3.21	24.20	2.30	28.15	9.22	28.15	8.70
Shelburne	15.23	2.71	15.23	2.55	22.74	3.21	22.74	1.79	26.69	9.22	26.69	7.25
Smiths Falls	13.60	2.71	12.42	2.40	14.28	3.21	9.62	2.00	18.23	9.22	13.84	7.33
South Glengarry	11.40	2.71	11.40	1.95	20.39	3.21	20.39	1.96	24.34	9.22	24.34	7.75
South River	15.21	2.71	15.21	2.71	24.21	3.21	24.21	2.95	28.16	9.22	28.16	9.22
Springwater	12.81	2.71	12.81	2.25	22.61	3.21	22.61	2.25	26.56	9.22	26.56	8.60
Stirling-Rawdon	13.62	2.71	13.62	2.20	25.71	3.21	25.71	2.47	29.66	9.22	29.66	9.22
Terrace Bay	19.56	2.71	19.56	2.71	38.41	3.21	38.41	2.67	231.38	9.22	231.38	9.22
Thedford	13.57	2.71	13.57	2.50	20.28	3.21	20.28	2.30	24.23	9.22	24.23	8.95
Thessalon	15.87	2.71	15.87	2.20	21.02	3.21	21.02	2.56	24.96	9.22	24.96	7.60
Thorndale	7.68	2.71	7.68	2.00	18.11	3.21	18.11	2.38	22.06	9.22	22.06	9.22
Thorold	14.34	2.71	13.16	2.40	24.08	3.21	19.43	2.00	28.03	9.22	23.64	7.33
Tweed	7.64	2.71	7.64	2.10	13.68	3.21	13.68	2.10	17.62	9.22	17.62	8.80
Wardsville	11.35	2.71	11.35	2.00	16.66	3.21	16.66	1.99	20.61	9.22	20.61	8.20
Warkworth		2.71		2.71		3.21		2.95				

	Residential				**GS<50**				**GS>50**			
Acquired LDC	**2008 Initial**		**2008 Mitigated**		**2008 Initial**		**2008 Mitigated**		**2008 Initial**		**2008 Mitigated**	
	SrChg	¢/kWh	SrChg	¢/kWh	SrChg*	¢/kWh	SrChg*	¢/kWh	SrChg	$/kW	SrChg	$/kW
	15.95		15.95		23.41		23.41		27.36	9.22	27.36	9.22
West Elgin	14.44	2.71	14.44	2.71	18.89	3.21	18.89	1.62	22.84	9.22	22.84	6.85
Whitchurch Stouffville	12.13	2.71	10.95	2.30	23.28	3.21	18.62	2.00	27.23	9.22	22.84	7.15
Wiarton	15.80	2.71	15.80	2.71	24.80	3.21	24.80	3.10	28.74	9.22	28.74	9.22
Woodville	6.82	2.71	6.82	2.00	19.52	3.21	19.52	3.21	23.47	9.22	23.47	9.22
Wyoming	12.88	2.71	12.88	1.90	20.40	3.21	20.40	2.46	24.35	9.22	24.35	9.22
	-	-	-	-	-	-			-	-	-	-
Acquired LDCs with Customers Classified as Urban												
Arnprior	11.70	2.40	11.70	2.40	18.74	2.00	18.74	2.00	22.95	7.33	22.95	7.33
Brockville	12.50	2.40	12.50	2.40	18.67	2.00	18.67	2.00	22.89	7.33	22.89	6.70
Caledon OH 01	16.95	2.40	16.95	2.15	-	-	-	-	-	-	-	-
Carleton Place	14.04	2.40	14.04	2.40	20.17	2.00	20.17	2.00	24.39	7.33	24.39	7.33
Dryden	14.01	2.40	14.01	2.40	17.31	2.00	17.31	2.00	21.52	7.33	21.52	7.33
GBE	10.16	2.40	10.16	2.35	10.39	2.00	10.39	2.00	14.61	7.33	14.61	7.33
Lindsay	14.63	2.40	14.63	2.40	20.10	2.00	20.10	2.00	24.31	7.33	24.31	7.33
Perth	13.96	2.40	13.96	2.40	17.10	2.00	17.10	2.00	21.32	7.33	21.32	7.15

	Residential				**GS<50**				**GS>50**			
Acquired LDC	**2008 Initial**		**2008 Mitigated**		**2008 Initial**		**2008 Mitigated**		**2008 Initial**		**2008 Mitigated**	
	SrChg	¢/kWh	SrChg	¢/kWh	SrChg*	¢/kWh	SrChg*	¢/kWh	SrChg	$/kW	SrChg	$/kW
Quinte West	7.94	2.40	7.94	2.10	5.15	2.00	5.15	2.00	9.36	7.33	9.36	7.33
Smiths Falls	12.42	2.40	12.42	2.40	9.62	2.00	9.62	2.00	13.84	7.33	13.84	7.33
Thorold	13.16	2.40	13.16	2.40	19.43	2.00	19.43	2.00	23.64	7.33	23.64	7.33
Whitchurch Stouffville	10.95	2.40	10.95	2.30	18.62	2.00	18.62	2.00	22.84	7.33	22.84	7.15

* Excludes $0.35 adder for USL meter credit

The following table shows the impacts for 2008 for the customer groups using the mitigated Distribution rates. As can be seen from Table 2, all customers of the Acquired LDCs have total bill impacts below 10% in 2008

Table 2
Ave Customer Total Bill Impact 2008

Acquired LDC	Residential	GS<50*	GS>50
Ailsa Craig	9.0%	8.9%	8.9%
Arkona	9.0%	8.8%	
Arnprior	4.3%	4.7%	6.9%
Arran-Elderslie	9.0%	8.8%	8.8%
Artemesia	9.0%	8.8%	1.9%
Bancroft	9.2%	8.7%	8.9%
Bath	8.9%	8.8%	8.9%
Blandford-Blenheim	8.9%	8.7%	9.0%
Blyth	8.7%	8.5%	9.0%
Bobcaygeon	8.8%	8.8%	8.8%
Brighton	9.1%	8.6%	8.9%
Brockville	9.6%	8.8%	9.5%
Caledon OH 01			
Caledon CH 02	8.8%		
Caledon OH 06	9.0%		
Caledon OH 07	9.5%		
Caledon CH		8.5%	4.6%
Caledon OH		8.9%	5.6%
Campbellford-Seymour	9.2%	8.7%	8.8%
Carleton Place	2.2%	-0.2%	1.8%
Cavan-Millbrook-North Monaghan	7.4%	8.8%	6.0%
Centre Hastings	9.0%	8.8%	8.9%
Chalk River	8.0%	8.8%	2.2%
Champlain	8.8%	8.7%	9.1%
Cobden	4.2%	6.0%	0.1%
Deep River	1.1%	6.5%	0.1%
Deseronto	8.8%	8.7%	9.0%
Dryden	2.8%	7.0%	
Dundalk	8.9%	8.7%	5.5%
Durham	8.9%	8.9%	9.3%
Eganville	9.0%	6.4%	-0.6%
Erin	1.7%	8.7%	9.1%
Exeter	9.2%	8.7%	9.2%
Fenelon Falls	9.0%	8.8%	9.1%

Acquired LDC	Residential	GS<50*	GS>50
Forest	9.0%	8.7%	8.9%
GBE	9.7%	6.4%	7.2%
Georgina	9.1%	8.8%	6.5%
Glencoe	9.1%	8.8%	8.9%
Grand Bend	9.0%	8.9%	8.8%
Hastings	9.0%	8.8%	5.0%
Havelock	9.0%	8.6%	7.5%
Kirkfield	8.9%	6.3%	-0.5%
Lanark Highlands	9.2%	5.4%	1.3%
Larder Lake	9.3%	8.8%	5.4%
Latchford	8.5%	8.8%	9.0%
Lindsay	8.0%	2.2%	4.7%
Lucan Granton	9.0%	8.8%	8.1%
Malahide	9.1%	4.1%	-0.9%
Mapleton	8.9%	8.8%	3.0%
Markdale	8.9%	8.8%	9.2%
Marmora	9.1%	8.8%	8.9%
McGarry	8.9%	5.4%	0.6%
Meaford	9.3%	8.8%	9.1%
Middlesex Centre	9.0%	8.7%	8.8%
Napanee	9.3%	8.8%	9.1%
Nipigon	1.7%	8.8%	9.0%
North Dorchester	8.9%	8.7%	9.1%
North Dundas	9.2%	8.7%	8.7%
North Glengarry	9.1%	8.8%	8.9%
North Grenville	7.4%	8.9%	5.7%
North Perth	9.0%	8.9%	8.8%
North Stormont	9.0%	8.8%	
Omemee	8.2%	8.6%	7.9%
Perth	5.8%	7.5%	9.6%
Perth East	9.0%	8.7%	9.1%
Prince Edward	9.0%	8.8%	8.4%
Quinte West	9.5%	8.7%	8.6%
Rainy River	9.0%	8.9%	1.9%
Ramara	9.0%	8.8%	9.1%
Red Rock	0.3%	8.7%	2.0%
Rockland	9.3%	8.5%	8.8%
Russell	9.0%	7.4%	0.0%
Schreiber	2.6%	1.8%	-3.5%
Severn	9.2%	8.9%	9.1%
Shelburne	9.1%	8.8%	8.9%
Smiths Falls	4.7%	7.9%	8.7%
South Glengarry	9.1%	8.8%	8.7%

Acquired LDC	Residential	GS<50*	GS>50
South River	8.7%	8.8%	4.8%
Springwater	9.2%	8.9%	9.0%
Stirling-Rawdon	9.1%	8.9%	9.3%
Terrace Bay	7.4%	8.8%	8.8%
Thedford	9.1%	8.7%	9.2%
Thessalon	9.0%	8.8%	8.9%
Thorndale	9.0%	8.9%	8.7%
Thorold	4.4%	1.4%	3.4%
Tweed	9.1%	8.8%	9.0%
Wardsville	8.9%	8.8%	9.0%
Warkworth	8.7%	8.7%	5.4%
West Elgin	7.4%	8.7%	8.9%
Whitchurch Stouffville	9.4%	7.3%	9.6%
Wiarton	7.5%	8.7%	3.3%
Woodville	9.2%	8.8%	3.6%
Wyoming	9.1%	8.7%	8.3%

1

Acquired LDCs with Customers Classified as Urban			
Arnprior	4.3%	4.7%	6.9%
Brockville	9.6%	8.8%	9.5%
Caledon OH 01	9.4%		
Carleton Place	2.2%	-0.2%	1.8%
Dryden	2.8%	7.0%	8.9%
GBE	9.7%	6.4%	7.2%
Lindsay	8.0%	2.2%	4.7%
Perth	5.8%	7.5%	9.6%
Quinte West	9.5%	8.7%	8.6%
Smiths Falls	4.7%	7.9%	8.7%
Thorold	4.4%	1.4%	3.4%
Whitchurch Stouffville	9.4%	7.3%	9.6%

2 * Excludes impact of $0.35 adder for USL credit
3

REVIEW OF PILOT TIME-OF-USE RATES

This exhibit provides an update on the experience to date of offering interim time-of-use (TOU) distribution rates to a selected group of customers.

1.0 INTRODUCTION

Hydro One Distribution received approval from the Board[1] to implement, on an interim basis, distribution TOU rates for customers whose off-peak demand consumption (kW) was at least twice their on-peak demand consumption. For customers on the interim TOU rates, the Distribution rates were the same as for other comparable Distribution customers, but the charge determinants are applied to billing demands (kW) established only during the peak period. The pilot program was included as part of Hydro One Distribution Conservation and Demand Management programs.

Originally three customers met the criteria for interim TOU rates.

2.0 ANALYSIS

The experience to date has been that no additional customers have modified their operation patterns to qualify for the interim TOU rate, so there has been no change in the program since the original application. This would indicate that distribution rates are not a major component in the customer’s total electricity bill and that any possible savings from customers modifying their electricity consumption to take advantage of interim TOU Distribution rates is not a significant enough benefit to warrant such a change in customer behavior.

[1] Interim Order dated November 24, 2004, RP-2004-0203/EB-2004-0457

Some interest has been expressed by ski resort operators to participate in this program, but given the interim nature of the program, no firm commitment has been made.

3.0 RECOMMENDATION

Hydro One Distribution recommends that its current Time-of-Use pilot program be discontinued. Hydro One will await the Board's recommendation with respect to Distribution TOU rates that are part of the Board's Distribution Rate Design review process before offering customers time-differentiated Distribution rates. The Board will need to address the issue of any potential shortfall in Distribution revenues resulting from customers participating in optional TOU distribution rates before TOU rates are implemented.

The move to new customer classes and rates will mitigate the impact of discontinuing the TOU pilot. Two of the three customers are being re-classified as ST customers and the third customer is being re-classified as General Service demand billed customer. Two of the three customers will receive lower bills while the third customer will see a significant percentage increase, the total dollar amount is about $73k per year.

TOTAL LOSS FACTORS

1.0 INTRODUCTION

This exhibit describes the proposal with respect to loss factors for Hydro One Distribution Legacy, Acquired and ST customers for use in conjunction with 2008 distribution rates.

1.1 Hydro One Distribution Situation

Hydro One Distribution undertook an update study of losses, as requested by the Board in RP-2005-0020/EB-2005-0378. Results of the study are presented in Exhibit A, Tab 15, Schedule 3, Attachment A. The study results show that, on average, Hydro One Distribution losses are estimated to be higher than the values currently approved by the Board. In light of Hydro One Distribution on going efforts to reduce losses as discussed in Exhibit A, Tab 15, Schedule 3, Hydro One Distribution does not propose at this time, to change the distribution loss factors to the values established in the study.

Hydro One also undertook a study of individual customer losses for all customers in its Sub-Transmission class, as requested by the Board in RP-2005-0020/EB-2005-0378. The study shows that some customers would benefit while other customers would see bill increases if losses are implemented on a customer by customer basis, as opposed to class average losses. The study also shows that site specific losses can vary unpredictably from year to year for reasons outside customer control. The study is included as Appendix A in this Schedule. Hydro One is proposing to maintain the average class loss approach for 2008 and beyond.

Losses are used to uplift, or adjust, the Commodity, Retail Transmission Service, Wholesale Market Service, and Rural or Remote Rate Protection charges to the wholesale level at which Hydro One Distribution settles for these charges with the IESO. Debt Retirement and Distribution charges are not subject to loss adjustments.

For energy billed customers, Board guidelines dictate that loss adjustments be applied to metered or estimated energy billing quantities. For demand billed customers, loss adjustments are applied to the corresponding tariffs and the billed quantities used are the metered quantities.

Exhibit G2, Tab 5 to Tab 94, Schedule 1, shows the corresponding Supply Facilities Loss Factors, Distribution Loss Factors, and Total Loss Factors that Hydro Ones Distribution proposes for 2008 for its Legacy, Acquired and ST customers, (including Embedded LDC).

The Total Loss Factors for the new proposed UR and R1 customer classes were derived by taking the weighted average, by energy, of the currently OEB approved TLFs of the customers comprising the new customer class. This approach was endorsed by Stakeholders at the Session on September 5th, 2007.

For example, the new Urban Residential class is made up of Legacy Urban Residential, Acquired Residential, Legacy R1 and Legacy R2 customers. Legacy customers have a TLF of 9.2% while Acquired Residential customers have TLFs of 5.45%. Taking these two TLFs values and multiplying by the energy for the Legacy and Acquired customer classes respectively, the weighted average TLF for the new Urban residential customer class is 7.8%. The same approach was used to develop the proposed TLFs for R1.

For R2, Seasonal, Distributed Generator, Street Light and Sentinel Lights, the TLFs are unchanged from their current TLFs. For Urban General Service energy billed and General Service energy billed the TLFs are the current TLFs approved for secondary metered customers of 9.2%. For Urban General Service demand, General Service demand, and Distributed Generator, the TLFs are the currently approved TLFs for primary metered customers of 6.1%. For the ST class, it is proposed to maintain the TLF of 3.4%, since the vast majority of the customers in this new class, by energy, are Embedded LDCs and Embedded Directs, with TLFs of 3.4%.

The Table below shows the proposed loss factors for the new customer classes compared with the current approved loss factors.

Table of loss factors

Proposed Customer Class	Current TLF %	Proposed TLF %
Urban Residential	5.45 or 9.2	7.8
R1	5.45 or 9.2	8.5
R2	5.45 or 9.2	9.2
Seasonal	5.45 or 9.2	9.2
Urban General Service energy	5.45, 6.1 or 9.2	9.2
Urban General Service demand	5.45, 6.1 or 9.2	6.1
General Service energy	5.45, 6.1 or 9.2	9.2
General Service demand	5.45, 6.1 or 9.2	6.1
Street Light	4.26 or 9.2	9.2
Sentinel Lights	9.2	9.2
Distributed Generator	5.45 or 6.1	6.1
Sub-Transmission	1.45, 3.4, 5.45, 6.1 or 9.2	3.4

Measurement Canada requires that meters used for billing must be sealed and re-verified on a periodic basis. The IESO market rules require that legacy metering installations must be brought into compliance with the IESO's metering standards upon the earliest seal expiry date after market opening. These metering installations are substantially more complex than a meter used for residential customers and the installation requires design engineering. This results in many meters requiring either a substantial upgrade or total replacement, depending on the degree of equipment replacement needed to achieve compliance with IESO market rules.

Hydro One Distribution requested and received Board approval as part of the 2006 Distribution rates, that if the meter is located at the TS or HVDS, at time of reseal of the meter, if Hydro One requires the customer to relocate the meter to either inside the fence or immediately outside the TS or HVDS, for safety, security and access reasons, depending on physical characteristics of the station, then the applicable Total Loss Factor is 0.6% for customers supplied by express feeders[1]. This applies to all ST customers whose meter is being relocated and was implemented as of May 1, 2006.

Also, if the meter is relocated away from the TS or HVDS, losses must be based on engineering studies. Hydro One will add non-technical losses consistent with the method inherent in the existing Distribution Loss Factors.

Customers also requested that they be allowed to estimate losses based on engineering studies, instead of using average loss factor, in cases where the meter is being relocated. In these situations, this would result in more accurate loss adjustments and would be consistent with the mechanism to apply loss adjustments in the IESO administered market.

[1] Feeder used by only one customer and the meter is located at the station

The above deal with situations in which Hydro One does not want the metering within the TS or HVDS. However, Hydro One Distribution proposes that in all situations in which a feeder delivers to solely one supply point, and in which the metering is located away from the supplying station, that the customer calculates applicable losses based on engineering studies. Hydro One will add non-technical losses consistent with the method inherent in the existing Distribution Loss Factors.

Also, Hydro One Distribution proposes that in situations in which the metering is at the supplying TS or HVDS (either inside the fence or immediately outside the fence), that the DLF not be applied, but solely the losses associated with the transformation at the station, i.e. the approved Supply Facility Loss Factor be applied.

There are situations in which there is no metering at the customer supply point, and quantities are calculated by taking the differences between other metering (for example, feeder total minus the only other customer on the feeder). In such situations, the normal application of the DLF to the difference in metering quantities could result in double-counting the feeder losses. Therefore, Hydro One Distribution proposes that in such a situation, the application of loss adjustment avoid double-counting the feeder losses by adjusting appropriately the meter quantities separately.

KINECTRICS

SITE SPECIFIC LOSSES

Kinectrics Inc. Report No: K-013154-001-RA-0001-R01

July 30 2007

Ray Piercy
Senior Engineer
Transmission and Distribution Technologies

Stephen L. Cress
Manager – Distribution Systems
Transmission and Distribution Technologies

PRIVATE INFORMATION

Kinectrics Inc., 800 Kipling Avenue
Toronto, Ontario, Canada M8Z 6C4

SITE SPECIFIC LOSSES

Kinectrics Inc. Report No.: K-013154-001-RA-0001-R01

July 30, 2007

Ray Piercy

Prepared by:

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Raymond Lings
Manager
Transmission and Distribution Technologies

Dated: September 25, 2007

DISCLAIMER

Kinectrics Inc. has prepared this report in accordance with, and subject to, the terms and conditions of the contract between Kinectrics Inc. and Hydro One, and PO 36240 August 24, 2006.

REVISIONS

Revision Number	Date	Comments	Approved
R1	25/09/2007	Removed customer identifications from Appendix A	RP

SITE SPECIFIC LOSSES

Kinectrics Inc. Report No.: K-013154-001-RA-0001-R01

July 30, 2007

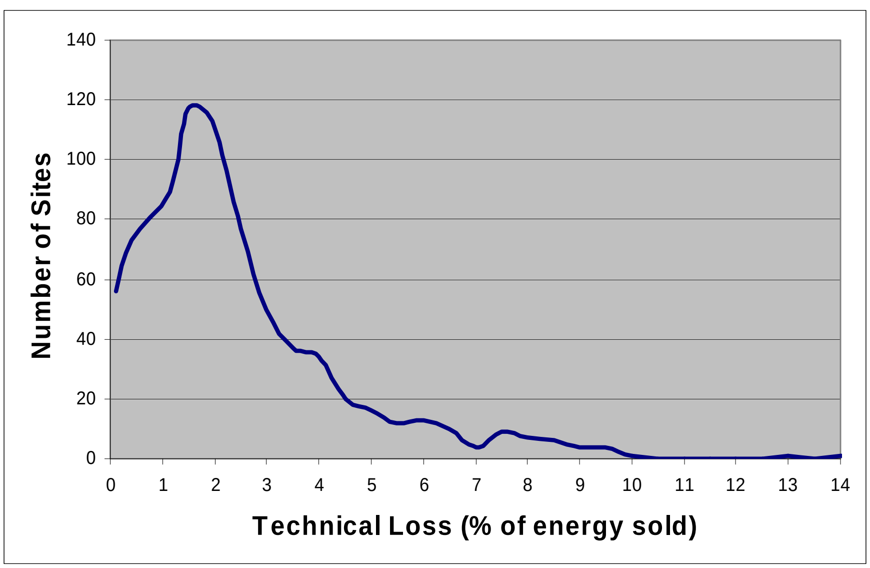
EXECUTIVE SUMMARY

As part of the support for the rate application to the OEB, Hydro One requested a calculation of the site specific technical losses for subtransmission customers and embedded LDC and Direct customers. Technical losses are part of the distribution loss factor (DLF) that is used to adjust metered energy to account for technical and non-technical losses. The technical losses include energy losses in power lines and transformers. The technical losses, expressed as a percentage of energy sold, can be multiplied with the annual energy sales of the specific customer site to determine the energy loss allocated to that customer site. Site specific technical losses depend on a large number of factors including:

- the site load
- the load of other sites on the circuit
- the length of line to the site and locations of other load sites
- the conductor size
- the line voltage
- the power factor
- the line current imbalance
- the site transformer's rating and loss parameters.

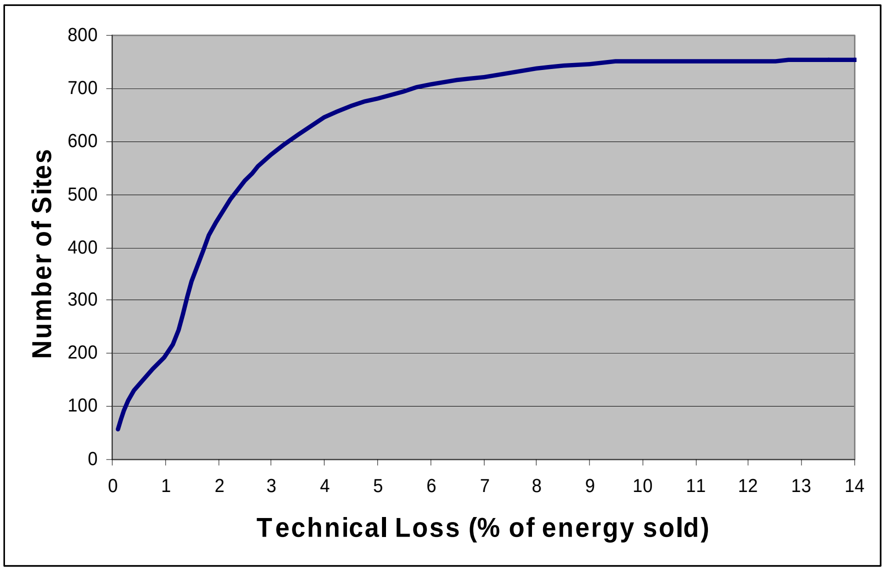
Calculations of site specific technical losses were made for all 765 subtransmission customer sites. The calculated technical losses ranged from 0 to 14% of energy sold at the site, with an average of 2.2%. The complete distribution is shown below in Figure 1. These technical losses represent only a part of the total loss factor that would result from implementation. Non-technical losses and the supply facilities loss factor must be added to these technical losses.

Figure 1 Frequency Distribution of Site Specific Technical Losses



About two thirds of site specific losses are less than the 2.6% overall subtransmission system loss and these sites would see a reduction in their allocated cost of losses if site specific losses are implemented in the rate structure. The remaining third would see their loss allocation increase, typically by a factor of 2 but by up to a factor of four at some sites.

Figure 2 Cumulative Frequency of Site Specific Technical Losses



If the average technical loss is weighted by the amount of energy sold at each customer site, then the average is 1.4%, i.e. the larger energy users tend to have lower losses. This is a due to their location closer to large transformer stations (TSs) and to their primary metering which includes the transformer losses in the metered energy. The weighted average is an indication of the actual cost of losses that would be recovered from this group of customers if site specific DLFs are adopted. The 1.4% weighted average loss represents a reduction of 35% in recovered costs compared to the technical loss recovered by the existing rate structure. This reduction in recovered loss would need to be balanced by a corresponding increase in technical losses recovered from other customers to ensure that the total technical loss is still recovered.

The 1.4% weighted average loss is lower than the 2.6% for subtransmission customers calculated in the overall loss report previously filed with the OEB because it is the loss of a different set of load sites. The overall loss report calculates the total loss on all subtransmission circuits and power transformers (2.6%) as a percentage of the total energy sold. The site specific losses have been calculated only for a subset of load sites that tend to be on shorter lines and 40% have no power transformer included because of primary metering.

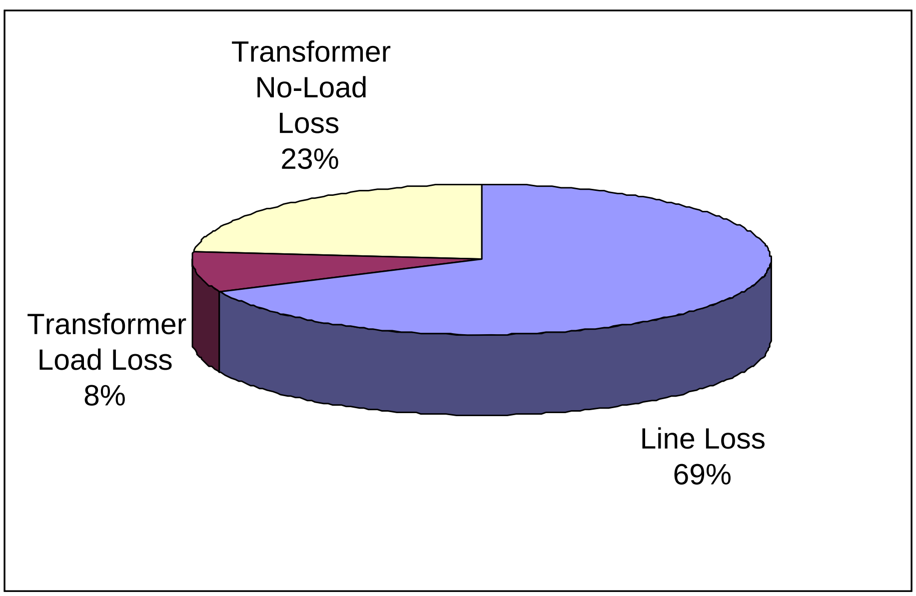
The average expected uncertainty in the individual calculated site specific technical loss is ±10% if no site transformer is required in the calculation and ±30% if a transformer is included. The largest sources of uncertainty are assumptions which need to be made for:

- the size and loss parameters of individual site transformers
- the conductor size on some circuits
- the location of some loads and current unbalance on the 27.6 kV lines in southwestern Ontario.

Hydro One would need complete data to generally eliminate the above assumptions solely if site specific loss factors were actually implemented. The data was unavailable because it has never been needed before and it would be expensive to collect and maintain. There are other smaller sources of uncertainty in the calculation that could be reduced with more data, such as the hourly load of Hydro One substations, power factors, and unknown load locations. There are some sources of uncertainty that can never be eliminated, such as conductor temperatures.

The proportion of the loss caused by line loss, transformer load loss and transformer no-load loss is shown on the pie chart in Figure 3. Again the differences from the proportions in the overall loss report are caused by these results being for a subset of all the load sites. In this subset the transformer no-load loss is a larger proportion because the transformers tend to be lightly loaded compared to Hydro One substations. The line loss is a lower proportion because the lines tend to be shorter to this subset of load sites.

Figure 3 Relative Contribution of Different Sources of Energy Loss



Based on the results of this study it is recommended that site specific losses not be used for all embedded LDC and Direct customers. This recommendation is based on the following rationale:

- site specific losses are highly dependent on variables outside of the control of the customers, such as loads of other customers and power system design and operation decisions. As a result, the customer's cost of losses could vary unpredictably from year to year for reasons beyond their control, which is inherently unfair.

- site specific losses would require expensive data to be collected and kept up to date, data that is not required for any other purpose.

- site specific losses would need to be re-calculated frequently because of changes to the power system and to the customers loads

- the inherent error in the loss estimate is larger than the difference in losses between most sites, the major exception being large customers with dedicated circuits metered at or near the TS. The exception might be better handled by not adding technical losses to this small group of customers.

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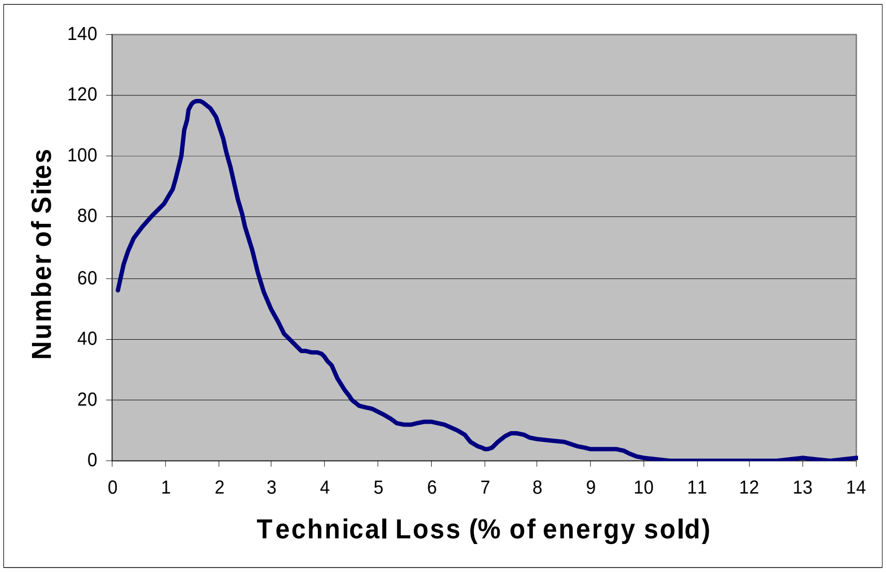
SITE SPECIFIC LOSSES

1. CONCLUSIONS AND RECOMMENDATIONS

1.1 TECHNICAL LOSS RESULTS

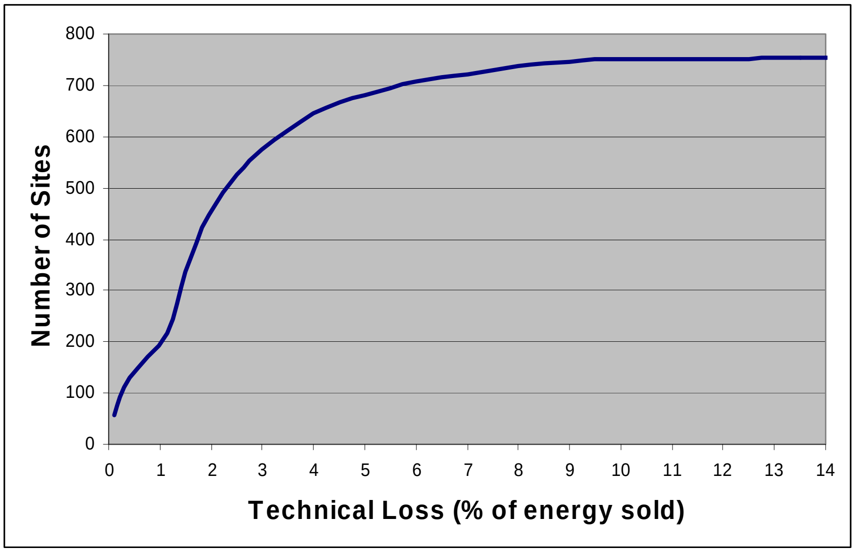
Calculations of site specific technical losses were made for all 765 subtransmission customer sites. The calculated technical losses ranged from 0 to 14% of energy sold at the site, with an average of 2.2%. The complete distribution is shown below in Figure 4.

Figure 4 Frequency Distribution of Site Specific Technical Losses



About two thirds of site specific losses are less than the 2.6% overall subtransmission system loss and these sites would see a reduction in their allocated cost of losses if site specific losses are implemented in the rate structure. The remaining third would see their loss allocation increase, typically by a factor of 2 but by up to a factor of four at some sites.

Figure 5   Cumulative Frequency of Site Specific Technical Losses



1.2 EFFECT ON RECOVERED COST OF LOSSES

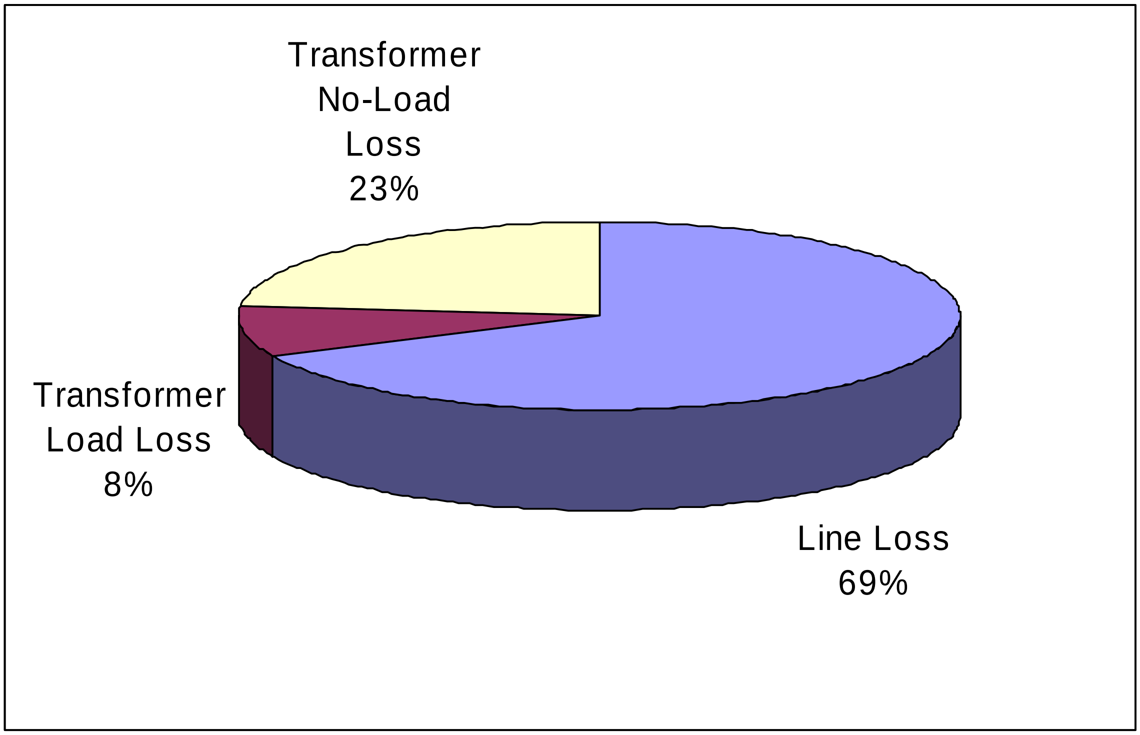
If the average technical loss is weighted by the amount of energy sold at each customer site, then the average is 1.4%, i.e. the larger energy users tend to have lower losses. This is a due to their location closer to large transformer stations (TSs) and to their primary metering which includes the transformer losses in the metered energy. The weighted average is an indication of the actual cost of losses that would be recovered from this group of customers if site specific DLFs are adopted. The 1.4% weighted average loss represents a reduction of 35% in recovered costs compared to the technical loss recovered by the existing rate structure. This reduction in recovered loss would need to be balanced by a corresponding increase in technical losses recovered from other customers to ensure that the total technical loss is still recovered.

1.3 COMPARISON WITH OTHER LOSS ESTIMATES

The 1.4% weighted average loss is lower than the 2.6% for subtransmission customers calculated in the overall loss report previously filed with the OEB (Reference 1) because it is the loss of a different set of load sites. The overall loss report calculates the total loss on all subtransmission circuits and power transformers as a percentage of the total energy sold on the entire system. The site specific losses have been calculated only for a subset of load sites that tend to be on shorter lines and many have no power transformer included because of primary metering.

The proportion of the loss caused by line loss, transformer load loss and transformer no-load loss is shown on the pie chart in Figure 6. Again the differences from the proportions in the overall loss report are caused by these results being for a subset of all the load sites. In this subset the transformer no-load loss is a larger proportion because the transformers tend to be lightly loaded compared to Hydro One substations. The line loss is a lower proportion because the lines tend to be shorter to this subset of load sites.

Figure 6   Relative Contribution of Different Sources of Energy Loss



1.4 ACCURACY

The average expected uncertainty in the individual calculated site specific technical loss is ±10% in most circuits where conductor size, load and phase current balance are known and if no site transformer is required in the calculation. The expected uncertainty increases to ±30% if a transformer is included. The largest sources of uncertainty are assumptions which need to be made for:

- the size and loss parameters of individual site transformers
- the conductor size on some circuits
- the location of some loads and current unbalance on the 27.6 kV lines in southwestern Ontario.

Hydro One would need complete data to generally eliminate the above assumptions solely if site specific loss factors were actually implemented. The data was unavailable because it has never been needed before and it would be expensive to collect and maintain. There are other smaller sources of uncertainty in the calculation that could be reduced with better data, such as the hourly load of Hydro One substations, power factors, and unknown load locations. There are also some sources of uncertainty that can never be eliminated, such as conductor temperatures.

Because the average values for many of the necessary assumptions are known quite well, the uncertainty in the average loss allocation is less than in the individual loss allocations.

1.5 RECOMMENDATION #1

Based on the results of this study it is recommended that site specific losses not be used for all embedded LDC and Direct customers. This recommendation is based on the following rationale:

- site specific losses are highly dependent on variables outside of the control of the customers, such as loads of other customers and power system design and operation decisions. As a result, the customer's cost of losses could vary unpredictably from year to year for reasons beyond their control, which is inherently unfair.
- site specific losses would require expensive data to be collected and kept up to date, data that is not required for any other purpose.
- site specific losses would need to be re-calculated frequently because of changes to the power system and to the customers loads
- the inherent error in the loss estimate is larger than the difference in losses between most sites, the major exception being large customers with dedicated circuits metered at or near the TS. The exception might be better handled by not adding technical losses to this small group of customers.

1.6 RECOMMENDATION #2

If site specific losses are implemented, the cost of data collection and maintenance at different levels of detail should be determined so that the level of data detail can be chosen appropriately, by comparing with the effect of data detail on accuracy.

1.7 RECOMMENDATION #3

If site specific losses are implemented, the frequency at which site specific losses will be estimated (every year, every two years, every five years) needs to be determined. Procedures will be needed to handle new customers in between recalculations.

2. INTRODUCTION

As part of the support for the rate application to the OEB, Hydro One requested a calculation of the site specific technical losses for subtransmission customers and embedded LDC and Direct customers. Technical losses are part of the distribution loss factor (DLF) that is used to adjust metered energy to account for technical and non-technical losses. The technical losses include energy losses in power lines and transformers. The technical losses, expressed as a percentage of energy sold, can be multiplied with the annual energy sales of the specific customer site to determine the energy loss allocated to that customer site. Site specific technical losses depend on a large number of factors including:

- the site load
- the load of other sites on the circuit
- the length of line to the site
- the conductor size
- the line voltage
- the power factor
- the line current imbalance
- the site transformer's rating and loss parameters.

Calculations of site specific technical losses were performed for all 765 subtransmission customer sites. Since the technical loss calculation is dependent on the total load on the circuit, data from Hydro One substation sites were also used in the calculations.

2.1 DEFINITION OF TERMS

Distribution Loss Factor (DLF)
A factor used to increase the measured energy from a customer's meter before billing to account for losses in the delivery of the energy. Strictly speaking it should be a value with no units such as 1.02, but it is often expressed as a fraction (0.02) or as a percentage (2%). It includes technical losses and an adjustment for theft and other non-technical losses.

Supply Facilities Loss Factor (SFLF)
A value added to the DLF to account for loss in the transmission system transformer. This has been previously approved by the OEB as 0.6%.

Total Loss Factor (TLF)
The "sum" of the DLF and SFLF. This is the value that is actually used to adjust the meter reading to determine the energy billed. The formula with all factors expressed as a fraction is: TLF = (1+DLF)x(1+SFLF)-1

Technical Losses
Power or energy used in the components of the system that delivers electricity to the customer's meter. This includes conductor losses that depend on resistance and current and transformer losses that include a conductor loss (load loss) and a transformer core loss (no-load loss). The core loss does not vary with loading.

Power losses are expressed in kW or as a % of the loss at peak load.
Energy losses are expressed in kW-h per year or as a % of the total energy sold in a year.

Non-technical Losses
Non-technical losses include all unaccounted for energy other than technical losses. This can occur through theft, meter inaccuracies, billing errors and various frauds.

Loss Allocation
When technical losses are not averaged over all customers on the system they are divided into parts and each part assigned (allocated) to a different customer or group of customers. The loss allocation can be either power or energy losses, but usually it is energy losses. It can be expressed in kW-h or as a % of energy sold to that customer or group of customers in a year. The loss allocation is often used as a basis for a DLF. The TLF for a specific customer group can be calculated by adjusting for the amount of energy sold to that group and adding a factor for non-technical losses and the supply facilities loss factor.

Loss Factor
A factor used to convert the power loss at peak load to the average power loss. It depends on the details of the load profile, i.e. how the load changes with time. It is often estimated based on an equation involving the load factor as follows:

$$\text{Loss Factor} = p \times \text{load factor} + (1-p) \times \text{load factor}^2$$

The constant "p" in this equation depends on the load profile. It is typically 0.3 for subtransmission systems, 0.2 for distribution lines, and 0.15 for distribution transformers and secondary circuits.

Load Factor
A factor used to convert peak power to average power. It is the ratio of the average power to the peak power.

2.2 FAIRNESS ISSUES IN LOSS ALLOCATION

One of the considerations when selecting a loss allocation method is the perceived fairness of each alternative. Unfair aspects arise in both alternatives, either to allocate losses based on the actual loss that each site contributes to the total loss (site specific losses), and the alternative of allocating losses evenly to all customers in proportion to their energy use.

The even allocation method has been used historically. It has the advantage that the amount a customer pays for losses compared to other customers does not change for reasons outside of the control of the customer. If customer "A" reduces their load then customer "A" will pay less for losses, but if customer "B" reduces load, then it does not significantly lower the loss allocated to customer "A". Similarly if "B" increases their load it will not significantly increase the cost of losses for customer "A". This seems inherently "fair".

Another factor outside the control of customers is the design and operation of the power system, and the "even" allocation method works well for this also. If Hydro One builds a new substation beside customer “A”, the reduced losses in the overall system will reduce the cost of losses for both customers “A” and “B” by the same amount. If Hydro One changes the circuit that supplies customer “A”, to a circuit with higher losses (perhaps done to alleviate overloading on a transformer station) then customer “A” will not pay more for losses. This also seems inherently “fair”.

However, in the “even” loss allocation method large customers located close to major supply points (TS, transformer stations), who contribute very little to the loss on Hydro One facilities will pay the same for losses on Hydro One facilitates as a customer located far from the supply point. This seems inherently “unfair”.

In the “even” loss allocation method there is no incentive to locate new facilities where losses will be minimized. Consider two new customers “A” and “B”. “A” chooses a location near a TS where land prices are higher, but losses will be lower. “B” chooses a location in a remote rural area where land prices are low, but electrical losses are high because of the large distance from a TS. In the “even” loss allocation method both will pay the same for losses and customer “B” will have gained a competitive advantage over customer “A”. Customer “A” is, in effect, subsidizing customer “B”. This seems inherently “unfair”.

Site specific loss allocation methods can remove the “unfairness” of the last two examples. Each customer pays for the losses that their own load creates in the Hydro One system. However, it creates “unfairness” in the first two example situations. Consider two customers “A” and “B”, both located at the same location on the same circuit, each drawing 10 amps over a line of 1 ohm. The total loss on the line will be 20x20x1 = 400 W. Each customer will pay for 200W of loss, since their energy use is the same. If customer “B” doubles their load to 20 amps, the total loss will be 30x30x1= 900W. Customer “A” now uses 1/3 of the total energy so customer “A” will pay only for 1/3 of the loss, which would be 300 W. Notice that customer “A” pays for more loss even though customer “A” load has not changed. In this case the site specific loss allocation method seems “unfair”. In the second example, in which Hydro One changes the circuit that supplies a customer to a higher loss circuit, site specific loss allocation would increase that customers loss cost. This also seems “unfair”.

In designing a site specific loss allocation method in this project, no method was identified that would be “fair” in all cases. For example, an allocation proportional to the square of the current rather than proportional to energy was considered. However, this results in unfairness to end-use customers of LDCs. If two LDCs (A and B) share a supply line, and every end use customer has an identical load, and A has twice as many customers as B, then the end use customers of A will pay a larger share of the line losses if they are allocated proportional to the square of the current. In this case allocating losses proportional to energy use is fair, because it results in all end use customers paying the same amount of the line loss.

The cost of implementation of site specific losses is not insignificant. The data required to calculate site specific losses is much more extensive than that required for “even” loss allocation methods. The data is expensive to obtain and expensive to keep up to date. Customers and loads change every year, even every month. The frequency at which losses would need to be recalculated will affect the implementation cost. This frequency could be determined from the desired accuracy and the rate at which changes are made to the customer loads and to the power system. Every other year would appear to be a minimum.

3. ALGORITHM USED IN THE CALCULATION OF TECHNICAL LOSSES

Energy losses on electricity distribution systems are often calculated using commercially available load flow software. The usual procedure is to calculate the loss at peak load and then apply an empirically derived "loss factor" to convert the calculated loss at peak to the average loss. This procedure is not suitable for calculation of site specific losses, because it cannot take into account the differences between the load profiles of the different customers. If the load for customer A occurs mainly at times of low overall load then customer A will contribute less loss than customer B whose load occurs mainly at heavily loaded times. This could only be taken into account by the general purpose software by running it on each circuit 8760 times, for every hour of the year. This calculation procedure would be very expensive to use on the 494 circuits included in this study.

Since the circuits are all radial, with no loops or meshed networks, a computer program can be easily written to do the energy loss calculation 8760 times. The calculation method used in the program developed for this study is shown in Figure 3. Basically, the load in a line section or transformer is calculated separately for each hour of the year by summing the hourly load of all customers who are supplied through that component. The loss from that total load is then divided among the customers who are supplied through that component in proportion to their load in that hour of the year.

The program has been verified against hand calculations and commercially available loss calculation software.

Step 8 accounts for the fact that not all loads are known on the circuit. This is especially critical for the distribution circuits and for the 27.6 kV subtransmission circuits in the south west that have significant single phase loads. The "extra load sites" are set up at locations evenly distributed on the circuit, unless specific information was available to suggest a more accurate location. The 'extra load sites" have zero loads, unless the total measured currents are larger than the currents from the known loads.

The losses in voltage regulators are added to the transformer losses for all customers downstream of the regulator. Since data on the actual tap position of the regulator at every hour of the year is not available, an average boost of 5% has been assumed. The increase in line current upstream of the regulator is accounted for by the adjustment of the total load to the measured peak currents.

When a line passes through the service area of an LDC, to serve other loads beyond it, a primary meter is installed at both boundaries of the LDC territory. The difference between the meters is used to bill the LDC. The LDC meter reading must be adjusted up with a DLF to account for losses before the first meter, and adjusted down by a DLF to account for losses on the line between the meters that are caused by the downstream loads. The later DLF was estimated based on a manual calculation using the energy lost on the line between the meters calculated by the program, and the proportion of the total energy sold to the LDC and the downstream load.

When the site specific loss is calculated on a distribution line, the algorithm calculates the loss on the distribution line separately from the loss on the subtransmission line and

Hydro One substation. The two separately calculated losses are summed manually to produce the total loss for the site.

Figure 7 Technical Losses Calculation Algorithm

1. Dimension and initialize variables
2. Open input data files
3. Open output data files
4. Input load data
5. Begin loop for each circuit
    6. Input circuit data
    7. Get load data for each site on the circuit
    8. Adjust the extra load sites so that the total peak load matches the measured peak for the circuit
    9. Begin loop for each hour
        10. Begin loop for each line section
            11. Calculate the line current from the load data, power factor and load imbalance (both phase and neutral currents)
            12. Calculate conductor resistance from conductor size, and section length
            13. Calculate the energy loss from the current and resistance
            14. Distribute the energy loss to each load site that uses this line section by proportion of the total load
        15. End loop for each line section
        16. Calculate the transformer load loss for each site
        17. Calculate the transformer no-load loss for each site
        18. Add losses for this hour to the totals
    19. End loop for each hour
    20. Write total losses to output file
21. End loop for each circuit
22. Close Files

3.1 INPUT PARAMETERS

The algorithm uses the following input parameters:

- length of each section of power line
- size of conductor in each section
- circuit topology (which line sections are used by each load site)
- peak current on the circuit
- hourly load in kW for each load site with hourly data available
- an estimated hourly load based on customer class load profiles for sites with monthly energy data
- an estimated hourly load based on customer class load profiles for sites with annual peak data
- power factor for each load site
- transformer rating
- transformer load loss %
- transformer no-load loss %
- voltage regulator location and rating
- metering locations

4. DATA QUALITY ISSUES

When the 8760 load data was incomplete (264 sites were missing 1 to 3 months) then data was estimated by using the data from the hour of the week that was viewed likely to be similar: the count of the weeks from the missing week forward to year end equaled the count of the weeks from the start of the year to the week to use as the data source. So if the data for October was missing, then the data for March was used for October; and if the data for January was missing then the data from December was used.

For 126 sites, only monthly energy sales and peak power data were available. In these cases the monthly energy sales were used to estimate the hourly loads by scaling the known hourly load profile for the customer class. The monthly peak power data was not used for scaling because adjusting the load profile by total energy is more likely to provide a good estimate of monthly loss since the peak power can be affected by circumstances that do not last for most of the month. The use of the class load profile will tend to under estimate the losses, since any individual customer would likely have a "peakier" load profile than the class as a whole.

For Hydro One substations the load data that was available was an estimate of the annual peak load. Hourly load data was estimated by multiplying the annual peak by the per unit hourly load profile of all customers combined, except leaving out the classes T, embedded LDC and embedded Direct customers.

The uncertainty in the results for sites at which a meter is installed on the low voltage side of a customer owned transformer could be reduced if more data on the transformer rating and loss parameters was available. The size of the customer owned transformer had to be estimated in many cases and typical loss and no-load loss parameters were used. The transformer size was estimated from the peak load of the site by doubling the load, i.e. a 50% load at peak was assumed. A previous study of one area of Hydro One had found that typically customer transformers were loaded to 30-50% at peak load.

It is not always known if the customer site energy meter is installed upstream or down stream of the transformer. If it is upstream then the transformer losses should not be included in the technical loss estimate used to calculate a DLF. This is a significant change since on average 31% of the energy loss is in the transformers rather than the lines. If a primary meter was shown on the operating diagram or map then no transformer losses were included for that site. The results are presented for all sites both with and without the transformer loss included so that if mistakes in the location of the meter have been made, the calculation will not have to be repeated.

Data was not available on the power factor of each customer site and the load current imbalance. Load current imbalance for the entire circuit was often available and it was assumed to apply to all customers evenly. When power factor was unknown it was assumed to be 0.95.

Conductor size data is available from maps and operating diagrams for about 63% of the circuits. For circuits with missing data, the conductor size was estimated from the load level and typical design practices for similar circuits.

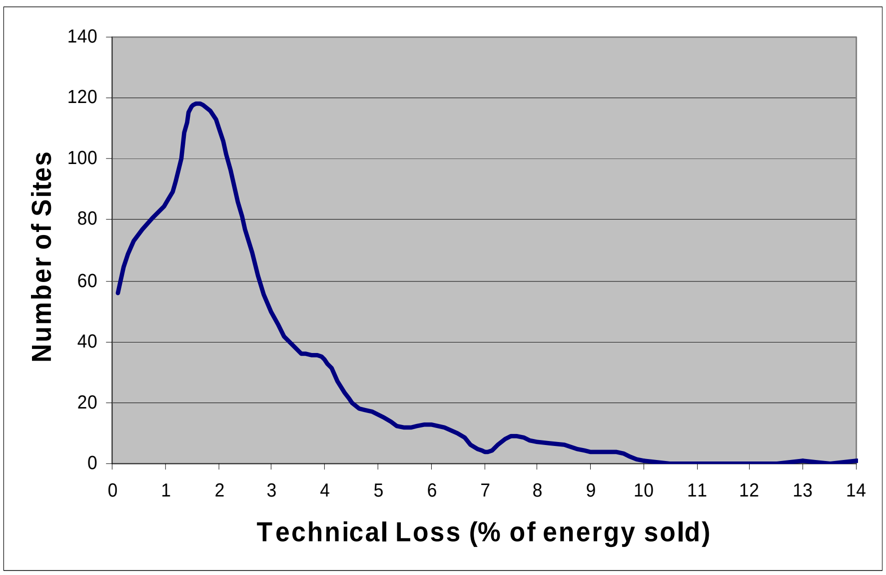
5. RESULTS

The detailed results for each site are shown in Appendix A.

The average technical loss is 2.2% and the frequency distribution is shown in Figure 8.

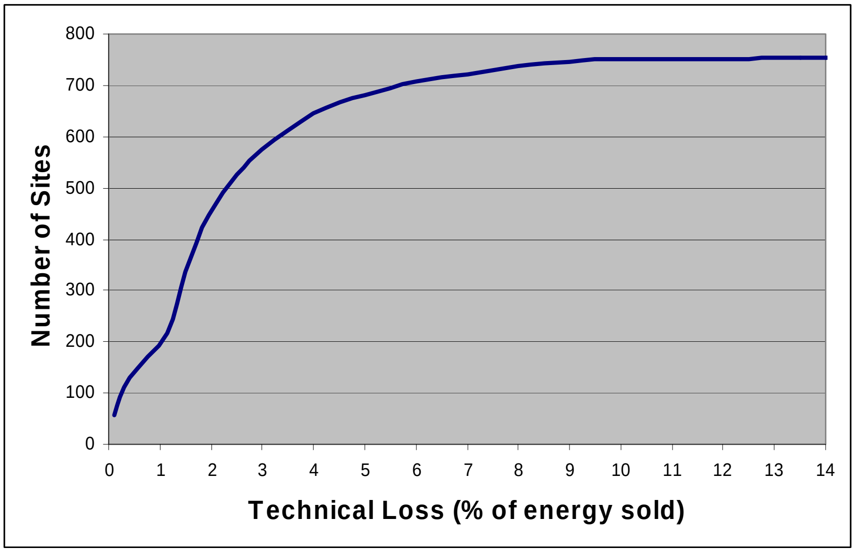
There were two sites with technical losses above 10% one at 13% and another at 14%. The high values here are caused by lightly loaded transformers and a predominance of no-load loss (>90% of the loss). The transformer size in these cases has not been assumed, but was clearly shown on the operating diagram. However, there are many sites that have predominantly no-load losses. This can be caused by a low load factor (for example a peak load ten times the average load) as well as by over sized transformers. A transformer can be over sized as a result of load reductions in a customer's processes or by a change in ownership with the new owner using much less energy than the original owner.

Figure 8 Frequency Distribution of Site Specific Technical Losses



About two thirds of site specific losses are less than the 2.6% overall subtransmission system loss and these sites would see a reduction in their allocated cost of losses if site specific losses are implemented in the rate structure. The remaining third would see their loss allocation increase, typically by a factor of 2 but by up to a factor of four at some sites.

Figure 9   Cumulative Frequency of Site Specific Technical Losses

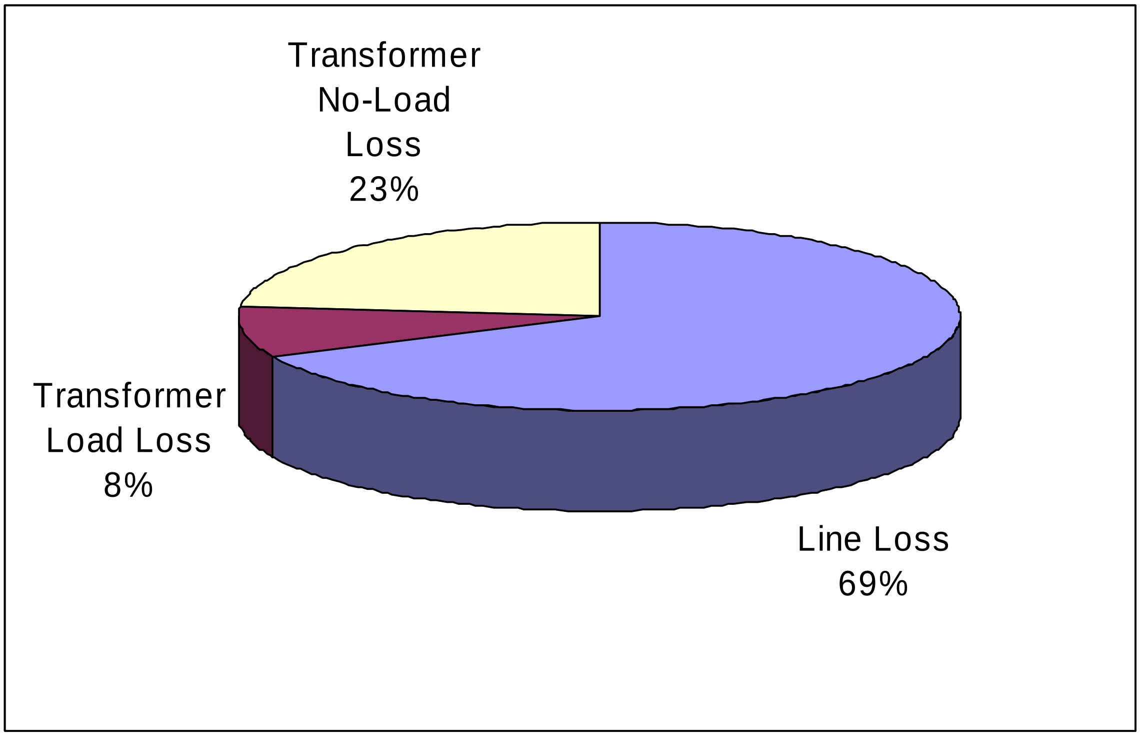


If the average technical loss is weighted by the amount of energy sold at each customer site, then the average is 1.4%, i.e. the larger energy users tend to have lower losses. This is a due to their location closer to large transformer stations (TSs) and to their primary metering which includes the transformer losses in the metered energy. The weighted average is an indication of the actual cost of losses that would be recovered from this group of customers if site specific DLFs are adopted. The 1.4% weighted average loss represents a reduction of 35% in recovered costs compared to the technical loss recovered by the existing rate structure. This reduction in recovered loss would need to be balanced by a corresponding increase in technical losses recovered from other customers to ensure that the total technical loss is still recovered. However, the method for recovering non-technical losses will also affect the total cost of loss recovered.

The 1.4% weighted average loss is lower than the 2.6% for subtransmission customers calculated in the overall loss report previously filed with the OEB because it is the loss of a different set of load sites. The overall loss report calculates the total loss on all subtransmission circuits and power transformers (2.6%) as a percentage of the total energy sold. The site specific losses have been calculated only for a subset of load sites that tend to be on shorter lines and many have no power transformer included because of primary metering.

The average composition of the losses by source is shown in Figure 10. The differences from the proportions in the overall loss report (Ref 1) are caused by these results being for a subset of all the load sites. In this subset the transformer no-load loss is a larger proportion because the transformers in the subset tend to be lightly loaded compared to Hydro One substations. Hydro One maintains a much higher loading level because Hydro One can re-configure the distribution lines to shift load between substation transformers. Customers often do not have this kind of load flexibility. The transformer losses are the least accurate, due to lack of data on the transformer size and loss parameters. This is discussed further in section 6. The line loss is a lower proportion because the lines tend to be shorter to this subset of load sites.

Figure 10 Relative Contribution of Different Sources of Energy Loss



6. ACCURACY OF THE DLF CALCULATION

Since every site specific technical loss may eventually be used to calculate a site specific DLF that will be applied to a customer's measured energy consumption to determine a total bill amount, it is critical to know the accuracy to which the site specific technical loss has been computed. There are several factors that can affect the accuracy of the technical loss calculation in general but they do not all apply to every calculation. The factors include uncertainties in the input data and inherent limitations in the modeling.

The accuracy of the technical loss calculation has been estimated by examining the underlying equations, or by changing the input data and repeating the calculation.

The factors that can affect the accuracy of loss allocations are summarized in Table 1 in two categories, line loss parameters and transformer loss parameters. On average 31% of the loss allocation is attributable to transformer losses and 69% to line losses.

Table 1 Summary of Accuracy Estimates

Loss Type	Parameter	Possible Error in Calculated Loss
Line Loss	line length	±3%
	conductor size (when not known)	±20%
	conductor temperature	±5%
	unknown loads	±2%
	unknown load location	±10%
	power factor	±10%
	phase current balance (some 27.6 kV only)	±20%
	load profile	±1%
Total Best Estimate for Line Loss		**±10%**
Transformer Loss	no-load loss %	±90%
	load loss %	±100%
	rating	±25%
Total Best Estimate for Transformer Loss		**±75%**

The accuracy of any specific technical loss depends on the circuit on which it is located and on the presence of a customer site transformer in the calculation.

The total error in line loss, if all errors were in the same direction, would be ±19% (in most circuits, where conductor size, load, and phase current balance are known). However, since all errors will not operate in the same direction, a reasonable estimate of actual error in the line loss portion of a specific technical loss can be estimated as ±10%.

The total error in transformer loss, if all errors were in the same direction, would be over 200%. However, since all errors will not operate in the same direction a reasonable estimate of the actual error in the transformer loss portion of a specific technical loss can be estimated as ±75%. This means that the accuracy of the technical loss for a customer site with a transformer upstream of the meter is 30% (10% of 69% plus 75% of 31%).

A discussion of each of the loss parameters is presented in section 6.1 and 6.2 below.

6.1 LINE LOSS PARAMETERS

- Circuit length to the customer
- Conductor resistance
    - o That in turn depends upon conductor size and temperature
- Conductor current
    - o That in turn depends on size and location of all loads on the circuit, power factor, and phase balance

In general the circuit length to the customer is known quite well. The estimated error in this input parameter is ±3%. This will create a ±3% uncertainty in the line loss.

The conductor size is only shown on the system maps or diagrams for 63% of the circuits. The others have been estimated based on loading and the size of conductors in similar situations, such as other circuits from the same transformer station. These estimated sizes could easily be either high or low by a single conductor size step. This represents an average error of ±20% in the resistance of the conductor. This will create a ±20% uncertainty in the line loss for circuits that have an estimated conductor size.

The temperature of the conductor affects its resistance. Tabulated values are typically made at 75ºC which represents a conductor loaded at its ampacity limit in a 35 ºC ambient with very light wind. Actual conductor resistance will be lower if the current is lower (about 25% lower at no load), if the ambient temperature is lower (about 25% less resistance in the winter), or if there is a large wind. The effect of loading was included in the calculations. A "typical" variation was assumed for the variation of resistance with load. Although different conductor types respond slightly differently the overall error would be insignificant. The effect of ambient temperature was not included since data was not available. The two effects acting together are not a simple sum. As the conductor temperature drops the effect on resistance becomes smaller and smaller. The effect of wind speed could also not be included in the model because of lack of data. Since the largest effect on conductor temperature has been included in the calculations, this source of error is estimated to contribute only ±5% uncertainty in the line loss estimate.

The size of the loads is known quite accurately for most of the circuits. For most 44 kV circuits every significant load is included in the input data. For the circuits at 27.6 kV and below, where many significant loads were not included in the input data, the total load was known from direct measurements at the transformer station. It is estimated that the load data is accurate to ±1%. This will create a ±2% uncertainty in the line loss.

Customers who have more than one load point but only one load data value (one Service Point ID#) create a similar situation to load data that is missing, it introduces an uncertainty into the size of the loads. The split of the total load among the load points must be estimated. Again since the total circuit load is adjusted anyway, this will affect the accuracy of other technical losses very little (<1%). However, it could have a much larger effect on the sites with the assumed loading. Errors of 10% in the calculated loss could be anticipated.

The location of the loads on the circuits relative to the other loads is also quite well known on the 44 kV circuits. However on the circuits at 27.6 kV and below, where the total load was only known by the measurement at the transformer station, the location of these loads is not known. If they are close to the station they will add little to the line losses. If they are far away from the station they will add significantly to the line losses. In order to estimate the likely effect of this unknown load location the calculations were performed under three separate assumptions. The “best estimate” assumption is that the loads with unknown location are evenly distributed over the entire circuit. The “minimum” estimate assumes they are all located at the transformer station. The “maximum” estimate assumes they re all located farther out on the circuit beyond the known loads. Comparing the three assumptions shows that the average loss allocation changes from 1.95 for the “best estimate” to 1.6 for the minimum and 4.4 for the maximum. This establishes an upper bound on the error due to the location of the unknown load. However since the “worst case” is highly unlikely, a more probable estimate for the error due to this parameter is ±10% of the line loss in circuits for which there is a significant level of load with an unknown location.

The power factor affects the loss calculation by altering the current calculated from the kW load. Although no site specific data on power factor was available, previous measurements on Hydro One circuits have shown the average to be about 0.95. This value was assumed for all loads. The circuit power factor on any specific circuit is not likely to be less than 0.9 which would increase line losses by 12%. Similarly if the actual power factor was 1 then the line loss would decrease by 10%.

The phase balance affects the line loss by increasing the current in some conductors and decreasing it in others. The net effect is an increase in line loss. Phase balance on the 44 kV circuits is usually quite good so this factor can be ignored. For circuits at 27.6 kV and below there are significant single phase loads which can produce up to a 40% imbalance. On average a more typical value would be 20% .

The load profile (how the load varies over the year) affects the calculation of the annual energy loss for the power loss at the peak load. Hourly load profile data was available for most loads which increases the accuracy of this calculation over methods based on monthly load data. The effect of the remaining uncertainty in load profiles has been estimated at 1%.

In total the line loss estimate for 44 kV circuits has a cumulative uncertainty of about 10% and circuits at 27.6 kV and less about 40%. If the conductor size had to be estimated these could increase by 20%.

These line loss parameters on average affect only 69% of the total loss allocation, so each estimate of uncertainty can be multiplied by 0.69 to get the effect of that parameter on the total loss allocation.

6.2 TRANSFORMER LOSS PARAMETERS

The estimate of the energy loss in transformers is calculated in two parts, load loss and no load loss.

The no load loss depends only on the size of the transformer and the details of its design. There was no data available on the no load loss of transformers supplying specific customers so a "typical" value of 0.15% of rating was used for all transformers. For individual transformers this could range from 0.38 % down to 0.014 % a range of ±90%.

The load loss depends on the transformer load loss value. Individual data on each customer transformer was not available so a "typical" value of 0.5% of rating at rated load was used. For individual transformers this could range from 0.84 % down to 0.015 % a range of over 100%. The load loss was adjusted for loadings other than the rated load by multiplying by the square of the ratio of the actual load to the rated load.

The rating of the transformer was known for only about 20% of the customers. The rating for the other customers was estimated based on previous studies that had shown that customer transformers are typically loaded at 30-50% of rating at their peak load time. This uncertainty in the size of the customer's transformer could be as large as a factor of two and that would introduce an error of ±25% in the transformer losses. Although this is smaller than the 100% range due to individual transformer loss parameters it is a significant addition to the uncertainty for many of the customer specific technical losses.

In summary, the errors in individual transformer load loss estimates could range from double the value estimated to one tenth of the value estimated, or ±90%.

The location of the energy meter relative to the transformer was not always known. If the meter is upstream then the transformer losses are included in the meter reading and the technical loss used to calculate DLF should not have transformer losses included. The technical loss has been calculated both with and without the transformer losses, so that if an assumed location is determined to be incorrect, the calculation would not have to be repeated.

6.3 OTHER CALCULATION ISSUES

In addition to data quality issues there have been other site specific technical loss calculation issues identified:

- changing loads from year to year will invalidate the site specific technical loss calculation
- changing operational configurations will invalidate the site specific technical loss calculation

The circuit loading and configuration that changes over time cannot be addressed in the technical loss calculation. Although the over all loss changes slowly, since some customer loads increase and others decrease and losses move from circuit to circuit with reconfiguration, the individual loss specific to each customer can change rapidly and it can change widely. It is not necessary for a particular customer's load to change for a change to occur in that customer's loss factor since any customer on the circuit affects all the others. The best that can be done is to calculate the loss factors at a particular point in time and then recalculate them again and again. The frequency of recalculation depends on the accuracy that is desired. A 10% change can easily occur in two years and a 30% change in five.

7.0 COMPARISON OF RESULTS WITH OTHER LOSS ESTIMATES

Estimates of the loss on the HONI subtransmission system have been made previously. The overall loss calculation filed with the OEB (Ref 2) estimated a 2.6% loss for subtransmission lines and power transformers. A recent update of this analysis (Ref 1) estimated 2.2% for subtransmission lines and 0.4% in power transformers.

The loss as a percentage of energy sold calculated in the site specific study for subtransmission customers (1.4%) is slightly lower than the studies estimating losses for the entire Hydro One subtransmission system (2.6%). This is expected since the site specific studies do not include the very long lines to remote rural substations and 40% of the site loss estimates do not include transformer losses because they are metered on the primary side. The LDC and Direct customers are on average closer to the TS than the Hydro One substations are.

The site specific studies calculate a larger proportion of the loss to be due to transformer losses. Again this is due to the long lines to rural stations being missing and also to the lower average loading on the site specific transformers compared to Hydro One substation transformers.

The total loss attributed to the group of customers calculated in this study is 288 GWh. This is composed of 197 GWh of line loss, 24 GWH of transformer load loss and 67 GWh of transformer no load loss. The total energy sales were 20,500 GWh. This indicates that the weighted average technical loss (weighted by the energy sold to each customer) is 1.4%. This weighted average is much lower then the average because the largest load sites have primary meters (no transformer in the technical loss calculation) and short dedicated lines and therefore have very low site specific technical losses.

Presently the total TLF for embedded LDC and Direct customers is 3.4%. Subtracting the supply facilities loss factor (0.6) and then the 10% that was included in this for non-technical losses (such as theft) estimates the technical losses as 2.55% of energy sold. This would be equivalent to an estimated loss of 522 GWh.

If the site specific technical losses were used in billing it would reduce the recovery of technical distribution system losses, compared to the existing rate structure by 36%, when the supply facilities factor (0.6%) is included. [1-(288+0.006*20500) / (522+0.006*20500) =1-(411/645)=0.36] This reduction in recovered loss would need to be balanced by a corresponding increase in technical losses recovered from other customers to ensure that the total technical loss is still recovered.

The actual reduction in revenue from the embedded LDC and embedded Direct customers from the move to site specific losses would depend on the treatment of the non-technical losses. Given the extremely small values of some site specific technical losses (0.0001) the treatment of non-technical losses as a percentage of technical losses may not be appropriate. If the new treatment is used, of adding a fixed percentage of energy sold to the technical losses (1.2%), to account for non-technical losses then the reduction in revenue would be 6%. [1-(288+(0.012+0.006)*20500) / (20500*0.034) = 1-(657/697) = 0.057)]

8.0 REFERENCES

1 Ray Piercy, Stephen Cress, “2007 Recalculation of Distribution System Energy Losses at Hydro One”, Kinectrics report K-013111-001-RA-0001-R01, July 27, 2007

2 Ray Piercy, Stephen Cress, “Distribution System Energy Losses at Hydro One”, Kinectrics report K-011568-001-RA-0001-R00, July 20, 2005

9.0 APPENDIX A Calculated Site Specific Loss Values

The table below contains the actual calculated values of site specific technical losses for all the customers included in the study and the maximum and minimum values based on the accuracy analysis specific to the individual circuit and site. The three rows above the table contain the minimum, average and maximum values of each column. The supply facilities loss factor and non-technical losses are not included.

Some data has been removed from the table to respect the confidentiality of customer information. This results in some blank columns.

Negative DLFs result from special cases. When a line serving Hydro One loads passes through the service territory of an LDC, the LDC is sometimes billed by the subtraction of a meter reading at the entrance and exit to the service territory. This energy measurement includes the losses that occur on the line between the meters that are caused by the current to the Hydro One beyond the LDC territory. These losses must be subtracted off the energy meter reading. If the loss on the circuit upstream of the LDC territory that is caused by the LDC load is less than the loss to subtract, then the technical loss for the LDC becomes negative.

Table of Site Specific Technical Loss Results[1]

Customer	CSS Account No.	SPID	Tech Loss	Tech Loss no transf	Max Tech Loss	Min Tech Loss	Circuit	Station Name	Circuit Length to Site (km)
Minimum			-0.0007	-0.0007	-0.0007	-0.0006			0.20
Average			0.0215	0.0110	0.0263	0.0167			13.6
Maximum			0.1388	0.0753	0.1790	0.1006			86.6
1			0.00010	0.00009	0.00013	0.00007			2.9
2			0.00000	0.00000	0.00000	0.00000			1.35
3			0.00030	0.00030	0.00032	0.00028			
4			0.00020	0.00016	0.00022	0.00018			
5			0.00000	0.00000	0.00000	0.00000			5.58
6			0.02200	0.00484	0.03124	0.01276			10.85
7			0.01600	0.00507	0.02272	0.00928			5.63
8			0.00220	0.00220	0.00312	0.00128			
9			0.01650	0.00482	0.02343	0.00957			42.32
10			0.04310	0.00462	0.06120	0.02500			18.5
11			0.01540	0.00087	0.01987	0.01093			4.18
12			0.00080	0.00080	0.00086	0.00074			4.14
13			0.01586	0.01582	0.01708	0.01464			1.63
14			0.00080	0.00080	0.00086	0.00074			13.64
15			0.00120	0.00116	0.00129	0.00111			25.44
16			0.00120	0.00116	0.00129	0.00111			13
17			0.01532	0.01530	0.01639	0.01424			0.2
18			0.00500	0.00496	0.00535	0.00465			24.19
19			-0.00068	-0.00068	-0.00073	-0.00063			20.41
20			0.01622	0.01622	0.01735	0.01508			0.7
21			0.00100	0.00097	0.00107	0.00093			12.19
22			0.01226	0.01226	0.01312	0.01140			
23			0.00030	0.00026	0.00032	0.00028			8.98
24			0.00120	0.00120	0.00128	0.00112			18.05
25			0.01660	0.00091	0.02025	0.01295			23.66
26			0.04160	0.00089	0.05075	0.03245			4.56
27			0.01230	0.00096	0.01501	0.00959			23.66

[1] Some columns have been blanked to respect the confidentiality of customer information.

Customer	CSS Account No.	SPID	Tech Loss	Tech Loss no transf	Max Tech Loss	Min Tech Loss	Circuit	Station Name	Circuit Length to Site (km)
28			0.01110	0.00096	0.01354	0.00866			23.66
29			0.01121	0.01121	0.01200	0.01043			
30			0.01306	0.01306	0.01397	0.01214			18.12
31			0.01306	0.01306	0.01397	0.01214			
32			0.03340	0.00050	0.04075	0.02605			8.23
33			0.02350	0.00050	0.02867	0.01833			18.08
34			0.00000	0.00000	0.00000	0.00000			0.585
35			0.01410	0.00137	0.01720	0.01100			27.95
36			0.02920	0.00139	0.03562	0.02278			29.09
37			0.01320	0.00138	0.01610	0.01030			31.43
38			0.01990	0.00117	0.02567	0.01413			15.37
39			0.01900	0.00116	0.02451	0.01349			30.59
40			0.02570	0.00110	0.03135	0.02005			25.33
41			0.01670	0.00106	0.02038	0.01303			26.84
42			0.04753	0.00123	0.05799	0.03707			39.13
43			0.04641	0.00109	0.05662	0.03620			35.57
44			0.00790	0.00789	0.01003	0.00577			23
45			0.00310	0.00310	0.00394	0.00226			3.78
46			0.00270	0.00272	0.00289	0.00251			37.3
47			0.00450	0.00448	0.00482	0.00419			4.73
48			0.00130	0.00129	0.00140	0.00120			24.29
49			0.01430	0.00129	0.01845	0.01015			11.77
50			0.01440	0.00438	0.01757	0.01123			3.67
51			0.02260	0.00440	0.02757	0.01763			7.95
52			0.01420	0.00439	0.01732	0.01108			7.65
53			0.01580	0.00442	0.01928	0.01232			7.98
54			0.01410	0.00437	0.01720	0.01100			7.72
55			0.01440	0.00441	0.01757	0.01123			5.47
56			0.01860	0.00445	0.02269	0.01451			7.9
57			0.01320	0.00082	0.01610	0.01030			5.82
58			0.00260	0.00260	0.00330	0.00190			8.29
59			0.05820	0.05815	0.07391	0.04249			24.8
60			0.06769	0.06769	0.08597	0.04942			
61			0.00590	0.00590	0.00749	0.00431			5.4

Customer	CSS Account No.	SPID	Tech Loss	Tech Loss no transf	Max Tech Loss	Min Tech Loss	Circuit	Station Name	Circuit Length to Site (km)
62			0.00600	0.00596	0.00762	0.00438			5.4
63			0.00180	0.00180	0.00193	0.00167			3.86
64			0.00180	0.00180	0.00193	0.00167			3.86
65			0.00180	0.00178	0.00193	0.00167			3.82
66			0.00840	0.00840	0.00899	0.00781			14.73
67			0.00770	0.00770	0.00824	0.00716			11.67
68			0.02350	0.00618	0.02867	0.01833			17.4
69			0.02220	0.00611	0.02708	0.01732			24.37
70			0.01570	0.00414	0.01915	0.01225			12.44
71			0.01450	0.01450	0.01842	0.01059			16.5
72			0.01680	0.00025	0.02167	0.01193			6.69
73			0.01210	0.00125	0.01476	0.00944			20.13
74			0.01720	0.00122	0.02098	0.01342			8.22
75			0.01230	0.00128	0.01501	0.00959			7.62
76			0.01530	0.00123	0.01867	0.01193			16.32
77			0.01240	0.00083	0.01600	0.00880			6.58
78			0.02000	0.00080	0.02580	0.01420			9.69
79			0.02020	0.00445	0.02612	0.01428			6.41
80			0.00020	0.00019	0.00025	0.00015			0.253
81			0.00020	0.00019	0.00025	0.00015			0.253
82			0.00260	0.00259	0.00330	0.00190			2.4
83			0.00260	0.00257	0.00330	0.00190			2.4
84			0.00050	0.00050	0.00064	0.00037			2.03
85			0.03850	0.03754	0.04697	0.03003			14.19
86			0.08580	0.00794	0.10468	0.06692			23.02
87			0.00820	0.00819	0.00877	0.00763			5.47
88			0.01670	0.00488	0.02037	0.01303			11.31
89			0.00490	0.00000	0.00524	0.00456			39.71
90			0.03760	0.00492	0.04587	0.02933			5.77
91			0.01770	0.00497	0.02159	0.01381			2.13
92			0.01290	0.00191	0.01574	0.01006			4.56
93			0.01200	0.00184	0.01464	0.00936			1.33
94			0.02750	0.00196	0.03355	0.02145			1.07
95			0.01520	0.00189	0.01854	0.01186			2.02

Customer	CSS Account No.	SPID	Tech Loss	Tech Loss no transf	Max Tech Loss	Min Tech Loss	Circuit	Station Name	Circuit Length to Site (km)
96			0.01370	0.00185	0.01671	0.01069			2.5
97			0.09100	0.06582	0.11102	0.07098			32.68
98			0.01270	0.00189	0.01642	0.00898			1.84
99			0.06350	0.00172	0.08211	0.04489			1.84
100			0.01170	0.00190	0.01513	0.00827			6.32
101			0.01140	0.00018	0.01474	0.00806			1.25
102			0.01101	0.00048	0.01423	0.00778			1.76
103			0.00990	0.00017	0.01280	0.00700			0.77
104			0.01280	0.00018	0.01655	0.00905			0.68
105			0.01680	0.00018	0.02172	0.01188			1.2
106			0.01860	0.00242	0.02269	0.01451			9.52
107			0.00290	0.00290	0.00310	0.00270			3.85
108			0.02370	0.00371	0.02891	0.01849			9.8
109			0.01500	0.00367	0.01830	0.01170			10.4
110			0.05150	0.00762	0.06659	0.03641			2.36
111			0.04180	0.02017	0.05405	0.02955			11.81
112			0.03630	0.02020	0.04694	0.02566			11.9
113			0.00620	0.00620	0.00663	0.00577			
114			0.00649	0.00649	0.00824	0.00474			
115			0.00130	0.00130	0.00165	0.00095			2.5
116			0.00070	0.00069	0.00089	0.00051			2.15
117			0.00340	0.00340	0.00432	0.00248			
118			0.00330	0.00330	0.00419	0.00241			3.937
119			0.01040	0.01040	0.01113	0.00967			5.74
120			0.01020	0.01020	0.01091	0.00949			5.23
121			0.01640	0.01636	0.01755	0.01525			4.86
122			0.00020	0.00019	0.00021	0.00019			0.3
123			0.01650	0.00337	0.02129	0.01172			25.38
124			0.00730	0.00725	0.00781	0.00679			28.45
125			0.00820	0.00820	0.01041	0.00599			
126			0.01610	0.00029	0.02286	0.00934			13
127			0.01030	0.00029	0.01463	0.00597			13
128			0.01080	0.00032	0.01534	0.00626			3.49
129			0.00670	0.00670	0.00717	0.00623			8.9

Customer	CSS Account No.	SPID	Tech Loss	Tech Loss no transf	Max Tech Loss	Min Tech Loss	Circuit	Station Name	Circuit Length to Site (km)
130			0.00100	0.00100	0.00107	0.00093			1.3
131			0.00400	0.00400	0.00428	0.00372			5.415
132			0.00500	0.00500	0.00535	0.00465			5.415
133			0.01890	0.00736	0.02306	0.01474			8.64
134			0.01790	0.00710	0.02184	0.01396			20.97
135			0.03780	0.02746	0.04612	0.02948			18.31
136			0.05620	0.00201	0.06856	0.04384			37.89
137			0.01230	0.00183	0.01501	0.00959			13.77
138			0.01321	0.01319	0.01422	0.01219			
139			0.00150	0.00147	0.00162	0.00138			29.1
140			0.01392	0.01392	0.01499	0.01284			
141			0.01760	0.00159	0.02270	0.01250			7.87
142			0.02750	0.00177	0.03556	0.01944			10.44
143			0.02180	0.00162	0.02819	0.01541			3.1
144			0.01520	0.00162	0.01965	0.01075			3.1
145			0.01410	0.00076	0.01819	0.01001			16.62
146			0.01150	0.00031	0.01403	0.00897			4.74
147			0.01590	0.00317	0.01940	0.01240			3.65
148			0.02120	0.00425	0.02586	0.01654			3.65
149			0.03200	0.02233	0.04138	0.02262			30
150			0.03200	0.02233	0.04138	0.02262			30.34
151			0.02506	0.02506	0.03182	0.01829			5.1
152			0.02149	0.00270	0.02622	0.01676			4.9
153			0.00560	0.00560	0.00711	0.00409			11.11
154			0.01701	0.01696	0.02160	0.01242			1.1
155			0.00560	0.00560	0.00711	0.00409			13.19
156			0.00230	0.00230	0.00246	0.00214			4.45
157			0.00320	0.00320	0.00342	0.00298			6.38
158			0.01050	0.00016	0.01355	0.00746			10.23
159			0.00000	0.00000	0.00000	0.00000			
160			0.02410	0.01115	0.02940	0.01880			19.75
161			0.02970	0.01152	0.03623	0.02317			26
162			0.00000	0.00000	0.00000	0.00000			
163			0.00000	0.00000	0.00000	0.00000			

Customer	CSS Account No.	SPID	Tech Loss	Tech Loss no transf	Max Tech Loss	Min Tech Loss	Circuit	Station Name	Circuit Length to Site (km)
164			0.00000	0.00000	0.00000	0.00000			
165			0.01470	0.00243	0.01793	0.01147			36.27
166			0.02900	0.00243	0.03538	0.02262			36.27
167			0.01440	0.00244	0.01757	0.01123			35.64
168			0.02170	0.00263	0.02647	0.01693			4.6
169			0.01980	0.00242	0.02416	0.01544			4.6
170			0.01670	0.01667	0.01787	0.01553			22.65
171			0.00790	0.00790	0.01003	0.00577			29.02
172			0.02780	0.00828	0.03595	0.01965			33.2
173			0.02750	0.01357	0.03555	0.01944			4.5
174			0.01374	0.00000	0.01754	0.00993			1.3
175			0.00360	0.00355	0.00460	0.00260			22.55
176			0.02020	0.00244	0.02464	0.01576			9.9
177			0.01330	0.00247	0.01623	0.01037			9.9
178			0.01330	0.00240	0.01623	0.01037			11.33
179			0.01360	0.00239	0.01659	0.01061			7.5
180			0.00060	0.00059	0.00076	0.00044			6.71
181			0.01320	0.01320	0.01685	0.00954			1.1
182			0.06240	0.05177	0.07613	0.04867			48.24
183			0.06220	0.05169	0.07588	0.04852			48.24
184			0.04180	0.00302	0.05100	0.03260			2.5
185			0.02310	0.01308	0.02819	0.01802			4.09
186			0.02780	0.00035	0.03586	0.01974			17.25
187			0.00030	0.00025	0.00032	0.00028			14.81
188			0.00640	0.00640	0.00685	0.00595			16.35
189			0.01880	0.00630	0.02294	0.01466			7.52
190			0.01240	0.00159	0.01513	0.00967			16.67
191			0.01300	0.00166	0.01586	0.01014			15.81
192			0.01670	0.00165	0.02037	0.01303			1.31
193			0.00230	0.00230	0.00246	0.00214			
194			0.00170	0.00169	0.00182	0.00158			
195			0.01770	0.00609	0.02289	0.01251			11.4
196			0.01760	0.00615	0.02276	0.01244			11.4
197			0.01220	0.01220	0.01549	0.00890			

Customer	CSS Account No.	SPID	Tech Loss	Tech Loss no transf	Max Tech Loss	Min Tech Loss	Circuit	Station Name	Circuit Length to Site (km)
198			0.01230	0.01229	0.01562	0.00898			7.5
199			0.01120	0.00115	0.01448	0.00792			4.55
200			0.01170	0.00119	0.01513	0.00827			2.3
201			0.01170	0.00118	0.01513	0.00827			2.3
202			0.00100	0.00100	0.00127	0.00073			1.9
203			0.00080	0.00080	0.00102	0.00058			3.2
204			0.00150	0.00150	0.00191	0.00110			3.2
205			0.00000	0.00000	0.00000	0.00000			
206			0.00000	0.00000	0.00000	0.00000			
207			0.00950	0.00950	0.01017	0.00884			23.43
208			0.00300	0.00299	0.00381	0.00219			4.54
209			0.02520	0.02516	0.03200	0.01840			26.33
210			0.02520	0.02517	0.03200	0.01840			28.76
211			0.02200	0.01031	0.02684	0.01716			15.74
212			0.01180	0.01175	0.01263	0.01097			12.67
213			0.01080	0.01079	0.01156	0.01004			24.33
214			0.02180	0.01065	0.02660	0.01700			58.25
215			0.02030	0.00994	0.02477	0.01583			22.67
216			0.00020	0.00020	0.00025	0.00015			2.3
217			0.00080	0.00080	0.00102	0.00058			2.3
218			0.02170	0.00323	0.02806	0.01534			4.45
219			0.02010	0.00324	0.02599	0.01421			
220			0.04260	0.03141	0.05508	0.03012			0.77
221			0.03270	0.01165	0.03989	0.02551			19.35
222			0.01850	0.00762	0.02257	0.01443			23.85
223			0.01820	0.00839	0.02220	0.01420			6.95
224			0.05510	0.03153	0.06722	0.04298			24.38
225			0.03380	0.03307	0.04124	0.02636			37.27
226			0.01090	0.00054	0.01330	0.00850			11.92
227			0.01070	0.00053	0.01305	0.00835			5.31
228			0.01070	0.00090	0.01305	0.00835			12.58
229			0.01840	0.00088	0.02245	0.01435			3.87
230			0.00240	0.00240	0.00305	0.00175			4.28
231			0.00000	0.00000	0.00000	0.00000			0.98

Customer	CSS Account No.	SPID	Tech Loss	Tech Loss no transf	Max Tech Loss	Min Tech Loss	Circuit	Station Name	Circuit Length to Site (km)
232			0.01030	0.00020	0.01257	0.00803			3.04
233			0.01650	0.00009	0.02129	0.01172			6.86
234			0.01110	0.00013	0.01354	0.00866			1.36
235			0.01260	0.00014	0.01537	0.00983			4.54
236			0.01570	0.00013	0.01915	0.01225			0.96
237			0.01360	0.00013	0.01659	0.01061			2.83
238			0.01150	0.00013	0.01403	0.00897			2.74
239			0.00250	0.00248	0.00268	0.00233			
240			0.00250	0.00248	0.00268	0.00233			4.69
241			0.08640	0.01243	0.10541	0.06739			17.39
242			0.03190	0.03190	0.03414	0.02967			8.5
243			0.01250	0.00195	0.01616	0.00884			2.6
244			0.02840	0.01395	0.03465	0.02215			19.15
245			0.02690	0.01355	0.03282	0.02098			17.48
246			0.00080	0.00078	0.00086	0.00074			0.87
247			0.00474	0.00474	0.00507	0.00441			2.1
248			0.00680	0.00680	0.00728	0.00632			10.94
249			0.02980	0.01525	0.03636	0.02324			19.05
250			0.02760	0.02760	0.02954	0.02567			4.8
251			0.03190	0.03125	0.03892	0.02488			38.89
252			0.04397	0.04395	0.04705	0.04089			2.6
253			0.05197	0.05194	0.05561	0.04833			4.2
254			0.04720	0.03598	0.05758	0.03682			33.29
255			0.04730	0.03579	0.05771	0.03689			22.39
256			0.12900	0.03435	0.15738	0.10062			23.85
257			0.03180	0.02015	0.03880	0.02480			31.15
258			0.03950	0.02978	0.04819	0.03081			30.18
259			0.00490	0.00486	0.00622	0.00358			7.77
260			0.04150	0.01520	0.05063	0.03237			8.49
261			0.02740	0.01615	0.03343	0.02137			24.08
262			0.03250	0.02227	0.03965	0.02535			4.46
263			0.02260	0.02260	0.02418	0.02102			10.37
264			0.00170	0.00169	0.00182	0.00158			5.22
265			0.01170	0.00167	0.01427	0.00913			18.5

Customer	CSS Account No.	SPID	Tech Loss	Tech Loss no transf	Max Tech Loss	Min Tech Loss	Circuit	Station Name	Circuit Length to Site (km)
266			0.01690	0.00060	0.02180	0.01200			10.41
267			0.04650	0.02218	0.05673	0.03627			7.64
268			0.03510	0.02304	0.04282	0.02738			11.86
269			0.03290	0.02274	0.04014	0.02566			2.94
270			0.00320	0.00315	0.00406	0.00234			2.89
271			0.00270	0.00270	0.00343	0.00197			2.41
272			0.00040	0.00036	0.00043	0.00037			8.06
273			0.00210	0.00210	0.00267	0.00153			1.85
274			0.01910	0.01910	0.02426	0.01394			6.47
275			0.02200	0.01199	0.02684	0.01716			36.1
276			0.01420	0.00139	0.01732	0.01108			5.12
277			0.05130	0.00139	0.06259	0.04001			1.67
278			0.05130	0.00139	0.06259	0.04001			1.39
279			0.02260	0.01265	0.02757	0.01763			2.33
280			0.03450	0.00728	0.04399	0.02501			18.06
281			0.03450	0.00728	0.04399	0.02501			18.45
282			0.03430	0.03342	0.04373	0.02487			20.53
283			0.03740	0.03499	0.04769	0.02712			32.75
284			0.02330	0.00152	0.03006	0.01654			7.55
285			0.01490	0.00150	0.01922	0.01058			6.87
286			0.01465	0.01465	0.01577	0.01352			
287			0.01330	0.00294	0.01716	0.00944			24.07
288			0.01860	0.00289	0.02399	0.01321			26.24
289			0.06360	0.05072	0.07759	0.04961			22.74
290			0.06770	0.05048	0.08259	0.05281			22.74
291			0.00280	0.00161	0.00361	0.00199			17.33
292			0.01810	0.00471	0.02335	0.01285			26.2
293			0.01689	0.01685	0.01819	0.01559			5.6
294			0.01617	0.01617	0.01741	0.01492			
295			0.02940	0.00472	0.03793	0.02087			23.96
296			0.04260	0.00079	0.05197	0.03323			16.79
297			0.01295	0.01295	0.01386	0.01205			
298			0.02670	0.02517	0.03257	0.02083			14.98
299			0.05460	0.02479	0.06661	0.04259			15.2

Customer	CSS Account No.	SPID	Tech Loss	Tech Loss no transf	Max Tech Loss	Min Tech Loss	Circuit	Station Name	Circuit Length to Site (km)
300			0.02314	0.02314	0.02938	0.01689			
301			0.02260	0.00130	0.02915	0.01605			8.46
302			0.13880	0.00146	0.17905	0.09855			8.46
303			0.01618	0.01618	0.02066	0.01170			27.43
304			0.01618	0.01618	0.02066	0.01170			27.43
305			0.04220	0.04218	0.04515	0.03925			35
306			0.00320	0.00316	0.00342	0.00298			2.38
307			0.01190	0.01093	0.01452	0.00928			9.08
308			0.02220	0.00998	0.02708	0.01732			5.53
309			0.01800	0.01800	0.02286	0.01314			15.18
310			0.05610	0.00780	0.06844	0.04376			10.49
311			0.01960	0.00859	0.02391	0.01529			10.23
312			0.02090	0.00829	0.02550	0.01630			10.49
313			0.03020	0.01769	0.03684	0.02356			6.86
314			0.03000	0.01896	0.03660	0.02340			27.7
315			0.02660	0.01489	0.03245	0.02075			8.37
316			0.02690	0.01565	0.03282	0.02098			70.01
317			0.01130	0.00012	0.01379	0.00881			1.31
318			0.01866	0.00000	0.02370	0.01362			2.7
319			0.01870	0.00606	0.02384	0.01356			16.97
320			0.03136	0.01868	0.03998	0.02274			0.34
321			0.03354	0.02258	0.04092	0.02616			6.42
322			0.02290	0.00919	0.02920	0.01660			7.74
323			0.02350	0.00897	0.02996	0.01704			7.65
324			0.02030	0.00902	0.02588	0.01472			9.75
325			0.02100	0.00898	0.02678	0.01523			16.19
326			0.02250	0.00902	0.02869	0.01631			16.19
327			0.02050	0.00908	0.02614	0.01486			
328			0.02477	0.01323	0.03021	0.01932			10.1
329			0.02030	0.00902	0.02477	0.01583			11.86
330			0.01630	0.00031	0.02103	0.01157			9.01
331			0.01520	0.00031	0.01961	0.01079			4.27
332			0.00140	0.00139	0.00178	0.00102			
334			0.00140	0.00139	0.00178	0.00102			1.6

Customer	CSS Account No.	SPID	Tech Loss	Tech Loss no transf	Max Tech Loss	Min Tech Loss	Circuit	Station Name	Circuit Length to Site (km)
335			0.00140	0.00139	0.00178	0.00102			
336			0.00140	0.00139	0.00178	0.00102			0.8
337			0.00140	0.00139	0.00178	0.00102			1.55
338			0.00140	0.00139	0.00178	0.00102			1.4
339			0.01570	0.00284	0.02025	0.01115			21.41
340			0.01330	0.00285	0.01716	0.00944			12.33
341			0.01260	0.00283	0.01625	0.00895			21.88
342			0.02250	0.00737	0.02745	0.01755			4.16
343			0.01300	0.00057	0.01677	0.00923			3.38
344			0.02100	0.00057	0.02709	0.01491			13.09
345			0.02100	0.00852	0.02562	0.01638			4.02
346			0.01970	0.00070	0.02541	0.01399			15.29
347			0.02370	0.00071	0.03057	0.01683			14.62
348			0.01330	0.00285	0.01716	0.00944			12.01
349			0.01230	0.00110	0.01747	0.00713			9.63
350			0.01920	0.00113	0.02726	0.01114			9.63
351			0.00130	0.00130	0.00166	0.00094			18.54
352			0.01250	0.00135	0.01775	0.00725			8.38
353			0.00040	0.00000	0.00051	0.00029			8.82
354			0.01310	0.00039	0.01860	0.00760			8.2
355			0.00680	0.00680	0.00868	0.00492			5.01
356			0.03770	0.02555	0.04807	0.02733			10.77
357			0.03860	0.02658	0.04922	0.02799			10.3
358			0.03840	0.02675	0.04896	0.02784			10.3
359			0.03610	0.02575	0.04603	0.02617			10.77
360			0.03689	0.02630	0.04703	0.02675			11.4
361			0.03640	0.02572	0.04641	0.02639			9.4
362			0.01670	0.01670	0.02121	0.01219			16.85
363			0.01000	0.01000	0.01270	0.00730			11.22
364			0.00000	0.00000	0.00000	0.00000			3.7
365			0.00210	0.00209	0.00267	0.00153			2.2
366			0.00220	0.00220	0.00279	0.00161			1.8
367			0.01570	0.00040	0.02025	0.01115			6.08
368			0.01270	0.00026	0.01638	0.00902			6.95

Customer	CSS Account No.	SPID	Tech Loss	Tech Loss no transf	Max Tech Loss	Min Tech Loss	Circuit	Station Name	Circuit Length to Site (km)
369			0.01880	0.00027	0.02425	0.01335			5.69
370			0.01400	0.00026	0.01806	0.00994			6.41
371			0.01270	0.00026	0.01638	0.00902			5.87
372			0.01120	0.00022	0.01366	0.00874			5.34
373			0.01130	0.00023	0.01379	0.00881			7.45
374			0.01310	0.00023	0.01598	0.01022			9.14
375			0.05840	0.04708	0.07125	0.04555			35.75
376			0.06060	0.04855	0.07393	0.04727			35.75
377			0.07870	0.05681	0.09601	0.06139			68.03
378			0.01270	0.00100	0.01638	0.00902			12.01
379			0.03595	0.03591	0.03871	0.03318			
380			0.01574	0.01569	0.01695	0.01453			2.3
381			0.01614	0.01614	0.01738	0.01489			1.8
382			0.01909	0.01909	0.02043	0.01776			
383			0.01313	0.01313	0.01414	0.01212			2.8
384			0.01820	0.00147	0.02348	0.01292			17.55
385			0.00090	0.00086	0.00115	0.00065			9.96
386			0.01410	0.00081	0.02002	0.00818			10.62
387			0.02140	0.00066	0.03039	0.01241			5.4
388			0.01760	0.00067	0.02499	0.01021			14.67
389			0.01600	0.00074	0.02272	0.00928			14.32
390			0.04330	0.00015	0.06149	0.02511			14.11
391			0.06530	0.00016	0.09273	0.03787			14.11
392			0.00660	0.00575	0.00842	0.00479			42.32
393			0.01680	0.01680	0.02133	0.01226			
394			0.01040	0.00000	0.01477	0.00603			17.6
395			0.01820	0.00526	0.02220	0.01420			4.48
396			0.00410	0.00409	0.00521	0.00299			
397			0.07890	0.03409	0.09626	0.06154			15.17
398			0.04730	0.02961	0.06031	0.03429			86.64
399			0.01930	0.00008	0.02355	0.01505			2.26
400			0.04430	0.03355	0.05405	0.03455			22.48
401			0.06010	0.02400	0.07332	0.04688			28.95
402			0.02780	0.01678	0.03392	0.02168			28.88

Customer	CSS Account No.	SPID	Tech Loss	Tech Loss no transf	Max Tech Loss	Min Tech Loss	Circuit	Station Name	Circuit Length to Site (km)
403			0.08200	0.01634	0.10004	0.06396			27.93
404			0.02000	0.01901	0.02440	0.01560			30.83
405			0.01806	0.00650	0.02203	0.01409			14.5
406			0.00678	0.00678	0.00725	0.00631			10.51
407			0.04390	0.00634	0.05356	0.03424			19.31
408			0.03010	0.00460	0.03672	0.02348			13.79
409			0.00810	0.00810	0.00867	0.00753			21.47
410			0.00610	0.00609	0.00653	0.00567			20.29
411			0.00660	0.00658	0.00706	0.00614			21.47
412			0.02990	0.01937	0.03648	0.02332			19
413			0.03040	0.01943	0.03709	0.02371			19.19
414			0.01950	0.01947	0.02087	0.01814			34.07
415			0.03940	0.01897	0.04807	0.03073			18.94
416			0.02850	0.01870	0.03477	0.02223			30.38
417			0.06100	0.02059	0.07442	0.04758			29.4
418			0.04800	0.02054	0.05856	0.03744			29.37
419			0.01500	0.00318	0.01830	0.01170			7.11
420			0.01520	0.00320	0.01854	0.01186			7.11
421			0.01610	0.00327	0.01964	0.01256			9.04
422			0.01191	0.01189	0.01283	0.01100			
423			0.00090	0.00090	0.00097	0.00083			8.78
424			0.01650	0.00146	0.02343	0.00957			6.51
425			0.02843	0.00087	0.03468	0.02217			2.53
426			0.01740	0.00704	0.02123	0.01357			3.48
427			0.03220	0.00637	0.03928	0.02512			3.65
428			0.02063	0.00698	0.02517	0.01609			2.47
429			0.01967	0.01967	0.02104	0.01829			0.2
430			0.08720	0.00512	0.10638	0.06802			58.53
431			0.01740	0.00482	0.02123	0.01357			59.72
432			0.01591	0.01591	0.01703	0.01480			1.6
433			0.01881	0.01877	0.02013	0.01750			7.2
434			0.02236	0.02236	0.02393	0.02080			2.4
435			0.01570	0.00486	0.01915	0.01225			15.02
436			0.02050	0.00497	0.02501	0.01599			23.83

Customer	CSS Account No.	SPID	Tech Loss	Tech Loss no transf	Max Tech Loss	Min Tech Loss	Circuit	Station Name	Circuit Length to Site (km)
437			0.02940	0.00753	0.03587	0.02293			32.85
438			0.00710	0.00710	0.00760	0.00660			62.2
439			0.00710	0.00710	0.00760	0.00660			62.2
440			0.00710	0.00710	0.00760	0.00660			62.2
441			0.00710	0.00710	0.00760	0.00660			
442			0.00710	0.00710	0.00760	0.00660			
443			0.01774	0.01774	0.01898	0.01650			
444			0.03624	0.02490	0.04421	0.02827			26.81
445			0.07640	0.06537	0.09321	0.05959			20.29
446			0.07483	0.07483	0.08007	0.06959			
447			0.07700	0.06498	0.09394	0.06006			21.03
448			0.07439	0.07439	0.07960	0.06918			0.5
449			0.07480	0.06296	0.09126	0.05834			35.05
450			0.07440	0.06215	0.09077	0.05803			25.32
451			0.07531	0.07531	0.08058	0.07004			23.42
452			0.07531	0.07531	0.08058	0.07004			
453			0.07310	0.06241	0.08918	0.05702			25.35
454			0.07439	0.07439	0.07960	0.06918			
455			0.07531	0.07531	0.08058	0.07004			
456			0.01090	0.00105	0.01406	0.00774			12.6
457			0.01090	0.00105	0.01406	0.00774			22.72
458			0.01260	0.00133	0.01625	0.00895			19.51
459			0.01320	0.00140	0.01703	0.00937			20.14
460			0.01300	0.00139	0.01677	0.00923			19.71
461			0.01500	0.00523	0.01830	0.01170			11.17
462			0.02180	0.00521	0.02660	0.01700			6.6
463			0.02260	0.01289	0.02757	0.01763			12.85
464			0.01240	0.00109	0.01600	0.00880			28.25
465			0.01470	0.00007	0.01896	0.01044			4.74
466			0.00480	0.00480	0.00514	0.00446			3.8
467			0.00720	0.00720	0.00770	0.00670			3.8
468			0.01964	0.01964	0.02494	0.01433			1.2
469			0.02050	0.00081	0.02614	0.01486			1.54
470			0.01310	0.00043	0.01690	0.00930			8.27

Customer	CSS Account No.	SPID	Tech Loss	Tech Loss no transf	Max Tech Loss	Min Tech Loss	Circuit	Station Name	Circuit Length to Site (km)
471			0.01630	0.00116	0.02315	0.00945			23.65
472			0.03750	0.01548	0.04781	0.02719			25.97
473			0.05780	0.01608	0.07370	0.04191			25.97
474			0.08220	0.02552	0.10481	0.05960			15.52
475			0.03460	0.02297	0.04412	0.02509			13.2
476			0.00020	0.00018	0.00025	0.00015			0.29
477			0.03538	0.03535	0.03786	0.03290			
478			0.05479	0.05475	0.05862	0.05095			7.2
479			0.00020	0.00018	0.00025	0.00015			0.29
480			0.01545	0.01545	0.01653	0.01437			3.27
481			0.01545	0.01545	0.01653	0.01437			
482			0.01545	0.01545	0.01653	0.01437			
483			0.00170	0.00165	0.00182	0.00158			5.74
484			0.00190	0.00190	0.00241	0.00139			2.2
485			0.00330	0.00325	0.00419	0.00241			3.75
486			0.00190	0.00190	0.00241	0.00139			2.7
487			0.00330	0.00325	0.00419	0.00241			2.7
488			0.02750	0.01779	0.03355	0.02145			21.8
489			0.03070	0.01798	0.03745	0.02395			21.82
490			0.01771	0.01771	0.01894	0.01647			
491			0.00400	0.00400	0.00428	0.00372			5.5
492			0.00410	0.00409	0.00439	0.00381			4.1
493			0.02714	0.00912	0.03311	0.02117			9.57
494			0.02060	0.00836	0.02513	0.01607			18.9
495			0.00390	0.00390	0.00417	0.00363			1.94
496			0.00410	0.00406	0.00439	0.00381			9.61
497			0.02640	0.01582	0.03221	0.02059			36.85
498			0.02870	0.01585	0.03501	0.02239			39.19
499			0.08750	0.01857	0.10675	0.06825			10.34
500			0.08090	0.02436	0.09870	0.06310			25.89
501			0.03060	0.02029	0.03733	0.02387			44.59
502			0.01570	0.01570	0.01680	0.01460			41.93
503			0.01570	0.01570	0.01680	0.01460			0.2
504			0.00330	0.00330	0.00353	0.00307			6.56

Customer	CSS Account No.	SPID	Tech Loss	Tech Loss no transf	Max Tech Loss	Min Tech Loss	Circuit	Station Name	Circuit Length to Site (km)
505			0.00200	0.00199	0.00214	0.00186			4.32
506			0.02950	0.01882	0.03599	0.02301			19.35
507			0.04770	0.04770	0.05104	0.04436			
508			0.04770	0.04770	0.05104	0.04436			
509			0.01680	0.00540	0.02142	0.01218			8.09
510			0.01230	0.00226	0.01568	0.00892			3.11
511			0.02800	0.01690	0.03571	0.02030			0.86
512			0.01430	0.00227	0.01823	0.01037			8.64
513			0.01530	0.00229	0.01951	0.01109			2.91
514			0.01340	0.00227	0.01709	0.00972			3.65
515			0.01990	0.00228	0.02537	0.01443			2.06
516			0.02020	0.00227	0.02576	0.01465			7.7
517			0.01230	0.00226	0.01568	0.00892			4.89
518			0.06040	0.02009	0.07701	0.04379			39.67
519			0.03000	0.01759	0.03825	0.02175			41.21
520			0.03440	0.01826	0.04386	0.02494			39.4
521			0.00040	0.00037	0.00051	0.00029			0.585
522			0.00040	0.00040	0.00051	0.00029			0.585
523			0.00040	0.00040	0.00051	0.00029			0.65
524			0.00020	0.00020	0.00025	0.00015			0.2
525			0.00070	0.00070	0.00089	0.00051			0.3
526			0.00030	0.00030	0.00038	0.00022			0.2
527			0.00030	0.00030	0.00038	0.00022			0.3
528			0.03240	0.02093	0.03953	0.02527			10.09
529			0.01610	0.00503	0.01964	0.01256			0.57
530			0.00520	0.00520	0.00556	0.00484			14.37
531			0.01563	0.01559	0.01672	0.01454			
532			0.01530	0.00520	0.01867	0.01193			2.92
533			0.01260	0.00235	0.01607	0.00914			11.3
534			0.02770	0.01664	0.03532	0.02008			24
535			0.09410	0.01637	0.11998	0.06822			24
536			0.01160	0.00100	0.01415	0.00905			4.23
537			0.01160	0.00100	0.01415	0.00905			4.23
538			0.01970	0.00263	0.02403	0.01537			16.95

Customer	CSS Account No.	SPID	Tech Loss	Tech Loss no transf	Max Tech Loss	Min Tech Loss	Circuit	Station Name	Circuit Length to Site (km)
539			0.01160	0.00100	0.01415	0.00905			9.21
540			0.01860	0.00660	0.02269	0.01451			8.92
541			0.01970	0.00872	0.02512	0.01428			22.94
542			0.01130	0.00109	0.01441	0.00819			2.1
543			0.01150	0.00087	0.01466	0.00834			2.02
544			0.00430	0.00430	0.00546	0.00314			
545			0.00430	0.00000	0.00546	0.00314			
546			0.00410	0.00410	0.00521	0.00299			6.3
547			0.00530	0.00526	0.00673	0.00387			6.3
548			0.01930	0.00002	0.02461	0.01399			1.35
549			0.00210	0.00210	0.00267	0.00153			1.66
550			0.03850	0.01903	0.04697	0.03003			40.99
551			0.04650	0.02008	0.05673	0.03627			35.05
552			0.03380	0.02013	0.04124	0.02636			32.53
553			0.05450	0.02026	0.06649	0.04251			38.89
554			0.00080	0.00080	0.00086	0.00074			24.49
555			0.00430	0.00429	0.00460	0.00400			4.45
556			0.00110	0.00110	0.00140	0.00080			1.44
557			0.00430	0.00429	0.00460	0.00400			4.34
558			0.04120	0.00082	0.05850	0.02390			4.07
559			0.01220	0.00061	0.01732	0.00708			4.62
560			0.01210	0.00062	0.01718	0.00702			4.87
561			0.03390	0.00078	0.04814	0.01966			4.87
562			0.01950	0.00110	0.02486	0.01414			13.08
563			0.01110	0.00080	0.01415	0.00805			11.76
564			0.06030	0.04918	0.07688	0.04372			12.61
565			0.05900	0.04895	0.07523	0.04278			12.05
566			0.04600	0.03507	0.05865	0.03335			18
567			0.00400	0.00400	0.00508	0.00292			2.5
568			0.00490	0.00489	0.00622	0.00358			
569			0.00000	0.00000	0.00000	0.00000			
570			0.00400	0.00400	0.00508	0.00292			5.85
571			0.00590	0.00587	0.00749	0.00431			5.85
572			0.07280	0.05781	0.08882	0.05678			

Customer	CSS Account No.	SPID	Tech Loss	Tech Loss no transf	Max Tech Loss	Min Tech Loss	Circuit	Station Name	Circuit Length to Site (km)
573			0.00000	0.00000	0.00000	0.00000			
574			0.00000	0.00000	0.00000	0.00000			
575			0.07280	0.05781	0.09282	0.05278			
576			0.07310	0.06157	0.08918	0.05702			19.78
577			0.07109	0.07109	0.07606	0.06611			
578			0.08100	0.06064	0.09882	0.06318			18.82
579			0.09840	0.06255	0.12005	0.07675			21.99
580			0.01790	0.00241	0.02184	0.01396			6.08
581			0.01240	0.00241	0.01513	0.00967			2.09
582			0.00625	0.00623	0.00669	0.00581			1.5
583			0.03640	0.01955	0.04441	0.02839			20.05
584			0.00600	0.00595	0.00762	0.00438			3.9
585			0.00550	0.00550	0.00699	0.00402			2.9
586			0.01750	0.00345	0.02258	0.01243			21.69
587			0.01120	0.00149	0.01366	0.00874			5.06
588			0.01140	0.00149	0.01391	0.00889			3.68
589			0.01340	0.00212	0.01709	0.00972			1.98
590			0.02070	0.00215	0.02639	0.01501			5.77
591			0.01430	0.00209	0.01823	0.01037			5.77
592			0.02600	0.00210	0.03315	0.01885			6.7
593			0.01460	0.00402	0.01862	0.01059			3.06
594			0.01780	0.00358	0.02270	0.01291			5.93
595			0.01280	0.00057	0.01632	0.00928			2.42
596			0.01250	0.00055	0.01594	0.00906			1.81
597			0.01730	0.00085	0.02206	0.01254			5.21
598			0.01430	0.00088	0.01823	0.01037			5.21
599			0.02460	0.00755	0.03137	0.01784			14.13
600			0.01930	0.00798	0.02461	0.01399			16.14
601			0.01460	0.00317	0.01781	0.01139			8.67
602			0.01580	0.00319	0.01928	0.01232			4.89
603			0.01580	0.00313	0.01928	0.01232			17.18
604			0.01300	0.00296	0.01586	0.01014			3.66
605			0.01340	0.00293	0.01635	0.01045			4.96
606			0.01280	0.00296	0.01562	0.00998			5.27

Customer	CSS Account No.	SPID	Tech Loss	Tech Loss no transf	Max Tech Loss	Min Tech Loss	Circuit	Station Name	Circuit Length to Site (km)
607			0.01620	0.00297	0.01976	0.01264			5.65
608			0.01800	0.00306	0.02196	0.01404			5.27
609			0.01570	0.00293	0.01915	0.01225			2.42
610			0.01450	0.00183	0.01871	0.01030			28.46
611			0.01260	0.00181	0.01625	0.00895			27.96
612			0.01205	0.00182	0.01555	0.00856			29.65
613			0.01938	0.00182	0.02499	0.01376			29.82
614			0.00270	0.00267	0.00343	0.00197			8.36
615			0.00160	0.00160	0.00203	0.00117			4.26
616			0.00290	0.00286	0.00368	0.00212			8.57
617			0.00290	0.00289	0.00368	0.00212			13.36
618			0.02024	0.02022	0.02570	0.01477			2.29
619			0.02024	0.02022	0.02570	0.01477			0.5
620			0.02004	0.02004	0.02545	0.01463			0.53
621			0.02004	0.02004	0.02545	0.01463			0.7
622			0.02190	0.01023	0.02792	0.01588			14.7
623			0.02670	0.01000	0.04005	0.01335			14.7
624			0.03260	0.02197	0.03977	0.02543			20.82
625			0.05120	0.01904	0.06246	0.03994			26.66
626			0.05680	0.04468	0.06930	0.04430			35.25
627			0.04250	0.02228	0.05185	0.03315			6.05
628			0.02910	0.01916	0.03550	0.02270			18.44
629			0.04280	0.01955	0.05222	0.03338			20.52
630			0.01530	0.00272	0.01867	0.01193			5.88
631			0.01250	0.00256	0.01525	0.00975			5.29
632			0.01530	0.00272	0.01867	0.01193			5.83
633			0.04160	0.04158	0.04451	0.03869			9.22
634			0.03852	0.03852	0.04121	0.03582			
635			0.04080	0.02911	0.04978	0.03182			41.82
636			0.05860	0.02802	0.07149	0.04571			49.76
637			0.04420	0.03029	0.05392	0.03448			47.52
638			0.05080	0.02997	0.06198	0.03962			41.03
639			0.03090	0.00409	0.03940	0.02240			4.39
640			0.03090	0.00409	0.03940	0.02240			3.6

Customer	CSS Account No.	SPID	Tech Loss	Tech Loss no transf	Max Tech Loss	Min Tech Loss	Circuit	Station Name	Circuit Length to Site (km)
641			0.08430	0.02409	0.10285	0.06575			24.45
642			0.01670	0.01670	0.01787	0.01553			18.65
643			0.04680	0.01653	0.05710	0.03650			22.56
644			0.08133	0.02408	0.09923	0.06344			29.26
645			0.09231	0.03041	0.11261	0.07200			55
646			0.05700	0.02239	0.06954	0.04446			15.08
647			0.01921	0.01921	0.02055	0.01786			0.65
648			0.01790	0.00689	0.02184	0.01396			0.51
649			0.01050	0.01048	0.01124	0.00977			12.01
650			0.02548	0.02545	0.02726	0.02369			1.4
651			0.02548	0.02545	0.02726	0.02369			1.5
652			0.01440	0.01440	0.01541	0.01339			14.22
653			0.02658	0.02658	0.02844	0.02472			
654			0.05860	0.01523	0.07149	0.04571			13.15
655			0.03160	0.03160	0.03381	0.02939			13.87
656			0.04378	0.03230	0.05341	0.03415			7.04
657			0.01230	0.01227	0.01316	0.01144			21.33
658			0.00750	0.00750	0.00803	0.00698			17.71
659			0.03770	0.03766	0.04034	0.03506			17.25
660			0.00850	0.00850	0.00910	0.00791			3.81
661			0.02100	0.00860	0.02562	0.01638			5.76
662			0.00130	0.00130	0.00165	0.00095			1.4
663			0.00020	0.00020	0.00025	0.00015			0.3
664			0.00020	0.00019	0.00025	0.00015			0.3
665			0.00090	0.00090	0.00114	0.00066			1.4
666			0.02170	0.00499	0.02647	0.01693			2.63
667			0.00000	0.00000	0.00000	0.00000			0.22
668			0.00000	0.00000	0.00000	0.00000			0.2
669			0.00030	0.00026	0.00038	0.00022			1.26
670			0.01420	0.01420	0.01803	0.01037			5.9
671			0.00310	0.00310	0.00394	0.00226			1.26
672			0.02626	0.02626	0.03335	0.01917			2.6
673			0.01560	0.01560	0.01981	0.01139			8.34
674			0.01450	0.01450	0.01842	0.01059			1.26

Customer	CSS Account No.	SPID	Tech Loss	Tech Loss no transf	Max Tech Loss	Min Tech Loss	Circuit	Station Name	Circuit Length to Site (km)
675			0.01400	0.00396	0.01806	0.00994			17.4
676			0.03020	0.00397	0.03896	0.02144			17.4
677			0.02044	0.02043	0.02202	0.01887			0.9
678			0.00614	0.00183	0.00792	0.00436			31.83
679			0.01590	0.00556	0.02051	0.01129			4.47
680			0.02110	0.00565	0.02722	0.01498			6.24
681			0.00660	0.00497	0.00851	0.00469			47.05
682			0.01781	0.01780	0.01906	0.01657			
683			0.01620	0.00018	0.02090	0.01150			4.01
684			0.01290	0.00079	0.01832	0.00748			11.33
685			0.01120	0.00019	0.01590	0.00650			2.24
686			0.01410	0.00019	0.02002	0.00818			1.86
687			0.01460	0.00034	0.02073	0.00847			9.48
688			0.00310	0.00307	0.00394	0.00226			2.7
689			0.00310	0.00307	0.00394	0.00226			2.7
690			0.00310	0.00307	0.00394	0.00226			0.95
691			0.00310	0.00307	0.00394	0.00226			0.95
692			0.00310	0.00307	0.00394	0.00226			0.95
693			0.04830	0.03506	0.05893	0.03767			46.79
694			0.06090	0.04014	0.07430	0.04750			46.79
695			0.04900	0.03670	0.05978	0.03822			37.43
696			0.018045	0.007596	0.02201	0.01408			2.9
697			0.028143	0.016175	0.03433	0.02195			6.6
698			0.03300	0.01739	0.04026	0.02574			50.21
699			0.03610	0.01747	0.04404	0.02816			44.56
700			0.04570	0.02777	0.05575	0.03565			29.52
701			0.04180	0.02615	0.05100	0.03260			27.48
702			0.00130	0.00125	0.00139	0.00121			17
703			0.00070	0.00066	0.00075	0.00065			2.01
704			0.02800	0.02798	0.02996	0.02604			53.22
705			0.00170	0.00169	0.00182	0.00158			2.01
706			0.03750	0.02302	0.04575	0.02925			15.72
707			0.06670	0.02371	0.08137	0.05203			15.7
708			0.03316	0.03316	0.03548	0.03084			

Customer	CSS Account No.	SPID	Tech Loss	Tech Loss no transf	Max Tech Loss	Min Tech Loss	Circuit	Station Name	Circuit Length to Site (km)
709			0.03910	0.02305	0.04770	0.03050			15.72
710			0.01920	0.01920	0.02054	0.01786			12.85
711			0.05233	0.05230	0.05599	0.04867			0.4
712			0.05170	0.04057	0.06307	0.04033			15.41
713			0.05090	0.04074	0.06210	0.03970			16.73
714			0.05620	0.04208	0.06856	0.04384			34.94
715			0.00030	0.00030	0.00038	0.00022			6.2
716			0.00340	0.00337	0.00432	0.00248			6.1
717			0.00500	0.00500	0.00635	0.00365			6.1
718			0.01180	0.00126	0.01440	0.00920			3.39
719			0.02290	0.01267	0.02794	0.01786			10.67
720			0.01280	0.01279	0.01370	0.01190			13.12
721			0.02590	0.01189	0.03160	0.02020			19.44
722			0.01210	0.01210	0.01295	0.01125			18.76
723			0.01210	0.01210	0.01295	0.01125			23.62
724			0.00950	0.00948	0.01017	0.00884			16.7
725			0.02580	0.01239	0.03148	0.02012			24.25
726			0.01050	0.00051	0.01281	0.00819			4.9
727			0.03165	0.03165	0.03386	0.02943			
728			0.02090	0.02089	0.02236	0.01944			23.29
729			0.03136	0.03136	0.03356	0.02917			0.4
730			0.01490	0.00241	0.01922	0.01058			13.26
731			0.00370	0.00369	0.00396	0.00344			1.7
732			0.01730	0.00565	0.02111	0.01349			0.34
733			0.01310	0.00147	0.01690	0.00930			7.58
734			0.01490	0.01488	0.01594	0.01386			16.94
735			0.03780	0.02435	0.04612	0.02948			49.86
736			0.03930	0.02552	0.04795	0.03065			43.17
737			0.04000	0.02476	0.04880	0.03120			42.66
738			0.03640	0.02542	0.04441	0.02839			45.39
739			0.02550	0.00941	0.03111	0.01989			25.05
740			0.03560	0.01510	0.04343	0.02777			7.84
741			0.02200	0.02202	0.02354	0.02046			3.9
742			0.04810	0.01458	0.05868	0.03752			32.65

Customer	CSS Account No.	SPID	Tech Loss	Tech Loss no transf	Max Tech Loss	Min Tech Loss	Circuit	Station Name	Circuit Length to Site (km)
743			0.01910	0.00808	0.02330	0.01490			30.37
744			0.00840	0.00837	0.00899	0.00781			18.14
745			0.02390	0.01254	0.02916	0.01864			23.47
746			0.02510	0.01252	0.03062	0.01958			37.19
747			0.02420	0.01169	0.02952	0.01888			35.72
748			0.02480	0.01235	0.03026	0.01934			36.17
749			0.03090	0.01158	0.03770	0.02410			25.31
750			0.02472	0.02471	0.02645	0.02299			6.7
751			0.02560	0.01224	0.03123	0.01997			34.84
752			0.02450	0.01216	0.02989	0.01911			14.81
753			0.02420	0.01144	0.02952	0.01888			14.82
754			0.02440	0.01175	0.02977	0.01903			8.3
755			0.00880	0.00883	0.00942	0.00818			7.74
756			0.00890	0.00890	0.00952	0.00828			8.91
757			0.00890	0.00890	0.00952	0.00828			8.17
758			0.00160	0.00157	0.00172	0.00148			21.65
759			0.03610	0.01042	0.04404	0.02816			17.3
760			0.00010	0.00010	0.00013	0.00007			
761			0.00650	0.00654	0.00826	0.00475			7.6
762			0.00760	0.00759	0.00965	0.00555			9.2
763			0.00220	0.00223	0.00279	0.00161			4.1
764			0.00150	0.00145	0.00191	0.00110			1.7
765			0.04000	0.00216	0.04880	0.03120			3.12

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MODIFICATION TO OEB COST ALLOCATION METHODOLOGY AND RESULTS

1.0 INTRODUCTION

This exhibit details the modifications that Hydro One Distribution made to the OEB Cost Allocation model to reflect its unique circumstances and also presents the results of the Cost Allocation Study.

2.0 COMPUTER MODEL

Hydro One modified the OEB Cost Allocation model to take into account density aspects, serving a large number of Embedded customers through its Low Voltage system and having multiple customer classes in addition to over 270 customer classes for Acquired LDCs.

Hydro One used Version 50 of the Cost Allocation model as a starting point and understands from Board staff that differences between version 50 and the first official Cost Allocation model version are mainly cosmetics. In addition, Hydro One has implemented updates to version 50 as identified by Board staff in the releases of the latest Cost Allocation Model versions 1.1 and 1.2.

Attachment A includes the Input and Output sheets of the Cost Allocation model, the same information provided for the Cost Allocation Information filing under Proceeding EB-2007-0001.

3.0 DENSITY WEIGHTING FACTORS

Density factors have been incorporated as weighting factors for Overhead lines and Transformers, consistent with the customer classes approved by the OEB that are based on Density definitions. The Density definitions have also been approved by the OEB.

For lines, Customer Density weighting factors were developed by calculating for all feeders the number of customers by customer class on each feeder and assigning the total distance of the feeders to the various customer classes proportionally. A similar method was used to develop Demand Density weighting factors, by using energy by customer class by feeder and total energy supplied by feeder to assign the feeder length for each feeder to customer classes proportionally.

For transformers, Customers Density weighting factors were developed by calculating Net Book Value of Transformation Assets by feeder and assigning the total Net Book Value of Transformation assets by feeder to the various customer classes proportionally. A similar method was used to develop Demand Density weighting factors, by using energy by customer class by feeder and total energy supplied by feeder to assign the Net Book Value of Transformation assets for each feeder to customer classes proportionally.

4.0 MODIFICATIONS

Hydro One created a new customer class, Subtransmission (ST) class that includes all Directs, Large Users, most T-class customers, all Embedded LDCs, some three-phase General Service, one Farm customer, some Acquired General Service customers, and some Urban General Service customers. All these customers are directly served at voltages between 44 kV and 13.8 kV, have consumption above 500 kW and provide their own transformation. Some of the LDCs are served below 13.8 kV and Hydro One provides an additional level of transformation.

Distribution assets which are used to supply the planned ST customer group include: High Voltage Distribution Stations, a small number of Low Voltage Distribution Stations whose secondary voltages are between 27.6 kV and 13.8 kV inclusive, and power lines between the voltages of 44 kV and 13.8 kV inclusive. In addition Distribution assets which are used to supply customers below 13.8 kV include Low Voltage Distribution Stations and power lines between the voltages of 12.5 kV and 4.16 kV inclusive.

To better align with the customer classes in other LDCs that typically have one Residential customer class and two General Service customers broken down between below and above 50 kW, and to better reflect customer characteristics, Hydro One has modified its Residential and General Service customer groupings. Four Residential customer classes have been created:

1. Urban includes the current Urban Residential customer class and customers from 12 Acquired LDC Residential customer classes who met the Urban Density Criteria,
2. Residential R1 includes the current high density and 88 Residential Acquired LDCs customers
3. Residential R2 includes normal density residential classes as well as Farm single phase and three phase energy billed customer classes that currently receive RRRP,
4. Seasonal includes the current high density and normal density seasonal residential customer classes.

Four General Service customer classes have been created:

1. General Service below 50 kW includes the existing single-phase General Service, three-phase General Service, Farm single-phase and Three-phase that do not qualify for RRRP, T-class customers that are energy billed, and Acquired General Service customers that are energy billed.
2. General Service above 50 kW includes General Service single-phase, General Service three-phase, T-class customers that are demand billed and consumption below 500 kW and all Farms that are demand billed and all these customers have not been reclassified into the ST customer class.
3. Urban General Service below 50 kW includes all current Urban General Service customers that are energy billed and energy billed single-phase General Service, three-phase General Service, single–phase Farms and Acquired General Service customers in 11 Acquired LDCs that meet the Urban density criteria.
4. Urban General Service above 50 kW includes all current Urban General Service customers that are demand billed and demand billed single-phase General Service, three-phase General Service, and Acquired General Service customers in 11 Acquired LDCs that meet the Urban density criteria and that have not been reclassified into the ST customer class.

As per OEB direction, Hydro One has created a new customer class for Merchant Generators (Distributed Generators). This class is composed of 76 interval meter customers and 5 non-interval metered customers. These customers are currently three-phase General Service, T-class customers, and one Acquired General Service customer. The load profile for this class is based on the consumption Distributed Generators require as station service when the active generators are not operating. No meter costs have been allocated to this class, as these customers are required to provide their own meters.

<u>Customer classes (Input Sheet 2)</u>

In Input Sheet 2, reproduced below, Hydro One is using the following Customer classes compared to the customer classes in the Model:

		Utility's Class Definition
1	Residential	Urban - Residential, Acquired Residential
2	GS <50	Residential – R1, Acquired Residential
3	GS>50-Regular	Residential – R2, Farms with RRRP
4	GS> 50-TOU	Seasonal
5	GS >50-Intermediate	General Service Energy-Billed
6	Large Use >5MW	General Service Demand-Billed
7	Street Light	Street Lights
8	Sentinel	Sentinel Lights
9	Unmetered Scattered Load	N/A
10	Embedded Distributor	N/A
11	Back-up/Standby Power	N/A
12	Rate Class 1	Distributed Generators
13	Rate Class 2	Sub-Transmission
14	Rate Class 3	Urban General Service Energy-Billed
15	Rate Class 4	Urban General Service Demand-Billed

4.0 MODEL CHANGES

As per Board staff instructions in version 1.1, Hydro One removed reference to step 4 and updated text for steps 1-3.

Trial Balance (Input Sheet 3)

Transformer Ownership Allowance not populated as Hydro One's approved Revenue Requirement of $1,067 million already includes cost of Transformer Ownership allowance.

Adjusted formula dealing with Working Capital (Cell G 20) to reflect the proposed Hydro One total working Capital of $296.5 million, or 11.2% instead of 15% for other LDCs. Hydro One's Working Capital includes $273.3 million of cash working capital and $23.3 million of Materials and Supplies Inventory in USoA 1330. USoA 1985 Sentinel Lights is also taken into account when calculating Working Capital. Hydro One has an exemption from the Government that allows it to continue maintaining Sentinel Lights.

Wholesale meters of $1.04 million reclassified from USoA 1815 to USoA 1820.

External Revenues of $5.85 million reclassified from USoA 4380 to USoA 5135, ($5.3 million Forestry Line work) and USoA 5420, ($0.58 million Health and Safety external revenues).

$4.5 million in USoA 5065 for Interval Meter Reads and Retail Settlements directly allocated to classes using number of interval meters by delivery point by customer class.

Amortization Environmental Assets of $8 million in USoA 5715 mapped 10% to USoA 5112 and 90% to USoA 5114 based on number of stations per category.

$1.19 million moved from USoA 5170 to USoA 5665 to reflect Sentinel Light and allocated directly to this class.

$0.3 million moved from USoA 5172 to USoA 5665 to reflect Sentinel Lights and allocated directly to this class.

$31.6 million moved from USoA 5715 to USoA 5645 reflecting amortization of OPEB, [$23.6million] and to USoA 5112/5114 reflecting land reclamation around stations [$8million].

Billing and Settlement Costs directly attributable to Interval Metered customers was determined for further direct assignment to classes using number of interval meters by delivery point by customer class. Balances direct assigned are: $59k from USoA 5610, $600k from USoA 5615, $11k from USoA 5630, $284k from USoA 5665 and $190k from USoA 5675.

Asset Breakout (Input Sheet 4)

Created sub-accounts for USoA 1815 1-5 Transformer Station Equipment to take into account that Hydro One owns High Voltage Distribution Stations and Low Voltage Distribution Stations. The stations can be shared between Low Voltage (LV) system customers and other end-use customers, or used exclusively by one customer group.

Created sub-accounts for USoA 1830-3 Poles, Towers and Fixtures – Sub-Transmission Bulk Delivery to provide a split between LV and other end use customers.

Created sub-accounts for USoA 1830-4 Poles, Towers and Fixtures - Primary to provide a split between LV and other end use customers.

Created sub-accounts for USoA 1835-3 Overhead Conductors and Devices – Sub-Transmission Bulk Delivery to provide a split between LV and other end use customers.

Created sub-accounts for USoA 1835-4 Overhead Conductors and Devices - Primary to provide a split between LV and other end use customers.

Created sub-accounts for USoA 1850 1-2 Line Transformers to provide a split between LV and other end use customers.

Created sub-accounts for USoA 1860 Meters to provide a split between single, poly, LV, and Smart meters.

Added USoA 1985 Sentinel Lights.

Modified Totals to include Sub Accounts and exclude Main Accounts when creating new sub-accounts.

Miscellaneous Data (Input Sheet 5)

The fixed service charge for the proposed rate classes is the customer weighted average service charge of the customer classes being mapped to the new classes.

Customer Data (Input Sheet 6)

The default Billing weighting factors were aligned with Hydro One’s customer classes.

Meter Capital (Input Sheet 7.1)

Hydro One matched its new customer classes (column B) with the default “Cost per Meter (installed) Col 1”. Column C default rate class definition not used.

Meter Reading (Input Sheet 7.2)

Used Hydro One specific Meter Reading weighting factors based on Hydro One Meter Reading Optimization analysis. The weights range between values of 1 to 4.

Demand Data (Input Sheet 8)

Total Loss Factor by class introduced in cells C16 to W25 to calculate load data at different delivery levels: TS, Bulk, Primary, and Secondary. The LT NCPs were developed using the ratio of the billed demand for customers that receive transformer ownership allowance over the total customer class billed demand as shown in Input Sheet 6.

Direct Allocation (Input Sheet 9)

The following USoA accounts were directly allocated:

5065 Meter Expense ($4.5 million),
5610 Management Salaries and Expenses ($59,000),
5615 General Administrative Salaries and Expenses ($0.6 million),
5630 Outside Services Employed ($11,000)
5665 Miscellaneous General Expenses ($1.8 million)
5675 Maintenance of General Plant ($0.19 million).

These expenses relate to interval meters and to staff dealing with this type of larger customers and Sentinel Light costs.

The allocation factor used for all these accounts is number of Interval Meter by delivery point by class except for Sentinel Lights included in account 5665 ($1.48 million) that has been allocated directly to Sentinel Lights..

Revenue To Cost RR (Output Sheet 1)

Hydro One Depreciation Expense includes $23.6 million for Other Post Employment Benefits (OPEB) and $8.2 million for Environmental work. OPEB was added to USoA 5645 in Input Sheet 3 and Environment was added to USoA 51112/5114 in Input Sheet 3. [Refer to rows 53 and 54.]

Also in Input Sheet 3 USoA 1330 of $23.3 million was included. Since Output Sheet 1 picks up the OM&A values from Input Sheet 3, Hydro One has to deduct these two amounts from the OM&A and add USoA 1330 when calculating Working Capital as a percentage of OM&A costs.[Refer to row 59]

Hydro One's Working Capital is based on 11% of OM&A instead of 15% in RP-2005-0020/EB-2005-0378. [Refer to row 58]

Rows 76 to 100 have been added to reflect Hydro One's Miscellaneous External Revenues and Common and Preferred Equity financial structure.

Rows 87 to 94 have been added to properly allocate Miscellaneous External Revenues instead of using Weighted Number of Bills (CWNB) as per OEB model.

Rows 97 to 100 reflect revenues and costs of standard distribution rates, including Miscellaneous External Revenues. The proposed Revenue Requirement of $1,067 million is recovered from Standard Distribution rates and from Miscellaneous External Revenues.

Adjusted the Rate Base checking formulae in Row 62 to be based on nearest million dollar.

Fixed Charge Floor Ceiling (Output Sheet 2)

Formula on row 28 changed for Gross Plant to include USoA 1985 Sentinel Light Assets.

Adjusted formulas in rows 94, 97, 131, 148, 149, 152, 153, 163 and 164 to reflect new sub-accounts.

Line Transformers PLCC Adjustment (Output Sheet 2.1)

Adjusted formulas in rows 11, 41, and 42 to reflect new sub-accounts.

Formula on row 28 changed for Gross Plant to include USoA 1985 Sentinel Light Assets.

Formula on row 25 adjusted to ensure allocated cost does not exceed total cost when the PLCC kW is changed from the default of 400 W in E3: PLCC.

Primary Costs PLCC Adjustment (Output Sheet 2.2)

Adjusted formulas in rows 11, 12, 43, 44, 49, 50, 58, and 59 to reflect new sub-accounts.

Formula on row 30 changed for Gross Plant to include USoA 1985 Sentinel Light Assets.

Secondary Costs PLCC Adjustment (Output Sheet 2.3)

Titles of USoA accounts in rows 11, 12, 13, 14, 41, 42, 43, 44, 47, 48, 49 and 50 changed to Secondary – 5, instead of -4.

Formula on row 28 changed for Gross Plant to include USoA 1985 Sentinel Light Assets.

Line Transformer Unit Costs (Output Sheet 3.1)

Adjusted formulas in rows 11, 44, and 45 to reflect new sub-accounts.

Formula on row 31 changed for Gross Plant to include USoA 1985 Sentinel Light Assets.

Substation Transformation Unit Costs (Output Sheet 3.2)

Formula on row 36 changed for Gross Plant to include USoA 1985 Sentinel Light Assets.

Primary Cost Pools (Output Sheet 3.3)

Adjusted formulas in rows 11, 12, 37, 38, 43, 44, 52, and 53 to reflect new sub-accounts.

Formula on row 24 changed for Gross Plant to include USoA 1985 Sentinel Light Assets.

Secondary Cost Pools (Output Sheet 3.4)

Titles of USoA accounts in rows 11, 12, 13, 14, 37, 38, 39, 40, 43, 44, 45, and 46 changed to Secondary – 5, instead of -4.

Formula on row 24 changed for Gross Plant to include USoA 1985 Sentinel Light Assets.

Formulas on rows 52 and 53 adjusted to reflect new sub-accounts.

USL Metering Credit (Output Sheet 3.5)

Formulas on rows 11, 41, and 42 adjusted to reflect new sub-accounts.

Formula on row 28 changed for Gross Plant to include USoA 1985 Sentinel Light Assets.

Summary By Class and Accounts (Output Sheet 4)

New rows added to reflect new Sub-accounts: 1815 -1, 2, 3, 4, 5, 1830 – 3A and 3B, 4A and 4B, 1835 -3A and 3B, 4A and 4B, 1850 – 1 and 2, 1860 – 1, 2, 3, and 4, and 1985 Sentinel Lights.

Details By Class and Accounts (Output Sheet 5)

New rows added to reflect new Sub-accounts: 1815 -1, 2, 3, 4, 5, 1830 – 3A and 3B, 4A and 4B, 1835 -3A and 3B, 4A and 4B, 1850 – 1 and 2, 1860 – 1, 2, 3, and 4, and 1985 Sentinel Lights.

Trial Balance Totals in column E of Main Accounts are zero to avoid double counting with new sub-accounts.

Source Data for E2, (Output Sheet 6)

New rows added to reflect new Sub-accounts: 1815 -1, 2, 3, 4, 5, 1830 – 3A and 3B, 4A and 4B, 1835 -3A and 3B, 4A and 4B, 1850 – 1 and 2, 1860 – 1, 2, 3, and 4, and 1985 Sentinel Lights.

Main account formulas adjusted to reflect the sum of sub-accounts.

Amortization (Output Sheet 7)

New rows added to reflect new Sub-accounts: 1815 -1, 2, 3, 4, 5, 1830 – 3A and 3B, 4A and 4B, 1835 -3A and 3B, 4A and 4B, 1850 – 1 and 2, 1860 – 1, 2, 3, and 4, and 1985 Sentinel Lights.

Main account formulas adjusted to reflect the sum of sub-accounts.

USoA 1985 directly allocated to Sentinel Lights.

Categorization (Exhibit Sheet 1)

New rows added to reflect new Sub-accounts: 1815 -1, 2, 3, 4, 5, 1830 – 3A and 3B, 4A and 4B, 1835 -3A and 3B, 4A and 4B, 1850 – 1 and 2, 1860 – 1, 2, 3, and 4, and 1985 Sentinel Lights.

Based on an updated Minimum System done for Hydro One, the Categorization factors for Fixtures, Conductors and Rural Transformers have been updated from the Rural default of 60% to 47.8%, 54.8% and 61.9%, respectively.

This was accommodated in the model by using the above on the following USoA Asset accounts and sub-accounts:

1830	Overhead Fixtures	47.8%
1835	Conductors	54.8%
1840/45	Underground	54.8%
1850	Transformers	61.9%

Further, the associated O&M accounts were also adjusted to track the Asset Accounts. For example:

USoA 5035, 5055 and 5160 for Rural Transformers was set at 61.9%

USoA 5120 for Fixtures Maintenance was set at 47.8%

Conductor Related USoA set to 54.8%.

Allocators (Exhibit Sheet 2)

New Allocators applicable to Hydro One added after row 119.

Allocator	ID	Basis
Mtr-Single	CWMC-1	Number of single-phase meters by class
Mtr-Poly	CWMC-2	Number of poly-phase meters by class
Mtr-LV	CWMC-3	Number of LV meters by class
Mtr-Smart	CWMC-4	Number of smart meters by class
1805/1806/1808/1810-2: <50 kV Assets	BCP(1-4-12)AA	Bulk CP with est of RCD of ST
1815-1	BCP (1-4-12) B	High Voltage DS Rural Only
1815-2	1815-2D	High Voltage DS Low Specific - LV Only
1815-3	1815-3D	High Voltage DS High Specific - LV Only
1815-4	1815-4D	High Voltage DS Low LV - LV Only
1815-5	1815-5D	High Voltage DS High LV - LV Only
1820-2	PNCP(1-4-12)AA	NCP with estimate for RCD of ST
1820-3	Cen2	Class Energy less Market Participants
1830-3A	1830-3A	Bulk Fixtures LV
1830-3B	BCP(1-4-12) DlinesB	Bulk Fixtures Retail (Density Weights)
1830-4A	1830-4AC 1830-4AD	Primary Fixtures LV Customer Related Primary Fixtures LV Demand Related
1830-4B	PNCP(1-4-12) DlinesB CCP-DLinesC	Primary Fixtures Retail (Density Wts) Retail customers with Density Wts
1835-3A	1835-3A	Bulk Lines LV

Allocator	ID	Basis
1835-3B	BCP(1-4-12)-DlinesB	Bulk Lines Retail (Density Weights)
1835-4A	1835-4AC 1835-4AD	Primary Lines LV Customer Related Primary Lines LV Demand Related
1835-4B	PNCP(1-4-12)-DlinesB CCP-DLinesC	Primary Lines Retail (Density Weights) Retail Customers Density Weighted
1840-4 &1845-4	PNCP(1-4-12)C CCP-C	Excludes ST/LV Excludes ST/LV
1840-5 & 1845-5	SNCP(1-4-1)C CCS-C	Excludes ST/LV Excludes ST/LV
1850-1	1850-1D 1850-1C	100% to ST/LV class 100% to ST/LV class
1850-2	LTNCP(1-4-12)RtransfB CCLT-RtransfB	Rural Transformers Retail Demand Related (Density Weights) Rural Transformers Retail Customer Related (Density Weights)

PLCC (Exhibit Sheet 3)

Hydro One has updated the 400 W PLCC default with new values based on Updated Minimum System study : 544 W for Conductors and 3100 W for Rural Transformers.

The PLCC-Customer Watts calculated in rows 24 to 28 were updated to replace 400 W:

PLCC-CCA	544W x number of customers
PLCC-CCB	544W x number of customers on bulk
PLCC-CCP	544W x number of customers on primary
PLCC-CCLT	3100W x number of customers with Rural Transformation
PLCC-CCS	544W x number of customers on secondary

Trial Balance Allocation Details (Exhibit Sheet 4)

New rows added to reflect new Sub-accounts: 1815 -1, 2, 3, 4, 5, 1830 – 3A and 3B, 4A and 4B, 1835 -3A and 3B, 4A and 4B, 1850 – 1 and 2, 1860 – 1, 2, 3, and 4, and 1985 Sentinel Lights.

Hydro One specific allocators were chosen and derived in E2: Allocators.

Reconciliation (Exhibit Sheet 5)

New rows added to reflect new Sub-accounts: 1815 -1, 2, 3, 4, 5, 1830 – 3A and 3B, 4A and 4B, 1835 -3A and 3B, 4A and 4B, 1850 – 1 and 2, 1860 – 1, 2, 3, and 4, and 1985 Sentinel Lights.

Cost Allocation Results

The results of the cost allocation methodology are presented below. Revenues collected from each customer class, Revenue Requirement by customer class, revenue cost ratios and the amount of miscellaneous revenues credited to each customer class is shown. The OEB Cost Allocation Methodology also determines the fixed charges based on three methods: a) Avoided costs, b) Directly Related customer costs and c) Minimum System with PLCC Adjustment. The table below shows the results of methods a and c. Finally, the credit applicable to USL connections is shown.

	Existing	**Alloc Cost**	**Rev-Cost**	**Misc Rev**	**Fixed Charge Method a**	**Fixed Charge Method c**	**USL Credit**
	Rev [$M]	**Rev Req [$M]**	**Ratio**	**[$M]**	**Avoid Cost**	**Min System**	
UR	57.70	65.95	0.87	3.82	$ 8.47	$ 22.12	
R1	197.14	240.19	0.82	10.63	$ 8.56	$ 29.67	
R2	404.61	390.30	1.04	11.96	$ 9.41	$ 45.37	
Seasonal	76.96	83.60	0.92	2.15	$ 6.34	$ 30.58	
GSe	119.59	111.13	1.08	5.67	$ 10.72	$ 30.97	$ 6.86
GSd	107.88	105.43	1.02	2.35	$ 26.49	$ 54.46	
UGe	12.08	9.34	1.29	0.47	$ 10.73	$ 12.33	
UGd	16.00	16.81	0.95	0.33	$ 29.19	$ 39.65	
St Lgt	4.89	8.11	0.60	0.11	$ 5.01	$ 12.40	
Sen Lgt	4.92	7.96	0.62	4.03	$ 2.36	$ 32.77	
Dgen	0.63	0.39	1.63	0.00	$ 25.26	$ 36.66	
ST	64.18	27.35	2.35	0.76	$ 192.71	$ 372.12	
	1,066.58	1,066.58	1.00	42.30			

In designing the proposed ST rates, the following information was calculated in the Cost Allocation Study.

	Amounts ($)
Fixed Revenue Requirement	8,381,668
Variable Revenue Requirement	18,968,378
Total ST Revenue Requirement	27,350,045

Minimum System Study

Hydro One retained Black and Veatch in 2007 to update the Minimum System Study used in the Cost Allocation Methodology. The Minimum System Study was first developed in the mid 1980's by Ontario Hydro. The results of the original Ontario Hydro study and the current Black and Veatch study are presented in the Table below.

Minimum System Study % of Fixed Costs

% Fixed	1980's	2007
Overhead Lines	61	54.8
Underground Lines	61	Included in Overhead Lines
Transformers	62	61.9
Poles Towers and Fixtures	N/A	47.8

The Minimum System Study update from Black and Veatch also updated the value of the Peak Load Carrying Capabilities (PLCC) and the new value for Conductors is 544 Watts and for Transformers is 3,100 Watts. These new values have been used in the Cost Allocation Study. The Black and Veatch report is included as Attachment B.

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Attachment A
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Ontario

Ontario Energy Board

2008 COST ALLOCATION MODEL

Sheet I1 Utility Information Sheet

Hydro One Networks - Distribution

2008 Distribution Rate Filing

Introduction Sheet

Name of LDC	**Hydro One Networks - Distribution**

Contact Information

Name	Mike Roger
Title	Manager - Distribution Rates
Phone	416-345-5876
Email	Mike.Roger@hydroone.com
This Iteration	**Hydro One Distribution: 12 Rate Classes**

Colour Coding

Input	
Output	
Exhibition	
Brought Forward	Brought Forward
Calculation	Calculation
Default Numbers	
Diagnostic	

INPUTS	**I1**	**Intro**	**Brief explanation of what the pages do.**
	I2	**LDC data and Classes**	**Enter LDC specific information and number of classes etc**
	I3	**TB Data**	**Balance from approved 2006 EDR Trial Balance**
	I4	**BO ASSETS**	**Break out assets into detail functions - bulk deliver, primary and secondary**
	I5	**Misc Data**	**Input for miscellaneous data where necessary - TBD**
	I6	**Customer Data**	**Input customer related data for generating customer allocators**
	I7.1	**Meter Capital**	**Input meter related data for calculating capital costs weighing factors**
	I7.2	**Meter Reading**	**Input meter related data for calculating meter reading weighing factors**
	I8	**Demand Data**	**Input demand allocators using load data and making LDC specific adjustments**
	I9	**Direct Allocation**	
OUTPUTS	**O1**	**Revenue to cost**	**Output showing revenue to cost ratios, inter class subsidy etc.**
	O2	**Fixed Charge**	**Output showing the range for the Basic Customer charge - TBD**
	O3.1	**Line Tran Unit Cost**	**Output showing the line transformation unit cost**
	O3.2	**Substat Tran Unit Cost**	**Output showing the substation transformation unit cost**
	O3.3	**Primary Cost Pool**	**Output showing the primary pool unit cost**
	O3.4	**Secondary Cost Pool**	**Output showing the secondary pool unit cost**
	O3.5	**USL Metering Credit**	**Output showing the unit cost for meters**
	O4	**Summary by Class**	**Output showing summary of all allocation by class and by US of A**
	O5	**Detail by Class**	**Output showing details of individual allocation by class and by US of A**
	O6	**Source Data for E2**	**Output showing the source allocation data for E2**
	O7	**Amortization**	**Output showing the details for amortization and capital contribution**
EXHIBITS	**E1**	**Trial Balance Index**	**Exhibit showing 1. how accounts are grouped for reporting, how accounts are categorized and how accounts are allocated**
	E2	**Categorization**	**Exhibit showing how costs are categorized**
	E3	**PLCC**	**Backup documentation for calculating Peak Load Carrying Capability.**
	E4	**Allocation Factors**	**Exhibit summarizing all allocation factors created in I5 to I8 and present the findings in percentages**
	E5	**Reconciliation**	**Exhibit showing reconciliation of accounts included and excluded from the allocation study to TB balance**

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Hydro One Networks - Distribution

2008 Distribution Rate Filing
Input Sheet for Selection of Classes, Demand Allocators and Specific Allocators

Hydro One Distribution: 12 Rate Classes

Instructions
Step 1 - Please input your existing classes
Step 2 - If this is your first run, select "First Run" in the drop down menu below
Step 3 - After all classes have been entered, Click the "Update" in cell E41.

If this is your first run, select "**First Run**" and click on the "**Update**" button.
Note: You must always do a first run with current selected.

First Run

		Utility's Class Definition	Current
1	Residential	UR	YES
2	GS <50	R1	YES
3	GS>50-Regular	R2	YES
4	GS> 50-TOU	Seasonal	YES
5	GS >50-Intermediate	GSe	YES
6	Large Use >5MW	GSd	YES
7	Street Light	St Lgt	YES
8	Sentinel	Sen Lgt	YES
9	Unmetered Scattered Load		NO
10	Embedded Distributor		NO
11	Back-up/Standby Power		NO
12	Rate Class 1	Dgen	YES
13	Rate class 2	ST	YES
14	Rate class 3	UGe	YES
15	Rate class 4	UGd	YES
16	Rate class 5		NO
17	Rate class 6		NO
18	Rate class 7		NO
19	Rate class 8		NO
20	Rate class 9		NO

After you have set all rate classes **Update**

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Hydro One 2008 Distribution Rate Filing
Input Sheet for Trial Balance Figures

Hydro One Distribution: 12 Rate Classes

Instructions

1	**Enter 2007 values**				
2	**Enter amounts you need to reclassify to column E**				
3	**Enter Net Income component of Return on Capital from EB-2007-0681 Exhibit E1-1-1**	Approved Target Net Inocme ($)	$151,400,000		
4	**Enter Taxes from EB-2007-0681 Exhibit E1-1-1**	Approved PILs ($)	$50,100,000		
5	**Enter Interest component of Return on Capital from EB-2007-0681 Exhibit E1-1-1**	Approved Interest ($)	$148,500,000		
6	**Enter External Revenues from EB-2007-0671**	Approved Specific Service Charges ($)	$27,800,000		
7	**Enter Transformation Ownership Allowance Credit**	Approved Transformer Ownership Allowance ($)			
8	**Enter Low Voltage Wheeling Adjustment**	Approved Low Voltage Wheeling Adjustment ($)			
9	**Enter Revenue Requirment from EB-2007-0681 Exhibit E1-1-1**	Approved Revenue Requirement ($)	$1,066,575,593	**From this Sheet**	
		Revenue Requirement to be Used in this model ($)	$1,066,575,593	**$1,066,575,593**	**Rev Req Matches**
10	**Enter Total Rate Base from EB-2007-06581 Exhibit D2-1-1**	Approved Rate Base ($)	**$ 4,382,000,000**		
		Rate Base to be Used in this model ($)	$4,382,000,000	**$4,382,000,061**	**Rate Base Matches**

Uniform System of Accounts - Detail Accounts:

USoA Account #	**Accounts**	**Financial Statement**	**Model Adjustments**	**Reclassify accounts**	**Direct Allocation**	**Reclassified Balance**
1005	Cash	$ -				$0
1010	Cash Advances and Working Funds	$ -				$0
1020	Interest Special Deposits	$ -				$0
1030	Dividend Special Deposits	$ -				$0
1040	Other Special Deposits	$ -				$0
1060	Term Deposits	$ -				$0
1070	Current Investments	$ -				$0
1100	Customer Accounts Receivable	$ -				$0

USoA Account #	Accounts	Financial Statement	Model Adjustments	Reclassify accounts	Direct Allocation	Reclassified Balance
1102	Accounts Receivable - Services	$ -				$0
1104	Accounts Receivable - Recoverable Work	$ -				$0
1105	Accounts Receivable - Merchandise, Jobbing, etc.	$ -				$0
1110	Other Accounts Receivable	$ -				$0
1120	Accrued Utility Revenues	$ -				$0
1130	Accumulated Provision for Uncollectible Accounts--Credit	$ -				$0
1140	Interest and Dividends Receivable	$ -				$0
1150	Rents Receivable	$ -				$0
1170	Notes Receivable	$ -				$0
1180	Prepayments	$ -				$0
1190	Miscellaneous Current and Accrued Assets	$ -				$0
1200	Accounts Receivable from Associated Companies	$ -				$0
1210	Notes Receivable from Associated Companies	$ -				$0
1305	Fuel Stock	$ -				$0
1330	Plant Materials and Operating Supplies	$ 23,300,000				$23,300,000
1340	Merchandise	$ -				$0
1350	Other Materials and Supplies	$ -				$0
1405	Long Term Investments in Non-Associated Companies	$ -				$0
1408	Long Term Receivable - Street Lighting Transfer	$ -				$0
1410	Other Special or Collateral Funds	$ -				$0
1415	Sinking Funds	$ -				$0
1425	Unamortized Debt Expense	$ -				$0
1445	Unamortized Discount on Long-Term Debt--Debit	$ -				$0
1455	Unamortized Deferred Foreign Currency Translation Gains and Losses	$ -				$0
1460	Other Non-Current Assets	$ -				$0
1465	O.M.E.R.S. Past Service Costs	$ -				$0
1470	Past Service Costs - Employee Future Benefits	$ -				$0
1475	Past Service Costs - Other Pension Plans	$ -				$0
1480	Portfolio Investments - Associated Companies	$ -				$0
1485	Investment in Associated Companies - Significant Influence	$ -				$0
1490	Investment in Subsidiary Companies	$ -				$0
1505	Unrecovered Plant and Regulatory Study Costs	$ -				$0
1508	Other Regulatory Assets	$ -				$0

USoA Account #	Accounts	Financial Statement	Model Adjustments	Reclassify accounts	Direct Allocation	Reclassified Balance
1510	Preliminary Survey and Investigation Charges	$ -				$0
1515	Emission Allowance Inventory	$ -				$0
1516	Emission Allowances Withheld	$ -				$0
1518	RCVARetail	$ -				$0
1520	Power Purchase Variance Account	$ -				$0
1525	Miscellaneous Deferred Debits	$ -				$0
1530	Deferred Losses from Disposition of Utility Plant	$ -				$0
1540	Unamortized Loss on Reacquired Debt	$ -				$0
1545	Development Charge Deposits/ Receivables	$ -				$0
1548	RCVASTR	$ -				$0
1560	Deferred Development Costs	$ -				$0
1562	Deferred Payments in Lieu of Taxes	$ -				$0
1563	Account 1563 - Deferred PILs Contra Account	$ -				$0
1565	Conservation and Demand Management Expenditures and Recoveries	$ 6,400,000				$6,400,000
1570	Qualifying Transition Costs	$ -				$0
1571	Pre-market Opening Energy Variance	$ -				$0
1572	Extraordinary Event Costs	$ -				$0
1574	Deferred Rate Impact Amounts	$ -				$0
1580	RSVAWMS	$ -				$0
1582	RSVAONE-TIME	$ -				$0
1584	RSVANW	$ -				$0
1586	RSVACN	$ -				$0
1588	RSVAPOWER	$ -				$0
1590	Recovery of Regulatory Asset Balances	$ -				$0
1605	Electric Plant in Service - Control Account	$ -				$0
1606	Organization	$ -				$0
1608	Franchises and Consents	$ -				$0
1610	Miscellaneous Intangible Plant	$ -				$0
1615	Land	$ -		$ -		$0
1616	Land Rights	$ -		$ -		$0
1620	Buildings and Fixtures	$ -		$ -		$0
1630	Leasehold Improvements	$ -		$ -		$0
1635	Boiler Plant Equipment	$ -		$ -		$0
1640	Engines and Engine-Driven Generators	$ -		$ -		$0
1645	Turbogenerator Units	$ -		$ -		$0
1650	Reservoirs, Dams and Waterways	$ -		$ -		$0
1655	Water Wheels, Turbines and Generators	$ -		$ -		$0
1660	Roads, Railroads and Bridges	$ -		$ -		$0
1665	Fuel Holders, Producers and Accessories	$ -		$ -		$0
1670	Prime Movers	$ -		$ -		$0
1675	Generators	$ -		$ -		$0

USoA Account #	Accounts	Financial Statement	Model Adjustments	Reclassify accounts	Direct Allocation	Reclassified Balance
1680	Accessory Electric Equipment	$ -		$ -		$0
1685	Miscellaneous Power Plant Equipment	$ -				$0
1705	Land	$ -				$0
1706	Land Rights	$ -				$0
1708	Buildings and Fixtures	$ -				$0
1710	Leasehold Improvements	$ -				$0
1715	Station Equipment	$ -				$0
1720	Towers and Fixtures	$ -				$0
1725	Poles and Fixtures	$ -				$0
1730	Overhead Conductors and Devices	$ -				$0
1735	Underground Conduit	$ -				$0
1740	Underground Conductors and Devices	$ -				$0
1745	Roads and Trails	$ -				$0
1805	Land	$ 61,219,197				$61,219,197
1806	Land Rights	$ 239,478,047				$239,478,047
1808	Buildings and Fixtures	$ 5,437,793				$5,437,793
1810	Leasehold Improvements	$ -				$0
1815	Transformer Station Equipment - Normally Primary above 50 kV	$ 108,889,874		($1,037,400)		$107,852,474
1820	Distribution Station Equipment - Normally Primary below 50 kV	$ 326,199,765		$1,037,400		$327,237,165
1825	Storage Battery Equipment	$ -				$0
1830	Poles, Towers and Fixtures	$ 1,931,765,752				$1,931,765,752
1835	Overhead Conductors and Devices	$ 1,291,841,808		$ -		$1,291,841,808
1840	Underground Conduit	$ 23,984,390				$23,984,390
1845	Underground Conductors and Devices	$ 679,439,007				$679,439,007
1850	Line Transformers	$ 1,283,933,745				$1,283,933,745
1855	Services	$ -				$0
1860	Meters	$ 172,889,855				$172,889,855
1865	Other Installations on Customer's Premises	$ -				$0
1870	Leased Property on Customer Premises	$ -				$0
1875	Street Lighting and Signal Systems	$ -				$0
1905	Land	$ 3,283,798				$3,283,798
1906	Land Rights	$ -				$0
1908	Buildings and Fixtures	$ 94,901,052				$94,901,052
1910	Leasehold Improvements	$ 4,620,582				$4,620,582
1915	Office Furniture and Equipment	$ 2,536,853				$2,536,853
1920	Computer Equipment - Hardware	$ 55,593,665				$55,593,665
1925	Computer Software	$ 205,570,861				$205,570,861
1930	Transportation Equipment	$ 199,220,074				$199,220,074
1935	Stores Equipment	$ 6,587,180				$6,587,180
1940	Tools, Shop and Garage Equipment	$ 2,282,022				$2,282,022
1945	Measurement and Testing Equipment	$ 3,066,387				$3,066,387
1950	Power Operated Equipment	$ 85,055,133				$85,055,133
1955	Communication Equipment	$ 28,160,887				$28,160,887
1960	Miscellaneous Equipment	$ 2,998,695				$2,998,695

USoA Account #	Accounts	Financial Statement	Model Adjustments	Reclassify accounts	Direct Allocation	Reclassified Balance
1965	Water Heater Rental Units	$ -				$0
1970	Load Management Controls - Customer Premises	$ -				$0
1975	Load Management Controls - Utility Premises	$ -				$0
1980	System Supervisory Equipment	$ 21,869,131				$21,869,131
1985	Sentinel Lighting Rental Units	$ 16,327,748				$16,327,748
1990	Other Tangible Property	$ 5,274,886				$5,274,886
1995	Contributions and Grants - Credit	-$ 418,704,641				($418,704,641)
2005	Property Under Capital Leases	$ -				$0
2010	Electric Plant Purchased or Sold	$ -				$0
2020	Experimental Electric Plant Unclassified	$ -				$0
2030	Electric Plant and Equipment Leased to Others	$ -				$0
2040	Electric Plant Held for Future Use	$ -				$0
2050	Completed Construction Not Classified--Electric	$ -				$0
2055	Construction Work in Progress--Electric	$ -				$0
2060	Electric Plant Acquisition Adjustment	$ -				$0
2065	Other Electric Plant Adjustment	$ -				$0
2070	Other Utility Plant	$ -				$0
2075	Non-Utility Property Owned or Under Capital Leases	$ -				$0
2105	Accum. Amortization of Electric Utility Plant - Property, Plant, & Equipment	-$ 2,364,639,589				($2,364,639,589)
2120	Accumulated Amortization of Electric Utility Plant - Intangibles	$ -				$0
2140	Accumulated Amortization of Electric Plant Acquisition Adjustment	$ -				$0
2160	Accumulated Amortization of Other Utility Plant	$ -				$0
2180	Accumulated Amortization of Non-Utility Property	$ -				$0
2205	Accounts Payable	$ -				$0
2208	Customer Credit Balances	$ -				$0
2210	Current Portion of Customer Deposits	$ -				$0
2215	Dividends Declared	$ -				$0
2220	Miscellaneous Current and Accrued Liabilities	$ -				$0
2225	Notes and Loans Payable	$ -				$0
2240	Accounts Payable to Associated Companies	$ -				$0
2242	Notes Payable to Associated Companies	$ -				$0
2250	Debt Retirement Charges(DRC) Payable	$ -				$0
2252	Transmission Charges Payable	$ -				$0
2254	Electrical Safety Authority Fees Payable	$ -				$0

USoA Account #	Accounts	Financial Statement	Model Adjustments	Reclassify accounts	Direct Allocation	Reclassified Balance
2256	Independent Market Operator Fees and Penalties Payable	$ -				$0
2260	Current Portion of Long Term Debt	$ -				$0
2262	Ontario Hydro Debt - Current Portion	$ -				$0
2264	Pensions and Employee Benefits - Current Portion	$ -				$0
2268	Accrued Interest on Long Term Debt	$ -				$0
2270	Matured Long Term Debt	$ -				$0
2272	Matured Interest on Long Term Debt	$ -				$0
2285	Obligations Under Capital Leases--Current	$ -				$0
2290	Commodity Taxes	$ -				$0
2292	Payroll Deductions / Expenses Payable	$ -				$0
2294	Accrual for Taxes, Payments in Lieu of Taxes, Etc.	$ -				$0
2296	Future Income Taxes - Current	$ -				$0
2305	Accumulated Provision for Injuries and Damages	$ -				$0
2306	Employee Future Benefits	$ -				$0
2308	Other Pensions - Past Service Liability	$ -				$0
2310	Vested Sick Leave Liability	$ -				$0
2315	Accumulated Provision for Rate Refunds	$ -				$0
2320	Other Miscellaneous Non-Current Liabilities	$ -				$0
2325	Obligations Under Capital Lease--Non-Current	$ -				$0
2330	Development Charge Fund	$ -				$0
2335	Long Term Customer Deposits	$ -				$0
2340	Collateral Funds Liability	$ -				$0
2345	Unamortized Premium on Long Term Debt	$ -				$0
2348	O.M.E.R.S. - Past Service Liability - Long Term Portion	$ -				$0
2350	Future Income Tax - Non-Current	$ -				$0
2405	Other Regulatory Liabilities	$ -				$0
2410	Deferred Gains from Disposition of Utility Plant	$ -				$0
2415	Unamortized Gain on Reacquired Debt	$ -				$0
2425	Other Deferred Credits	$ -				$0
2435	Accrued Rate-Payer Benefit	$ -				$0
2505	Debentures Outstanding - Long Term Portion	$ -				$0
2510	Debenture Advances	$ -				$0
2515	Reacquired Bonds	$ -				$0
2520	Other Long Term Debt	$ -				$0
2525	Term Bank Loans - Long Term Portion	$ -				$0
2530	Ontario Hydro Debt Outstanding - Long Term Portion	$ -				$0
2550	Advances from Associated Companies	$ -				$0

USoA Account #	Accounts	Financial Statement	Model Adjustments	Reclassify accounts	Direct Allocation	Reclassified Balance
3005	Common Shares Issued	$ -				$0
3008	Preference Shares Issued	$ -				$0
3010	Contributed Surplus	$ -				$0
3020	Donations Received	$ -				$0
3022	Development Charges Transferred to Equity	$ -				$0
3026	Capital Stock Held in Treasury	$ -				$0
3030	Miscellaneous Paid-In Capital	$ -				$0
3035	Installments Received on Capital Stock	$ -				$0
3040	Appropriated Retained Earnings	$ -				$0
3045	Unappropriated Retained Earnings	$ -				$0
3046	Balance Transferred From Income	$ 151,400,000	($151,400,000)		$0	($151,400,000)
3047	Appropriations of Retained Earnings - Current Period	$ -				$0
3048	Dividends Payable-Preference Shares	$ -				$0
3049	Dividends Payable-Common Shares	$ -				$0
3055	Adjustment to Retained Earnings	$ -				$0
3065	Unappropriated Undistributed Subsidiary Earnings	$ -				$0
4006	Residential Energy Sales	$ -				$0
4010	Commercial Energy Sales	$ -				$0
4015	Industrial Energy Sales	$ -				$0
4020	Energy Sales to Large Users	$ -				$0
4025	Street Lighting Energy Sales	$ -				$0
4030	Sentinel Lighting Energy Sales	$ -				$0
4035	General Energy Sales	$ -				$0
4040	Other Energy Sales to Public Authorities	$ -				$0
4045	Energy Sales to Railroads and Railways	$ -				$0
4050	Revenue Adjustment	$ -				$0
4055	Energy Sales for Resale	$ -				$0
4060	Interdepartmental Energy Sales	$ -				$0
4062	Billed WMS	$ -				$0
4064	Billed-One-Time	$ -				$0
4066	Billed NW	$ -				$0
4068	Billed CN	$ -				$0
4080	Distribution Services Revenue	$ -	$1,024,275,593			($1,024,275,593)
4082	Retail Services Revenues	$ -				$0
4084	Service Transaction Requests (STR) Revenues	$ -				$0
4090	Electric Services Incidental to Energy Sales	$ -				$0
4105	Transmission Charges Revenue	$ -				$0
4110	Transmission Services Revenue	$ -				$0
4205	Interdepartmental Rents	$ -				$0
4210	Rent from Electric Property	$ -				$0
4215	Other Utility Operating Income	$ -				$0
4220	Other Electric Revenues	$ -				$0

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USoA Account #	Accounts	Financial Statement	Model Adjustments	Reclassify accounts	Direct Allocation	Reclassified Balance
4225	Late Payment Charges	-$ 14,500,000				($14,500,000)
4230	Sales of Water and Water Power	$ -				$0
4235	Miscellaneous Service Revenues	$ -	$0			($27,800,000)
4240	Provision for Rate Refunds	$ -				$0
4245	Government Assistance Directly Credited to Income	$ -				$0
4305	Regulatory Debits	$ -				$0
4310	Regulatory Credits	$ -				$0
4315	Revenues from Electric Plant Leased to Others	$ -				$0
4320	Expenses of Electric Plant Leased to Others	$ -				$0
4325	Revenues from Merchandise, Jobbing, Etc.	$ -				$0
4330	Costs and Expenses of Merchandising, Jobbing, Etc.	$ -				$0
4335	Profits and Losses from Financial Instrument Hedges	$ -				$0
4340	Profits and Losses from Financial Instrument Investments	$ -				$0
4345	Gains from Disposition of Future Use Utility Plant	$ -				$0
4350	Losses from Disposition of Future Use Utility Plant	$ -				$0
4355	Gain on Disposition of Utility and Other Property	$ -				$0
4360	Loss on Disposition of Utility and Other Property	$ -				$0
4365	Gains from Disposition of Allowances for Emission	$ -				$0
4370	Losses from Disposition of Allowances for Emission	$ -				$0
4375	Revenues from Non-Utility Operations	$ -				$0
4380	Expenses of Non-Utility Operations	$ 5,850,000		-$ 5,850,000.00		$0
4385	Non-Utility Rental Income	$ -				$0
4390	Miscellaneous Non-Operating Income	$ -				$0
4395	Rate-Payer Benefit Including Interest	$ -				$0
4398	Foreign Exchange Gains and Losses, Including Amortization	$ -				$0
4405	Interest and Dividend Income	$ -				$0
4415	Equity in Earnings of Subsidiary Companies	$ -				$0
4505	Operation Supervision and Engineering	$ -				$0
4510	Fuel	$ -				$0
4515	Steam Expense	$ -				$0
4520	Steam From Other Sources	$ -				$0
4525	Steam Transferred--Credit	$ -				$0
4530	Electric Expense	$ -				$0

USoA Account #	Accounts	Financial Statement	Model Adjustments	Reclassify accounts	Direct Allocation	Reclassified Balance
4535	Water For Power	$ -				$0
4540	Water Power Taxes	$ -				$0
4545	Hydraulic Expenses	$ -				$0
4550	Generation Expense	$ -				$0
4555	Miscellaneous Power Generation Expenses	$ -				$0
4560	Rents	$ -				$0
4565	Allowances for Emissions	$ -				$0
4605	Maintenance Supervision and Engineering	$ -				$0
4610	Maintenance of Structures	$ -				$0
4615	Maintenance of Boiler Plant	$ -				$0
4620	Maintenance of Electric Plant	$ -				$0
4625	Maintenance of Reservoirs, Dams and Waterways	$ -				$0
4630	Maintenance of Water Wheels, Turbines and Generators	$ -				$0
4635	Maintenance of Generating and Electric Plant	$ -				$0
4640	Maintenance of Miscellaneous Power Generation Plant	$ -				$0
4705	Power Purchased	$ 1,959,300,000				$1,959,300,000
4708	Charges-WMS	$ -				$0
4710	Cost of Power Adjustments	$ -				$0
4712	Charges-One-Time	$ -				$0
4714	Charges-NW	$ -				$0
4715	System Control and Load Dispatching	$ -				$0
4716	Charges-CN	$ -				$0
4720	Other Expenses	$ -				$0
4725	Competition Transition Expense	$ -				$0
4730	Rural Rate Assistance Expense	$ -				$0
4805	Operation Supervision and Engineering	$ -				$0
4810	Load Dispatching	$ -				$0
4815	Station Buildings and Fixtures Expenses	$ -				$0
4820	Transformer Station Equipment - Operating Labour	$ -				$0
4825	Transformer Station Equipment - Operating Supplies and Expense	$ -				$0
4830	Overhead Line Expenses	$ -				$0
4835	Underground Line Expenses	$ -				$0
4840	Transmission of Electricity by Others	$ -				$0
4845	Miscellaneous Transmission Expense	$ -				$0
4850	Rents	$ -				$0
4905	Maintenance Supervision and Engineering	$ -				$0
4910	Maintenance of Transformer Station Buildings and Fixtures	$ -				$0

USoA Account #	Accounts	Financial Statement	Model Adjustments	Reclassify accounts	Direct Allocation	Reclassified Balance
4916	Maintenance of Transformer Station Equipment	$ -				$0
4930	Maintenance of Towers, Poles and Fixtures	$ -				$0
4935	Maintenance of Overhead Conductors and Devices	$ -				$0
4940	Maintenance of Overhead Lines - Right of Way	$ -				$0
4945	Maintenance of Overhead Lines - Roads and Trails Repairs	$ -				$0
4950	Maintenance of Overhead Lines - Snow Removal from Roads and Trails	$ -				$0
4960	Maintenance of Underground Lines	$ -				$0
4965	Maintenance of Miscellaneous Transmission Plant	$ -				$0
5005	Operation Supervision and Engineering	$ 2,234,150				$2,234,150
5010	Load Dispatching	$ 849,600				$849,600
5012	Station Buildings and Fixtures Expense	$ 396,000				$396,000
5014	Transformer Station Equipment - Operation Labour	$ 590,000				$590,000
5015	Transformer Station Equipment - Operation Supplies and Expenses	$ 290,000				$290,000
5016	Distribution Station Equipment - Operation Labour	$ 6,620,000				$6,620,000
5017	Distribution Station Equipment - Operation Supplies and Expenses	$ 2,500,000				$2,500,000
5020	Overhead Distribution Lines and Feeders - Operation Labour	$ 6,030,870				$6,030,870
5025	Overhead Distribution Lines & Feeders - Operation Supplies and Expenses	$ 987,630				$987,630
5030	Overhead Subtransmission Feeders - Operation	$ 564,400				$564,400
5035	Overhead Distribution Transformers- Operation	$ -	$0			$0
5040	Underground Distribution Lines and Feeders - Operation Labour	$ -				$0
5045	Underground Distribution Lines & Feeders - Operation Supplies & Expenses	$ -				$0
5050	Underground Subtransmission Feeders - Operation	$ -				$0
5055	Underground Distribution Transformers - Operation	$ -	$0			$0
5060	Street Lighting and Signal System Expense	$ -				$0
5065	Meter Expense	$ 12,700,400			$4,543,350	$8,157,050
5070	Customer Premises - Operation Labour	$ 15,338,600				$15,338,600

USoA Account #	Accounts	Financial Statement	Model Adjustments	Reclassify accounts	Direct Allocation	Reclassified Balance
5075	Customer Premises - Materials and Expenses	$ 2,325,800				$2,325,800
5085	Miscellaneous Distribution Expense	$ 11,169,190				$11,169,190
5090	Underground Distribution Lines and Feeders - Rental Paid	$ -				$0
5095	Overhead Distribution Lines and Feeders - Rental Paid	$ 162,160				$162,160
5096	Other Rent	$ -				$0
5105	Maintenance Supervision and Engineering	$ 11,257,600				$11,257,600
5110	Maintenance of Buildings and Fixtures - Distribution Stations	$ -				$0
5112	Maintenance of Transformer Station Equipment	$ 1,097,800		$797,700		$1,895,500
5114	Maintenance of Distribution Station Equipment	$ 11,160,000		$7,179,300		$18,339,300
5120	Maintenance of Poles, Towers and Fixtures	$ 20,408,580				$20,408,580
5125	Maintenance of Overhead Conductors and Devices	$ 51,236,400				$51,236,400
5130	Maintenance of Overhead Services	$ -				$0
5135	Overhead Distribution Lines and Feeders - Right of Way	$ 115,890,000		$5,265,000		$121,155,000
5145	Maintenance of Underground Conduit	$ 265,540				$265,540
5150	Maintenance of Underground Conductors and Devices	$ 1,130,000				$1,130,000
5155	Maintenance of Underground Services	$ -				$0
5160	Maintenance of Line Transformers	$ 3,196,880	$0			$3,196,880
5165	Maintenance of Street Lighting and Signal Systems	$ -				$0
5170	Sentinel Lights - Labour	$ 1,187,120		-$ 1,187,120.00		$0
5172	Sentinel Lights - Materials and Expenses	$ 296,780		-$ 296,780.00		$0
5175	Maintenance of Meters	$ 1,846,200				$1,846,200
5178	Customer Installations Expenses- Leased Property	$ -				$0
5185	Water Heater Rentals - Labour	$ -				$0
5186	Water Heater Rentals - Materials and Expenses	$ -				$0
5190	Water Heater Controls - Labour	$ -				$0
5192	Water Heater Controls - Materials and Expenses	$ -				$0
5195	Maintenance of Other Installations on Customer Premises	$ -				$0
5205	Purchase of Transmission and System Services	$ -				$0
5210	Transmission Charges	$ -				$0
5215	Transmission Charges Recovered	$ -				$0

USoA Account #	Accounts	Financial Statement	Model Adjustments	Reclassify accounts	Direct Allocation	Reclassified Balance
5305	Supervision	$ -				$0
5310	Meter Reading Expense	$ 23,513,850				$23,513,850
5315	Customer Billing	$ 35,828,600				$35,828,600
5320	Collecting	$ 8,626,330				$8,626,330
5325	Collecting- Cash Over and Short	$ -				$0
5330	Collection Charges	$ 869,820				$869,820
5335	Bad Debt Expense	$ 17,396,400				$17,396,400
5340	Miscellaneous Customer Accounts Expenses	$ 4,763,820				$4,763,820
5405	Supervision	$ -				$0
5410	Community Relations - Sundry	$ 673,080				$673,080
5415	Energy Conservation	$ 1,000,000				$1,000,000
5420	Community Safety Program	$ 279,318		$585,000		$864,318
5425	Miscellaneous Customer Service and Informational Expenses	$ 10,200				$10,200
5505	Supervision	$ -				$0
5510	Demonstrating and Selling Expense	$ -				$0
5515	Advertising Expense	$ -				$0
5520	Miscellaneous Sales Expense	$ -				$0
5605	Executive Salaries and Expenses	$ 5,793,895				$5,793,895
5610	Management Salaries and Expenses	$ 21,658,559			$59,000	$21,599,559
5615	General Administrative Salaries and Expenses	$ 32,392,404			$598,000	$31,794,404
5620	Office Supplies and Expenses	$ -				$0
5625	Administrative Expense Transferred Credit	-$ 49,300,954				($49,300,954)
5630	Outside Services Employed	$ 6,559,043			$11,000	$6,548,043
5635	Property Insurance	$ 2,715,447				$2,715,447
5640	Injuries and Damages	$ 1,694,082				$1,694,082
5645	Employee Pensions and Benefits	$ -		$23,592,000		$23,592,000
5650	Franchise Requirements	$ -				$0
5655	Regulatory Expenses	$ 4,993,529				$4,993,529
5660	General Advertising Expenses	$ -				$0
5665	Miscellaneous General Expenses	-$ 129,370	$0	$ 1,483,900	$ 1,767,900	($413,370)
5670	Rent	$ 7,740,487				$7,740,487
5675	Maintenance of General Plant	$ 58,502,009			$190,000	$58,312,009
5680	Electrical Safety Authority Fees	$ -				$0
5685	Independent Market Operator Fees and Penalties	$ -				$0
5705	Amortization Expense - Property, Plant, and Equipment	$ 207,380,346				$207,380,346
5710	Amortization of Limited Term Electric Plant	$ -				$0
5715	Amortization of Intangibles and Other Electric Plant	$ 31,569,000		-$ 31,569,000.00		$0
5720	Amortization of Electric Plant Acquisition Adjustments	$ -				$0
5725	Miscellaneous Amortization	$ -				$0

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USoA Account #	Accounts	Financial Statement	Model Adjustments	Reclassify accounts	Direct Allocation	Reclassified Balance
5730	Amortization of Unrecovered Plant and Regulatory Study Costs	$ -				$0
5735	Amortization of Deferred Development Costs	$ -				$0
5740	Amortization of Deferred Charges	$ -				$0
6005	Interest on Long Term Debt	$ 148,500,000	($148,500,000)		$0	$148,500,000
6010	Amortization of Debt Discount and Expense	$ -				$0
6015	Amortization of Premium on Debt Credit	$ -				$0
6020	Amortization of Loss on Reacquired Debt	$ -				$0
6025	Amortization of Gain on Reacquired Debt--Credit	$ -				$0
6030	Interest on Debt to Associated Companies	$ -				$0
6035	Other Interest Expense	$ -				$0
6040	Allowance for Borrowed Funds Used During Construction--Credit	$ -				$0
6042	Allowance For Other Funds Used During Construction	$ -				$0
6045	Interest Expense on Capital Lease Obligations	$ -				$0
6105	Taxes Other Than Income Taxes	$ 4,464,000				$4,464,000
6110	Income Taxes	$ 50,100,000	($50,100,000)		$0	$50,100,000
6115	Provision for Future Income Taxes	$ -				$0
6205	Donations	$ -				$0
6210	Life Insurance	$ -				$0
6215	Penalties	$ -				$0
6225	Other Deductions	$ -				$0
6305	Extraordinary Income	$ -				$0
6310	Extraordinary Deductions	$ -				$0
6315	Income Taxes, Extraordinary Items	$ -				$0
6405	Discontinues Operations - Income/ Gains	$ -				$0
6410	Discontinued Operations - Deductions/ Losses	$ -				$0
6415	Income Taxes, Discontinued Operations	$ -				$0

Reconciliation of total cost	$7,120,159,551		$0
Revenue	$0		
Net Income	($151,400,000)		
	$6,968,759,551		

Reclassification has been done correctly

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Hydro One Networks - Distribution
Input Sheet for the Break Out Of Distribution Assets, Contributed Capital and Amortization and Amortization Expenses

Hydro One Distribution: 12 Rate Classes

See Handbook for Detail Instructions

Enter Net Fixed Assets from EB-2007-0681 Exhibit D2, Tab 1, Sch 1	**$ 4,085,500,000**

		BALANCE SHEET ITEMS									**EXPENSE ITEMS**			
RATE BASE AND DISTRIBUTION ASSETS											5705	5710	5715	5720
Account	Description	Break out Functions	BREAK OUT (%)	BREAK OUT ($)	After BO	Contributed Capital - 1995	Accumulated Depreciation - 2105 Capital Contribution	Accumulated Depreciation - 2105 Fixed Assets Only	Accumulated Depreciation - 2120	Asset net of Acc Dep and Cont Cap	Amortization Expense - Property, Plant, and Equipment	Amortization of Limited Term Electric Plant	Amortization of Intangibles and Other Electric Plant	Amortization of Electric Plant Acquisition Adjustments
1565	Conservation and Demand Management	$6,400,000		-	6,400,000			($775,688)		5,624,312	$426,880			
1805	Land	$61,219,197		($61,219,197)	-	($443,615)	($137,823)	($31,082,664)			$473,420			
1805-1	Land Station >50 kV		**10.00%**	$6,121,920	6,121,920	($44,362)	($13,782)	($3,108,266)		2,955,509	$47,342			
1805-2	Land Station <50 kV		90.00%	$55,097,277	55,097,277	($399,254)	($124,040)	($27,974,398)		26,599,585	$426,078			
1806	Land Rights	$239,478,047		($239,478,047)	-	($8,619,326)	($2,130,226)	($69,491,518)			$2,818,534			
1806-1	Land Rights Station >50 kV		**10.00%**	$23,947,805	23,947,805	($861,933)	($213,023)	($6,949,152)		15,923,698	$281,853			
1806-2	Land Rights Station <50 kV		90.00%	$215,530,242	215,530,242	($7,757,394)	($1,917,203)	($62,542,366)		143,313,279	$2,536,680			
1808	Buildings and Fixtures	$5,437,793		($5,437,793)	-	($80,204)	($32,787)	($1,916,304)			$95,977			
1808-1	Buildings and Fixtures > 50 kV		50.00%	$2,718,897	2,718,897	($40,102)	($16,393)	($958,152)		1,704,249	$47,989			
1808-2	Buildings and Fixtures < 50 KV		50.00%	$2,718,897	2,718,897	($40,102)	($16,393)	($958,152)		1,704,249	$47,989			
1810	Leasehold Improvements	$0		$0	-									
1810-1	Leasehold Improvements >50 kV		50.00%	$0	-	$0	$0	$0		-	$0			
1810-2	Leasehold Improvements <50 kV		50.00%	$0	-	$0	$0	$0		-	$0			
1815	Transformer Station Equipment - Normally Primary above 50 kV	$107,852,474		($107,852,474)	-	($3,354,573)	($1,257,888)	($35,001,013)		- 39,613,474	$2,207,159			
1815-1	HVDS - Rural		80.2%	$86,497,684	86,497,684	($2,690,367)	($1,008,827)	($28,077,231)		54,721,259	$1,770,142			
1815-2	HVDS - lo LV Specific		**0.5%**	**$571,618**	571,618	($17,779)	($6,667)	**($244,283)**		302,890	$11,698			
1815-3	HVDS - hi LV Specific		**1.8%**	**$1,908,989**	1,908,989	($59,376)	($22,265)	**($554,322)**		1,273,026	$39,067			
1815-4	HVDS - lo LV Shared		8.8%	$9,437,091	9,437,091	($293,525)	($110,065)	($3,062,589)		5,970,912	$193,126			
1815-5	HVDS - hi LV Shared		8.8%	$9,437,091	9,437,091	($293,525)	($110,065)	($3,062,589)		5,970,912	$193,126			
1820	Distribution Station Equipment - Normally Primary below 50 kV	$327,237,165		($327,237,165)	-	($1,648,708)	($1,088,478)	($136,355,247)		- 139,092,433	$7,452,285			
1820-1	Distribution Station Equipment - Normally Primary below 50 kV (Bulk)		0.00%	$0	-	$0	$0	$0		-	$0			
1820-2	Distribution Station Equipment - Normally Primary below 50 kV Primary)		87.83%	$287,412,402	287,412,402	($1,648,708)	($1,088,478)	($121,355,247)		163,319,969	$6,183,733			
1820-3	Distribution Station Equipment - Normally Primary below 50 kV (Wholesale Meters)		12.17%	$39,824,763	39,824,763			$ (15,000,000)		24,824,763	$1,268,552			
1825	Storage Battery Equipment	$0		$0	-									
1825-1	Storage Battery Equipment > 50 kV		50.00%	$0	-					-				
1825-2	Storage Battery Equipment <50 kV		50.00%	$0	-					-				
1830	Poles, Towers and Fixtures	$1,931,765,752		($1,931,765,752)	-	($124,290,053)	($30,945,903)	($635,754,791)			$41,901,515			
1830-3	Poles, Towers and Fixtures - Subtransmission Bulk Delivery		**20.00%**	$386,353,150		($24,858,011)	($6,189,181)	($127,150,958)		- 158,198,149	$8,380,303			
1830-3A	Bulk-LV Fixtures		**13.00%**	$50,225,910	50,225,910	($3,231,541)	($804,593)	($16,529,625)		29,660,150	$1,089,439			
1830-3B	Bulk-Retail Fixtures		**87.00%**	$336,127,241	336,127,241	($21,626,469)	($5,384,587)	($110,621,334)		198,494,851	$7,290,864			
1830-4	Poles, Towers and Fixtures - Primary		**65.00%**	$1,255,647,739		($80,788,534)	($20,114,837)	($413,240,614)		- 514,143,985	$27,235,985			
1830-4A	Primary-LV Fixtures		**0.11%**	$1,403,814	1,403,814	($90,322)	($22,488)	($462,003)		829,001	$30,450			
1830-4B	Primary-Retail Fixtures		**99.89%**	$1,254,243,925	1,254,243,925	($80,698,213)	($20,092,349)	($412,778,611)		740,674,753	$27,205,535			
1830-5	Poles, Towers and Fixtures - Secondary		**15.00%**	$289,764,863	289,764,863	($18,643,508)	($4,641,885)	($95,363,219)		171,116,251	$6,285,227			
1835	Overhead Conductors and Devices	$1,291,841,808		($1,291,841,808)	-	($66,898,941)	($14,870,323)	($451,075,879)		- 532,845,143	$30,777,374			
1835-3	Overhead Conductors and Devices - Subtransmission Bulk Delivery		**20.00%**	$258,368,362		($13,379,788)	($2,974,065)	($90,215,176)		- 106,569,029	$6,155,475			
1835-3A	Bulk-LV Conductors		**13.00%**	$33,587,887	33,587,887	($1,739,372)	($386,628)	($11,727,973)		19,733,913	$800,212			
1835-3B	Bulk-Retail Conductors		**87.00%**	$224,780,475	224,780,475	($11,640,416)	($2,587,436)	($78,487,203)		132,065,420	$5,355,263			
1835-4	Overhead Conductors and Devices - Primary		**65.00%**	$839,697,175		($43,484,312)	($9,665,710)	($293,199,321)		- 346,349,343	$20,005,293			
1835-4A	Primary-LV Conductors		**0.11%**	$938,781	938,781	($48,615)	($10,806)	($327,797)		551,563	$22,366			
1835-4B	Primary-Retail Conductors		**99.89%**	$838,758,394	838,758,394	($43,435,696)	($9,654,903)	($292,871,525)		492,796,270	$19,982,927			
1835-5	Overhead Conductors and Devices - Secondary		**15.00%**	$193,776,271	193,776,271	($10,034,841)	($2,230,548)	($67,661,382)		113,849,500	$4,616,606			
1840	Underground Conduit	$23,984,390		($23,984,390)	-	($1,089,202)	($476,947)	($9,630,326)		- 11,196,475	$451,035			
1840-3	Underground Conduit - Bulk Delivery			$0	-	$0	$0	$0		-	$0			
1840-4	Underground Conduit - Primary		20.00%	$4,796,878	4,796,878	($217,840)	($95,389)	($1,926,065)		2,557,583	$90,207			
1840-5	Underground Conduit - Secondary		80.00%	$19,187,512	19,187,512	($871,362)	($381,557)	($7,704,261)		10,230,332	$360,828			
1845	Underground Conductors and Devices	$679,439,007		($679,439,007)	-	($120,883,300)	($46,698,712)	($174,434,832)		- 342,016,844	$20,813,363			
1845-3	Underground Conductors and Devices - Bulk Delivery			$0	-	$0	$0	$0		-	$0			
1845-4	Underground Conductors and Devices - Primary		20.00%	$135,887,801	135,887,801	($24,176,660)	($9,339,742)	($34,886,966)		67,484,433	$4,162,673			
1845-5	Underground Conductors and Devices - Secondary		80.00%	$543,551,206	543,551,206	($96,706,640)	($37,358,969)	($139,547,865)		269,937,731	$16,650,691			
1850	Line Transformers	$1,283,933,745		($1,283,933,745)	-	($85,947,524)	($14,256,721)	($331,295,116)		- 431,499,360	$31,211,446			
1850-1	TRF-LV		**0.3%**	$3,851,801	3,851,801	($257,843)	($42,770)	($993,885)		2,557,303	$93,634			
1850-2	TRF-Rural		**99.7%**	$1,280,081,943	1,280,081,943	($85,689,681)	($14,213,951)	($330,301,230)		849,877,081	$31,117,811			
1855	Services	$0		$0	-					-				
1860	Meters	$172,889,855		($172,889,855)	-	($4,519,700)	($2,745,536)	$31,043,316		23,778,079	$14,899,710			

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1860-1	Mtr-Single		8%	$13,081,021	13,081,021	($341,965)	($207,730)	$2,348,769		14,880,095	$1,127,327			
1860-2	Mtr-Poly		3%	$5,379,048	5,379,048	($140,620)	($85,421)	$965,837		6,118,845	$463,568			
1860-3	Mtr-LV		4%	$6,689,107	6,689,107	($174,867)	($106,225)	$1,201,066		7,609,081	$576,470			
1860-4	Mtr-Smart		85%	$147,740,678	147,740,678	($3,862,249)	($2,346,160)	$26,527,644		168,059,912	$12,732,345			
1875	St Lgts+Signal Systems				-	$0	$0	$0						
modified	Total	$6,131,479,233	$6,131,479,233 from O1		6,131,479,233 -	417,775,147 -	114,641,343 -	1,845,770,061	$0	3,753,292,682	153,528,698	$0	$0	$0
	I3 sub total	$6,131,479,233										$153,528,698		
											5705	5710	5715	5720
General Plant		Break out Functions				Contributed Capital - 1995	Accumulated Depreciation - 2105 Capital Contribution	Accumulated Depreciation - 2105 Fixed Assets Only	Accumulated Depreciation - 2120	Net Asset	Amortization Expense - Property, Plant, and Equipment	Amortization of Limited Term Electric Plant	Amortization of Intangibles and Other Electric Plant	Amortization of Electric Plant Acquisition Adjustments
1905	Land	$3,283,798			3,283,798			($20,263)		$ 3,263,535	$0			
1906	Land Rights	$0			-			$0		$ -				
1908	Buildings and Fixtures	$94,901,052			94,901,052	($124,317)	($22,732)	($44,386,901)		$ 50,367,102	$1,948,322			
1910	Leasehold Improvements	$4,620,582			4,620,582			($3,700,025)		$ 920,557	$389,149			
1915	Office Furniture and Equipment	$2,536,853			2,536,853			($671,827)		$ 1,865,026	$362,408			
1920	Computer Equipment - Hardware	$55,593,665			55,593,665	($6,399)	($2,918)	($25,231,142)		$ 30,353,205	$8,103,834			
1925	Computer Software	$205,570,861			205,570,861	($2,133)	($1,044)	($107,402,562)		$ 98,165,122	$20,793,821			
1930	Transportation Equipment	$199,220,074			199,220,074			($101,991,639)		$ 97,228,435	$12,052,905			
1935	Stores Equipment	$6,587,180			6,587,180			($3,308,717)		$ 3,278,463	$823,398			
1940	Tools, Shop and Garage Equipment	$2,282,022			2,282,022			($1,024,244)		$ 1,257,777	$188,948			
1945	Measurement and Testing Equipment	$3,066,387			3,066,387			($1,034,519)		$ 2,031,869	$613,277			
1950	Power Operated Equipment	$85,055,133			85,055,133			($71,517,234)		$ 13,537,899	$2,876,786			
1955	Communication Equipment	$28,160,887			28,160,887	($83,530)	($19,830)	($20,908,064)		$ 7,149,463	$2,706,386			
1960	Miscellaneous Equipment	$2,998,695			2,998,695			($1,155,954)		$ 1,842,741	$599,739			
1970	Load Management Controls - Customer Premises	$0			-			$0		$ -				
1975	Load Management Controls - Utility Premises	$0			-			$0		$ -				
1980	System Supervisory Equipment	$21,869,131			21,869,131	($412,025)	($129,134)	($6,426,248)		$ 14,901,724	$1,760,833			
1985	Sentinel Lgts	$16,327,748			16,327,748	($301,089)	($170,254)	($11,723,467)			$482,401			
1990	Other Tangible Property	$5,274,886			5,274,886			($3,379,466)		$ 1,895,419	$149,442			
2005	Property Under Capital Leases	$0			-			$0		$ -				
2010	Electric Plant Purchased or Sold	$0			-			$0		$ -				
	Total	$737,348,954			$737,348,954	($929,494)	($345,912)	($403,882,273)	$0	$328,058,338	$53,851,648	$0	$0	$0
	I3 Sub total	$737,348,954		$737,348,954 from O1	check									
	I3 Directly Allocated	$0												
	Grand Total	$6,868,828,187			$6,868,828,187	($418,704,641)	($114,987,255)	($2,249,652,334)	$0	$4,081,351,020	$207,380,345.84	$0	$0	$0

To be Prorated

1995	Contributed Capital - 1995	($418,704,641)	$418,704,641	**Balanced**	
2105	Accumulated Depreciation - 2105	($2,364,639,589)	$2,364,639,589	**Balanced**	
2120	Accumulated Depreciation - 2120	$0	$0	**Balanced**	
	Total	($2,783,344,230)			
	Net Assets	$4,085,483,957.0	**Net Fixed Assets Match EDR**		

Amortization Expenses

5705	Amortization Expense - Property, Plant, and Equipment	$207,380,346	($207,380,346)	**Balanced**
5710	Amortization of Limited Term Electric Plant	$0	$0	**Balanced**
5715	Amortization of Intangibles and Other Electric Plant	$0	$0	**Balanced**
5720	Amortization of Electric Plant Acquisition Adjustments	$0	$0	
	Total Amortization Expense	$207,380,346		

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Hydro One Networks - Distribution

Input Sheet for Miscellaneous Data

1 Calculation of kM of Lines for Determining Density for Categorization - See Handbook for Instructions

Hydro One Distribution: 12 Rate Classes

kMs of Roads in Service Area Where Distribution Lines Exist	119,900
Deemed Equity Component of Rate Base (%)	40%

2 Fixed Monthly Charge

		1	2	3	4	5	6	7	8	12	13	14	15
	Total	**UR**	**R1**	**R2**	**Seasonal**	**GSe**	**GSd**	**St Lgt**	**Sen Lgt**	**Dgen**	**ST**	**UGe**	**UGd**
Weighted Average of contributing Rate Classes		14.29	17.76	57.91	28.64	39.41	50.19	-	-	173.73	83.85	9.72	11.07
Smart Meter Adder Included in Approved Monthly Service Charge		0.93	0.93	0.93	0.93	0.93	0.93	0.93	0.93	0.93	0.93	0.93	0.93

Hydro One Networks - Distribution

Input Sheet for Customer Related Data

Hydro One Distribution: 12 Rate Classes

Total kWhs	38,411,399,050
Total kWs	56,943,444
Total Approved Distribution Revenue ($)	1,024,275,593

			1	2	3	4	5	6	7	8	12	13	14	15
	ID	Total	**UR**	**R1**	**R2**	**Seasonal**	**GSe**	**GSd**	**St Lgt**	**Sen Lgt**	**Dgen**	**ST**	**UGe**	**UGd**
Billing Data														
	CEN	38,411,399,050	1,494,185,912	4,407,443,581	5,624,484,001	706,724,087	2,299,316,442	3,237,369,296	120,597,533	22,417,163	3,389,731	19,240,494,337	424,162,641	830,814,325
kW	**CDEM**	56,943,444	-	96	68,268	-	512,108	11,019,445	-	-	48,843	43,021,924	69,464	2,203,297
kW, included in CDEM, from customers with line transformer allowance		6,433,286	-	-	-	-	-	1,273,323	-	-	30,680	4,886,216	-	243,067
Optional - kWh, included in CEN, from customers that receive a line transformation allowance on a kWh basis. In most cases this will not be applicable and will be left blank.		2,783,515,813	-	-	-	-	-	456,111,674	-	-	1,776,527	2,231,058,442	-	94,569,170
KWh excluding KWh from Wholesale Market Participants	**CEN EWMP**	24,266,815,576	1,494,185,912	4,407,443,581	5,624,484,001	706,724,087	2,299,316,442	3,237,369,296	120,597,533	22,417,163	3,389,731	5,095,910,863	424,162,641	830,814,325
kWh - 30 year weather normalized amount		38,411,399,050	1,494,185,912	4,407,443,581	5,624,484,001	706,724,087	2,299,316,442	3,237,369,296	120,597,533	22,417,163	3,389,731	19,240,494,337	424,162,641	830,814,325
	CREV	$1,024,275,593	53,878,006	186,515,673	392,645,261	74,805,048	113,915,687	105,528,769	4,775,662	887,720	627,466	63,422,672	11,607,755	15,665,873
Bad Debt 3 Year Historical Average	**BDHA**	$44,088,260	5,052,597	13,957,729	14,178,775	1,062,756	3,363,783	3,733,687	280,127	52,071	2,570	1,199,955	399,432	804,780
Late Payment 3 Year Historical Average	**LPHA**	$12,206,226	1,026,633	3,362,574	3,930,013	676,557	1,346,493	1,070,450	17,607	4,528	2,693	401,251	216,470	150,956
Weighting Factor - Services			1.0	1.0	1.0	1.0	2.0	10.0	1.0	1.0	2.0	10.0	2.0	10.0
Weighting Factor - Billings			1.0	1.0	1.0	1.0	2.0	7.0	1.0	0.1	2.0	15.0	2.0	7.0
Number of Bills	**CNB**	12,570,372	1,870,368	4,372,092	4,299,852	617,756	1,047,360	81,708	66,730	43,266	972	4,524	149,232	16,512
Number of Connections (Unmetered)	**CCON**	9,166	-	-	-	-	-	-	5,561	3,606	-	-	-	-
Customer number from EB-2007-0681	**CCA**	1,177,552	162,058	376,430	364,938	155,177	97,005	7,015	-	-	84	673	12,744	1,429
Bulk Customer Base	**CCB**	1,177,552	162,058	376,430	364,938	155,177	97,005	7,015	-	-	84	673	12,744	1,429
Primary Customer Base	**CCP**	1,176,906	162,058	376,430	364,938	155,177	97,005	7,015	-	-	32	78	12,744	1,429
Line Transformer Customer Base	**CCLT**	1,176,828	162,058	376,430	364,938	155,177	97,005	7,015	-	-	32	-	12,744	1,429
Secondary Customer Base	**CCS**	1,168,352	162,058	376,430	364,938	155,177	97,005	-	-	-	-	-	12,744	-
Weighted - Services	**CWCS**	1,287,268	162,058	376,430	364,938	155,177	194,010	-	5,561	3,606	-	-	25,489	-
Weighted Meter -Capital	**CWMC**	274,283,678	32,653,951	77,766,040	80,682,304	34,827,221	23,861,405	4,156,006	-	-	76,305	16,233,676	3,243,245	783,524
Weighted Meter Reading	**CWMR**	6,294,007	623,456	1,821,705	2,866,568	386,098	436,360	94,920	-	-	-	-	49,744	15,156
Weighted Bills	**CWNB**	14,381,653	1,870,368	4,372,092	4,299,852	617,756	2,094,720	571,956	66,730	4,327	1,944	67,860	298,464	115,584
Data Mismatch Analysis														
Revenue with 30 year weather normalized kWh		1,024,275,593	53,878,006	186,515,673	392,645,261	74,805,048	113,915,687	105,528,769	4,775,662	887,720	627,466	63,422,672	11,607,755	15,665,873

Hydro One Distribution: 12 Rate Classes

tails

			1			2			3		
			UR			R1			R2		
		Col.1	1	2	3	1	2	3	1	2	3
		Cost per Meter (Installed)	**Number of Meters**	**Weighted Metering Costs (1)**	**Weighted Average Costs (2)**	**Number of Meters**	**Weighted Metering Costs (1)**	**Weighted Average Costs (2)**	**Number of Meters**	**Weighted Metering Costs (1)**	**Weighted Average Costs (2)**
		Allocation Percentage			11.9%			28.4%			29.4%
		Weighted Factor			1			1			1
	Meter Types	Total	155495.0058	32653951.21	210	370314.4744	77766039.63	210	384201.4493	80682304.35	210
	Single Phase 200 Amp - Urban	50		0			0			0	
	Single Phase 200 Amp - Rural	150		0			0			0	
	Central Meter	250		0			0			0	
	Network Meter (Costs to be updated)	225		0			0			0	
UR,R1,R2,Seasonal	Three-phase - No demand	210	155,495	32653951.21		370,314	77766039.63		384,201	80682304.35	
	Smart Meters	300		0			0			0	
GSd,Dgen,Ugd	Demand without IT (usually three-phase)	500		0			0			0	
	Demand with IT	2,100		0			0			0	
	Demand with IT and Interval Capability - Secondary	2,300		0			0			0	
	Demand with IT and Interval Capability - Primary	10,000		0			0			0	
	Demand with IT and Interval Capability -Special (WMP)	40,000		0			0			0	
Gse,Uge	LDC Specific 1	230		0			0			0	
ST	LDC Specific 2	31,000		0			0			0	
	LDC Specific 3	$350		0			0			0	

Hydro One Distribution: 12 Rate Classes

tails

			4			5			6		
			Seasonal			GSe			GSd		
		Col.1	1	2	3	1	2	3	1	2	3
		Cost per Meter (Installed)	**Number of Meters**	**Weighted Metering Costs (1)**	**Weighted Average Costs (2)**	**Number of Meters**	**Weighted Metering Costs (1)**	**Weighted Average Costs (2)**	**Number of Meters**	**Weighted Metering Costs (1)**	**Weighted Average Costs (2)**
		Allocation Percentage			12.7%			8.7%			1.5%
		Weighted Factor			1			1.095238095			2.380952381
	Meter Types	Total	165843.9114	34827221.38	210	103745.2394	23861405.07	230	8312.012839	4156006.42	500
	Single Phase 200 Amp - Urban	50		0			0			0	
	Single Phase 200 Amp - Rural	150		0			0			0	
	Central Meter	250		0			0			0	
	Network Meter (Costs to be updated)	225		0			0			0	
UR,R1,R2,Seasonal	Three-phase - No demand	210	165,844	34827221.38			0			0	
	Smart Meters	300		0			0			0	
GSd,Dgen,Ugd	Demand without IT (usually three-phase)	500		0			0		8,312	4156006.42	
	Demand with IT	2,100		0			0			0	
	Demand with IT and Interval Capability - Secondary	2,300		0			0			0	
	Demand with IT and Interval Capability - Primary	10,000		0			0			0	
	Demand with IT and Interval Capability -Special (WMP)	40,000		0			0			0	
Gse,Uge	LDC Specific 1	230		0		103,745	23861405.07			0	
ST	LDC Specific 2	31,000		0			0			0	
	LDC Specific 3	$350		0			0			0	

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tails

			7			8			12		
			St Lgt			**Sen Lgt**			**Dgen**		
		Col.1	1	2	3	1	2	3	1	2	3
		Cost per Meter (Installed)	**Number of Meters**	**Weighted Metering Costs (1)**	**Weighted Average Costs (2)**	**Number of Meters**	**Weighted Metering Costs (1)**	**Weighted Average Costs (2)**	**Number of Meters**	**Weighted Metering Costs (1)**	**Weighted Average Costs (2)**
		Allocation Percentage			0.0%			0.0%			0.0%
		Weighted Factor									2.380952381
	Meter Types	Total	0	0		0	0		152.6099567	76304.97836	500
	Single Phase 200 Amp - Urban	50		0			0			0	
	Single Phase 200 Amp - Rural	150		0			0			0	
	Central Meter	250		0			0			0	
	Network Meter (Costs to be updated)	225		0			0			0	
UR,R1,R2,Seasonal	Three-phase - No demand	210		0			0			0	
	Smart Meters	300		0			0			0	
GSd,Dgen,Ugd	Demand without IT (usually three-phase)	500		0			0		153	76304.97836	
	Demand with IT	2,100		0			0			0	
	Demand with IT and Interval Capability - Secondary	2,300		0			0			0	
	Demand with IT and Interval Capability - Primary	10,000		0			0			0	
	Demand with IT and Interval Capability -Special (WMP)	40,000		0			0			0	
Gse,Uge	LDC Specific 1	230		0			0			0	
ST	LDC Specific 2	31,000		0			0			0	
	LDC Specific 3	$350		0			0			0	

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Hydro One Distribution: 12 Rate Classes

tails

			13			14			15		
			ST			UGe			UGd		
		Col.1	1	2	3	1	2	3	1	2	3
		Cost per Meter (Installed)	Number of Meters	Weighted Metering Costs (1)	Weighted Average Costs (2)	Number of Meters	Weighted Metering Costs (1)	Weighted Average Costs (2)	Number of Meters	Weighted Metering Costs (1)	Weighted Average Costs (2)
		Allocation Percentage			5.9%			1.2%			0.3%
		Weighted Factor			147.6190476			1.095238095			2.380952381
	Meter Types	Total	523.6669756	16233676.24	31000	14101.0635	3243244.606	230	1567.048585	783524.2924	500
	Single Phase 200 Amp - Urban	50		0			0			0	
	Single Phase 200 Amp - Rural	150		0			0			0	
	Central Meter	250		0			0			0	
	Network Meter (Costs to be updated)	225		0			0			0	
UR,R1,R2,Seasonal	Three-phase - No demand	210		0			0			0	
	Smart Meters	300		0			0			0	
GSd,Dgen,Ugd	Demand without IT (usually three-phase)	500		0			0		1,567	783524.2924	
	Demand with IT	2,100		0			0			0	
	Demand with IT and Interval Capability - Secondary	2,300		0			0			0	
	Demand with IT and Interval Capability - Primary	10,000		0			0			0	
	Demand with IT and Interval Capability -Special (WMP)	40,000		0			0			0	
Gse,Uge	LDC Specific 1	230		0		14,101	3243244.606			0	
ST	LDC Specific 2	31,000	524	16233676.24			0			0	
	LDC Specific 3	$350		0			0			0	

Hydro One Distribution: 12 Rate Classes

tails

		Col.1	TOTAL 1	2	3
		Cost per Meter (Installed)	**Number of Meters**	**Weighted Metering Costs (1)**	**Weighted Average Costs (2)**
		Allocation Percentage	check		100.0%
		Weighted Factor	1,204,256		
	Meter Types	Total	1,204,256	274,283,678	227.761845
	Single Phase 200 Amp - Urban	50	0	0	
	Single Phase 200 Amp - Rural	150	0	0	
	Central Meter	250	0	0	
	Network Meter (Costs to be updated)	225	0	0	
UR,R1,R2,Seasonal	Three-phase - No demand	210	1,075,855	225929516.6	
	Smart Meters	300	0	0	
GSd,Dgen,Ugd	Demand without IT (usually three-phase)	500	10,032	5015835.69	
	Demand with IT	2,100	0	0	
	Demand with IT and Interval Capability - Secondary	2,300	0	0	
	Demand with IT and Interval Capability - Primary	10,000	0	0	
	Demand with IT and Interval Capability -Special (WMP)	40,000	0	0	
Gse,Uge	LDC Specific 1	230	117,846	27104649.67	
ST	LDC Specific 2	31,000	524	16233676.24	
	LDC Specific 3	$350	0	0	

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Hydro One Networks - Distribution

Input Sheet for Calculating Weighted Meter Reading Costs - Based on Contractors Pricing

Hydro One Distribution: 12 Rate Classes

See Handbook for More Details

Weighting Factors

Based on Contractor Pricing

			1			**2**			**3**		
Description	**Combined**		**UR**			**R1**			**R2**		
	Rate	**Factor**	**Units**	**Weighted Factor**	**Weighted Average Costs**	**Units**	**Weighted Factor**	**Weighted Average Costs**	**Units**	**Weighted Factor**	**Weighted Average Costs**
	Allocation Percentage				0.10			0.29			0.46
	Weighted Factor				1.00			1.25			2.00
	Total		**623,456**	**623,456**	**1.00**	**1,457,364**	**1,821,705**	**1.25**	**1,433,284**	**2,866,568**	**2.00**
Residential - Urban - Outside		1.00		0			0			0	
Residential - Urban - Outside with other services		1.00		0			0			0	
Residential - Urban - Inside		2.00		0			0			0	
Residential - Urban - Inside - with other services		1.00		0			0			0	
Residential - Rural - Outside		3.00		0			0			0	
Residential - Rural - Outside with other services		2.00		0			0			0	
LDC Specific 1		**1.00**	623,456	623,456			0			0	
LDC Specific 2		**1.25**		0		1,457,364	1,821,705			0	
GS - Walking		2.00		0			0			0	
GS - Walking - with other services		3.00		0			0			0	
GS - Vehicle with other services --- TOU Read		3.00		0			0			0	
GS - Vehicle with other services		3.00		0			0			0	
LDC Specific 3		**2.00**		0			0		1,433,284	2,866,568	
LDC Specific 4		**2.50**		0			0			0	
Interval		49.00		0			0			0	
LDC Specific 5		**1.10**		0			0			0	
LDC Specific 6		1.5		0			0			0	

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Input Sheet for Calculating Weighted Meter Reading Costs - Based on Contractors

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Weighting Factors

Based on Contractor Pricing

			4			5			6		
Description	**Combined**		**Seasonal**			**GSe**			**GSd**		
	Rate	**Factor**	**Units**	**Weighted Factor**	**Weighted Average Costs**	**Units**	**Weighted Factor**	**Weighted Average Costs**	**Units**	**Weighted Factor**	**Weighted Average Costs**
	Allocation Percentage				0.06			0.07			0.02
	Weighted Factor				2.50			1.25			1.25
	Total		**154,439**	**386,098**	**2.50**	**349,088**	**436,360**	**1.25**	**75,936**	**94,920**	**1.25**
Residential - Urban - Outside		1.00		0			0			0	
Residential - Urban - Outside with other services		1.00		0			0			0	
Residential - Urban - Inside		2.00		0			0			0	
Residential - Urban - Inside - with other services		1.00		0			0			0	
Residential - Rural - Outside		3.00		0			0			0	
Residential - Rural - Outside with other services		2.00		0			0			0	
LDC Specific 1		**1.00**		0			0			0	
LDC Specific 2		**1.25**		0		349,088	436,360		75,936	94,920	
GS - Walking		2.00		0			0			0	
GS - Walking - with other services		3.00		0			0			0	
GS - Vehicle with other services --- TOU Read		3.00		0			0			0	
GS - Vehicle with other services		3.00		0			0			0	
LDC Specific 3		**2.00**		0			0			0	
LDC Specific 4		**2.50**	154,439	386,098			0			0	
Interval		49.00		0			0			0	
LDC Specific 5		**1.10**		0			0			0	
LDC Specific 6		1.5		0			0			0	

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Weighting Factors

Based on Contractor Pricing

			7			8			12		
Description	**Combined**		**St Lgt**			**Sen Lgt**			**Dgen**		
	Rate	**Factor**	**Units**	**Weighted Factor**	**Weighted Average Costs**	**Units**	**Weighted Factor**	**Weighted Average Costs**	**Units**	**Weighted Factor**	**Weighted Average Costs**
	Allocation Percentage				-			-			-
	Weighted Factor				0.00			0.00			0.00
	Total		**-**	**-**	**0**	**-**	**-**	**0**	**-**	**-**	**0**
Residential - Urban - Outside		1.00		0			0			0	
Residential - Urban - Outside with other services		1.00		0			0			0	
Residential - Urban - Inside		2.00		0			0			0	
Residential - Urban - Inside - with other services		1.00		0			0			0	
Residential - Rural - Outside		3.00		0			0			0	
Residential - Rural - Outside with other services		2.00		0			0			0	
LDC Specific 1		**1.00**		0			0			0	
LDC Specific 2		**1.25**		0			0			0	
GS - Walking		2.00		0			0			0	
GS - Walking - with other services		3.00		0			0			0	
GS - Vehicle with other services --- TOU Read		3.00		0			0			0	
GS - Vehicle with other services		3.00		0			0			0	
LDC Specific 3		**2.00**		0			0			0	
LDC Specific 4		**2.50**		0			0			0	
Interval		49.00		0			0			0	
LDC Specific 5		**1.10**		0			0			0	
LDC Specific 6		1.5		0			0			0	

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Input Sheet for Calculating Weighted Meter Reading Costs - Based on Contractors

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Weighting Factors

Based on Contractor Pricing

			13			14			15		
Description	**Combined**		**ST**			**UGe**			**UGd**		
	Rate	**Factor**	**Units**	**Weighted Factor**	**Weighted Average Costs**	**Units**	**Weighted Factor**	**Weighted Average Costs**	**Units**	**Weighted Factor**	**Weighted Average Costs**
	Allocation Percentage				-			0.01			0.00
	Weighted Factor				0.00			1.00			1.00
	Total		**-**	**-**	**0**	**49,744**	**49,744**	**1.00**	**15,156**	**15,156**	**1.00**
Residential - Urban - Outside		1.00		0			0			0	
Residential - Urban - Outside with other services		1.00		0			0			0	
Residential - Urban - Inside		2.00		0			0			0	
Residential - Urban - Inside - with other services		1.00		0			0			0	
Residential - Rural - Outside		3.00		0			0			0	
Residential - Rural - Outside with other services		2.00		0			0			0	
LDC Specific 1		**1.00**		0		49,744	49,744		15,156	15,156	
LDC Specific 2		**1.25**		0			0			0	
GS - Walking		2.00		0			0			0	
GS - Walking - with other services		3.00		0			0			0	
GS - Vehicle with other services --- TOU Read		3.00		0			0			0	
GS - Vehicle with other services		3.00		0			0			0	
LDC Specific 3		**2.00**		0			0			0	
LDC Specific 4		**2.50**		0			0			0	
Interval		49.00		0			0			0	
LDC Specific 5		**1.10**		0			0			0	
LDC Specific 6		1.5		0			0			0	

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Weighting Factors

Based on Contractor Pricing

Description	**Combined**		TOTAL		
	Rate	**Factor**	**Units**	**Weighted Factor**	**Weighted Average Costs**
	Allocation Percentage		check		1.00
	Weighted Factor		4,158,467		11.25
	Total		**4,158,467**	**6,294,007**	**11**
Residential - Urban - Outside		1.00	-	-	
Residential - Urban - Outside with other services		1.00	-	-	
Residential - Urban - Inside		2.00	-	-	
Residential - Urban - Inside - with other services		1.00	-	-	
Residential - Rural - Outside		3.00	-	-	
Residential - Rural - Outside with other services		2.00	-	-	
LDC Specific 1		**1.00**	688,356	688,356	
LDC Specific 2		**1.25**	1,882,388	2,352,985	
GS - Walking		2.00	-	-	
GS - Walking - with other services		3.00	-	-	
GS - Vehicle with other services --- TOU Read		3.00	-	-	
GS - Vehicle with other services		3.00	-	-	
LDC Specific 3		**2.00**	1,433,284	2,866,568	
LDC Specific 4		**2.50**	154,439	386,098	
Interval		49.00	-	-	
LDC Specific 5		**1.10**	-	-	
LDC Specific 6		1.5	-	-	

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Hydro One Networks - Distribution

Hydro One Distribution: 12 Rate Classes

CP TEST RESULTS	**12 CP**
NCP TEST RESULTS	**4 NCP**

Co-incident Peak	Indicator
1 CP	**CP 1**
4 CP	**CP 4**
12 CP	**CP 12**

Non-co-incident Peak	
1 NCP	**NCP 1**
4 NCP	**NCP 4**
12 NCP	**NCP 12**

			1	2	3	4	5	6	7	8	12	13	14	15
Customer Classes		**Total**	**UR**	**R1**	**R2**	**Seasonal**	**GSe**	**GSd**	**St Lgt**	**Sen Lgt**	**Dgen**	**ST**	**UGe**	**UGd**
CO-INCIDENT PEAK														
1 CP														
Transformation CP	TCP1	6,716,619	339,882	1,047,380	1,208,430	113,585	341,335	471,767	25,967	5,120	461	2,977,680	62,625	122,387
Bulk Delivery CP	BCP1	6,488,254	328,326	1,011,769	1,167,343	109,723	329,729	455,727	25,084	4,946	445	2,876,439	60,496	118,226
Total Sytem CP	DCP1	6,716,619	339,882	1,047,380	1,208,430	113,585	341,335	471,767	25,967	5,120	461	2,977,680	62,625	122,387
4 CP														
Transformation CP	TCP4	26,078,514	1,270,911	4,020,290	4,765,830	468,705	1,271,553	1,829,931	108,260	21,348	1,827	11,614,299	237,141	468,420
Bulk Delivery CP	BCP4	25,191,845	1,227,700	3,883,600	4,603,791	452,769	1,228,321	1,767,713	104,579	20,622	1,765	11,219,412	229,078	452,494
Total Sytem CP	DCP4	26,078,514	1,270,911	4,020,290	4,765,830	468,705	1,271,553	1,829,931	108,260	21,348	1,827	11,614,299	237,141	468,420
12 CP														
Transformation CP	TCP12	70,226,697	3,193,520	9,660,672	11,676,098	1,460,978	3,551,695	5,129,265	146,171	28,823	5,306	33,391,892	669,408	1,312,870
Bulk Delivery CP	BCP12	67,838,990	3,084,940	9,332,209	11,279,111	1,411,305	3,430,938	4,954,870	141,202	27,843	5,125	32,256,567	646,648	1,268,232
Total Sytem CP	DCP12	70,226,697	3,193,520	9,660,672	11,676,098	1,460,978	3,551,695	5,129,265	146,171	28,823	5,306	33,391,892	669,408	1,312,870
NON CO_INCIDENT PEAK														
1 NCP														
Classification NCP from Load Data Provider	DNCP1	7,181,439	348,839	1,069,672	1,254,505	153,781	452,085	574,622	43,296	8,537	589	3,055,756	74,224	145,533
Primary NCP	PNCP1	3,962,074	327,559	1,004,422	1,177,980	144,400	424,508	539,570	40,655	8,017	55	88,556	69,697	136,655
Line Transformer NCP	LTNCP1	3,796,059	327,559	1,004,422	1,177,980	144,400	424,508	477,222	40,655	8,017	21		69,697	121,579
Secondary NCP	SNCP1	3,091,684	316,745	971,262	1,139,090	139,633	410,493		39,313	7,752			67,396	
4 NCP														
Classification NCP from Load Data Provider	DNCP4	27,937,041	1,332,602	4,205,680	4,820,483	594,083	1,717,103	2,227,067	169,928	33,508	2,276	11,972,432	290,877	570,999
Primary NCP	PNCP4	15,335,805	1,251,313	3,949,134	4,526,434	557,844	1,612,360	2,091,216	159,563	31,464	214	346,961	273,134	536,168
Line Transformer NCP	LTNCP4	14,687,915	1,251,313	3,949,134	4,526,434	557,844	1,612,360	1,849,571	159,563	31,464	79		273,134	477,018
Secondary NCP	SNCP4	11,953,154	1,210,003	3,818,758	4,376,999	539,428	1,559,130		154,295	30,425			264,117	
12 NCP														
Classification NCP from Load Data Provider	DNCP12	74,442,142	3,419,092	10,245,116	11,877,973	1,626,008	4,620,404	6,169,589	401,516	79,175	6,328	33,604,756	809,454	1,582,732
Primary NCP	PNCP12	39,314,824	3,210,527	9,620,164	11,153,416	1,526,821	4,338,560	5,793,244	377,024	74,345	594	973,866	760,077	1,486,185
Line Transformer NCP	LTNCP12	37,507,206	3,210,527	9,620,164	11,153,416	1,526,821	4,338,560	5,123,821	377,024	74,345	221		760,077	1,322,230
Secondary NCP	SNCP12	30,035,493	3,104,535	9,302,566	10,785,199	1,476,415	4,195,327		364,577	71,890			734,984	

Hydro One Networks - Distribution

Hydro One Distribution: 12 Rate Classes

USoA Account #	Accounts	Direct Allocation	Total Allocated to Rate Classifications?	1 UR	2 R1	3 R2	4 Seasonal	5 GSe	6 GSd	7 St Lgt	8 Sen Lgt	12 Dgen	13 ST	14 UGe	15 UGd
To Allocate Capital Contribution by Rate Classification, Input Allocation on Next Line															
1995	Contributions and Grants - Credit	$0	Yes												
The Following is Used to Allocate Directly Allocated Costs, from I3, to Rate Classifications															
1805	Land	$0	Yes												
1806	Land Rights	$0	Yes												
1808	Buildings and Fixtures	$0	Yes												
1810	Leasehold Improvements	$0	Yes												
1815	Transformer Station Equipment - Normally Primary above 50 kV	$0	Yes												
1820	Distribution Station Equipment - Normally Primary below 50 kV	$0	Yes												
1825	Storage Battery Equipment	$0	Yes												
1830	Poles, Towers and Fixtures	$0	Yes												
1835	Overhead Conductors and Devices	$0	Yes												
1840	Underground Conduit	$0	Yes												
1845	Underground Conductors and Devices	$0	Yes												
1850	Line Transformers	$0	Yes												
1855	Services	$0	Yes												
1860	Meters	$0	Yes												
1905	Land	$0	Yes												
1906	Land Rights	$0	Yes												
1908	Buildings and Fixtures	$0	Yes												
1910	Leasehold Improvements	$0	Yes												
1915	Office Furniture and Equipment	$0	Yes												
1920	Computer Equipment - Hardware	$0	Yes												
1925	Computer Software	$0	Yes												
1930	Transportation Equipment	$0	Yes												
1935	Stores Equipment	$0	Yes												
1940	Tools, Shop and Garage Equipment	$0	Yes												
1945	Measurement and Testing Equipment	$0	Yes												
1950	Power Operated Equipment	$0	Yes												
1955	Communication Equipment	$0	Yes												
1960	Miscellaneous Equipment	$0	Yes												
1970	Load Management Controls - Customer Premises	$0	Yes												
1975	Load Management Controls - Utility Premises	$0	Yes												
1980	System Supervisory Equipment	$0	Yes												
1990	Other Tangible Property	$0	Yes												
2005	Property Under Capital Leases	$0	Yes												

				1	2	3	4	5	6	7	8	12	13	14	15
USoA Account #	**Accounts**	**Direct Allocation**	**Total Allocated to Rate Classifications?**	**UR**	**R1**	**R2**	**Seasonal**	**GSe**	**GSd**	**St Lgt**	**Sen Lgt**	**Dgen**	**ST**	**UGe**	**UGd**
2010	Electric Plant Purchased or Sold	$0	**Yes**												
2050	Completed Construction Not Classified--Electric	$0	**Yes**												
2105	Accum. Amortization of Electric Utility Plant - Property, Plant, & Equipment	$0	**Yes**												
2120	Accumulated Amortization of Electric Utility Plant - Intangibles	$0	**Yes**												
	Directly Allocated Net Fixed Assets			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5005	Operation Supervision and Engineering	$0	**Yes**												
5010	Load Dispatching	$0	**Yes**												
5012	Station Buildings and Fixtures Expense	$0	**Yes**												
5014	Transformer Station Equipment - Operation Labour	$0	**Yes**												
5015	Transformer Station Equipment - Operation Supplies and Expenses	$0	**Yes**												
5016	Distribution Station Equipment - Operation Labour	$0	**Yes**												
5017	Distribution Station Equipment - Operation Supplies and Expenses	$0	**Yes**												
5020	Overhead Distribution Lines and Feeders - Operation Labour	$0	**Yes**												
5025	Overhead Distribution Lines & Feeders - Operation Supplies and Expenses	$0	**Yes**												
5030	Overhead Subtransmission Feeders - Operation	$0	**Yes**												
5035	Overhead Distribution Transformers- Operation	$0	**Yes**												
5040	Underground Distribution Lines and Feeders - Operation Labour	$0	**Yes**												
5045	Underground Distribution Lines & Feeders - Operation Supplies & Expenses	$0	**Yes**												
5050	Underground Subtransmission Feeders - Operation	$0	**Yes**												
5055	Underground Distribution Transformers - Operation	$0	**Yes**												
5065	Meter Expense	$4,543,350	**Yes**	$0	$0	$0	$0	$25,614	$1,540,064	$0	$0	$259,346	$2,356,523	$0	$361,803
5070	Customer Premises - Operation Labour	$0	**Yes**												
5075	Customer Premises - Materials and Expenses	$0	**Yes**												
5085	Miscellaneous Distribution Expense	$0	**Yes**												
5090	Underground Distribution Lines and Feeders - Rental Paid	$0	**Yes**												
5095	Overhead Distribution Lines and Feeders - Rental Paid	$0	**Yes**												
5096	Other Rent	$0	**Yes**												
5105	Maintenance Supervision and Engineering	$0	**Yes**												
5110	Maintenance of Buildings and Fixtures - Distribution Stations	$0	**Yes**												
5112	Maintenance of Transformer Station Equipment	$0	**Yes**												

USoA Account #	Accounts	Direct Allocation	Total Allocated to Rate Classifications?	UR (1)	R1 (2)	R2 (3)	Seasonal (4)	GSe (5)	GSd (6)	St Lgt (7)	Sen Lgt (8)	Dgen (12)	ST (13)	UGe (14)	UGd (15)
5114	Maintenance of Distribution Station Equipment	$0	Yes												
5120	Maintenance of Poles, Towers and Fixtures	$0	Yes												
5125	Maintenance of Overhead Conductors and Devices	$0	Yes												
5130	Maintenance of Overhead Services	$0	Yes												
5135	Overhead Distribution Lines and Feeders - Right of Way	$0	Yes												
5145	Maintenance of Underground Conduit	$0	Yes												
5150	Maintenance of Underground Conductors and Devices	$0	Yes												
5155	Maintenance of Underground Services	$0	Yes												
5160	Maintenance of Line Transformers	$0	Yes												
5170	Sentinel Lights - Labour	$0	Yes												
5172	Sentinel Lights - Materials and Expenses	$0	Yes												
5175	Maintenance of Meters	$0	Yes												
5305	Supervision	$0	Yes												
5310	Meter Reading Expense	$0	Yes												
5315	Customer Billing	$0	Yes												
5320	Collecting	$0	Yes												
5325	Collecting- Cash Over and Short	$0	Yes												
5330	Collection Charges	$0	Yes												
5335	Bad Debt Expense	$0	Yes												
5340	Miscellaneous Customer Accounts Expenses	$0	Yes												
5405	Supervision	$0	Yes												
5410	Community Relations - Sundry	$0	Yes												
5415	Energy Conservation	$0	Yes												
5420	Community Safety Program	$0	Yes												
5425	Miscellaneous Customer Service and Informational Expenses	$0	Yes	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5505	Supervision	$0	Yes												
5510	Demonstrating and Selling Expense	$0	Yes												
5515	Advertising Expense	$0	Yes												
5520	Miscellaneous Sales Expense	$0	Yes												
5605	Executive Salaries and Expenses	$0	Yes												
5610	Management Salaries and Expenses	$59,000	Yes	$0	$0	$0	$0	$333	$19,999	$0	$0	$3,368	$30,602	$0	$4,698
5615	General Administrative Salaries and Expenses	$598,000	Yes	$0	$0	$0	$0	$3,371	$202,705	$0	$0	$34,135	$310,168	$0	$47,621
5620	Office Supplies and Expenses	$0	Yes												
5625	Administrative Expense Transferred Credit	$0	Yes												
5630	Outside Services Employed	$11,000	Yes	$0	$0	$0	$0	$62	$3,729	$0	$0	$628	$5,705	$0	$876
5635	Property Insurance	$0	Yes												
5640	Injuries and Damages	$0	Yes												
5645	Employee Pensions and Benefits	$0	Yes												
5650	Franchise Requirements	$0	Yes												
5655	Regulatory Expenses	$0	Yes												
5660	General Advertising Expenses	$0	Yes												

				1	2	3	4	5	6	7	8	12	13	14	15
USoA Account #	**Accounts**	**Direct Allocation**	**Total Allocated to Rate Classifications?**	**UR**	**R1**	**R2**	**Seasonal**	**GSe**	**GSd**	**St Lgt**	**Sen Lgt**	**Dgen**	**ST**	**UGe**	**UGd**
5665	Miscellaneous General Expenses	$1,767,900	**Yes**	$0	$0	$0	$0	$1,601	$96,268	$0	$1,483,900	$16,211	$147,304	$0	$22,616
5670	Rent	$0	**Yes**												
5675	Maintenance of General Plant	$190,000	**Yes**	$0	$0	$0	$0	$1,071	$64,405	$0	$0	$10,846	$98,548	$0	$15,130
5680	Electrical Safety Authority Fees	$0	**Yes**												
5705	Amortization Expense - Property, Plant, and Equipment	$0	**Yes**												
5710	Amortization of Limited Term Electric Plant	$0	**Yes**												
5715	Amortization of Intangibles and Other Electric Plant	$0	**Yes**												
5720	Amortization of Electric Plant Acquisition Adjustments	$0	**Yes**												
6105	Taxes Other Than Income Taxes	$0	**Yes**												
6205	Donations	$0	**Yes**												
6210	Life Insurance	$0	**Yes**												
6215	Penalties	$0	**Yes**												
6225	Other Deductions	$0	**Yes**												
	Total Expenses			$0	$0	$0	$0	$32,053	$1,927,169	$0	$1,483,900	$324,534	$2,948,850	$0	$452,745
	Depreciation Expense			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Total Net Fixed Assets Excluding Gen Plant	**$6,131,479,233**	**Allocated**												
	Approved Total PILs	**$50,100,000**	**$0**	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Approved Total Return on Debt	**$148,500,000**	**$0**	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Approved Total Return on Equity	**$151,400,000**	**$0**	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Total			**$0**	**$0**	**$0**	**$0**	**$32,053**	**$1,927,169**	**$0**	**$1,483,900**	**$324,534**	**$2,948,850**	**$0**	**$452,745**

Hydro One Networks - Distribution

Output Sheet Showing Revenue to Cost Summary by Major Groupings by Class

Hydro One Distribution: 12 Rate Classes

Class Revenue and Cost Analysis and Return on Rate Base

			1	2	3	4	5	6	7	8	12	13	14	15
Rate Base Assets		**Total**	**UR**	**R1**	**R2**	**Seasonal**	**GSe**	**GSd**	**St Lgt**	**Sen Lgt**	**Dgen**	**ST**	**UGe**	**UGd**
crev	Distribution Revenue (sale)	**$1,024,275,593**	$53,878,006	$186,515,673	$392,645,261	$74,805,048	$113,915,687	$105,528,769	$4,775,662	$887,720	$627,466	$63,422,672	$11,607,755	$15,665,873
mi	Miscellaneous Revenue (mi) -- ***allocated by CWNB+LPHA***	**$42,300,000**	$4,835,012	$12,445,798	$12,980,227	$1,997,828	$5,648,656	$2,377,209	$149,907	$13,743	$6,957	$607,828	$834,086	$402,750
	Total Revenue	**$1,066,575,593**	**$58,713,019**	**$198,961,471**	**$405,625,488**	**$76,802,876**	**$119,564,343**	**$107,905,978**	**$4,925,569**	**$901,462**	**$634,423**	**$64,030,500**	**$12,441,840**	**$16,068,623**
	Expenses													
di	Distribution Costs (di)	**$261,278,800**	$11,224,779	$55,354,302	$107,735,113	$23,044,520	$27,278,881	$23,202,982	$1,998,144	$595,355	$8,389	$6,173,365	$1,831,288	$2,831,682
cu	Customer Related Costs (cu)	**$118,666,470**	$14,455,479	$36,003,520	$39,644,541	$7,585,990	$12,549,687	$4,104,877	$425,715	$89,283	$12,285	$1,274,953	$1,687,958	$832,183
ad	General and Administration (ad)	**$122,080,727**	$8,175,774	$29,160,678	$47,082,017	$9,807,237	$12,800,842	$9,184,009	$799,545	$221,038	$6,691	$2,444,240	$1,128,977	$1,269,678
dep	Depreciation and Amortization (dep)	**$207,380,346**	$12,869,748	$46,004,555	$73,016,682	$16,346,053	$21,643,440	$23,739,397	$1,798,563	$878,431	$15,442	$5,125,788	$1,904,979	$4,037,266
INPUT	PILs (INPUT)	**$50,100,000**	$2,897,238	$10,805,328	$17,727,069	$3,816,346	$5,268,947	$6,197,521	$447,639	$96,221	$3,097	$1,321,737	$450,780	$1,068,075
INT	Interest	**$148,500,000**	$8,587,623	$32,027,770	$52,544,306	$11,311,923	$15,617,539	$18,369,897	$1,326,835	$285,207	$9,180	$3,917,724	$1,336,144	$3,165,852
	Total Expenses	**$908,006,343**	**$58,210,641**	**$209,356,153**	**$337,749,728**	**$71,912,069**	**$95,159,336**	**$84,798,683**	**$6,796,442**	**$2,165,535**	**$55,084**	**$20,257,807**	**$8,340,126**	**$13,204,737**
	Direct Allocation	**$7,169,250**	**$0**	**$0**	**$0**	**$0**	**$32,053**	**$1,927,169**	**$0**	**$1,483,900**	**$324,534**	**$2,948,850**	**$0**	**$452,745**
NI	Allocated Net Income (NI)	**$151,400,000**	$8,755,327	$32,653,228	$53,570,424	$11,532,830	$15,922,528	$18,728,636	$1,352,746	$290,776	$9,359	$3,994,232	$1,362,237	$3,227,677
	Revenue Requirement (includes NI)	$1,066,575,593	$66,965,969	$242,009,381	$391,320,152	$83,444,899	$111,113,917	$105,454,489	$8,149,189	$3,940,212	$388,978	$27,200,888	$9,702,363	$16,885,159
		Revenue Requirement Input equals Output												
	Rate Base Calculation													
	Net Assets													
dp	Distribution Plant - Gross	**$6,131,479,233**	$347,938,518	$1,325,022,017	$2,198,478,584	$461,520,438	$649,566,251	$742,239,398	$55,417,412	$12,211,481	$301,573	$157,896,039	$55,650,611	$125,236,912
gp	General Plant - Gross	**$737,348,954**	$42,285,241	$156,645,429	$255,375,173	$55,135,038	$75,974,676	$87,737,631	$6,477,816	$17,732,968	$42,396	$18,314,565	$6,554,838	$15,073,182
accum dep	Accumulated Depreciation	**($2,364,639,589)**	($126,329,707)	($504,073,473)	($860,106,456)	($172,568,313)	($251,397,594)	($282,423,361)	($21,468,426)	($16,740,713)	($79,386)	($61,912,930)	($21,297,966)	($46,241,264)
co	Capital Contribution	**($418,704,641)**	($27,605,063)	($96,829,462)	($149,512,348)	($33,095,751)	($44,846,947)	($43,340,204)	($3,944,093)	($1,222,923)	($13,267)	($6,945,420)	($4,154,457)	($7,194,706)
	Total Net Plant	**$4,085,483,957**	**$236,288,989**	**$880,764,511**	**$1,444,234,953**	**$310,991,412**	**$429,296,386**	**$504,213,464**	**$36,482,709**	**$11,980,813**	**$251,316**	**$107,352,253**	**$36,753,027**	**$86,874,124**
	Directly Allocated Net Fixed Assets	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
COP	Cost of Power (COP)	**$1,959,300,000**	$120,640,405	$355,856,506	$454,120,215	$57,060,824	$185,646,555	$261,384,838	$9,737,031	$1,809,959	$273,686	$411,443,278	$34,246,845	$67,079,857
	OM&A Expenses	**$502,025,997**	$33,856,032	$120,518,500	$194,461,671	$40,437,746	$52,629,410	$36,491,868	$3,223,404	$905,676	$27,365	$9,892,558	$4,648,223	$4,933,543
	USoA 5645 Adjustment of $23.6M	**($23,592,000)**	($1,594,568)	($5,672,695)	($9,151,267)	($1,901,945)	($2,473,081)	($1,695,631)	($150,505)	($42,511)	($1,284)	($462,490)	($218,521)	($227,501)
	USoA 5112/5114 Adjustment of $8.2M	**($7,977,000)**	($560,578)	($1,928,665)	($2,302,341)	($148,384)	($850,862)	($1,258,371)	($85,837)	($13,836)	($168)	($355,123)	($149,781)	($323,054)
	Directly Allocated Expenses	**$7,169,250**	$0	$0	$0	$0	$32,053	$1,927,169	$0	$1,483,900	$324,534	$2,948,850	$0	$452,745
	Subtotal	**$2,436,926,247**	$152,341,291	$468,773,645	$637,128,277	$95,448,242	$234,984,075	$296,849,873	$12,724,094	$4,143,188	$624,134	$423,467,073	$38,526,766	$71,915,589
	Working Capital [11% not 15%]	**$273,179,432**	**$17,077,459**	**$52,549,526**	**$71,422,080**	**$10,699,748**	**$26,341,715**	**$33,276,871**	**$1,426,371**	**$464,451**	**$69,965**	**$47,470,659**	**$4,318,851**	**$8,061,738**
	USoA 1330: Supplies Inventory -- based on O&M	**$23,300,000**	$1,574,832	$5,602,484	$9,038,002	$1,878,404	$2,442,472	$1,674,644	$148,642	$41,985	$1,268	$456,765	$215,816	$224,685
	Total Rate Base [per Exhibit D2-1-1]	**$4,381,963,390**	**$254,941,280**	**$938,916,520**	**$1,524,695,035**	**$323,569,564**	**$458,080,573**	**$539,164,979**	**$38,057,722**	**$12,487,250**	**$322,549**	**$155,279,677**	**$41,287,694**	**$95,160,547**
		Rate Base Input equals Output - nearest $M												
	Equity Component of Rate Base	**$1,752,785,356**	**$101,976,512**	**$375,566,608**	**$609,878,014**	**$129,427,826**	**$183,232,229**	**$215,665,991**	**$15,223,089**	**$4,994,900**	**$129,020**	**$62,111,871**	**$16,515,078**	**$38,064,219**
	Net Income	**$151,400,000**	**$502,377**	**($10,394,682)**	**$67,875,761**	**$4,890,807**	**$24,372,953**	**$21,180,126**	**($1,870,873)**	**($2,747,973)**	**$254,805**	**$40,823,844**	**$4,101,714**	**$2,411,141**

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Exhibit G2-1-1
Attachment A
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Rate Base Assets		Total	UR	R1	R2	Seasonal	GSe	GSd	St Lgt	Sen Lgt	Dgen	ST	UGe	UGd
	RATIOS ANALYSIS													
	REVENUE TO EXPENSES %	**100.00%**	87.68%	82.21%	103.66%	92.04%	107.61%	102.32%	60.44%	22.88%	163.10%	235.40%	128.24%	95.16%
	EXISTING REVENUE MINUS ALLOCATED COSTS	**$0**	($8,252,950)	($43,047,910)	$14,305,337	($6,642,023)	$8,450,426	$2,451,490	($3,223,620)	($3,038,749)	$245,446	$36,829,612	$2,739,477	($816,536)
	RETURN ON EQUITY COMPONENT OF RATE BASE	8.64%	0.49%	-2.77%	11.13%	3.78%	13.30%	9.82%	-12.29%	-55.02%	197.49%	65.73%	24.84%	6.33%
	$40.2M External Revenues Unique Allocation	**$42,300,000**	**$ 3,823,728**	**$ 10,629,022**	**$ 11,964,874**	**$ 2,151,672**	**$ 5,669,671**	**$ 2,353,833**	**$ 112,143**	**$ 4,031,147**	**$ 4,678**	**$ 756,986**	**$ 471,108**	**$ 331,138**
Dir	Sentinel Lgts	**$4,000,000**								$4,000,000				
LPHA	Late Payments	**$14,500,000**	1,219,557	3,994,463	4,668,534	803,694	1,599,523	1,271,608	20,916	5,379	3,199	476,654	257,149	179,324
Connects	Collections	**$5,500,000**	948,110	1,850,387	1,012,818	112,974	1,488,543	31,518	-	-	405	-	47,187	8,057
Connects	New Connects + Upgrades	**$4,000,000**	689,534	1,345,736	736,595	82,163	1,082,577	22,922	-	-	295	-	34,318	5,860
O&M	Joint Use	**$9,500,000**	$ 642,099	$ 2,284,275	$ 3,685,022	$ 765,873	$ 995,858	$ 682,795	$ 60,605	$ 17,118	$ 517	$ 186,235	$ 87,994	$ 91,610
O&M	Other	**$4,500,000**	$ 304,152	$ 1,082,025	$ 1,745,537	$ 362,782	$ 471,722	$ 323,429	$ 28,708	$ 8,109	$ 245	$ 88,216	$ 41,681	$ 43,394
O&M	Internal Transfer with Telecom	**$300,000**	$ 20,277	$ 72,135	$ 116,369	$ 24,185	$ 31,448	$ 21,562	$ 1,914	$ 541	$ 16	$ 5,881	$ 2,779	$ 2,893
	Allocated Costs based on Alloc External Revenues	**$1,066,575,593**	**$65,954,685**	**$240,192,605**	**$390,304,799**	**$83,598,743**	**$111,134,932**	**$105,431,113**	**$8,111,425**	**$7,957,616**	**$386,698**	**$27,350,045**	**$9,339,386**	**$16,813,547**
	CREV + Uniquie Allocation of Misc External Revenues	**$1,066,575,593**	**$57,701,735**	**$197,144,695**	**$404,610,136**	**$76,956,720**	**$119,585,358**	**$107,882,602**	**$4,887,805**	**$4,918,867**	**$632,144**	**$64,179,658**	**$12,078,863**	**$15,997,011**
	Rev to Cost Ratio -- External Rev CWNB Allocation		0.877	0.822	1.037	0.920	1.076	1.023	0.604	0.229	1.631	2.354	1.282	0.952
	Rev to Cost Ratio -- External Rev Unique Allocation	**1.00**	**0.875**	**0.821**	**1.037**	**0.921**	**1.076**	**1.023**	**0.603**	**0.618**	**1.635**	**2.347**	**1.293**	**0.951**

Hydro One Networks - Distribution
Output Sheet Showing Minimum and Maximum Level For Fixed Monthly Charge

Hydro One Distribution: 12 Rate Classes

		1	2	3	4	5	6	7	8	12	13	14	15
Summary	**Total**	**UR**	**R1**	**R2**	**Seasonal**	**GSe**	**GSd**	**St Lgt**	**Sen Lgt**	**Dgen**	**ST**	**UGe**	**UGd**
Customer Unit Cost per month - Avoided Cost		$8.47	$8.56	$9.41	$6.34	$10.72	$26.49	$5.01	$2.36	$25.26	$192.71	$10.73	$29.19
Customer Unit Cost per month - Directly Related		$10.69	$10.89	$12.07	$7.82	$13.91	$37.79	$6.46	$2.86	$30.85	$244.33	$14.02	$40.26
Customer Unit Cost per month - Minimum System with PLCC Adjustment		$22.12	$29.67	$45.37	$30.58	$30.97	$54.46	$12.40	$32.77	$36.66	$372.12	$12.33	$39.65
Fixed Charge per approved 2006 EDR		$14.29	$17.76	$57.91	$28.64	$39.41	$50.19	$0.00	$0.00	$173.73	$83.85	$9.72	$11.07

USoA Account #	Accounts		1	2	3	4	5	6	7	8	12	13	14	15
		Total	**UR**	**R1**	**R2**	**Seasonal**	**GSe**	**GSd**	**St Lgt**	**Sen Lgt**	**Dgen**	**ST**	**UGe**	**UGd**
Information to be Used to Allocate PILs, ROD, ROE and A&G														
	General Plant - Gross Assets	$737,348,954	$42,285,241	$156,645,429	$255,375,173	$55,135,038	$75,974,676	$87,737,631	$6,477,816	$17,732,968	$42,396	$18,314,565	$6,554,838	$15,073,182
	General Plant - Accumulated Depreciation	($405,157,678)	($23,045,827)	($85,373,130)	($139,181,704)	($30,049,079)	($41,406,864)	($47,817,777)	($3,530,466)	($12,960,668)	($23,106)	($9,981,598)	($3,572,444)	($8,215,016)
	General Plant - Net Fixed Assets	$332,191,276	$19,239,415	$71,272,299	$116,193,469	$25,085,960	$34,567,813	$39,919,854	$2,947,350	$4,772,300	$19,290	$8,332,967	$2,982,394	$6,858,166
	General Plant - Depreciation	$53,851,648	$3,129,910	$11,594,733	$18,902,607	$4,081,039	$5,623,567	$6,494,249	$479,481	$586,414	$3,138	$1,355,625	$485,182	$1,115,701
	Total Net Fixed Assets Excluding General Plant	$3,753,292,682	$217,049,574	$809,492,211	$1,328,041,485	$285,905,452	$394,728,573	$464,293,609	$33,535,359	$7,208,513	$232,026	$99,019,286	$33,770,633	$80,015,958
	Total Administration and General Expense	$122,080,727	$8,175,774	$29,160,678	$47,082,017	$9,807,237	$12,800,842	$9,184,009	$799,545	$221,038	$6,691	$2,444,240	$1,128,977	$1,269,678
	Total O&M	$379,945,270	$25,680,258	$91,357,822	$147,379,654	$30,630,509	$39,828,568	$27,307,859	$2,423,859	$684,638	$20,673	$7,448,318	$3,519,246	$3,663,865
Scenario 1														
Accounts included in Avoided Costs														
Plus General Administration Allocation														
USoA Account #	**Accounts**													
	Distribution Plant													
1860	Meters	$172,889,855	$22,020,598	$51,248,721	$49,957,652	$21,269,622	$13,404,195	$5,337,076	$0	$0	$92,325	$6,773,545	$1,766,616	$1,019,505
	Accumulated Amortization													
	Accum. Amortization of Electric Utility Plant - Meters only	$23,778,079	$3,028,561	$7,048,396	$6,870,831	$2,925,277	$1,843,521	$734,025	$0	$0	$12,698	$931,587	$242,968	$140,216
	Meter Net Fixed Assets	$196,667,934	$25,049,159	$58,297,117	$56,828,483	$24,194,899	$15,247,715	$6,071,101	$0	$0	$105,023	$7,705,131	$2,009,584	$1,159,721
	Misc Revenue													
4082	Retail Services Revenues	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4084	Service Transaction Requests (STR) Revenues	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4090	Electric Services Incidental to Energy Sales	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4220	Other Electric Revenues	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4225	Late Payment Charges	($14,500,000)	($1,219,557)	($3,994,463)	($4,668,534)	($803,694)	($1,599,523)	($1,271,608)	($20,916)	($5,379)	($3,199)	($476,654)	($257,149)	($179,324)
	Sub-total	($14,500,000)	($1,219,557)	($3,994,463)	($4,668,534)	($803,694)	($1,599,523)	($1,271,608)	($20,916)	($5,379)	($3,199)	($476,654)	($257,149)	($179,324)
	Operation													
5065	Meter Expense	$8,157,050	$971,111	$2,312,720	$2,399,449	$1,035,743	$709,625	$123,597	$0	$0	$2,269	$482,781	$96,452	$23,302
5070	Customer Premises - Operation Labour	$15,338,600	$2,094,637	$4,865,439	$4,716,903	$2,005,698	$1,253,809	$90,669	$71,875	$46,602	$1,081	$8,699	$164,723	$18,465
5075	Customer Premises - Materials and Expenses	$2,325,800	$317,611	$737,749	$715,226	$304,125	$190,116	$13,748	$10,898	$7,066	$164	$1,319	$24,977	$2,800
	Sub-total	$25,821,450	$3,383,359	$7,915,908	$7,831,578	$3,345,566	$2,153,550	$228,015	$82,774	$53,668	$3,514	$492,799	$286,152	$44,567

		Total	UR	R1	R2	Seasonal	GSe	GSd	St Lgt	Sen Lgt	Dgen	ST	UGe	UGd
	Maintenance													
5175	Maintenance of Meters	$1,846,200	$235,146	$547,258	$533,472	$227,127	$143,136	$56,992	$0	$0	$986	$72,331	$18,865	$10,887
	Billing and Collection													
5310	Meter Reading Expense	$23,513,850	$2,329,176	$6,805,728	$10,709,244	$1,442,426	$1,630,202	$354,613	$0	$0	$0	$0	$185,839	$56,621
5315	Customer Billing	$35,828,600	$4,659,594	$10,892,068	$10,712,098	$1,538,998	$5,218,516	$1,424,898	$166,243	$10,779	$4,843	$169,058	$743,555	$287,951
5320	Collecting	$8,626,330	$1,121,875	$2,622,446	$2,579,115	$370,539	$1,256,444	$343,068	$40,026	$2,595	$1,166	$40,703	$179,023	$69,329
5325	Collecting- Cash Over and Short	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5330	Collection Charges	$869,820	$113,122	$264,429	$260,060	$37,363	$126,691	$34,593	$4,036	$262	$118	$4,104	$18,051	$6,991
	Sub-total	$68,838,600	$8,223,767	$20,584,671	$24,260,518	$3,389,326	$8,231,854	$2,157,171	$210,305	$13,636	$6,127	$213,865	$1,126,469	$420,892
	Total Operation, Maintenance and Billing	$114,163,350	$11,842,273	$29,047,838	$32,625,567	$6,962,019	$10,528,541	$2,442,177	$293,078	$67,304	$10,627	$778,995	$1,431,485	$476,346
	Amortization Expense - Meters	$14,899,710	$1,897,743	$4,416,633	$4,305,368	$1,833,024	$1,155,178	$459,951	$0	$0	$7,957	$583,747	$152,248	$87,861
	Allocated PILs	$2,413,609	$307,138	$715,196	$697,534	$296,909	$187,142	$74,623	$0	$0	$1,294	$94,867	$24,648	$14,258
	Allocated Debt Return	$7,154,110	$910,380	$2,119,893	$2,067,540	$880,059	$554,703	$221,187	$0	$0	$3,836	$281,192	$73,058	$42,262
	Allocated Equity Return	$7,293,820	$928,158	$2,161,292	$2,107,916	$897,246	$565,535	$225,507	$0	$0	$3,911	$286,683	$74,484	$43,088
	Total	**$113,767,498**	**$14,666,136**	**$34,466,389**	**$37,135,391**	**$10,065,562**	**$11,391,575**	**$2,151,837**	**$272,163**	**$61,924**	**$24,426**	**$1,548,830**	**$1,498,774**	**$484,492**

Scenario 2
Accounts included in Directly Related Customer Costs
Plus General Administration Allocation

USoA Account #	Accounts	Total	UR	R1	R2	Seasonal	GSe	GSd	St Lgt	Sen Lgt	Dgen	ST	UGe	UGd
	Distribution Plant													
1860	Meters	$172,889,855	$22,020,598	$51,248,721	$49,957,652	$21,269,622	$13,404,195	$5,337,076	$0	$0	$92,325	$6,773,545	$1,766,616	$1,019,505
	Accumulated Amortization													
	Accum. Amortization of Electric Utility Plant - Meters only	$23,778,079	$3,028,561	$7,048,396	$6,870,831	$2,925,277	$1,843,521	$734,025	$0	$0	$12,698	$931,587	$242,968	$140,216
	Meter Net Fixed Assets	$196,667,934	$25,049,159	$58,297,117	$56,828,483	$24,194,899	$15,247,715	$6,071,101	$0	$0	$105,023	$7,705,131	$2,009,584	$1,159,721
	Allocated General Plant Net Fixed Assets	$17,239,472	$2,220,374	$5,132,810	$4,972,057	$2,122,913	$1,335,298	$521,992	$0	$0	$8,731	$648,425	$177,473	$99,400
	Meter Net Fixed Assets Including General Plant	$213,907,406	$27,269,533	$63,429,927	$61,800,541	$26,317,812	$16,583,013	$6,593,092	$0	$0	$113,754	$8,353,557	$2,187,057	$1,259,120
	Misc Revenue													
4082	Retail Services Revenues	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4084	Service Transaction Requests (STR) Revenues	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4090	Electric Services Incidental to Energy Sales	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4220	Other Electric Revenues	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4225	Late Payment Charges	($14,500,000)	($1,219,557)	($3,994,463)	($4,668,534)	($803,694)	($1,599,523)	($1,271,608)	($20,916)	($5,379)	($3,199)	($476,654)	($257,149)	($179,324)
	Sub-total	($14,500,000)	($1,219,557)	($3,994,463)	($4,668,534)	($803,694)	($1,599,523)	($1,271,608)	($20,916)	($5,379)	($3,199)	($476,654)	($257,149)	($179,324)
	Operation													
5065	Meter Expense	$8,157,050	$971,111	$2,312,720	$2,399,449	$1,035,743	$709,625	$123,597	$0	$0	$2,269	$482,781	$96,452	$23,302
5070	Customer Premises - Operation Labour	$15,338,600	$2,094,637	$4,865,439	$4,716,903	$2,005,698	$1,253,809	$90,669	$71,875	$46,602	$1,081	$8,699	$164,723	$18,465
5075	Customer Premises - Materials and Expenses	$2,325,800	$317,611	$737,749	$715,226	$304,125	$190,116	$13,748	$10,898	$7,066	$164	$1,319	$24,977	$2,800
	Sub-total	$25,821,450	$3,383,359	$7,915,908	$7,831,578	$3,345,566	$2,153,550	$228,015	$82,774	$53,668	$3,514	$492,799	$286,152	$44,567
	Maintenance													
5175	Maintenance of Meters	$1,846,200	$235,146	$547,258	$533,472	$227,127	$143,136	$56,992	$0	$0	$986	$72,331	$18,865	$10,887
	Billing and Collection													
5310	Meter Reading Expense	$23,513,850	$2,329,176	$6,805,728	$10,709,244	$1,442,426	$1,630,202	$354,613	$0	$0	$0	$0	$185,839	$56,621
5315	Customer Billing	$35,828,600	$4,659,594	$10,892,068	$10,712,098	$1,538,998	$5,218,516	$1,424,898	$166,243	$10,779	$4,843	$169,058	$743,555	$287,951
5320	Collecting	$8,626,330	$1,121,875	$2,622,446	$2,579,115	$370,539	$1,256,444	$343,068	$40,026	$2,595	$1,166	$40,703	$179,023	$69,329
5325	Collecting- Cash Over and Short	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5330	Collection Charges	$869,820	$113,122	$264,429	$260,060	$37,363	$126,691	$34,593	$4,036	$262	$118	$4,104	$18,051	$6,991
	Sub-total	$68,838,600	$8,223,767	$20,584,671	$24,260,518	$3,389,326	$8,231,854	$2,157,171	$210,305	$13,636	$6,127	$213,865	$1,126,469	$420,892
	Total Operation, Maintenance and Billing	$114,163,350	$11,842,273	$29,047,838	$32,625,567	$6,962,019	$10,528,541	$2,442,177	$293,078	$67,304	$10,627	$778,995	$1,431,485	$476,346

	Total	UR	R1	R2	Seasonal	GSe	GSd	St Lgt	Sen Lgt	Dgen	ST	UGe	UGd
Amortization Expense - Meters	$14,899,710	$1,897,743	$4,416,633	$4,305,368	$1,833,024	$1,155,178	$459,951	$0	$0	$7,957	$583,747	$152,248	$87,861
Amortization Expense - General Plant assigned to Meters	$2,804,555	$361,215	$835,017	$808,865	$345,360	$217,229	$84,919	$0	$0	$1,420	$105,487	$28,872	$16,171
Admin and General	$30,900,686	$3,770,202	$9,271,835	$10,422,589	$2,229,090	$3,383,857	$821,338	$96,676	$21,729	$3,440	$255,635	$459,222	$165,073
Allocated PILs	$2,625,179	$334,363	$778,166	$758,562	$322,960	$203,531	$81,039	$0	$0	$1,402	$102,850	$26,824	$15,480
Allocated Debt Return	$7,781,218	$991,076	$2,306,541	$2,248,434	$957,277	$603,280	$240,205	$0	$0	$4,155	$304,856	$79,510	$45,885
Allocated Equity Return	$7,933,174	$1,010,431	$2,351,584	$2,292,343	$975,972	$615,061	$244,896	$0	$0	$4,236	$310,809	$81,062	$46,781
Total	**$148,950,771**	**$18,987,747**	**$45,013,150**	**$48,793,194**	**$12,822,008**	**$15,107,153**	**$3,102,917**	**$368,839**	**$83,654**	**$30,038**	**$1,965,725**	**$2,002,074**	**$674,273**

Scenario 3

Minimum System Customer Costs Adjusted for PLCC - High Limit Fixed Customer Charge

USoA Account #	**Accounts**	Total	UR	R1	R2	Seasonal	GSe	GSd	St Lgt	Sen Lgt	Dgen	ST	UGe	UGd
	Distribution Plant													
1565	Conservation and Demand Management Expenditures and Recoveries	$6,400,000	$432,572	$1,538,880	$2,482,541	$515,957	$670,894	$459,988	$40,829	$11,532	$348	$125,463	$59,280	$61,716
1830	Poles, Towers and Fixtures	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1830-3	Poles, Towers and Fixtures - Subtransmission Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1830-4	Poles, Towers and Fixtures - Primary	$600,199,619	$15,606,832	$125,842,105	$298,610,653	$94,434,843	$54,548,167	$4,057,348	$2,820,858	$1,828,965	$16,233	$671,023	$1,540,656	$221,937
1830-5	Poles, Towers and Fixtures - Secondary	$138,507,604	$19,062,363	$44,278,199	$42,926,438	$18,252,967	$11,410,362	$0	$654,104	$424,103	$0	$0	$1,499,068	$0
1835	Overhead Conductors and Devices	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1835-3	Overhead Conductors and Devices - Subtransmission Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1835-4	Overhead Conductors and Devices - Primary	$460,154,052	$11,965,264	$96,479,159	$228,935,336	$72,400,205	$41,820,353	$3,110,641	$2,162,662	$1,402,210	$12,445	$514,452	$1,181,172	$170,152
1835-5	Overhead Conductors and Devices - Secondary	$106,189,397	$14,614,511	$33,946,694	$32,910,341	$13,993,972	$8,747,963	$0	$501,481	$325,146	$0	$0	$1,149,288	$0
1840	Underground Conduit	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1840-3	Underground Conduit - Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1840-4	Underground Conduit - Primary	$2,628,689	$359,193	$834,336	$808,864	$343,941	$215,006	$15,548	$12,325	$7,991	$71	$0	$28,247	$3,167
1840-5	Underground Conduit - Secondary	$10,514,756	$1,447,113	$3,361,364	$3,258,746	$1,385,668	$866,214	$0	$49,656	$32,196	$0	$0	$113,801	$0
1845	Underground Conductors and Devices	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1845-3	Underground Conductors and Devices - Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1845-4	Underground Conductors and Devices - Primary	$74,466,515	$10,175,351	$23,635,380	$22,913,820	$9,743,301	$6,090,768	$440,454	$349,156	$226,383	$2,009	$0	$800,191	$89,702
1845-5	Underground Conductors and Devices - Secondary	$297,866,061	$40,994,363	$95,222,012	$92,314,996	$39,253,725	$24,538,433	$0	$1,406,677	$912,050	$0	$0	$3,223,804	$0
1850	Line Transformers	$794,754,988	$84,031,654	$236,378,793	$303,567,488	$91,845,247	$65,345,125	$4,977,253	$3,763,414	$2,440,092	$21,657	$2,384,265	$0	$0
1855	Services	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1860	Meters	$172,889,855	$22,020,598	$51,248,721	$49,957,652	$21,269,622	$13,404,195	$5,337,076	$0	$0	$92,325	$6,773,545	$1,766,616	$1,019,505
	Sub-total	$2,664,571,536	$220,709,813	$712,765,643	$1,078,686,874	$363,439,448	$227,657,479	$18,398,308	$11,761,163	$7,610,670	$145,088	$10,468,749	$11,362,123	$1,566,179
	Accumulated Amortization													
	Accum. Amortization of Electric Utility Plant -Line Transformers, Services and Meters	($988,730,784)	($77,948,759)	($260,547,963)	($406,682,193)	($135,689,375)	($85,408,497)	($6,168,932)	($4,778,828)	($3,062,172)	($9,542)	($3,521,796)	($4,324,223)	($588,505)
	Customer Related Net Fixed Assets	$1,675,840,753	$142,761,054	$452,217,680	$672,004,682	$227,750,073	$142,248,981	$12,229,376	$6,982,335	$4,548,498	$135,546	$6,946,953	$7,037,900	$977,674
	Allocated General Plant Net Fixed Assets	$149,683,698	$12,654,432	$39,815,817	$58,795,268	$19,983,282	$12,457,259	$1,051,479	$613,662	$3,011,273	$11,269	$584,621	$621,540	$83,796
	Customer Related NFA Including General Plant	$1,825,524,451	$155,415,486	$492,033,497	$730,799,950	$247,733,354	$154,706,241	$13,280,855	$7,595,997	$7,559,771	$146,814	$7,531,573	$7,659,440	$1,061,471
	Misc Revenue													
4082	Retail Services Revenues	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4084	Service Transaction Requests (STR) Revenues	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4090	Electric Services Incidental to Energy Sales	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4220	Other Electric Revenues	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4225	Late Payment Charges	($14,500,000)	($1,219,557)	($3,994,463)	($4,668,534)	($803,694)	($1,599,523)	($1,271,608)	($20,916)	($5,379)	($3,199)	($476,654)	($257,149)	($179,324)
4235	Miscellaneous Service Revenues	($27,800,000)	($3,615,456)	($8,451,334)	($8,311,693)	($1,194,134)	($4,049,132)	($1,105,601)	($128,991)	($8,363)	($3,758)	($131,175)	($576,936)	($223,426)
	Sub-total	($42,300,000)	($4,835,012)	($12,445,798)	($12,980,227)	($1,997,828)	($5,648,656)	($2,377,209)	($149,907)	($13,743)	($6,957)	($607,828)	($834,086)	($402,750)
	Operating and Maintenance													
5005	Operation Supervision and Engineering	$1,224,314	$97,315	$323,502	$502,058	$166,215	$105,386	$8,686	$5,779	$3,702	$28	$5,786	$4,961	$896
5010	Load Dispatching	$465,581	$37,007	$123,021	$190,922	$63,208	$40,076	$3,303	$2,197	$1,408	$11	$2,200	$1,887	$341

		Total	UR	R1	R2	Seasonal	GSe	GSd	St Lgt	Sen Lgt	Dgen	ST	UGe	UGd
5020	Overhead Distribution Lines and Feeders - Operation Labour	$3,304,917	$155,107	$761,105	$1,528,009	$504,156	$295,093	$18,152	$15,547	$10,080	$73	$3,002	$13,599	$993
5025	Overhead Distribution Lines & Feeders - Operation Supplies and Expenses	$541,221	$25,401	$124,640	$250,231	$82,562	$48,325	$2,973	$2,546	$1,651	$12	$492	$2,227	$163
5035	Overhead Distribution Transformers- Operation	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5040	Underground Distribution Lines and Feeders - Operation Labour	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5045	Underground Distribution Lines & Feeders - Operation Supplies & Expenses	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5055	Underground Distribution Transformers - Operation	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5065	Meter Expense	$8,157,050	$971,111	$2,312,720	$2,399,449	$1,035,743	$709,625	$123,597	$0	$0	$2,269	$482,781	$96,452	$23,302
5070	Customer Premises - Operation Labour	$15,338,600	$2,094,637	$4,865,439	$4,716,903	$2,005,698	$1,253,809	$90,669	$71,875	$46,602	$1,081	$8,699	$164,723	$18,465
5075	Customer Premises - Materials and Expenses	$2,325,800	$317,611	$737,749	$715,226	$304,125	$190,116	$13,748	$10,898	$7,066	$164	$1,319	$24,977	$2,800
5085	Miscellaneous Distribution Expense	$6,120,716	$486,507	$1,617,282	$2,509,938	$830,961	$526,858	$43,423	$28,889	$18,509	$141	$28,924	$24,803	$4,480
5090	Underground Distribution Lines and Feeders - Rental Paid	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5095	Overhead Distribution Lines and Feeders - Rental Paid	$88,864	$4,171	$20,465	$41,086	$13,556	$7,935	$488	$418	$271	$2	$81	$366	$27
5096	Other Rent	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5105	Maintenance Supervision and Engineering	$6,169,165	$490,358	$1,630,084	$2,529,806	$837,539	$531,029	$43,767	$29,118	$18,656	$142	$29,153	$24,999	$4,516
5120	Maintenance of Poles, Towers and Fixtures	$9,755,301	$457,838	$2,246,593	$4,510,308	$1,488,145	$871,042	$53,581	$45,890	$29,754	$214	$8,861	$40,142	$2,931
5125	Maintenance of Overhead Conductors and Devices	$28,077,547	$1,317,743	$6,466,108	$12,981,495	$4,283,155	$2,507,020	$154,216	$132,080	$85,637	$617	$25,505	$115,537	$8,436
5130	Maintenance of Overhead Services	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5135	Overhead Distribution Lines and Feeders - Right of Way	$66,392,940	$3,115,970	$15,289,937	$30,696,399	$10,128,065	$5,928,168	$364,663	$312,320	$202,499	$1,459	$60,310	$273,202	$19,947
5145	Maintenance of Underground Conduit	$145,516	$19,998	$46,452	$45,034	$19,149	$11,971	$172	$686	$445	$1	$0	$1,573	$35
5150	Maintenance of Underground Conductors and Devices	$619,240	$85,102	$197,676	$191,641	$81,489	$50,941	$733	$2,920	$1,893	$3	$0	$6,692	$149
5155	Maintenance of Underground Services	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5160	Maintenance of Line Transformers	$1,978,869	$209,231	$588,562	$755,856	$228,686	$162,704	$12,393	$9,371	$6,076	$54	$5,937	$0	$0
5175	Maintenance of Meters	$1,846,200	$235,146	$547,258	$533,472	$227,127	$143,136	$56,992	$0	$0	$986	$72,331	$18,865	$10,887
	Sub-total	$152,551,841	$10,120,253	$37,898,594	$65,097,831	$22,299,580	$13,383,234	$991,556	$670,534	$434,249	$7,256	$735,380	$815,005	$98,367
	Billing and Collection													
5305	Supervision	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5310	Meter Reading Expense	$23,513,850	$2,329,176	$6,805,728	$10,709,244	$1,442,426	$1,630,202	$354,613	$0	$0	$0	$0	$185,839	$56,621
5315	Customer Billing	$35,828,600	$4,659,594	$10,892,068	$10,712,098	$1,538,998	$5,218,516	$1,424,898	$166,243	$10,779	$4,843	$169,058	$743,555	$287,951
5320	Collecting	$8,626,330	$1,121,875	$2,622,446	$2,579,115	$370,539	$1,256,444	$343,068	$40,026	$2,595	$1,166	$40,703	$179,023	$69,329
5325	Collecting- Cash Over and Short	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5330	Collection Charges	$869,820	$113,122	$264,429	$260,060	$37,363	$126,691	$34,593	$4,036	$262	$118	$4,104	$18,051	$6,991
5335	Bad Debt Expense	$17,396,400	$1,993,660	$5,507,458	$5,594,679	$419,343	$1,327,286	$1,473,243	$110,533	$20,546	$1,014	$473,480	$157,608	$317,551
5340	Miscellaneous Customer Accounts Expenses	$4,763,820	$619,546	$1,448,224	$1,424,295	$204,627	$693,861	$189,456	$22,104	$1,433	$644	$22,478	$98,864	$38,286
	Sub-total	$90,998,820	$10,836,973	$27,540,354	$31,279,492	$4,013,296	$10,253,000	$3,819,870	$342,941	$35,615	$7,785	$709,823	$1,382,941	$776,730
	Sub Total Operating, Maintenance and Biling	$243,550,661	$20,957,227	$65,438,948	$96,377,323	$26,312,876	$23,636,235	$4,811,426	$1,013,476	$469,864	$15,041	$1,445,203	$2,197,946	$875,097
	Amortization Expense - Customer Related	$77,083,856	$7,034,157	$21,013,105	$29,397,310	$10,173,107	$6,502,669	$956,761	$294,312	$186,911	$9,395	$943,276	$425,770	$147,084
	Amortization Expense - General Plant assigned to Meters	$24,231,012	$2,058,651	$6,477,324	$9,564,943	$3,250,924	$2,026,574	$171,057	$99,832	$370,021	$1,833	$95,107	$101,113	$13,632
	Admin and General	$77,961,583	$6,672,112	$20,887,583	$30,788,773	$8,424,823	$7,596,650	$1,618,149	$334,310	$151,697	$4,868	$474,258	$705,103	$303,257
	Allocated PILs	$22,369,591	$1,905,614	$6,036,328	$8,970,106	$3,040,072	$1,898,779	$163,241	$93,202	$60,715	$1,809	$92,730	$93,944	$13,050
	Allocated Debt Return	$66,305,075	$5,648,378	$17,892,110	$26,588,040	$9,010,991	$5,628,118	$483,858	$276,258	$179,963	$5,363	$274,858	$278,456	$38,682
	Allocated Equity Return	$67,599,921	$5,758,683	$18,241,518	$27,107,268	$9,186,963	$5,738,027	$493,308	$281,653	$183,477	$5,468	$280,226	$283,894	$39,437
	PLCC Adjsutment for Line Transformer	$12,008,115	$0	$0	$24,135	$0	$7,594,407	$1,573,607	$1,231,761	$0	$0	$0	$1,234,442	$349,763
	PLCC Adjsutment for Primary Costs	$32,716,542	$935,624	$6,734,881	$14,369,354	$6,980,351	$3,088,917	$240,716	$152,366	$126,355	$950	$87	$73,061	$13,880
	PLCC Adjsutment for Secondary Costs	$24,160,605	$3,047,972	$6,977,007	$6,813,417	$5,214,657	$1,727,918	$0	$93,534	$85,177	$0	$0	$200,923	$0
	Total	$467,916,437	**$41,216,215**	**$129,829,230**	**$194,606,630**	**$55,206,920**	**$34,967,155**	**$4,506,266**	**$765,475**	**$1,377,373**	**$35,870**	**$2,997,743**	**$1,743,715**	**$663,846**

Primary Conductors and Poles Cost Pool Demand Unit Cost for PLCC Adjustment to Customer Related Cost

Hydro One Distribution: 12 Rate Classes

ALLOCATION BY RATE CLASSIFICATION

		1	2	3	4	5	6	7	8	12	13	14	15
Description	**Total**	**UR**	**R1**	**R2**	**Seasonal**	**GSe**	**GSd**	**St Lgt**	**Sen Lgt**	**Dgen**	**ST**	**UGe**	**UGd**
Depreciation on Acct 1830-4 Primary Poles, Towers & Fixtures	$14,217,184	$190,813	$2,322,373	$6,142,484	$407,959	$1,870,497	$2,830,067	$170,971	$27,384	$167	$15,895	$52,010	$186,565
Depreciation on Acct 1835-4 Primary Overhead Conductors	$9,042,392	$121,361	$1,477,072	$3,906,733	$259,470	$1,189,671	$1,799,975	$108,741	$17,417	$106	$10,109	$33,079	$118,659
Depreciation on Acct 1840-4 Primary Underground Conduit	$40,774	$2,953	$10,285	$12,265	$724	$4,605	$6,822	$485	$78	$0	$0	$806	$1,752
Depreciation on Acct 1845-4 Primary Underground Conductors	$1,881,528	$136,272	$474,627	$565,959	$33,387	$212,485	$314,791	$22,361	$3,581	$22	$0	$37,212	$80,831
Depreciation on General Plant Assigned to Primary C&P	$9,196,847	$151,135	$1,541,764	$3,887,103	$257,894	$1,194,415	$1,772,686	$110,273	$100,491	$102	$9,338	$41,059	$130,589
Primary C&P Operations and Maintenance	$45,785,644	$558,386	$6,964,941	$19,578,198	$1,358,526	$5,816,961	$10,023,242	$508,320	$81,963	$618	$55,967	$149,324	$689,197
Allocation of General Expenses	$4,058,855	$68,338	$683,900	$1,722,778	$113,895	$529,629	$800,494	$48,777	$7,812	$48	$4,275	$18,635	$60,272
Admin and General Assigned to Primary C&P	$14,830,323	$177,772	$2,223,153	$6,254,466	$434,971	$1,869,562	$3,370,954	$167,677	$26,462	$200	$18,366	$47,903	$238,835
PILs on Primary C&P	$8,565,820	$139,900	$1,436,796	$3,645,367	$241,167	$1,119,096	$1,691,690	$102,950	$16,489	$101	$9,104	$38,148	$125,014
Debt Return on Primary C&P	$25,389,707	$414,672	$4,258,765	$10,805,130	$714,836	$3,317,080	$5,014,291	$305,151	$48,875	$298	$26,985	$113,072	$370,551
Equity Return on Primary C&P	$25,885,532	$422,770	$4,341,933	$11,016,139	$728,796	$3,381,858	$5,112,213	$311,110	$49,829	$304	$27,512	$115,280	$377,787
Total	**$124,515,881**	**$2,384,372**	**$25,735,610**	**$67,536,622**	**$4,551,626**	**$20,505,858**	**$32,737,224**	**$1,856,814**	**$380,381**	**$1,966**	**$177,552**	**$646,529**	**$2,380,052**
Primary NCP	12,754,912	898,675	3,130,023	3,732,329	220,179	1,401,277	2,075,952	147,462	23,618	144	346,791	245,402	533,060
PLCC Amount	2,580,893	352,639	819,111	794,105	337,665	211,083	15,264	12,100	7,846	70	170	27,732	3,109
Adjustment to Customer Related Cost for PLCC	**$32,716,542**	**$935,624**	**$6,734,881**	**$14,369,354**	**$6,980,351**	**$3,088,917**	**$240,716**	**$152,366**	**$126,355**	**$950**	**$87**	**$73,061**	**$13,880**
General Plant - Gross Assets	$737,348,954	$42,285,241	$156,645,429	$255,375,173	$55,135,038	$75,974,676	$87,737,631	$6,477,816	$17,732,968	$42,396	$18,314,565	$6,554,838	$15,073,182
General Plant - Accumulated Depreciation	($405,157,678)	($23,045,827)	($85,373,130)	($139,181,704)	($30,049,079)	($41,406,864)	($47,817,777)	($3,530,466)	($12,960,668)	($23,106)	($9,981,598)	($3,572,444)	($8,215,016)
General Plant - Net Fixed Assets	$332,191,276	$19,239,415	$71,272,299	$116,193,469	$25,085,960	$34,567,813	$39,919,854	$2,947,350	$4,772,300	$19,290	$8,332,967	$2,982,394	$6,858,166
General Plant - Depreciation	$53,851,648	$3,129,910	$11,594,733	$18,902,607	$4,081,039	$5,623,567	$6,494,249	$479,481	$586,414	$3,138	$1,355,625	$485,182	$1,115,701
Total Net Fixed Assets Excluding General Plant	$3,753,292,682	$217,049,574	$809,492,211	$1,328,041,485	$285,905,452	$394,728,573	$464,293,609	$33,535,359	$7,208,513	$232,026	$99,019,286	$33,770,633	$80,015,958
Total Administration and General Expense	$122,080,727	$8,175,774	$29,160,678	$47,082,017	$9,807,237	$12,800,842	$9,184,009	$799,545	$221,038	$6,691	$2,444,240	$1,128,977	$1,269,678
Total O&M	$379,945,270	$25,680,258	$91,357,822	$147,379,654	$30,630,509	$39,828,568	$27,307,859	$2,423,859	$684,638	$20,673	$7,448,318	$3,519,246	$3,663,865
Primary Conductors and Poles Gross Assets													
Acct 1830-4 Primary Poles, Towers & Fixtures	$655,448,120	$8,796,968	$107,067,273	$283,184,021	$18,807,947	$86,234,634	$130,473,253	$7,882,189	$1,262,458	$7,701	$732,791	$2,397,775	$8,601,110
Acct 1835-4 Primary Overhead Conductors	$379,543,123	$5,093,963	$61,998,267	$163,980,252	$10,890,910	$49,934,940	$75,551,710	$4,564,252	$731,038	$4,460	$424,329	$1,388,453	$4,980,550
Acct 1840-4 Primary Underground Conduit	$2,168,189	$157,034	$546,939	$652,185	$38,474	$244,859	$362,751	$25,767	$4,127	$25	$0	$42,881	$93,147
Acct 1845-4 Primary Underground Conductors	$61,421,286	$4,448,519	$15,493,886	$18,475,356	$1,089,905	$6,936,446	$10,276,142	$729,951	$116,913	$713	$0	$1,214,762	$2,638,692
Subtotal	$1,098,580,718	$18,496,485	$185,106,365	$466,291,814	$30,827,236	$143,350,879	$216,663,856	$13,202,160	$2,114,536	$12,899	$1,157,120	$5,043,871	$16,313,498
Primary Conductors and Poles Accumulated Depreciation													
Acct 1830-4 Primary Poles, Towers & Fixtures	($268,383,160)	($3,602,052)	($43,840,317)	($115,953,987)	($7,701,199)	($35,310,077)	($53,424,250)	($3,227,482)	($516,933)	($3,153)	($300,052)	($981,805)	($3,521,855)
Acct 1835-4 Primary Overhead Conductors	($156,549,903)	($2,101,104)	($25,572,384)	($67,636,827)	($4,492,167)	($20,596,632)	($31,162,764)	($1,882,614)	($301,531)	($1,839)	($175,023)	($572,694)	($2,054,324)
Acct 1840-4 Primary Underground Conduit	($1,012,161)	($73,307)	($255,324)	($304,455)	($17,961)	($114,306)	($169,341)	($12,029)	($1,927)	($12)	$0	($20,018)	($43,483)
Acct 1845-4 Primary Underground Conductors	($30,918,323)	($2,239,301)	($7,799,331)	($9,300,147)	($548,638)	($3,491,677)	($5,172,817)	($367,444)	($58,852)	($359)	$0	($611,489)	($1,328,268)
Subtotal	($456,863,547)	($8,015,764)	($77,467,356)	($193,195,416)	($12,759,964)	($59,512,691)	($89,929,172)	($5,489,568)	($879,242)	($5,364)	($475,075)	($2,186,006)	($6,947,930)
Primary Conductor & Pools - Net Fixed Assets	$641,717,171	$10,480,721	$107,639,008	$273,096,398	$18,067,272	$83,838,187	$126,734,684	$7,712,591	$1,235,294	$7,536	$682,045	$2,857,865	$9,365,568
General Plant Assigned to Primary C&P - NFA	$56,732,694	$929,018	$9,477,151	$23,893,845	$1,585,261	$7,342,014	$10,896,618	$677,843	$817,810	$626	$57,397	$252,387	$802,723
Primary C&P Net Fixed Assets Including General Plant	$698,449,865	$11,409,739	$117,116,159	$296,990,243	$19,652,534	$91,180,201	$137,631,302	$8,390,434	$2,053,104	$8,162	$739,443	$3,110,253	$10,168,291
Acct 1830-3 Bulk Poles, Towers & Fixtures	$386,353,150	$5,386,505	$56,940,804	$152,648,853	$21,503,857	$37,661,735	$55,547,736	$1,346,281	$265,472	$48,866	$50,225,910	$1,127,010	$3,650,121
Acct 1835-3 Bulk Overhead Conductors	$258,368,362	$3,602,151	$38,078,381	$102,081,823	$14,380,409	$25,185,768	$37,146,786	$900,307	$177,531	$32,679	$33,587,887	$753,673	$2,440,969
Acct 1840-3 Bulk Underground Conduit	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Acct 1845-3 Bulk Underground Conductors	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Subtotal	$644,721,512	$8,988,656	$95,019,185	$254,730,677	$35,884,267	$62,847,503	$92,694,522	$2,246,587	$443,002	$81,545	$83,813,797	$1,880,683	$6,091,090
Acct 1830-5 Secondary Poles, Towers & Fixtures	$151,257,258	$13,809,425	$48,314,814	$57,709,087	$3,249,753	$21,712,775	$0	$2,290,303	$363,687	$0	$0	$3,807,414	$0
Acct 1835-5 Secondary Overhead Conductors	$87,586,875	$7,996,471	$27,977,127	$33,416,966	$1,881,799	$12,572,977	$0	$1,326,221	$210,596	$0	$0	$2,204,717	$0
Acct 1840-5 Secondary Underground Conduit	$8,672,755	$791,802	$2,770,264	$3,308,911	$186,334	$1,244,962	$0	$131,321	$20,853	$0	$0	$218,309	$0

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Exhibit G2-1-1
Attachment A
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Primary Conductors and Poles Cost Pool Demand Unit Cost for PLCC Adjustment to Customer Related Cost

Hydro One Distribution: 12 Rate Classes

ALLOCATION BY RATE CLASSIFICATION

		1	2	3	4	5	6	7	8	12	13	14	15
Description	**Total**	**UR**	**R1**	**R2**	**Seasonal**	**GSe**	**GSd**	**St Lgt**	**Sen Lgt**	**Dgen**	**ST**	**UGe**	**UGd**
Acct 1845-5 Secondary Underground Conductors	$245,685,145	$22,430,464	$78,477,108	$93,736,100	$5,278,530	$35,267,770	$0	$3,720,109	$590,732	$0	$0	$6,184,332	$0
Subtotal	$493,202,033	$45,028,162	$157,539,314	$188,171,064	$10,596,415	$70,798,485	$0	$7,467,953	$1,185,869	$0	$0	$12,414,772	$0
Operations and Maintenance													
Acct 5020 Overhead Distribution Lines & Feeders - Labour	$2,725,953	$63,491	$483,619	$1,126,752	$100,474	$331,485	$424,431	$26,015	$4,278	$133	$120,730	$16,594	$27,952
Acct 5025 Overhead Distribution Lines & Feeders - Other	$446,409	$10,397	$79,199	$184,520	$16,454	$54,285	$69,506	$4,260	$701	$22	$19,771	$2,717	$4,577
Acct 5040 Underground Distribution Lines & Feeders - Labour	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Acct 5045 Underground Distribution Lines & Feeders - Other	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Acct 5090 Underground Distribution Lines & Feeders - Rental Paid	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Acct 5095 Overhead Distribution Lines & Feeders - Rental Paid	$73,296	$1,707	$13,004	$30,296	$2,702	$8,913	$11,412	$699	$115	$4	$3,246	$446	$752
Acct 5120 Maintenance of Poles, Towers & Fixtures	$10,653,279	$249,959	$1,895,913	$4,407,026	$388,978	$1,300,200	$1,661,053	$102,856	$16,891	$505	$455,030	$65,472	$109,396
Acct 5125 Maintenance of Overhead Conductors & Devices	$23,158,853	$532,849	$4,087,643	$9,559,761	$866,763	$2,799,297	$3,597,483	$216,771	$35,725	$1,185	$1,085,714	$138,757	$236,905
Acct 5135 Overhead Distribution Lines & Feeders - Right of Way	$54,762,060	$1,275,474	$9,715,494	$22,635,484	$2,018,434	$6,659,247	$8,526,458	$522,616	$85,938	$2,675	$2,425,355	$333,359	$561,526
Acct 5145 Maintenance of Underground Conduit	$120,024	$10,505	$36,726	$43,855	$2,489	$16,494	$4,016	$1,739	$277	$0	$0	$2,892	$1,031
Acct 5150 Maintenance of Underground Conductors & Devices	$510,760	$44,703	$156,287	$186,623	$10,592	$70,191	$17,091	$7,401	$1,177	$1	$0	$12,306	$4,389
Total	$92,450,634	$2,189,086	$16,467,884	$38,174,317	$3,406,885	$11,240,112	$14,311,450	$882,357	$145,101	$4,525	$4,109,846	$572,543	$946,527
General Expenses													
Acct 5005 - Operation Supervision and Engineering	$1,009,836	$32,432	$171,741	$330,305	$27,727	$126,462	$219,736	$13,698	$1,405	$36	$37,543	$12,440	$36,310
Acct 5010 - Load Dispatching	$384,019	$12,333	$65,310	$125,608	$10,544	$48,091	$83,561	$5,209	$534	$14	$14,277	$4,731	$13,808
Acct 5085 - Miscellaneous Distribution Expense	$5,048,474	$162,137	$858,586	$1,651,292	$138,617	$632,223	$1,098,529	$68,481	$7,024	$178	$187,690	$62,193	$181,523
Acct 5105 - Maintenance Supervision and Engineering	$5,088,435	$163,420	$865,382	$1,664,363	$139,714	$637,228	$1,107,224	$69,023	$7,080	$180	$189,175	$62,685	$182,960
Total	$11,530,764	$370,322	$1,961,019	$3,771,568	$316,603	$1,444,005	$2,509,050	$156,412	$16,044	$407	$428,685	$142,050	$414,601
Primary Conductors and Poles Gross Assets	$1,098,580,718	$18,496,485	$185,106,365	$466,291,814	$30,827,236	$143,350,879	$216,663,856	$13,202,160	$2,114,536	$12,899	$1,157,120	$5,043,871	$16,313,498
Acct 1815 - 1855	$3,120,947,897	$100,232,259	$530,774,596	$1,020,822,743	$85,692,591	$390,838,196	$679,106,396	$42,334,910	$4,342,495	$110,145	$116,029,025	$38,447,545	$112,216,995

Secondary Conductors and Poles Cost Pool Demand Unit Cost for PLCC Adjustment to Customer Related Cost

Hydro One Distribution: 12 Rate Classes

ALLOCATION BY RATE CLASSIFICATION

		1	2	3	4	5	6	7	8	12	13	14	15
Description	**Total**	**UR**	**R1**	**R2**	**Seasonal**	**GSe**	**GSd**	**St Lgt**	**Sen Lgt**	**Dgen**	**ST**	**UGe**	**UGd**
Depreciation on Acct 1830-5 Secondary Poles, Towers & Fixtures	$3,280,889	$299,537	$1,047,986	$1,251,755	$70,490	$470,967	$0	$49,678	$7,889	$0	$0	$82,586	$0
Depreciation on Acct 1835-5 Secondary Overhead Conductors	$4,616,606	$538,693	$1,475,299	$1,580,209	$378,231	$507,959	$0	$43,544	$12,764	$0	$0	$79,907	$0
Depreciation on Acct 1840-5 Secondary Underground Conduit	$360,828	$42,104	$115,308	$123,507	$29,562	$39,701	$0	$3,403	$998	$0	$0	$6,245	$0
Depreciation on Acct 1845-5 Secondary Underground Conductors	$16,650,691	$1,942,903	$5,320,953	$5,699,333	$1,364,164	$1,832,053	$0	$157,050	$46,035	$0	$0	$288,201	$0
Depreciation on General Plant Assigned to Secondary C&P	$3,863,595	$352,066	$1,223,500	$1,452,211	$82,011	$546,895	$0	$57,894	$52,307	$0	$0	$96,710	$0
Secondary C&P Operations and Maintenance	$19,228,681	$1,359,344	$5,927,684	$7,900,740	$466,974	$2,872,895	$0	$287,537	$45,966	$0	$0	$367,541	$0
Allocation of General Expenses	$1,822,202	$166,363	$582,050	$695,223	$39,150	$261,575	$0	$27,591	$4,381	$0	$0	$45,868	$0
Admin and General Assigned to Primary C&P	$6,149,272	$432,772	$1,892,069	$2,523,976	$149,515	$923,344	$0	$94,848	$14,840	$0	$0	$117,907	$0
PILs on Secondary C&P	$3,569,579	$325,894	$1,140,200	$1,361,899	$76,692	$512,408	$0	$54,050	$8,583	$0	$0	$89,853	$0
Debt Return on Secondary C&P	$10,580,487	$965,973	$3,379,635	$4,036,767	$227,321	$1,518,815	$0	$160,207	$25,440	$0	$0	$266,330	$0
Equity Return on Secondary C&P	$10,787,110	$984,837	$3,445,634	$4,115,599	$231,760	$1,548,475	$0	$163,336	$25,937	$0	$0	$271,531	$0
Total	**$52,137,330**	**$7,410,485**	**$25,550,317**	**$30,741,220**	**$3,115,870**	**$11,035,087**	**$0**	**$1,099,140**	**$245,140**	**$0**	**$0**	**$1,712,679**	**$0**
Secondary NCP	9,390,873	857,364	2,999,647	3,582,894	201,762	1,348,047	0	142,194	22,580	0	0	236,385	0
PLCC Amount	2,562,280	352,639	819,111	794,105	337,665	211,083	0	12,100	7,846	0	0	27,732	0
Adjustment to Customer Related Cost for PLCC	**$24,160,605**	**$3,047,972**	**$6,977,007**	**$6,813,417**	**$5,214,657**	**$1,727,918**	**$0**	**$93,534**	**$85,177**	**$0**	**$0**	**$200,923**	**$0**
General Plant - Gross Assets	$737,348,954	$42,285,241	$156,645,429	$255,375,173	$55,135,038	$75,974,676	$87,737,631	$6,477,816	$17,732,968	$42,396	$18,314,565	$6,554,838	$15,073,182
General Plant - Accumulated Depreciation	($405,157,678)	($23,045,827)	($85,373,130)	($139,181,704)	($30,049,079)	($41,406,864)	($47,817,777)	($3,530,466)	($12,960,668)	($23,106)	($9,981,598)	($3,572,444)	($8,215,016)
General Plant - Net Fixed Assets	$332,191,276	$19,239,415	$71,272,299	$116,193,469	$25,085,960	$34,567,813	$39,919,854	$2,947,350	$4,772,300	$19,290	$8,332,967	$2,982,394	$6,858,166
General Plant - Depreciation	$53,851,648	$3,129,910	$11,594,733	$18,902,607	$4,081,039	$5,623,567	$6,494,249	$479,481	$586,414	$3,138	$1,355,625	$485,182	$1,115,701
Total Net Fixed Assets Excluding General Plant	$3,753,292,682	$217,049,574	$809,492,211	$1,328,041,485	$285,905,452	$394,728,573	$464,293,609	$33,535,359	$7,208,513	$232,026	$99,019,286	$33,770,633	$80,015,958
Total Administration and General Expense	$122,080,727	$8,175,774	$29,160,678	$47,082,017	$9,807,237	$12,800,842	$9,184,009	$799,545	$221,038	$6,691	$2,444,240	$1,128,977	$1,269,678
Total O&M	$379,945,270	$25,680,258	$91,357,822	$147,379,654	$30,630,509	$39,828,568	$27,307,859	$2,423,859	$684,638	$20,673	$7,448,318	$3,519,246	$3,663,865
Secondary Conductors and Poles Gross Plant													
Acct 1830-5 Secondary Poles, Towers & Fixtures	$151,257,258	$13,809,425	$48,314,814	$57,709,087	$3,249,753	$21,712,775	$0	$2,290,303	$363,687	$0	$0	$3,807,414	$0
Acct 1835-5 Secondary Overhead Conductors	$87,586,875	$7,996,471	$27,977,127	$33,416,966	$1,881,799	$12,572,977	$0	$1,326,221	$210,596	$0	$0	$2,204,717	$0
Acct 1840-5 Secondary Underground Conduit	$8,672,755	$791,802	$2,770,264	$3,308,911	$186,334	$1,244,962	$0	$131,321	$20,853	$0	$0	$218,309	$0
Acct 1845-5 Secondary Underground Conductors	$245,685,145	$22,430,464	$78,477,108	$93,736,100	$5,278,530	$35,267,770	$0	$3,720,109	$590,732	$0	$0	$6,184,332	$0
Subtotal	$493,202,033	$45,028,162	$157,539,314	$188,171,064	$10,596,415	$70,798,485	$0	$7,467,953	$1,185,869	$0	$0	$12,414,772	$0
Secondary Conductors and Poles Accumulated Depreciation													
Acct 1830-5 Secondary Poles, Towers & Fixtures	($61,934,575)	($5,654,478)	($19,783,233)	($23,629,860)	($1,330,661)	($8,890,625)	$0	($937,799)	($148,917)	$0	$0	($1,559,003)	$0
Acct 1835-5 Secondary Overhead Conductors	($36,126,901)	($3,298,299)	($11,539,707)	($13,783,474)	($776,184)	($5,185,968)	$0	($547,025)	($86,865)	$0	$0	($909,378)	$0
Acct 1840-5 Secondary Underground Conduit	($4,048,645)	($369,632)	($1,293,224)	($1,544,677)	($86,985)	($581,178)	$0	($61,304)	($9,735)	$0	$0	($101,912)	$0
Acct 1845-5 Secondary Underground Conductors	($123,673,291)	($11,291,075)	($39,503,903)	($47,184,993)	($2,657,113)	($17,753,134)	$0	($1,872,633)	($297,364)	$0	$0	($3,113,077)	$0
Subtotal	($225,783,412)	($20,613,484)	($72,120,067)	($86,143,004)	($4,850,943)	($32,410,903)	$0	($3,418,761)	($542,880)	$0	$0	($5,683,370)	$0
Secondary Conductor & Pools - Net Fixed Assets	$267,418,621	$24,414,678	$85,419,246	$102,028,060	$5,745,472	$38,387,581	$0	$4,049,192	$642,989	$0	$0	$6,731,402	$0
General Plant Assigned to Secondary C&P - NFA	$23,853,492	$2,164,133	$7,520,796	$8,926,675	$504,120	$3,361,740	$0	$355,875	$425,682	$0	$0	$594,472	$0
Secondary C&P Net Fixed Assets Including General Plant	$291,272,113	$26,578,811	$92,940,043	$110,954,734	$6,249,593	$41,749,321	$0	$4,405,067	$1,068,671	$0	$0	$7,325,874	$0
Acct 1830-3 Bulk Poles, Towers & Fixtures	$386,353,150	$5,386,505	$56,940,804	$152,648,853	$21,503,857	$37,661,735	$55,547,736	$1,346,281	$265,472	$48,866	$50,225,910	$1,127,010	$3,650,121
Acct 1835-3 Bulk Overhead Conductors	$258,368,362	$3,602,151	$38,078,381	$102,081,823	$14,380,409	$25,185,768	$37,146,786	$900,307	$177,531	$32,679	$33,587,887	$753,673	$2,440,969
Acct 1840-3 Bulk Underground Conduit	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Acct 1845-3 Bulk Underground Conductors	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Subtotal	$644,721,512	$8,988,656	$95,019,185	$254,730,677	$35,884,267	$62,847,503	$92,694,522	$2,246,587	$443,002	$81,545	$83,813,797	$1,880,683	$6,091,090
Acct 1830-4 Primary Poles, Towers & Fixtures	$655,448,120	$8,796,968	$107,067,273	$283,184,021	$18,807,947	$86,234,634	$130,473,253	$7,882,189	$1,262,458	$7,701	$732,791	$2,397,775	$8,601,110
Acct 1835-4 Primary Overhead Conductors	$379,543,123	$5,093,963	$61,998,267	$163,980,252	$10,890,910	$49,934,940	$75,551,710	$4,564,252	$731,038	$4,460	$424,329	$1,388,453	$4,980,550
Acct 1840-4 Primary Underground Conduit	$2,168,189	$157,034	$546,939	$652,185	$38,474	$244,859	$362,751	$25,767	$4,127	$25	$0	$42,881	$93,147
Acct 1845-4 Primary Underground Conductors	$61,421,286	$4,448,519	$15,493,886	$18,475,356	$1,089,905	$6,936,446	$10,276,142	$729,951	$116,913	$713	$0	$1,214,762	$2,638,692
Subtotal	$1,098,580,718	$18,496,485	$185,106,365	$466,291,814	$30,827,236	$143,350,879	$216,663,856	$13,202,160	$2,114,536	$12,899	$1,157,120	$5,043,871	$16,313,498

Secondary Conductors and Poles Cost Pool Demand Unit Cost for PLCC Adjustment to Customer Related Cost

Hydro One Distribution: 12 Rate Classes

ALLOCATION BY RATE CLASSIFICATION		1	2	3	4	5	6	7	8	12	13	14	15
Description	**Total**	**UR**	**R1**	**R2**	**Seasonal**	**GSe**	**GSd**	**St Lgt**	**Sen Lgt**	**Dgen**	**ST**	**UGe**	**UGd**
Operations and Maintenance													
Acct 5020 Overhead Distribution Lines & Feeders - Labour	$2,725,953	$63,491	$483,619	$1,126,752	$100,474	$331,485	$424,431	$26,015	$4,278	$133	$120,730	$16,594	$27,952
Acct 5025 Overhead Distribution Lines & Feeders - Other	$446,409	$10,397	$79,199	$184,520	$16,454	$54,285	$69,506	$4,260	$701	$22	$19,771	$2,717	$4,577
Acct 5040 Underground Distribution Lines & Feeders - Labour	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Acct 5045 Underground Distribution Lines & Feeders - Other	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Acct 5090 Underground Distribution Lines & Feeders - Rental Paid	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Acct 5095 Overhead Distribution Lines & Feeders - Rental Paid	$73,296	$1,707	$13,004	$30,296	$2,702	$8,913	$11,412	$699	$115	$4	$3,246	$446	$752
Acct 5120 Maintenance of Poles, Towers & Fixtures	$10,653,279	$249,959	$1,895,913	$4,407,026	$388,978	$1,300,200	$1,661,053	$102,856	$16,891	$505	$455,030	$65,472	$109,396
Acct 5125 Maintenance of Overhead Conductors & Devices	$23,158,853	$532,849	$4,087,643	$9,559,761	$866,763	$2,799,297	$3,597,483	$216,771	$35,725	$1,185	$1,085,714	$138,757	$236,905
Acct 5135 Overhead Distribution Lines & Feeders - Right of Way	$54,762,060	$1,275,474	$9,715,494	$22,635,484	$2,018,434	$6,659,247	$8,526,458	$522,616	$85,938	$2,675	$2,425,355	$333,359	$561,526
Acct 5145 Maintenance of Underground Conduit	$120,024	$10,505	$36,726	$43,855	$2,489	$16,494	$4,016	$1,739	$277	$0	$0	$2,892	$1,031
Acct 5150 Maintenance of Underground Conductors & Devices	$510,760	$44,703	$156,287	$186,623	$10,592	$70,191	$17,091	$7,401	$1,177	$1	$0	$12,306	$4,389
Total	$92,450,634	$2,189,086	$16,467,884	$38,174,317	$3,406,885	$11,240,112	$14,311,450	$882,357	$145,101	$4,525	$4,109,846	$572,543	$946,527
General Expenses													
Acct 5005 - Operation Supervision and Engineering	$1,009,836	$32,432	$171,741	$330,305	$27,727	$126,462	$219,736	$13,698	$1,405	$36	$37,543	$12,440	$36,310
Acct 5010 - Load Dispatching	$384,019	$12,333	$65,310	$125,608	$10,544	$48,091	$83,561	$5,209	$534	$14	$14,277	$4,731	$13,808
Acct 5085 - Miscellaneous Distribution Expense	$5,048,474	$162,137	$858,586	$1,651,292	$138,617	$632,223	$1,098,529	$68,481	$7,024	$178	$187,690	$62,193	$181,523
Acct 5105 - Maintenance Supervision and Engineering	$5,088,435	$163,420	$865,382	$1,664,363	$139,714	$637,228	$1,107,224	$69,023	$7,080	$180	$189,175	$62,685	$182,960
Total	$11,530,764	$370,322	$1,961,019	$3,771,568	$316,603	$1,444,005	$2,509,050	$156,412	$16,044	$407	$428,685	$142,050	$414,601
Secondary Conductors and Poles Gross Assets	$493,202,033	$45,028,162	$157,539,314	$188,171,064	$10,596,415	$70,798,485	$0	$7,467,953	$1,185,869	$0	$0	$12,414,772	$0
Acct 1815 - 1855	$3,120,947,897	$100,232,259	$530,774,596	$1,020,822,743	$85,692,591	$390,838,196	$679,106,396	$42,334,910	$4,342,495	$110,145	$116,029,025	$38,447,545	$112,216,995

Primary Conductors and Poles Cost Pool

Hydro One Distribution: 12 Rate Classes

ALLOCATION BY RATE CLASSIFICATION

		1	2	3	4	5	6	7	8	12	13	14	15
Description	**Total**	**UR**	**R1**	**R2**	**Seasonal**	**GSe**	**GSd**	**St Lgt**	**Sen Lgt**	**Dgen**	**ST**	**UGe**	**UGd**
Depreciation on Acct 1830-4 Primary Poles, Towers & Fixtures	$27,235,985	$529,338	$5,051,987	$12,619,583	$2,456,325	$3,053,689	$2,918,074	$232,157	$67,055	$519	$30,450	$85,428	$191,379
Depreciation on Acct 1835-4 Primary Overhead Conductors	$20,005,293	$406,426	$3,775,632	$9,360,983	$1,984,362	$2,186,016	$1,874,084	$160,265	$50,823	$403	$22,366	$61,220	$122,712
Depreciation on Acct 1840-4 Primary Underground Conduit	$90,207	$9,708	$25,975	$27,476	$7,191	$8,648	$7,114	$716	$228	$2	$0	$1,338	$1,811
Depreciation on Acct 1845-4 Primary Underground Conductors	$4,162,673	$447,975	$1,198,653	$1,267,881	$331,855	$399,065	$328,283	$33,056	$10,516	$83	$0	$61,724	$83,579
Depreciation on General Plant Assigned to Primary C&P	$18,792,546	$461,042	$3,592,615	$8,479,627	$1,732,785	$2,048,115	$1,834,938	$154,831	$264,867	$344	$18,901	$70,026	$134,455
Primary C&P Operations and Maintenance	$115,898,080	$2,234,082	$20,871,576	$55,133,706	$12,706,415	$12,127,053	$10,547,371	$837,897	$299,193	$2,408	$114,418	$305,330	$718,633
Allocation of General Expenses	$10,214,477	$278,653	$2,038,705	$4,703,201	$1,073,652	$1,070,901	$839,278	$76,029	$27,168	$189	$9,057	$35,079	$62,566
Admin and General Assigned to Primary C&P	$37,257,821	$711,260	$6,662,038	$17,613,056	$4,068,324	$3,897,617	$3,547,226	$276,392	$96,595	$779	$37,548	$97,950	$249,035
PILs on Primary C&P	$17,418,085	$426,769	$3,348,019	$7,952,286	$1,620,398	$1,918,961	$1,751,098	$144,549	$43,461	$340	$18,428	$65,061	$128,715
Debt Return on Primary C&P	$51,628,454	$1,264,974	$9,923,768	$23,571,147	$4,802,976	$5,687,939	$5,190,381	$428,452	$128,820	$1,008	$54,622	$192,845	$381,521
Equity Return on Primary C&P	$52,636,687	$1,289,677	$10,117,566	$24,031,459	$4,896,771	$5,799,017	$5,291,742	$436,820	$131,336	$1,027	$55,689	$196,611	$388,972
Total	**$285,053,604**	**$8,059,904**	**$66,606,534**	**$164,760,405**	**$35,681,055**	**$38,197,021**	**$34,129,590**	**$2,781,165**	**$1,120,062**	**$7,103**	**$361,479**	**$1,172,612**	**$2,463,378**
General Plant - Gross Assets	$737,348,954	$42,285,241	$156,645,429	$255,375,173	$55,135,038	$75,974,676	$87,737,631	$6,477,816	$17,732,968	$42,396	$18,314,565	$6,554,838	$15,073,182
General Plant - Accumulated Depreciation	($405,157,678)	($23,045,827)	($85,373,130)	($139,181,704)	($30,049,079)	($41,406,864)	($47,817,777)	($3,530,466)	($12,960,668)	($23,106)	($9,981,598)	($3,572,444)	($8,215,016)
General Plant - Net Fixed Assets	$332,191,276	$19,239,415	$71,272,299	$116,193,469	$25,085,960	$34,567,813	$39,919,854	$2,947,350	$4,772,300	$19,290	$8,332,967	$2,982,394	$6,858,166
General Plant - Depreciation	$53,851,648	$3,129,910	$11,594,733	$18,902,607	$4,081,039	$5,623,567	$6,494,249	$479,481	$586,414	$3,138	$1,355,625	$485,182	$1,115,701
Total Net Fixed Assets Excluding General Plant	$3,753,292,682	$217,049,574	$809,492,211	$1,328,041,485	$285,905,452	$394,728,573	$464,293,609	$33,535,359	$7,208,513	$232,026	$99,019,286	$33,770,633	$80,015,958
Total Administration and General Expense	$122,080,727	$8,175,774	$29,160,678	$47,082,017	$9,807,237	$12,800,842	$9,184,009	$799,545	$221,038	$6,691	$2,444,240	$1,128,977	$1,269,678
Total O&M	$379,945,270	$25,680,258	$91,357,822	$147,379,654	$30,630,509	$39,828,568	$27,307,859	$2,423,859	$684,638	$20,673	$7,448,318	$3,519,246	$3,663,865
Primary Conductors and Poles Gross Assets													
Acct 1830-4 Primary Poles, Towers & Fixtures	$1,255,647,739	$24,403,800	$232,909,378	$581,794,673	$113,242,790	$140,782,801	$134,530,601	$10,703,047	$3,091,423	$23,934	$1,403,814	$3,938,431	$8,823,047
Acct 1835-4 Primary Overhead Conductors	$839,697,175	$17,059,228	$158,477,425	$392,915,588	$83,291,116	$91,755,293	$78,662,350	$6,726,915	$2,133,248	$16,905	$938,781	$2,569,625	$5,150,702
Acct 1840-4 Primary Underground Conduit	$4,796,878	$516,227	$1,381,274	$1,461,050	$382,415	$459,864	$378,299	$38,093	$12,118	$96	$0	$71,128	$96,313
Acct 1845-4 Primary Underground Conductors	$135,887,801	$14,623,870	$39,129,266	$41,389,175	$10,833,206	$13,027,214	$10,716,596	$1,079,107	$343,296	$2,722	$0	$2,014,954	$2,728,394
Subtotal	$2,236,029,594	$56,603,125	$431,897,344	$1,017,560,487	$207,749,526	$246,025,172	$224,287,847	$18,547,161	$5,580,086	$43,657	$2,342,596	$8,594,138	$16,798,456
Primary Conductors and Poles Accumulated Depreciation													
Acct 1830-4 Primary Poles, Towers & Fixtures	($514,143,985)	($9,992,506)	($95,368,273)	($238,224,641)	($46,368,975)	($57,645,650)	($55,085,592)	($4,382,525)	($1,265,830)	($9,800)	($574,813)	($1,612,650)	($3,612,730)
Acct 1835-4 Primary Overhead Conductors	($346,349,343)	($7,036,408)	($65,367,080)	($162,065,635)	($34,355,032)	($37,846,245)	($32,445,808)	($2,774,646)	($879,899)	($6,973)	($387,219)	($1,059,892)	($2,124,507)
Acct 1840-4 Primary Underground Conduit	($2,239,295)	($240,987)	($644,811)	($682,052)	($178,520)	($214,675)	($176,599)	($17,783)	($5,657)	($45)	$0	($33,204)	($44,961)
Acct 1845-4 Primary Underground Conductors	($68,403,369)	($7,361,382)	($19,696,938)	($20,834,534)	($5,453,232)	($6,557,655)	($5,394,534)	($543,202)	($172,809)	($1,370)	$0	($1,014,290)	($1,373,422)
Subtotal	($931,135,992)	($24,631,283)	($181,077,102)	($421,806,862)	($86,355,760)	($102,264,226)	($93,102,533)	($7,718,155)	($2,324,195)	($18,188)	($962,032)	($3,720,036)	($7,155,620)
Primary Conductor & Pools - Net Fixed Assets	$1,304,893,602	$31,971,842	$250,820,242	$595,753,624	$121,393,766	$143,760,946	$131,185,314	$10,829,006	$3,255,890	$25,469	$1,380,564	$4,874,102	$9,642,836
General Plant Assigned to Primary C&P - NFA	$116,044,320	$2,834,005	$22,083,641	$52,123,884	$10,651,350	$12,589,667	$11,279,282	$951,738	$2,155,519	$2,117	$116,181	$430,448	$826,487
Primary C&P Net Fixed Assets Including General Plant	$1,420,937,922	$34,805,847	$272,903,883	$647,877,508	$132,045,117	$156,350,614	$142,464,596	$11,780,743	$5,411,409	$27,586	$1,496,745	$5,304,549	$10,469,323
Acct 1830-3 Bulk Poles, Towers & Fixtures	$386,353,150	$5,386,505	$56,940,804	$152,648,853	$21,503,857	$37,661,735	$55,547,736	$1,346,281	$265,472	$48,866	$50,225,910	$1,127,010	$3,650,121
Acct 1835-3 Bulk Overhead Conductors	$258,368,362	$3,602,151	$38,078,381	$102,081,823	$14,380,409	$25,185,768	$37,146,786	$900,307	$177,531	$32,679	$33,587,887	$753,673	$2,440,969
Acct 1840-3 Bulk Underground Conduit	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Acct 1845-3 Bulk Underground Conductors	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Subtotal	$644,721,512	$8,988,656	$95,019,185	$254,730,677	$35,884,267	$62,847,503	$92,694,522	$2,246,587	$443,002	$81,545	$83,813,797	$1,880,683	$6,091,090
Acct 1830-5 Secondary Poles, Towers & Fixtures	$289,764,863	$32,871,788	$92,593,014	$100,635,525	$21,502,720	$33,123,137	$0	$2,944,407	$787,790	$0	$0	$5,306,482	$0
Acct 1835-5 Secondary Overhead Conductors	$193,776,271	$22,610,982	$61,923,821	$66,327,307	$15,875,771	$21,320,941	$0	$1,827,702	$535,743	$0	$0	$3,354,005	$0
Acct 1840-5 Secondary Underground Conduit	$19,187,512	$2,238,914	$6,131,628	$6,567,656	$1,572,001	$2,111,176	$0	$180,977	$53,049	$0	$0	$332,110	$0
Acct 1845-5 Secondary Underground Conductors	$543,551,206	$63,424,827	$173,699,120	$186,051,096	$44,532,255	$59,806,203	$0	$5,126,786	$1,502,783	$0	$0	$9,408,136	$0
Subtotal	$1,046,279,852	$121,146,512	$334,347,584	$359,581,584	$83,482,747	$116,361,457	$0	$10,079,872	$2,879,364	$0	$0	$18,400,733	$0
Operations and Maintenance													
Acct 5020 Overhead Distribution Lines & Feeders - Labour	$6,030,870	$218,598	$1,244,724	$2,654,762	$604,630	$626,578	$442,583	$41,562	$14,358	$206	$123,732	$30,193	$28,945
Acct 5025 Overhead Distribution Lines & Feeders - Other	$987,630	$35,798	$203,839	$434,750	$99,016	$102,610	$72,479	$6,806	$2,351	$34	$20,263	$4,945	$4,740

Primary Conductors and Poles Cost Pool

Hydro One Distribution: 12 Rate Classes

ALLOCATION BY RATE CLASSIFICATION

		1	2	3	4	5	6	7	8	12	13	14	15
Description	**Total**	**UR**	**R1**	**R2**	**Seasonal**	**GSe**	**GSd**	**St Lgt**	**Sen Lgt**	**Dgen**	**ST**	**UGe**	**UGd**
Acct 5040 Underground Distribution Lines & Feeders - Labour	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Acct 5045 Underground Distribution Lines & Feeders - Other	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Acct 5090 Underground Distribution Lines & Feeders - Rental Paid	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Acct 5095 Overhead Distribution Lines & Feeders - Rental Paid	$162,160	$5,878	$33,469	$71,382	$16,257	$16,848	$11,900	$1,118	$386	$6	$3,327	$812	$778
Acct 5120 Maintenance of Poles, Towers & Fixtures	$20,408,580	$707,798	$4,142,506	$8,917,334	$1,877,123	$2,171,242	$1,714,634	$148,746	$46,645	$719	$463,891	$105,614	$112,327
Acct 5125 Maintenance of Overhead Conductors & Devices	$51,236,400	$1,850,592	$10,553,752	$22,541,256	$5,149,918	$5,306,317	$3,751,699	$348,850	$121,362	$1,802	$1,111,219	$254,294	$245,340
Acct 5135 Overhead Distribution Lines & Feeders - Right of Way	$121,155,000	$4,391,444	$25,005,431	$53,331,883	$12,146,500	$12,587,415	$8,891,121	$834,936	$288,437	$4,134	$2,485,665	$606,561	$581,473
Acct 5145 Maintenance of Underground Conduit	$265,540	$30,503	$83,178	$88,889	$21,638	$28,465	$4,188	$2,425	$721	$1	$0	$4,464	$1,066
Acct 5150 Maintenance of Underground Conductors & Devices	$1,130,000	$129,806	$353,963	$378,264	$92,080	$121,132	$17,823	$10,321	$3,070	$5	$0	$18,998	$4,538
Total	$201,376,180	$7,370,416	$41,620,861	$88,418,520	$20,007,162	$20,960,606	$14,906,427	$1,394,764	$477,331	$6,906	$4,208,097	$1,025,882	$979,207
General Expenses													
Acct 5005 - Operation Supervision and Engineering	$2,234,150	$129,747	$495,243	$832,362	$193,943	$231,849	$228,422	$19,477	$5,107	$64	$43,329	$17,402	$37,206
Acct 5010 - Load Dispatching	$849,600	$49,340	$188,330	$316,530	$73,752	$88,167	$86,864	$7,407	$1,942	$24	$16,477	$6,617	$14,149
Acct 5085 - Miscellaneous Distribution Expense	$11,169,190	$648,643	$2,475,868	$4,161,231	$969,578	$1,159,082	$1,141,952	$97,371	$25,534	$319	$216,614	$86,996	$186,004
Acct 5105 - Maintenance Supervision and Engineering	$11,257,600	$653,778	$2,495,466	$4,194,169	$977,253	$1,168,257	$1,150,991	$98,141	$25,736	$321	$218,329	$87,684	$187,476
Total	$25,510,540	$1,481,508	$5,654,908	$9,504,292	$2,214,526	$2,647,354	$2,608,229	$222,395	$58,319	$728	$494,748	$198,699	$424,834
Primary Conductors and Poles Gross Assets	$2,236,029,594	$56,603,125	$431,897,344	$1,017,560,487	$207,749,526	$246,025,172	$224,287,847	$18,547,161	$5,580,086	$43,657	$2,342,596	$8,594,138	$16,798,456
Acct 1815 - 1855	$5,646,054,341	$300,941,041	$1,197,985,783	$2,056,299,879	$428,506,279	$608,194,042	$697,020,553	$54,253,159	$11,978,422	$168,122	$127,961,768	$48,679,874	$114,065,420

Secondary Conductors and Poles Cost Pool

Hydro One Distribution: 12 Rate Classes

ALLOCATION BY RATE CLASSIFICATION

		1	2	3	4	5	6	7	8	12	13	14	15
Description	**Total**	**UR**	**R1**	**R2**	**Seasonal**	**GSe**	**GSd**	**St Lgt**	**Sen Lgt**	**Dgen**	**ST**	**UGe**	**UGd**
Depreciation on Acct 1830-5 Secondary Poles, Towers & Fixtures	$6,285,227	$713,015	$2,008,415	$2,182,863	$466,411	$718,467	$0	$63,867	$17,088	$0	$0	$115,102	$0
Depreciation on Acct 1835-5 Secondary Overhead Conductors	$4,616,606	$538,693	$1,475,299	$1,580,209	$378,231	$507,959	$0	$43,544	$12,764	$0	$0	$79,907	$0
Depreciation on Acct 1840-5 Secondary Underground Conduit	$360,828	$42,104	$115,308	$123,507	$29,562	$39,701	$0	$3,403	$998	$0	$0	$6,245	$0
Depreciation on Acct 1845-5 Secondary Underground Conductors	$16,650,691	$1,942,903	$5,320,953	$5,699,333	$1,364,164	$1,832,053	$0	$157,050	$46,035	$0	$0	$288,201	$0
Depreciation on General Plant Assigned to Secondary C&P	$8,180,952	$942,916	$2,586,718	$2,765,506	$642,039	$896,309	$0	$77,997	$126,465	$0	$0	$143,003	$0
Secondary C&P Operations and Maintenance	$52,527,109	$4,781,559	$16,157,453	$19,482,935	$5,105,987	$5,735,679	$0	$455,374	$154,386	$0	$0	$653,735	$0
Allocation of General Expenses	$4,905,014	$596,394	$1,578,236	$1,661,999	$431,440	$506,500	$0	$41,320	$14,019	$0	$0	$75,107	$0
Admin and General Assigned to Primary C&P	$16,791,699	$1,522,296	$5,157,328	$6,224,033	$1,634,828	$1,843,439	$0	$150,212	$49,844	$0	$0	$209,719	$0
PILs on Secondary C&P	$7,543,564	$872,821	$2,410,606	$2,593,521	$600,396	$839,788	$0	$72,817	$20,751	$0	$0	$132,863	$0
Debt Return on Secondary C&P	$22,359,666	$2,587,104	$7,145,210	$7,687,384	$1,779,618	$2,489,192	$0	$215,835	$61,507	$0	$0	$393,816	$0
Equity Return on Secondary C&P	$22,796,320	$2,637,627	$7,284,746	$7,837,507	$1,814,372	$2,537,803	$0	$220,050	$62,708	$0	$0	$401,506	$0
Total	**$126,923,373**	**$17,177,432**	**$51,240,272**	**$57,838,799**	**$14,247,048**	**$17,946,890**	**$0**	**$1,501,467**	**$566,564**	**$0**	**$0**	**$2,499,205**	**$0**
General Plant - Gross Assets	$737,348,954	$42,285,241	$156,645,429	$255,375,173	$55,135,038	$75,974,676	$87,737,631	$6,477,816	$17,732,968	$42,396	$18,314,565	$6,554,838	$15,073,182
General Plant - Accumulated Depreciation	($405,157,678)	($23,045,827)	($85,373,130)	($139,181,704)	($30,049,079)	($41,406,864)	($47,817,777)	($3,530,466)	($12,960,668)	($23,106)	($9,981,598)	($3,572,444)	($8,215,016)
General Plant - Net Fixed Assets	$332,191,276	$19,239,415	$71,272,299	$116,193,469	$25,085,960	$34,567,813	$39,919,854	$2,947,350	$4,772,300	$19,290	$8,332,967	$2,982,394	$6,858,166
General Plant - Depreciation	$53,851,648	$3,129,910	$11,594,733	$18,902,607	$4,081,039	$5,623,567	$6,494,249	$479,481	$586,414	$3,138	$1,355,625	$485,182	$1,115,701
Total Net Fixed Assets Excluding General Plant	$3,753,292,682	$217,049,574	$809,492,211	$1,328,041,485	$285,905,452	$394,728,573	$464,293,609	$33,535,359	$7,208,513	$232,026	$99,019,286	$33,770,633	$80,015,958
Total Administration and General Expense	$122,080,727	$8,175,774	$29,160,678	$47,082,017	$9,807,237	$12,800,842	$9,184,009	$799,545	$221,038	$6,691	$2,444,240	$1,128,977	$1,269,678
Total O&M	$379,945,270	$25,680,258	$91,357,822	$147,379,654	$30,630,509	$39,828,568	$27,307,859	$2,423,859	$684,638	$20,673	$7,448,318	$3,519,246	$3,663,865
Secondary Conductors and Poles Gross Plant													
Acct 1830-5 Secondary Poles, Towers & Fixtures	$289,764,863	$32,871,788	$92,593,014	$100,635,525	$21,502,720	$33,123,137	$0	$2,944,407	$787,790	$0	$0	$5,306,482	$0
Acct 1835-5 Secondary Overhead Conductors	$193,776,271	$22,610,982	$61,923,821	$66,327,307	$15,875,771	$21,320,941	$0	$1,827,702	$535,743	$0	$0	$3,354,005	$0
Acct 1840-5 Secondary Underground Conduit	$19,187,512	$2,238,914	$6,131,628	$6,567,656	$1,572,001	$2,111,176	$0	$180,977	$53,049	$0	$0	$332,110	$0
Acct 1845-5 Secondary Underground Conductors	$543,551,206	$63,424,827	$173,699,120	$186,051,096	$44,532,255	$59,806,203	$0	$5,126,786	$1,502,783	$0	$0	$9,408,136	$0
Subtotal	$1,046,279,852	$121,146,512	$334,347,584	$359,581,584	$83,482,747	$116,361,457	$0	$10,079,872	$2,879,364	$0	$0	$18,400,733	$0
Secondary Conductors and Poles Accumulated Depreciation													
Acct 1830-5 Secondary Poles, Towers & Fixtures	($118,648,612)	($13,459,851)	($37,913,612)	($41,206,740)	($8,804,614)	($13,562,770)	$0	($1,205,632)	($322,573)	$0	$0	($2,172,819)	$0
Acct 1835-5 Secondary Overhead Conductors	($79,926,771)	($9,326,337)	($25,541,678)	($27,357,981)	($6,548,269)	($8,794,234)	$0	($753,871)	($220,977)	$0	$0	($1,383,424)	$0
Acct 1840-5 Secondary Underground Conduit	($8,957,180)	($1,045,178)	($2,862,388)	($3,065,936)	($733,847)	($985,546)	$0	($84,484)	($24,764)	$0	$0	($155,037)	$0
Acct 1845-5 Secondary Underground Conductors	($273,613,475)	($31,926,868)	($87,436,877)	($93,654,630)	($22,416,701)	($30,105,320)	$0	($2,580,728)	($756,473)	$0	$0	($4,735,879)	$0
Subtotal	($481,146,039)	($55,758,234)	($153,754,555)	($165,285,286)	($38,503,431)	($53,447,871)	$0	($4,624,715)	($1,324,787)	$0	$0	($8,447,159)	$0
Secondary Conductor & Pools - Net Fixed Assets	$565,133,813	$65,388,278	$180,593,029	$194,296,298	$44,979,315	$62,913,586	$0	$5,455,157	$1,554,577	$0	$0	$9,953,573	$0
General Plant Assigned to Secondary C&P - NFA	$50,539,751	$5,796,059	$15,900,438	$16,999,439	$3,946,582	$5,509,571	$0	$479,442	$1,029,187	$0	$0	$879,032	$0
Secondary C&P Net Fixed Assets Including General Plant	$615,673,563	$71,184,337	$196,493,467	$211,295,737	$48,925,897	$68,423,156	$0	$5,934,599	$2,583,764	$0	$0	$10,832,606	$0
Acct 1830-3 Bulk Poles, Towers & Fixtures	$386,353,150	$5,386,505	$56,940,804	$152,648,853	$21,503,857	$37,661,735	$55,547,736	$1,346,281	$265,472	$48,866	$50,225,910	$1,127,010	$3,650,121
Acct 1835-3 Bulk Overhead Conductors	$258,368,362	$3,602,151	$38,078,381	$102,081,823	$14,380,409	$25,185,768	$37,146,786	$900,307	$177,531	$32,679	$33,587,887	$753,673	$2,440,969
Acct 1840-3 Bulk Underground Conduit	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Acct 1845-3 Bulk Underground Conductors	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Subtotal	$644,721,512	$8,988,656	$95,019,185	$254,730,677	$35,884,267	$62,847,503	$92,694,522	$2,246,587	$443,002	$81,545	$83,813,797	$1,880,683	$6,091,090
Acct 1830-4 Primary Poles, Towers & Fixtures	$1,255,647,739	$24,403,800	$232,909,378	$581,794,673	$113,242,790	$140,782,801	$134,530,601	$10,703,047	$3,091,423	$23,934	$1,403,814	$3,938,431	$8,823,047
Acct 1835-4 Primary Overhead Conductors	$839,697,175	$17,059,228	$158,477,425	$392,915,588	$83,291,116	$91,755,293	$78,662,350	$6,726,915	$2,133,248	$16,905	$938,781	$2,569,625	$5,150,702
Acct 1840-4 Primary Underground Conduit	$4,796,878	$516,227	$1,381,274	$1,461,050	$382,415	$459,864	$378,299	$38,093	$12,118	$96	$0	$71,128	$96,313
Acct 1845-4 Primary Underground Conductors	$135,887,801	$14,623,870	$39,129,266	$41,389,175	$10,833,206	$13,027,214	$10,716,596	$1,079,107	$343,296	$2,722	$0	$2,014,954	$2,728,394
Subtotal	$2,236,029,594	$56,603,125	$431,897,344	$1,017,560,487	$207,749,526	$246,025,172	$224,287,847	$18,547,161	$5,580,086	$43,657	$2,342,596	$8,594,138	$16,798,456

Secondary Conductors and Poles Cost Pool

Hydro One Distribution: 12 Rate Classes

ALLOCATION BY RATE CLASSIFICATION

		1	2	3	4	5	6	7	8	12	13	14	15
Description	**Total**	**UR**	**R1**	**R2**	**Seasonal**	**GSe**	**GSd**	**St Lgt**	**Sen Lgt**	**Dgen**	**ST**	**UGe**	**UGd**
Operations and Maintenance													
Acct 5020 Overhead Distribution Lines & Feeders - Labour	$6,030,870	$218,598	$1,244,724	$2,654,762	$604,630	$626,578	$442,583	$41,562	$14,358	$206	$123,732	$30,193	$28,945
Acct 5025 Overhead Distribution Lines & Feeders - Other	$987,630	$35,798	$203,839	$434,750	$99,016	$102,610	$72,479	$6,806	$2,351	$34	$20,263	$4,945	$4,740
Acct 5040 Underground Distribution Lines & Feeders - Labour	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Acct 5045 Underground Distribution Lines & Feeders - Other	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Acct 5090 Underground Distribution Lines & Feeders - Rental Paid	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Acct 5095 Overhead Distribution Lines & Feeders - Rental Paid	$162,160	$5,878	$33,469	$71,382	$16,257	$16,848	$11,900	$1,118	$386	$6	$3,327	$812	$778
Acct 5120 Maintenance of Poles, Towers & Fixtures	$20,408,580	$707,798	$4,142,506	$8,917,334	$1,877,123	$2,171,242	$1,714,634	$148,746	$46,645	$719	$463,891	$105,614	$112,327
Acct 5125 Maintenance of Overhead Conductors & Devices	$51,236,400	$1,850,592	$10,553,752	$22,541,256	$5,149,918	$5,306,317	$3,751,699	$348,850	$121,362	$1,802	$1,111,219	$254,294	$245,340
Acct 5135 Overhead Distribution Lines & Feeders - Right of Way	$121,155,000	$4,391,444	$25,005,431	$53,331,883	$12,146,500	$12,587,415	$8,891,121	$834,936	$288,437	$4,134	$2,485,665	$606,561	$581,473
Acct 5145 Maintenance of Underground Conduit	$265,540	$30,503	$83,178	$88,889	$21,638	$28,465	$4,188	$2,425	$721	$1	$0	$4,464	$1,066
Acct 5150 Maintenance of Underground Conductors & Devices	$1,130,000	$129,806	$353,963	$378,264	$92,080	$121,132	$17,823	$10,321	$3,070	$5	$0	$18,998	$4,538
Total	$201,376,180	$7,370,416	$41,620,861	$88,418,520	$20,007,162	$20,960,606	$14,906,427	$1,394,764	$477,331	$6,906	$4,208,097	$1,025,882	$979,207
General Expenses													
Acct 5005 - Operation Supervision and Engineering	$2,234,150	$129,747	$495,243	$832,362	$193,943	$231,849	$228,422	$19,477	$5,107	$64	$43,329	$17,402	$37,206
Acct 5010 - Load Dispatching	$849,600	$49,340	$188,330	$316,530	$73,752	$88,167	$86,864	$7,407	$1,942	$24	$16,477	$6,617	$14,149
Acct 5085 - Miscellaneous Distribution Expense	$11,169,190	$648,643	$2,475,868	$4,161,231	$969,578	$1,159,082	$1,141,952	$97,371	$25,534	$319	$216,614	$86,996	$186,004
Acct 5105 - Maintenance Supervision and Engineering	$11,257,600	$653,778	$2,495,466	$4,194,169	$977,253	$1,168,257	$1,150,991	$98,141	$25,736	$321	$218,329	$87,684	$187,476
Total	$25,510,540	$1,481,508	$5,654,908	$9,504,292	$2,214,526	$2,647,354	$2,608,229	$222,395	$58,319	$728	$494,748	$198,699	$424,834
Secondary Conductors and Poles Gross Assets	$1,046,279,852	$121,146,512	$334,347,584	$359,581,584	$83,482,747	$116,361,457	$0	$10,079,872	$2,879,364	$0	$0	$18,400,733	$0
Acct 1815 - 1855	$5,646,054,341	$300,941,041	$1,197,985,783	$2,056,299,879	$428,506,279	$608,194,042	$697,020,553	$54,253,159	$11,978,422	$168,122	$127,961,768	$48,679,874	$114,065,420

Metering Unit Cost

ALLOCATION BY RATE CLASSIFICATION

Description	GSe
Depreciation on Acct 1860 Metering	$1,155,178
Depreciation on General Plant Assigned to Metering	$217,229
Acct 5065 - Meter expense	$709,625
Acct 5070 & 5075 - Customer Premises	$1,443,925
Acct 5175 - Meter Maintenance	$143,136
Acct 5310 - Meter Reading	$1,630,202
Admin and General Assigned to Metering	$1,262,096
PILs on Metering	$203,531
Debt Return on Metering	$603,280
Equity Return on Metering	$615,061
Total	$7,983,264
Number of Customers	97,005
Metering Unit Cost ($/Customer/Month)	**$6.86**
General Plant - Gross Assets	$75,974,676
General Plant - Accumulated Depreciation	($41,406,864)
General Plant - Net Fixed Assets	$34,567,813
General Plant - Depreciation	$5,623,567
Total Net Fixed Assets Excluding General Plant	$394,728,573
Total Administration and General Expense	$12,800,842
Total O&M	$39,828,568
Metering Rate Base	
Acct 1860 - Metering - Gross Assets	$13,404,195
Metering - Accumulated Depreciation	$1,843,521
Metering - Net Fixed Assets	$15,247,715
General Plant Assigned to Metering - NFA	$1,335,298
Metering Net Fixed Assets Including General Plant	$16,583,013

Output Sheet Summarizing All Allocators by Accounts by Class

Hydro One Distribution: 12 Rate Classes

TOTAL ALLOCATION BY CLASS

				1	2	3	4	5	6	7	8	12	13	14	15
USoA Account #	Accounts	O1 Grouping	Total	UR	R1	R2	Seasonal	GSe	GSd	St Lgt	Sen Lgt	Dgen	ST	UGe	UGd
1565	Conservation and Demand Management Expenditures and Recoveries	dp	$6,400,000	$432,572	$1,538,880	$2,482,541	$515,957	$670,894	$459,988	$40,829	$11,532	$348	$125,463	$59,280	$61,716
1608	Franchises and Consents	gp	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1805	Land	dp	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1805-1	Land Station >50 kV	dp	$6,121,920	$278,391	$842,156	$1,017,848	$127,359	$309,614	$447,137	$12,742	$2,513	$463	$2,910,894	$58,355	$114,448
1805-2	Land Station <50 kV	dp	$55,097,277	$4,646,748	$14,056,812	$16,989,369	$2,125,804	$5,167,913	$7,463,364	$212,688	$41,940	$7,720	$1,500,596	$974,026	$1,910,298
1806	Land Rights	dp	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1806-1	Land Rights Station >50 kV	dp	$23,947,805	$1,089,013	$3,294,358	$3,981,633	$498,204	$1,211,153	$1,749,116	$49,846	$9,829	$1,809	$11,386,873	$228,273	$447,698
1806-2	Land Rights Station <50 kV	dp	$215,530,242	$18,177,210	$54,987,620	$66,459,232	$8,315,748	$20,215,910	$29,195,284	$831,994	$164,060	$30,199	$5,870,049	$3,810,206	$7,472,730
1808	Buildings and Fixtures	dp	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1808-1	Buildings and Fixtures > 50 kV	dp	$2,718,897	$123,640	$374,023	$452,052	$56,563	$137,507	$198,585	$5,659	$1,116	$205	$1,292,800	$25,917	$50,829
1808-2	Buildings and Fixtures < 50 KV	dp	$2,718,897	$229,304	$693,664	$838,378	$104,902	$255,022	$368,296	$10,496	$2,070	$381	$74,050	$48,065	$94,268
1810	Leasehold Improvements	dp	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1810-1	Leasehold Improvements >50 kV	dp	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1810-2	Leasehold Improvements <50 kV	dp	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1815	Transformer Station Equipment - Normally Primary above 50 kV	dp	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1815-1	HVDS - Rural	dp	$86,497,684	$7,499,214	$22,685,764	$27,418,508	$3,430,756	$8,340,302	$12,044,845	$343,249	$67,685	$12,459	$0	$1,571,943	$3,082,959
1815-2	HVDS - lo LV Specific	dp	$571,618	$0	$0	$0	$0	$0	$0	$0	$0	$0	$571,618	$0	$0
1815-3	HVDS - hi LV Specific	dp	$1,908,989	$0	$0	$0	$0	$0	$0	$0	$0	$0	$1,908,989	$0	$0
1815-4	HVDS - lo LV Shared	dp	$9,437,091	$0	$0	$0	$0	$0	$0	$0	$0	$0	$9,437,091	$0	$0
1815-5	HVDS - hi LV Shared	dp	$9,437,091	$0	$0	$0	$0	$0	$0	$0	$0	$0	$9,437,091	$0	$0
1820	Distribution Station Equipment - Normally Primary below 50 kV	dp	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1820-1	Distribution Station Equipment - Normally Primary below 50 kV (Bulk)	dp	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1820-2	Distribution Station Equipment - Normally Primary below 50 kV (Primary)	dp	$287,412,402	$20,219,742	$70,423,968	$83,975,568	$4,953,917	$31,528,052	$46,707,891	$3,317,828	$531,403	$3,242	$8,235,782	$5,521,428	$11,993,581
1820-3	Distribution Station Equipment - Normally Primary below 50 kV (Wholesale Meters)	dp	$39,824,763	$2,452,139	$7,233,145	$9,230,455	$1,159,819	$3,773,455	$5,312,912	$197,915	$36,789	$5,563	$8,363,003	$696,102	$1,363,466
1825	Storage Battery Equipment	dp	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1825-1	Storage Battery Equipment > 50 kV	dp	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1825-2	Storage Battery Equipment <50 kV	dp	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1830	Poles, Towers and Fixtures	dp	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1830-3	Poles, Towers and Fixtures - Subtransmission Bulk Delivery	dp	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1830-3A	Bulk-LV Fixtures	dp	$50,225,910	$0	$0	$0	$0	$0	$0	$0	$0	$0	$50,225,910	$0	$0
1830-3B	Bulk-Retail Fixtures	dp	$336,127,241	$5,386,505	$56,940,804	$152,648,853	$21,503,857	$37,661,735	$55,547,736	$1,346,281	$265,472	$48,866	$0	$1,127,010	$3,650,121
1830-4	Poles, Towers and Fixtures - Primary	dp	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1830-4A	Primary-LV Fixtures	dp	$1,403,814	$0	$0	$0	$0	$0	$0	$0	$0	$0	$1,403,814	$0	$0
1830-4B	Primary-Retail Fixtures	dp	$1,254,243,925	$24,403,800	$232,909,378	$581,794,673	$113,242,790	$140,782,801	$134,530,601	$10,703,047	$3,091,423	$23,934	$0	$3,938,431	$8,823,047
1830-5	Poles, Towers and Fixtures - Secondary	dp	$289,764,863	$32,871,788	$92,593,014	$100,635,525	$21,502,720	$33,123,137	$0	$2,944,407	$787,790	$0	$0	$5,306,482	$0
1835	Overhead Conductors and Devices	dp	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1835-3	Overhead Conductors and Devices - Subtransmission Bulk Delivery	dp	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1835-3A	Bulk-LV Conductors	dp	$33,587,887	$0	$0	$0	$0	$0	$0	$0	$0	$0	$33,587,887	$0	$0
1835-3B	Bulk-Retail Conductors	dp	$224,780,475	$3,602,151	$38,078,381	$102,081,823	$14,380,409	$25,185,768	$37,146,786	$900,307	$177,531	$32,679	$0	$753,673	$2,440,969
1835-4	Overhead Conductors and Devices - Primary	dp	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1835-4A	Primary-LV Conductors	dp	$938,781	$0	$0	$0	$0	$0	$0	$0	$0	$0	$938,781	$0	$0
1835-4B	Primary-Retail Conductors	dp	$838,758,394	$17,059,228	$158,477,425	$392,915,588	$83,291,116	$91,755,293	$78,662,350	$6,726,915	$2,133,248	$16,905	$0	$2,569,625	$5,150,702
1835-5	Overhead Conductors and Devices - Secondary	dp	$193,776,271	$22,610,982	$61,923,821	$66,327,307	$15,875,771	$21,320,941	$0	$1,827,702	$535,743	$0	$0	$3,354,005	$0
1840	Underground Conduit	dp	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

TOTAL ALLOCATION BY CLASS

				1	2	3	4	5	6	7	8	12	13	14	15
USoA Account #	Accounts	O1 Grouping	Total	UR	R1	R2	Seasonal	GSe	GSd	St Lgt	Sen Lgt	Dgen	ST	UGe	UGd
1840-3	Underground Conduit - Bulk Delivery	dp	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1840-4	Underground Conduit - Primary	dp	$4,796,878	$516,227	$1,381,274	$1,461,050	$382,415	$459,864	$378,299	$38,093	$12,118	$96	$0	$71,128	$96,313
1840-5	Underground Conduit - Secondary	dp	$19,187,512	$2,238,914	$6,131,628	$6,567,656	$1,572,001	$2,111,176	$0	$180,977	$53,049	$0	$0	$332,110	$0
1845	Underground Conductors and Devices	dp	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1845-3	Underground Conductors and Devices - Bulk Delivery	dp	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1845-4	Underground Conductors and Devices - Primary	dp	$135,887,801	$14,623,870	$39,129,266	$41,389,175	$10,833,206	$13,027,214	$10,716,596	$1,079,107	$343,296	$2,722	$0	$2,014,954	$2,728,394
1845-5	Underground Conductors and Devices - Secondary	dp	$543,551,206	$63,424,827	$173,699,120	$186,051,096	$44,532,255	$59,806,203	$0	$5,126,786	$1,502,783	$0	$0	$9,408,136	$0
1850	Line Transformers	dp	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1850-1	TRF-LV	dp	$3,851,801	$0	$0	$0	$0	$0	$0	$0	$0	$0	$3,851,801	$0	$0
1850-2	TRF-Rural	dp	$1,280,081,943	$84,031,654	$236,378,793	$303,802,601	$91,845,247	$139,318,101	$315,972,536	$19,520,547	$2,440,092	$21,657	$0	$12,014,848	$74,735,867
1855	Services	dp	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1860	Meters	dp	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1860-1	Mtr-Single	dp	$13,081,021	$1,688,100	$4,020,245	$4,171,006	$1,800,451	$1,233,555	$0	$0	$0	$0	$0	$167,665	$0
1860-2	Mtr-Poly	dp	$5,379,048	$0	$0	$0	$0	$0	$4,456,956	$0	$0	$81,830	$0	$0	$840,262
1860-3	Mtr-LV	dp	$6,689,107	$0	$0	$0	$0	$0	$0	$0	$0	$0	$6,689,107	$0	$0
1860-4	Mtr-Smart	dp	$147,740,678	$20,332,497	$47,228,476	$45,786,646	$19,469,171	$12,170,640	$880,120	$0	$0	$10,495	$84,437	$1,598,951	$179,243
1875	Street Lights	dp	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1905	Land	gp	$3,283,798	$192,583	$713,421	$1,163,073	$251,105	$346,017	$399,590	$29,502	$6,400	$193	$83,411	$29,853	$68,649
1906	Land Rights	gp	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1908	Buildings and Fixtures	gp	$94,901,052	$5,565,598	$20,617,724	$33,612,566	$7,256,892	$9,999,812	$11,548,056	$852,612	$184,956	$5,580	$2,410,569	$862,750	$1,983,937
1910	Leasehold Improvements	gp	$4,620,582	$270,980	$1,003,844	$1,636,543	$353,327	$486,875	$562,257	$41,512	$9,005	$272	$117,367	$42,006	$96,595
1915	Office Furniture and Equipment	gp	$2,536,853	$148,777	$551,144	$898,516	$193,988	$267,311	$308,697	$22,792	$4,944	$149	$64,438	$23,063	$53,034
1920	Computer Equipment - Hardware	gp	$55,593,665	$3,260,364	$12,077,999	$19,690,463	$4,251,135	$5,857,956	$6,764,928	$499,466	$108,348	$3,269	$1,412,127	$505,405	$1,162,204
1925	Computer Software	gp	$205,570,861	$12,055,975	$44,661,288	$72,810,194	$15,719,589	$21,661,193	$25,014,937	$1,846,895	$400,643	$12,087	$5,221,678	$1,868,855	$4,297,526
1930	Transportation Equipment	gp	$199,220,074	$11,683,524	$43,281,548	$70,560,838	$15,233,958	$20,992,005	$24,242,140	$1,789,838	$388,266	$11,714	$5,060,363	$1,811,119	$4,164,760
1935	Stores Equipment	gp	$6,587,180	$386,314	$1,431,098	$2,333,083	$503,708	$694,097	$801,563	$59,181	$12,838	$387	$167,320	$59,884	$137,707
1940	Tools, Shop and Garage Equipment	gp	$2,282,022	$133,832	$495,781	$808,259	$174,502	$240,459	$277,688	$20,502	$4,448	$134	$57,965	$20,746	$47,706
1945	Measurement and Testing Equipment	gp	$3,066,387	$179,832	$666,188	$1,086,070	$234,480	$323,108	$373,134	$27,549	$5,976	$180	$77,889	$27,877	$64,104
1950	Power Operated Equipment	gp	$85,055,133	$4,988,171	$18,478,649	$30,125,285	$6,503,995	$8,962,339	$10,349,953	$764,154	$165,767	$5,001	$2,160,474	$773,240	$1,778,105
1955	Communication Equipment	gp	$28,160,887	$1,651,532	$6,118,092	$9,974,175	$2,153,406	$2,967,339	$3,426,764	$253,004	$54,884	$1,656	$715,311	$256,012	$588,712
1960	Miscellaneous Equipment	gp	$2,998,695	$175,862	$651,481	$1,062,094	$229,304	$315,975	$364,897	$26,941	$5,844	$176	$76,169	$27,261	$62,689
1970	Load Management Controls - Customer Premises	gp	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1975	Load Management Controls - Utility Premises	gp	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1980	System Supervisory Equipment	gp	$21,869,131	$1,282,544	$4,751,177	$7,745,727	$1,672,288	$2,304,371	$2,661,150	$196,477	$42,621	$1,286	$555,495	$198,813	$457,181
1985	Sentinel Lgts	gp	$16,327,748	$0	$0	$0	$0	$0	$0	$0	$16,327,748	$0	$0	$0	$0
1990	Other Tangible Property	gp	$5,274,886	$309,353	$1,145,995	$1,868,287	$403,360	$555,820	$641,876	$47,391	$10,280	$310	$133,987	$47,954	$110,273
1995	Contributions and Grants - Credit	co	($418,704,641)	($27,605,063)	($96,829,462)	($149,512,348)	($33,095,751)	($44,846,947)	($43,340,204)	($3,944,093)	($1,222,923)	($13,267)	($6,945,420)	($4,154,457)	($7,194,706)
2005	Property Under Capital Leases	gp	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2010	Electric Plant Purchased or Sold	gp	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2105	Accum. Amortization of Electric Utility Plant - Property, Plant, & Equipment	accum dep	($2,364,639,589)	($126,329,707)	($504,073,473)	($860,106,456)	($172,568,313)	($251,397,594)	($282,423,361)	($21,468,426)	($16,740,713)	($79,386)	($61,912,930)	($21,297,966)	($46,241,264)
2120	Accumulated Amortization of Electric Utility Plant - Intangibles	accum dep	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
3046	Balance Transferred From Income	NI	($151,400,000)	($8,755,327)	($32,653,228)	($53,570,424)	($11,532,830)	($15,922,528)	($18,728,636)	($1,352,746)	($290,776)	($9,359)	($3,994,232)	($1,362,237)	($3,227,677)
4080	Distribution Services Revenue	CREV	($1,024,275,593)	($53,878,006)	($186,515,673)	($392,645,261)	($74,805,048)	($113,915,687)	($105,528,769)	($4,775,662)	($887,720)	($627,466)	($63,422,672)	($11,607,755)	($15,665,873)
4082	Retail Services Revenues	mi	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4084	Service Transaction Requests (STR) Revenues	mi	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4090	Electric Services Incidental to Energy Sales	mi	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4205	Interdepartmental Rents	mi	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4210	Rent from Electric Property	mi	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

TOTAL ALLOCATION BY CLASS

				1	2	3	4	5	6	7	8	12	13	14	15
USoA Account #	**Accounts**	**O1 Grouping**	**Total**	**UR**	**R1**	**R2**	**Seasonal**	**GSe**	**GSd**	**St Lgt**	**Sen Lgt**	**Dgen**	**ST**	**UGe**	**UGd**
4215	Other Utility Operating Income	mi	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4220	Other Electric Revenues	mi	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4225	Late Payment Charges	mi	($14,500,000)	($1,219,557)	($3,994,463)	($4,668,534)	($803,694)	($1,599,523)	($1,271,608)	($20,916)	($5,379)	($3,199)	($476,654)	($257,149)	($179,324)
4235	Miscellaneous Service Revenues	mi	($27,800,000)	($3,615,456)	($8,451,334)	($8,311,693)	($1,194,134)	($4,049,132)	($1,105,601)	($128,991)	($8,363)	($3,758)	($131,175)	($576,936)	($223,426)
4240	Provision for Rate Refunds	mi	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4245	Government Assistance Directly Credited to Income	mi	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4305	Regulatory Debits	mi	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4310	Regulatory Credits	mi	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4315	Revenues from Electric Plant Leased to Others	mi	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4320	Expenses of Electric Plant Leased to Others	mi	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4325	Revenues from Merchandise, Jobbing, Etc.	mi	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4330	Costs and Expenses of Merchandising, Jobbing, Etc.	mi	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4335	Profits and Losses from Financial Instrument Hedges	mi	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4340	Profits and Losses from Financial Instrument Investments	mi	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4345	Gains from Disposition of Future Use Utility Plant	mi	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4350	Losses from Disposition of Future Use Utility Plant	mi	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4355	Gain on Disposition of Utility and Other Property	mi	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4360	Loss on Disposition of Utility and Other Property	mi	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4365	Gains from Disposition of Allowances for Emission	mi	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4370	Losses from Disposition of Allowances for Emission	mi	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4390	Miscellaneous Non-Operating Income	mi	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4395	Rate-Payer Benefit Including Interest	mi	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4398	Foreign Exchange Gains and Losses, Including Amortization	mi	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4405	Interest and Dividend Income	mi	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4415	Equity in Earnings of Subsidiary Companies	mi	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4705	Power Purchased	cop	$1,959,300,000	$120,640,405	$355,856,506	$454,120,215	$57,060,824	$185,646,555	$261,384,838	$9,737,031	$1,809,959	$273,686	$411,443,278	$34,246,845	$67,079,857
4708	Charges-WMS	cop	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4710	Cost of Power Adjustments	cop	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4712	Charges-One-Time	cop	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4714	Charges-NW	cop	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4715	System Control and Load Dispatching	cop	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4716	Charges-CN	cop	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4730	Rural Rate Assistance Expense	cop	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5005	Operation Supervision and Engineering	di	$2,234,150	$129,747	$495,243	$832,362	$193,943	$231,849	$228,422	$19,477	$5,107	$64	$43,329	$17,402	$37,206
5010	Load Dispatching	di	$849,600	$49,340	$188,330	$316,530	$73,752	$88,167	$86,864	$7,407	$1,942	$24	$16,477	$6,617	$14,149
5012	Station Buildings and Fixtures Expense	di	$396,000	$25,703	$77,753	$93,974	$11,759	$28,585	$41,282	$1,176	$232	$43	$99,539	$5,388	$10,566
5014	Transformer Station Equipment - Operation Labour	di	$590,000	$41,024	$124,101	$149,991	$18,768	$45,625	$65,891	$1,878	$370	$68	$116,820	$8,599	$16,865
5015	Transformer Station Equipment - Operation Supplies and Expenses	di	$290,000	$20,164	$60,999	$73,724	$9,225	$22,426	$32,387	$923	$182	$34	$57,420	$4,227	$8,290
5016	Distribution Station Equipment - Operation Labour	di	$6,620,000	$465,723	$1,622,083	$1,934,218	$114,104	$726,189	$1,075,828	$76,420	$12,240	$75	$189,696	$127,176	$276,249
5017	Distribution Station Equipment - Operation Supplies and Expenses	di	$2,500,000	$175,877	$612,569	$730,445	$43,091	$274,241	$406,279	$28,859	$4,622	$28	$71,637	$48,027	$104,324

TOTAL ALLOCATION BY CLASS

				1	2	3	4	5	6	7	8	12	13	14	15
USoA Account #	Accounts	O1 Grouping	Total	UR	R1	R2	Seasonal	GSe	GSd	St Lgt	Sen Lgt	Dgen	ST	UGe	UGd
5020	Overhead Distribution Lines and Feeders - Operation Labour	di	$6,030,870	$218,598	$1,244,724	$2,654,762	$604,630	$626,578	$442,583	$41,562	$14,358	$206	$123,732	$30,193	$28,945
5025	Overhead Distribution Lines & Feeders - Operation Supplies and Expenses	di	$987,630	$35,798	$203,839	$434,750	$99,016	$102,610	$72,479	$6,806	$2,351	$34	$20,263	$4,945	$4,740
5030	Overhead Subtransmission Feeders - Operation	di	$564,400	$13,146	$100,132	$233,290	$20,803	$68,633	$87,877	$5,386	$886	$28	$24,997	$3,436	$5,787
5035	Overhead Distribution Transformers- Operation	di	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5040	Underground Distribution Lines and Feeders - Operation Labour	di	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5045	Underground Distribution Lines & Feeders - Operation Supplies & Expenses	di	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5050	Underground Subtransmission Feeders - Operation	di	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5055	Underground Distribution Transformers - Operation	di	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5065	Meter Expense	cu	$8,157,050	$971,111	$2,312,720	$2,399,449	$1,035,743	$709,625	$123,597	$0	$0	$2,269	$482,781	$96,452	$23,302
5070	Customer Premises - Operation Labour	cu	$15,338,600	$2,094,637	$4,865,439	$4,716,903	$2,005,698	$1,253,809	$90,669	$71,875	$46,602	$1,081	$8,699	$164,723	$18,465
5075	Customer Premises - Materials and Expenses	cu	$2,325,800	$317,611	$737,749	$715,226	$304,125	$190,116	$13,748	$10,898	$7,066	$164	$1,319	$24,977	$2,800
5085	Miscellaneous Distribution Expense	di	$11,169,190	$648,643	$2,475,868	$4,161,231	$969,578	$1,159,082	$1,141,952	$97,371	$25,534	$319	$216,614	$86,996	$186,004
5090	Underground Distribution Lines and Feeders - Rental Paid	di	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5095	Overhead Distribution Lines and Feeders - Rental Paid	di	$162,160	$5,878	$33,469	$71,382	$16,257	$16,848	$11,900	$1,118	$386	$6	$3,327	$812	$778
5096	Other Rent	di	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5105	Maintenance Supervision and Engineering	di	$11,257,600	$653,778	$2,495,466	$4,194,169	$977,253	$1,168,257	$1,150,991	$98,141	$25,736	$321	$218,329	$87,684	$187,476
5110	Maintenance of Buildings and Fixtures - Distribution Stations	di	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5112	Maintenance of Transformer Station Equipment	di	$1,895,500	$131,798	$398,701	$481,878	$60,295	$146,580	$211,687	$6,033	$1,190	$219	$375,309	$27,627	$54,183
5114	Maintenance of Distribution Station Equipment	di	$18,339,300	$1,290,188	$4,493,634	$5,358,339	$316,101	$2,011,752	$2,980,352	$211,705	$33,908	$207	$525,511	$352,313	$765,290
5120	Maintenance of Poles, Towers and Fixtures	di	$20,408,580	$707,798	$4,142,506	$8,917,334	$1,877,123	$2,171,242	$1,714,634	$148,746	$46,645	$719	$463,891	$105,614	$112,327
5125	Maintenance of Overhead Conductors and Devices	di	$51,236,400	$1,850,592	$10,553,752	$22,541,256	$5,149,918	$5,306,317	$3,751,699	$348,850	$121,362	$1,802	$1,111,219	$254,294	$245,340
5130	Maintenance of Overhead Services	di	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5135	Overhead Distribution Lines and Feeders - Right of Way	di	$121,155,000	$4,391,444	$25,005,431	$53,331,883	$12,146,500	$12,587,415	$8,891,121	$834,936	$288,437	$4,134	$2,485,665	$606,561	$581,473
5145	Maintenance of Underground Conduit	di	$265,540	$30,503	$83,178	$88,889	$21,638	$28,465	$4,188	$2,425	$721	$1	$0	$4,464	$1,066
5150	Maintenance of Underground Conductors and Devices	di	$1,130,000	$129,806	$353,963	$378,264	$92,080	$121,132	$17,823	$10,321	$3,070	$5	$0	$18,998	$4,538
5155	Maintenance of Underground Services	di	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5160	Maintenance of Line Transformers	di	$3,196,880	$209,231	$588,562	$756,441	$228,686	$346,890	$786,743	$48,604	$6,076	$54	$9,591	$29,916	$186,086
5175	Maintenance of Meters	cu	$1,846,200	$235,146	$547,258	$533,472	$227,127	$143,136	$56,992	$0	$0	$986	$72,331	$18,865	$10,887
5305	Supervision	cu	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5310	Meter Reading Expense	cu	$23,513,850	$2,329,176	$6,805,728	$10,709,244	$1,442,426	$1,630,202	$354,613	$0	$0	$0	$0	$185,839	$56,621
5315	Customer Billing	cu	$35,828,600	$4,659,594	$10,892,068	$10,712,098	$1,538,998	$5,218,516	$1,424,898	$166,243	$10,779	$4,843	$169,058	$743,555	$287,951
5320	Collecting	cu	$8,626,330	$1,121,875	$2,622,446	$2,579,115	$370,539	$1,256,444	$343,068	$40,026	$2,595	$1,166	$40,703	$179,023	$69,329
5325	Collecting- Cash Over and Short	cu	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5330	Collection Charges	cu	$869,820	$113,122	$264,429	$260,060	$37,363	$126,691	$34,593	$4,036	$262	$118	$4,104	$18,051	$6,991
5335	Bad Debt Expense	cu	$17,396,400	$1,993,660	$5,507,458	$5,594,679	$419,343	$1,327,286	$1,473,243	$110,533	$20,546	$1,014	$473,480	$157,608	$317,551
5340	Miscellaneous Customer Accounts Expenses	cu	$4,763,820	$619,546	$1,448,224	$1,424,295	$204,627	$693,861	$189,456	$22,104	$1,433	$644	$22,478	$98,864	$38,286
5405	Supervision	ad	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5410	Community Relations - Sundry	ad	$673,080	$45,493	$161,842	$261,086	$54,263	$70,557	$48,376	$4,294	$1,213	$37	$13,195	$6,234	$6,491
5415	Energy Conservation	ad	$1,000,000	$67,589	$240,450	$387,897	$80,618	$104,827	$71,873	$6,379	$1,802	$54	$19,604	$9,263	$9,643

Filed: February 28, 2008
EB-2007-0681
Exhibit G2-1-1
Attachment A

TOTAL ALLOCATION BY CLASS

				1	2	3	4	5	6	7	8	12	13	14	15
USoA Account #	**Accounts**	**O1 Grouping**	**Total**	**UR**	**R1**	**R2**	**Seasonal**	**GSe**	**GSd**	**St Lgt**	**Sen Lgt**	**Dgen**	**ST**	**UGe**	**UGd**
5420	Community Safety Program	ad	$864,318	$50,689	$187,777	$306,129	$66,093	$91,074	$105,175	$7,765	$1,684	$51	$21,954	$7,858	$18,069
5425	Miscellaneous Customer Service and Informational Expenses	ad	$10,200	$689	$2,453	$3,957	$822	$1,069	$733	$65	$18	$1	$200	$94	$98
5505	Supervision	ad	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5510	Demonstrating and Selling Expense	ad	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5515	Advertising Expense	ad	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5520	Miscellaneous Sales Expense	ad	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5605	Executive Salaries and Expenses	ad	$5,793,895	$391,606	$1,393,142	$2,247,435	$467,093	$607,357	$416,425	$36,962	$10,440	$315	$113,582	$53,666	$55,871
5610	Management Salaries and Expenses	ad	$21,599,559	$1,459,900	$5,193,613	$8,378,406	$1,741,318	$2,264,220	$1,552,428	$137,794	$38,921	$1,175	$423,430	$200,066	$208,288
5615	General Administrative Salaries and Expenses	ad	$31,794,404	$2,148,963	$7,644,963	$12,332,956	$2,563,208	$3,332,916	$2,285,164	$202,832	$57,292	$1,730	$623,287	$294,496	$306,598
5620	Office Supplies and Expenses	ad	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5625	Administrative Expense Transferred Credit	ad	($49,300,954)	($3,332,220)	($11,854,412)	($19,123,695)	($3,974,555)	($5,168,077)	($3,543,414)	($314,515)	($88,837)	($2,683)	($966,479)	($456,650)	($475,416)
5630	Outside Services Employed	ad	$6,548,043	$442,578	$1,574,477	$2,539,967	$527,892	$686,412	$470,628	$41,773	$11,799	$356	$128,366	$60,651	$63,144
5635	Property Insurance	ad	$2,715,447	$159,251	$589,944	$961,771	$207,645	$286,129	$330,430	$24,396	$5,292	$160	$68,975	$24,686	$56,767
5640	Injuries and Damages	ad	$1,694,082	$114,502	$407,342	$657,129	$136,574	$177,586	$121,759	$10,807	$3,053	$92	$33,210	$15,691	$16,336
5645	Employee Pensions and Benefits	ad	$23,592,000	$1,594,568	$5,672,695	$9,151,267	$1,901,945	$2,473,081	$1,695,631	$150,505	$42,511	$1,284	$462,490	$218,521	$227,501
5650	Franchise Requirements	ad	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5655	Regulatory Expenses	ad	$4,993,529	$337,509	$1,200,694	$1,936,975	$402,569	$523,457	$358,901	$31,856	$8,998	$272	$97,891	$46,253	$48,153
5660	General Advertising Expenses	ad	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5665	Miscellaneous General Expenses	ad	($413,370)	($27,939)	($99,395)	($160,345)	($33,325)	($43,332)	($29,710)	($2,637)	($745)	($22)	($8,104)	($3,829)	($3,986)
5670	Rent	ad	$7,740,487	$523,175	$1,861,200	$3,002,512	$624,024	$811,413	$556,333	$49,380	$13,948	$421	$151,742	$71,696	$74,643
5675	Maintenance of General Plant	ad	$58,312,009	$3,941,271	$14,021,120	$22,619,057	$4,701,010	$6,112,680	$4,191,067	$372,001	$105,075	$3,173	$1,143,129	$540,115	$562,311
5680	Electrical Safety Authority Fees	ad	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5685	Independent Market Operator Fees and Penalties	cop	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5705	Amortization Expense - Property, Plant, and Equipment	dep	$207,380,346	$12,869,748	$46,004,555	$73,016,682	$16,346,053	$21,643,440	$23,739,397	$1,798,563	$878,431	$15,442	$5,125,788	$1,904,979	$4,037,266
5710	Amortization of Limited Term Electric Plant	dep	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5715	Amortization of Intangibles and Other Electric Plant	dep	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5720	Amortization of Electric Plant Acquisition Adjustments	dep	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5730	Amortization of Unrecovered Plant and Regulatory Study Costs	dep	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5735	Amortization of Deferred Development Costs	dep	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5740	Amortization of Deferred Charges	dep	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
6005	Interest on Long Term Debt	INT	$148,500,000	$8,587,623	$32,027,770	$52,544,306	$11,311,923	$15,617,539	$18,369,897	$1,326,835	$285,207	$9,180	$3,917,724	$1,336,144	$3,165,852
6105	Taxes Other Than Income Taxes	ad	$4,464,000	$258,149	$962,774	$1,579,514	$340,043	$469,473	$552,210	$39,885	$8,573	$276	$117,769	$40,165	$95,167
6110	Income Taxes	Input	$50,100,000	$2,897,238	$10,805,328	$17,727,069	$3,816,346	$5,268,947	$6,197,521	$447,639	$96,221	$3,097	$1,321,737	$450,780	$1,068,075
6205	Donations	ad	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
6210	Life Insurance	ad	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
6215	Penalties	ad	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
6225	Other Deductions	ad	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
			$5,734,814,707	$347,671,689	$1,214,362,471	$1,776,908,983	$351,628,600	$574,615,407	$723,762,371	$46,737,867	$14,764,069	($63,696)	$471,028,606	$65,535,921	$147,862,418

Hydro One Networks - Distribution

Output Sheet Summarizing All Allocators by Accounts by Class

Hydro One Distribution: 12 Rate Classes

Uniform System of Accounts - Detail Accounts:

					Categorization			Allocation - Demand Related												
								1	2	3	4	5	6	7	8	12	13	14	15	
USoA Account #	**Accounts**	**Reclassified Balance**	**Financial Statement - Asset Break Out includes Acc Dep and Contributed Capital**	**Adjusted TB**	**Demand**	**Customer**	**Total**	**UR**	**R1**	**R2**	**Seasonal**	**GSe**	**GSd**	**St Lgt**	**Sen Lgt**	**Dgen**	**ST**	**UGe**	**UGd**	**Total - Demand**
1565	Conservation and Demand Management Expenditures and Recoveries	$6,400,000	$0	$6,400,000	$0	$6,400,000	$6,400,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1608	Franchises and Consents	$0		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1805	Land	$61,219,197	($61,219,197)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1805-1	Land Station >50 kV	$0	$6,121,920	$6,121,920	$6,121,920	$0	$6,121,920	$278,391	$842,156	$1,017,848	$127,359	$309,614	$447,137	$12,742	$2,513	$463	$2,910,894	$58,355	$114,448	$6,121,920
1805-2	Land Station <50 kV	$0	$55,097,277	$55,097,277	$55,097,277	$0	$55,097,277	$4,646,748	$14,056,812	$16,989,369	$2,125,804	$5,167,913	$7,463,364	$212,688	$41,940	$7,720	$1,500,596	$974,026	$1,910,298	$55,097,277
1806	Land Rights	$239,478,047	($239,478,047)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1806-1	Land Rights Station >50 kV	$0	$23,947,805	$23,947,805	$23,947,805	$0	$23,947,805	$1,089,013	$3,294,358	$3,981,633	$498,204	$1,211,153	$1,749,116	$49,846	$9,829	$1,809	$11,386,873	$228,273	$447,698	$23,947,805
1806-2	Land Rights Station <50 kV	$0	$215,530,242	$215,530,242	$215,530,242	$0	$215,530,242	$18,177,210	$54,987,620	$66,459,232	$8,315,748	$20,215,910	$29,195,284	$831,994	$164,060	$30,199	$5,870,049	$3,810,206	$7,472,730	$215,530,242
1808	Buildings and Fixtures	$5,437,793	($5,437,793)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1808-1	Buildings and Fixtures > 50 kV	$0	$2,718,897	$2,718,897	$2,718,897	$0	$2,718,897	$123,640	$374,023	$452,052	$56,563	$137,507	$198,585	$5,659	$1,116	$205	$1,292,800	$25,917	$50,829	$2,718,897
1808-2	Buildings and Fixtures < 50 KV	$0	$2,718,897	$2,718,897	$2,718,897	$0	$2,718,897	$229,304	$693,664	$838,378	$104,902	$255,022	$368,296	$10,496	$2,070	$381	$74,050	$48,065	$94,268	$2,718,897
1810	Leasehold Improvements	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1810-1	Leasehold Improvements >50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1810-2	Leasehold Improvements <50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1815	Transformer Station Equipment - Normally Primary above 50 kV	$107,852,474	($107,852,474)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1815-1	HVDS - Rural	$0	$86,497,684	$86,497,684	$86,497,684	$0	$86,497,684	$7,499,214	$22,685,764	$27,418,508	$3,430,756	$8,340,302	$12,044,845	$343,249	$67,685	$12,459	$0	$1,571,943	$3,082,959	$86,497,684
1815-2	HVDS - lo LV Specific	$0	$571,618	$571,618	$571,618	$0	$571,618	$0	$0	$0	$0	$0	$0	$0	$0	$0	$571,618	$0	$0	$571,618
1815-3	HVDS - hi LV Specific	$0	$1,908,989	$1,908,989	$1,908,989	$0	$1,908,989	$0	$0	$0	$0	$0	$0	$0	$0	$0	$1,908,989	$0	$0	$1,908,989
1815-4	HVDS - lo LV Shared	$0	$9,437,091	$9,437,091	$9,437,091	$0	$9,437,091	$0	$0	$0	$0	$0	$0	$0	$0	$0	$9,437,091	$0	$0	$9,437,091
1815-5	HVDS - hi LV Shared	$0	$9,437,091	$9,437,091	$9,437,091	$0	$9,437,091	$0	$0	$0	$0	$0	$0	$0	$0	$0	$9,437,091	$0	$0	$9,437,091
1820	Distribution Station Equipment - Normally Primary below 50 kV	$327,237,165	($327,237,165)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1820-1	Distribution Station Equipment - Normally Primary below 50 kV (Bulk)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1820-2	Distribution Station Equipment - Normally Primary below 50 kV (Primary)	$0	$287,412,402	$287,412,402	$287,412,402	$0	$287,412,402	$20,219,742	$70,423,968	$83,975,568	$4,953,917	$31,528,052	$46,707,891	$3,317,828	$531,403	$3,242	$8,235,782	$5,521,428	$11,993,581	$287,412,402
1820-3	Distribution Station Equipment - Normally Primary below 50 kV (Wholesale Meters)	$0	$39,824,763	$39,824,763	$0	$39,824,763	$39,824,763	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1825	Storage Battery Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1825-1	Storage Battery Equipment > 50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1825-2	Storage Battery Equipment <50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1830	Poles, Towers and Fixtures	$1,931,765,752	($1,931,765,752)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1830-3	Poles, Towers and Fixtures - Subtransmission Bulk Delivery	$0	$386,353,150	***$0***	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1830-3A	Bulk-LV Fixtures	$0	$50,225,910	$50,225,910	$50,225,910	$0	$50,225,910	$0	$0	$0	$0	$0	$0	$0	$0	$0	$50,225,910	$0	$0	$50,225,910
1830-3B	Bulk-Retail Fixtures	$0	$336,127,241	$336,127,241	$336,127,241	$0	$336,127,241	$5,386,505	$56,940,804	$152,648,853	$21,503,857	$37,661,735	$55,547,736	$1,346,281	$265,472	$48,866	$0	$1,127,010	$3,650,121	$336,127,241
1830-4	Poles, Towers and Fixtures - Primary	$0	$1,255,647,739	***$0***	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1830-4A	Primary-LV Fixtures	$0	$1,403,814	$1,403,814	$732,791	$671,023	$1,403,814	$0	$0	$0	$0	$0	$0	$0	$0	$0	$732,791	$0	$0	$732,791
1830-4B	Primary-Retail Fixtures	$0	$1,254,243,925	$1,254,243,925	$654,715,329	$599,528,596	$1,254,243,925	$8,796,968	$107,067,273	$283,184,021	$18,807,947	$86,234,634	$130,473,253	$7,882,189	$1,262,458	$7,701	$0	$2,397,775	$8,601,110	$654,715,329
1830-5	Poles, Towers and Fixtures - Secondary	$0	$289,764,863	$289,764,863	$151,257,258	$138,507,604	$289,764,863	$13,809,425	$48,314,814	$57,709,087	$3,249,753	$21,712,775	$0	$2,290,303	$363,687	$0	$0	$3,807,414	$0	$151,257,258
1835	Overhead Conductors and Devices	$1,291,841,808	($1,291,841,808)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1835-3	Overhead Conductors and Devices - Subtransmission Bulk Delivery	$0	$258,368,362	***$0***	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1835-3A	Bulk-LV Conductors	$0	$33,587,887	$ 33,587,887.02	$33,587,887	$0	$33,587,887	$0	$0	$0	$0	$0	$0	$0	$0	$0	$33,587,887	$0	$0	$33,587,887
1835-3B	Bulk-Retail Conductors	$0	$224,780,475	$224,780,475	$224,780,475	$0	$224,780,475	$3,602,151	$38,078,381	$102,081,823	$14,380,409	$25,185,768	$37,146,786	$900,307	$177,531	$32,679	$0	$753,673	$2,440,969	$224,780,475
1835-4	Overhead Conductors and Devices - Primary	$0	$839,697,175	***$0***	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1835-4A	Primary-LV Conductors	$0	$938,781	$938,781	$424,329	$514,452	$938,781	$0	$0	$0	$0	$0	$0	$0	$0	$0	$424,329	$0	$0	$424,329
1835-4B	Primary-Retail Conductors	$0	$838,758,394	$838,758,394	$379,118,794	$459,639,600	$838,758,394	$5,093,963	$61,998,267	$163,980,252	$10,890,910	$49,934,940	$75,551,710	$4,564,252	$731,038	$4,460	$0	$1,388,453	$4,980,550	$379,118,794
1835-5	Overhead Conductors and Devices - Secondary	$0	$193,776,271	$193,776,271	$87,586,875	$106,189,397	$193,776,271	$7,996,471	$27,977,127	$33,416,966	$1,881,799	$12,572,977	$0	$1,326,221	$210,596	$0	$0	$2,204,717	$0	$87,586,875
1840	Underground Conduit	$23,984,390	($23,984,390)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1840-3	Underground Conduit - Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1840-4	Underground Conduit - Primary	$0	$4,796,878	$4,796,878	$2,168,189	$2,628,689	$4,796,878	$157,034	$546,939	$652,185	$38,474	$244,859	$362,751	$25,767	$4,127	$25	$0	$42,881	$93,147	$2,168,189
1840-5	Underground Conduit - Secondary	$0	$19,187,512	$19,187,512	$8,672,755	$10,514,756	$19,187,512	$791,802	$2,770,264	$3,308,911	$186,334	$1,244,962	$0	$131,321	$20,853	$0	$0	$218,309	$0	$8,672,755
1845	Underground Conductors and Devices	$679,439,007	($679,439,007)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1845-3	Underground Conductors and Devices - Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1845-4	Underground Conductors and Devices - Primary	$0	$135,887,801	$135,887,801	$61,421,286	$74,466,515	$135,887,801	$4,448,519	$15,493,886	$18,475,356	$1,089,905	$6,936,446	$10,276,142	$729,951	$116,913	$713	$0	$1,214,762	$2,638,692	$61,421,286
1845-5	Underground Conductors and Devices - Secondary	$0	$543,551,206	$543,551,206	$245,685,145	$297,866,061	$543,551,206	$22,430,464	$78,477,108	$93,736,100	$5,278,530	$35,267,770	$0	$3,720,109	$590,732	$0	$0	$6,184,332	$0	$245,685,145
1850	Line Transformers	$1,283,933,745	($1,283,933,745)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1850-1	TRF-LV	$0	$3,851,801	$3,851,801	$1,467,536	$2,384,265	$3,851,801	$0	$0	$0	$0	$0	$0	$0	$0	$0	$1,467,536	$0	$0	$1,467,536

USoA Account #	Accounts	Reclassified Balance	Financial Statement - Asset Break Out includes Acc Dep and Contributed Capital	Adjusted TB	Demand	Customer	Total	UR	R1	R2	Seasonal	GSe	GSd	St Lgt	Sen Lgt	Dgen	ST	UGe	UGd	Total - Demand
1850-2	TRF-Rural	$0	$1,280,081,943	$1,280,081,943	$487,711,220	$792,370,723	$1,280,081,943	$0	$0	$235,113	$0	$73,972,976	$310,995,284	$15,757,133	$0	$0	$0	$12,014,848	$74,735,867	$487,711,220
1855	Services	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1860	Meters	$172,889,855	($172,889,855)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1860-1	Mtr-Single	$0	$13,081,021	$13,081,021	$0	$13,081,021	$13,081,021	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1860-2	Mtr-Poly	$0	$5,379,048	$5,379,048	$0	$5,379,048	$5,379,048	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1860-3	Mtr-LV	$0	$6,689,107	$6,689,107	$0	$6,689,107	$6,689,107	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1860-4	Mtr-Smart	$0	$147,740,678	$147,740,678	$0	$147,740,678	$147,740,678	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1875	St Lgts	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1905	Land	$3,283,798	$0	$3,283,798	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1906	Land Rights	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1908	Buildings and Fixtures	$94,901,052	$0	$94,901,052	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1910	Leasehold Improvements	$4,620,582	$0	$4,620,582	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1915	Office Furniture and Equipmen	$2,536,853	$0	$2,536,853	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1920	Computer Equipment - Hardware	$55,593,665	$0	$55,593,665	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1925	Computer Software	$205,570,861	$0	$205,570,861	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1930	Transportation Equipmen	$199,220,074	$0	$199,220,074	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1935	Stores Equipment	$6,587,180	$0	$6,587,180	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1940	Tools, Shop and Garage Equipmen	$2,282,022	$0	$2,282,022	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1945	Measurement and Testing Equipmen	$3,066,387	$0	$3,066,387	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1950	Power Operated Equipmen	$85,055,133	$0	$85,055,133	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1955	Communication Equipmen	$28,160,887	$0	$28,160,887	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1960	Miscellaneous Equipmen	$2,998,695	$0	$2,998,695	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1970	Load Management Controls - Customer Premises	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1975	Load Management Controls - Utility Premises	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1980	System Supervisory Equipmen	$21,869,131	$0	$21,869,131	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1985	Sentinel Lgts	$16,327,748	$0	$16,327,748	$16,327,748	$0	$16,327,748	$0	$0	$0	$0	$0	$0	$0	$16,327,748	$0	$0	$0	$0	$16,327,748
1990	Other Tangible Property	$5,274,886	$0	$5,274,886	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1995	Contributions and Grants - Credi	($418,704,641)		($418,704,641)			$0	($8,574,370)	($40,492,842)	($71,442,521)	($5,823,225)	($27,695,031)	($42,289,826)	($3,009,771)	($318,481)	($7,317)	($6,522,964)	($3,063,915)	($7,115,723)	($216,355,986)
2005	Property Under Capital Lease	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2010	Electric Plant Purchased or Sold	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2105	Accum. Amortization of Electric Utility Plant - Property, Plant, & Equipment	($2,364,639,589)		($2,364,639,589)			$0	($44,365,815)	($214,489,001)	($392,312,385)	($34,102,386)	($141,734,149)	($229,487,030)	($14,093,454)	($1,622,315)	($52,687)	($48,831,993)	($14,491,841)	($37,516,726)	($1,173,099,781)
2120	Accumulated Amortization of Electric Utility Plant - Intangibles	$0		$0			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
3046	Balance Transferred From Income	($151,400,000)		($151,400,000)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4080	Distribution Services Revenue	($1,024,275,593)		($1,024,275,593)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4082	Retail Services Revenues	$0		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4084	Service Transaction Requests (STR) Revenues	$0		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4090	Electric Services Incidental to Energy Sales	$0		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4205	Interdepartmental Rents	$0		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4210	Rent from Electric Property	$0		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4215	Other Utility Operating Income	$0		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4220	Other Electric Revenues	$0		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4225	Late Payment Charges	($14,500,000)		($14,500,000)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4235	Miscellaneous Service Revenue	($27,800,000)		($27,800,000)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4240	Provision for Rate Refunds	$0		$0	$0	$0	$0	$0	$0	$0	$0									$0
4245	Government Assistance Directly Credited to Income	$0		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4305	Regulatory Debits	$0		$0	$0	$0	$0	$0	$0	$0	$0									$0
4310	Regulatory Credits	$0		$0	$0	$0	$0	$0	$0	$0	$0									$0
4315	Revenues from Electric Plant Leased to Others	$0		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4320	Expenses of Electric Plant Leased to Others	$0		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4325	Revenues from Merchandise, Jobbing, Etc.	$0		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4330	Costs and Expenses of Merchandising, Jobbing, Etc.	$0		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4335	Profits and Losses from Financial Instrument Hedges	$0		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4340	Profits and Losses from Financial Instrument Investments	$0		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4345	Gains from Disposition of Future Use Utility Plant	$0		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4350	Losses from Disposition of Future Use Utility Plant	$0		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4355	Gain on Disposition of Utility and Other Property	$0		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4360	Loss on Disposition of Utility and Other Property	$0		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4365	Gains from Disposition of Allowances for Emission	$0		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4370	Losses from Disposition of Allowances for Emission	$0		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4390	Miscellaneous Non-Operating Income	$0		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4395	Rate-Payer Benefit Including Interest	$0		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4398	Foreign Exchange Gains and Losses, Including Amortization	$0		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

USoA Account #	Accounts	Reclassified Balance	Financial Statement - Asset Break Out includes Acc Dep and Contributed Capital	Adjusted TB	Demand	Customer	Total	UR	R1	R2	Seasonal	GSe	GSd	St Lgt	Sen Lgt	Dgen	ST	UGe	UGd	Total - Demand
4405	Interest and Dividend Income	$0		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4415	Equity in Earnings of Subsidiary Companies	$0		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4705	Power Purchased	$1,959,300,000		$1,959,300,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4708	Charges-WMS	$0		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4710	Cost of Power Adjustments	$0		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4712	Charges-One-Time	$0		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4714	Charges-NW	$0		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4715	System Control and Load Dispatching	$0		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4716	Charges-CN	$0		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4730	Rural Rate Assistance Expense	$0		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5005	Operation Supervision and Engineerin	$2,234,150		$2,234,150	$1,009,836	$1,224,314	$2,234,150	$32,432	$171,741	$330,305	$27,727	$126,462	$219,736	$13,698	$1,405	$36	$37,543	$12,440	$36,310	$1,009,836
5010	Load Dispatching	$849,600		$849,600	$384,019	$465,581	$849,600	$12,333	$65,310	$125,608	$10,544	$48,091	$83,561	$5,209	$534	$14	$14,277	$4,731	$13,808	$384,019
5012	Station Buildings and Fixtures Expens	$396,000		$396,000	$396,000	$0	$396,000	$25,703	$77,753	$93,974	$11,759	$28,585	$41,282	$1,176	$232	$43	$99,539	$5,388	$10,566	$396,000
5014	Transformer Station Equipment - Operation Labour	$590,000		$590,000	$590,000	$0	$590,000	$41,024	$124,101	$149,991	$18,768	$45,625	$65,891	$1,878	$370	$68	$116,820	$8,599	$16,865	$590,000
5015	Transformer Station Equipment - Operation Supplies and Expenses	$290,000		$290,000	$290,000	$0	$290,000	$20,164	$60,999	$73,724	$9,225	$22,426	$32,387	$923	$182	$34	$57,420	$4,227	$8,290	$290,000
5016	Distribution Station Equipment - Operation Labour	$6,620,000		$6,620,000	$6,620,000	$0	$6,620,000	$465,723	$1,622,083	$1,934,218	$114,104	$726,189	$1,075,828	$76,420	$12,240	$75	$189,696	$127,176	$276,249	$6,620,000
5017	Distribution Station Equipment - Operation Supplies and Expenses	$2,500,000		$2,500,000	$2,500,000	$0	$2,500,000	$175,877	$612,569	$730,445	$43,091	$274,241	$406,279	$28,859	$4,622	$28	$71,637	$48,027	$104,324	$2,500,000
5020	Overhead Distribution Lines and Feeders - Operation Labour	$6,030,870		$6,030,870	$2,725,953	$3,304,917	$6,030,870	$63,491	$483,619	$1,126,752	$100,474	$331,485	$424,431	$26,015	$4,278	$133	$120,730	$16,594	$27,952	$2,725,953
5025	Overhead Distribution Lines & Feeders - Operation Supplies and Expenses	$987,630		$987,630	$446,409	$541,221	$987,630	$10,397	$79,199	$184,520	$16,454	$54,285	$69,506	$4,260	$701	$22	$19,771	$2,717	$4,577	$446,409
5030	Overhead Subtransmission Feeders - Operation	$564,400		$564,400	$564,400	$0	$564,400	$13,146	$100,132	$233,290	$20,803	$68,633	$87,877	$5,386	$886	$28	$24,997	$3,436	$5,787	$564,400
5035	Overhead Distribution Transformers- Operation	$0		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5040	Underground Distribution Lines and Feeders Operation Labour	$0		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5045	Underground Distribution Lines & Feeders - Operation Supplies & Expenses	$0		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5050	Underground Subtransmission Feeders - Operation	$0		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5055	Underground Distribution Transformers - Operation	$0		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5065	Meter Expense	$8,157,050		$8,157,050	$0	$8,157,050	$8,157,050	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5070	Customer Premises - Operation Labou	$15,338,600		$15,338,600	$0	$15,338,600	$15,338,600	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5075	Customer Premises - Materials and Expenses	$2,325,800		$2,325,800	$0	$2,325,800	$2,325,800	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5085	Miscellaneous Distribution Expense	$11,169,190		$11,169,190	$5,048,474	$6,120,716	$11,169,190	$162,137	$858,586	$1,651,292	$138,617	$632,223	$1,098,529	$68,481	$7,024	$178	$187,690	$62,193	$181,523	$5,048,474
5090	Underground Distribution Lines and Feeders Rental Paid	$0		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5095	Overhead Distribution Lines and Feeders - Rental Paid	$162,160		$162,160	$73,296	$88,864	$162,160	$1,707	$13,004	$30,296	$2,702	$8,913	$11,412	$699	$115	$4	$3,246	$446	$752	$73,296
5096	Other Rent	$0		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5105	Maintenance Supervision and Engineering	$11,257,600		$11,257,600	$5,088,435	$6,169,165	$11,257,600	$163,420	$865,382	$1,664,363	$139,714	$637,228	$1,107,224	$69,023	$7,080	$180	$189,175	$62,685	$182,960	$5,088,435
5110	Maintenance of Buildings and Fixtures - Distribution Stations	$0		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5112	Maintenance of Transformer Station Equipment	$1,895,500		$1,895,500	$1,895,500	$0	$1,895,500	$131,798	$398,701	$481,878	$60,295	$146,580	$211,687	$6,033	$1,190	$219	$375,309	$27,627	$54,183	$1,895,500
5114	Maintenance of Distribution Station Equipment	$18,339,300		$18,339,300	$18,339,300	$0	$18,339,300	$1,290,188	$4,493,634	$5,358,339	$316,101	$2,011,752	$2,980,352	$211,705	$33,908	$207	$525,511	$352,313	$765,290	$18,339,300
5120	Maintenance of Poles, Towers and Fixtures	$20,408,580		$20,408,580	$10,653,279	$9,755,301	$20,408,580	$249,959	$1,895,913	$4,407,026	$388,978	$1,300,200	$1,661,053	$102,856	$16,891	$505	$455,030	$65,472	$109,396	$10,653,279
5125	Maintenance of Overhead Conductors and Devices	$51,236,400		$51,236,400	$23,158,853	$28,077,547	$51,236,400	$532,849	$4,087,643	$9,559,761	$866,763	$2,799,297	$3,597,483	$216,771	$35,725	$1,185	$1,085,714	$138,757	$236,905	$23,158,853
5130	Maintenance of Overhead Service	$0		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5135	Overhead Distribution Lines and Feeders - Right of Way	$121,155,000		$121,155,000	$54,762,060	$66,392,940	$121,155,000	$1,275,474	$9,715,494	$22,635,484	$2,018,434	$6,659,247	$8,526,458	$522,616	$85,938	$2,675	$2,425,355	$333,359	$561,526	$54,762,060
5145	Maintenance of Underground Condu	$265,540		$265,540	$120,024	$145,516	$265,540	$10,505	$36,726	$43,855	$2,489	$16,494	$4,016	$1,739	$277	$0	$0	$2,892	$1,031	$120,024
5150	Maintenance of Underground Conductors and Devices	$1,130,000		$1,130,000	$510,760	$619,240	$1,130,000	$44,703	$156,287	$186,623	$10,592	$70,191	$17,091	$7,401	$1,177	$1	$0	$12,306	$4,389	$510,760
5155	Maintenance of Underground Service	$0		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5160	Maintenance of Line Transformers	$3,196,880		$3,196,880	$1,218,011	$1,978,869	$3,196,880	$0	$0	$585	$0	$184,186	$774,350	$39,234	$0	$0	$3,654	$29,916	$186,086	$1,218,011
5175	Maintenance of Meters	$1,846,200		$1,846,200	$0	$1,846,200	$1,846,200	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5305	Supervision	$0		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5310	Meter Reading Expense	$23,513,850		$23,513,850	$0	$23,513,850	$23,513,850	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5315	Customer Billing	$35,828,600		$35,828,600	$0	$35,828,600	$35,828,600	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5320	Collecting	$8,626,330		$8,626,330	$0	$8,626,330	$8,626,330	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5325	Collecting- Cash Over and Shor	$0		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5330	Collection Charges	$869,820		$869,820	$0	$869,820	$869,820	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5335	Bad Debt Expense	$17,396,400		$17,396,400	$0	$17,396,400	$17,396,400	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5340	Miscellaneous Customer Accounts Expenses	$4,763,820		$4,763,820	$0	$4,763,820	$4,763,820	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5405	Supervision	$0		$0			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5410	Community Relations - Sundry	$673,080		$673,080			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5415	Energy Conservation	$1,000,000		$1,000,000			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

USoA Account #	Accounts	Reclassified Balance	Financial Statement - Asset Break Out includes Acc Dep and Contributed Capital	Adjusted TB	Demand	Customer	Total	UR	R1	R2	Seasonal	GSe	GSd	St Lgt	Sen Lgt	Dgen	ST	UGe	UGd	Total - Demand
5420	Community Safety Program	$864,318		$864,318			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5425	Miscellaneous Customer Service and Informational Expenses	$10,200		$10,200			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5505	Supervision	$0		$0			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5510	Demonstrating and Selling Expense	$0		$0			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5515	Advertising Expense	$0		$0			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5520	Miscellaneous Sales Expense	$0		$0			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5605	Executive Salaries and Expenses	$5,793,895		$5,793,895			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5610	Management Salaries and Expenses	$21,599,559		$21,599,559			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5615	General Administrative Salaries and Expenses	$31,794,404		$31,794,404			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5620	Office Supplies and Expenses	$0		$0			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5625	Administrative Expense Transferred Credit	($49,300,954)		($49,300,954)			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5630	Outside Services Employed	$6,548,043		$6,548,043			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5635	Property Insurance	$2,715,447		$2,715,447			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5640	Injuries and Damages	$1,694,082		$1,694,082			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5645	Employee Pensions and Benefits	$23,592,000		$23,592,000			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5650	Franchise Requirements	$0		$0			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5655	Regulatory Expenses	$4,993,529		$4,993,529			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5660	General Advertising Expenses	$0		$0			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5665	Miscellaneous General Expenses	($413,370)		($413,370)			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5670	Rent	$7,740,487		$7,740,487			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5675	Maintenance of General Plant	$58,312,009		$58,312,009			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5680	Electrical Safety Authority Fees	$0		$0			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5685	Independent Market Operator Fees and Penalties	$0		$0			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5705	Amortization Expense - Property, Plant, and Equipment	$207,380,346	$0	$207,380,346			$0	$2,705,681	$13,396,717	$24,716,764	$2,091,908	$9,517,204	$16,288,387	$1,024,770	$105,106	$2,909	$2,826,887	$994,027	$2,774,481	$76,444,841
5710	Amortization of Limited Term Electric Plant	$0	$0	$0			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5715	Amortization of Intangibles and Other Electric Plant	$0	$0	$0			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5720	Amortization of Electric Plant Acquisition Adjustments	$0	$0	$0			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5730	Amortization of Unrecovered Plant and Regulatory Study Costs	$0		$0																
5735	Amortization of Deferred Development Costs	$0		$0																
5740	Amortization of Deferred Charges	$0		$0																
6005	Interest on Long Term Debt	$148,500,000		$148,500,000				$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
6105	Taxes Other Than Income Taxes	$4,464,000		$4,464,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
6110	Income Taxes	$50,100,000		$50,100,000			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
6205	Donations	$0		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
6210	Life Insurance	$0		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
6215	Penalties	$0		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
6225	Other Deductions	$0		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
		$5,734,814,707	$2,740,066,427	$5,734,814,707	$3,579,805,291	$2,947,946,960	$6,527,752,251	$79,265,093	$389,356,977	$722,525,443	$63,405,101	$274,415,675	$485,536,141	$28,790,263	$19,270,854	$99,460	$92,539,333	$28,351,959	$83,238,067	$2,266,794,364

Hydro One Networks - Distribution

Output Sheet Summarizing All Allocators by Accounts by Cl

Uniform System of Accounts - Detail Accounts:		Allocation - Customer Related													Allocation of Miscellaneous Revenue						
		1	2	3	4	5	6	7	8	12	13	14	15		1	2	3	4	5	6	7
USoA Account #	Accounts	UR	R1	R2	Seasonal	GSe	GSd	St Lgt	Sen Lgt	Dgen	ST	UGe	UGd	Total - Customer	UR	R1	R2	Seasonal	GSe	GSd	St Lgt
1565	Conservation and Demand Management Expenditures and Recoveries	$432,572	$1,538,880	$2,482,541	$515,957	$670,894	$459,988	$40,829	$11,532	$348	$125,463	$59,280	$61,716	$6,400,000	$0	$0	$0	$0	$0	$0	$0
1608	Franchises and Consents	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1805	Land	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1805-1	Land Station >50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1805-2	Land Station <50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1806	Land Rights	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1806-1	Land Rights Station >50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1806-2	Land Rights Station <50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1808	Buildings and Fixtures	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1808-1	Buildings and Fixtures > 50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1808-2	Buildings and Fixtures < 50 KV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1810	Leasehold Improvements	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1810-1	Leasehold Improvements >50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1810-2	Leasehold Improvements <50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1815	Transformer Station Equipment - Normally Primary above 50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1815-1	HVDS - Rural	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1815-2	HVDS - lo LV Specific	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1815-3	HVDS - hi LV Specific	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1815-4	HVDS - lo LV Shared	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1815-5	HVDS - hi LV Shared	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1820	Distribution Station Equipment - Normally Primary below 50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1820-1	Distribution Station Equipment - Normally Primary below 50 kV (Bulk)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1820-2	Distribution Station Equipment - Normally Primary below 50 kV (Primary)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1820-3	Distribution Station Equipment - Normally Primary below 50 kV (Wholesale Meters)	$2,452,139	$7,233,145	$9,230,455	$1,159,819	$3,773,455	$5,312,912	$197,915	$36,789	$5,563	$8,363,003	$696,102	$1,363,466	$39,824,763	$0	$0	$0	$0	$0	$0	$0
1825	Storage Battery Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1825-1	Storage Battery Equipment > 50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1825-2	Storage Battery Equipment <50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1830	Poles, Towers and Fixtures	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1830-3	Poles, Towers and Fixtures - Subtransmission Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1830-3A	Bulk-LV Fixtures	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1830-3B	Bulk-Retail Fixtures	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1830-4	Poles, Towers and Fixtures - Primary	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1830-4A	Primary-LV Fixtures	$0	$0	$0	$0	$0	$0	$0	$0	$0	$671,023	$0	$0	$671,023	$0	$0	$0	$0	$0	$0	$0
1830-4B	Primary-Retail Fixtures	$15,606,832	$125,842,105	$298,610,653	$94,434,843	$54,548,167	$4,057,348	$2,820,858	$1,828,965	$16,233	$0	$1,540,656	$221,937	$599,528,596	$0	$0	$0	$0	$0	$0	$0
1830-5	Poles, Towers and Fixtures - Secondary	$19,062,363	$44,278,199	$42,926,438	$18,252,967	$11,410,362	$0	$654,104	$424,103	$0	$0	$1,499,068	$0	$138,507,604	$0	$0	$0	$0	$0	$0	$0
1835	Overhead Conductors and Devices	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1835-3	Overhead Conductors and Devices - Subtransmission Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1835-3A	Bulk-LV Conductors	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1835-3B	Bulk-Retail Conductors	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1835-4	Overhead Conductors and Devices - Primary	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1835-4A	Primary-LV Conductors	$0	$0	$0	$0	$0	$0	$0	$0	$0	$514,452	$0	$0	$514,452	$0	$0	$0	$0	$0	$0	$0
1835-4B	Primary-Retail Conductors	$11,965,264	$96,479,159	$228,935,336	$72,400,205	$41,820,353	$3,110,641	$2,162,662	$1,402,210	$12,445	$0	$1,181,172	$170,152	$459,639,600	$0	$0	$0	$0	$0	$0	$0
1835-5	Overhead Conductors and Devices - Secondary	$14,614,511	$33,946,694	$32,910,341	$13,993,972	$8,747,963	$0	$501,481	$325,146	$0	$0	$1,149,288	$0	$106,189,397	$0	$0	$0	$0	$0	$0	$0
1840	Underground Conduit	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1840-3	Underground Conduit - Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1840-4	Underground Conduit - Primary	$359,193	$834,336	$808,864	$343,941	$215,006	$15,548	$12,325	$7,991	$71	$0	$28,247	$3,167	$2,628,689	$0	$0	$0	$0	$0	$0	$0
1840-5	Underground Conduit - Secondary	$1,447,113	$3,361,364	$3,258,746	$1,385,668	$866,214	$0	$49,656	$32,196	$0	$0	$113,801	$0	$10,514,756	$0	$0	$0	$0	$0	$0	$0
1845	Underground Conductors and Devices	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1845-3	Underground Conductors and Devices - Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1845-4	Underground Conductors and Devices - Primary	$10,175,351	$23,635,380	$22,913,820	$9,743,301	$6,090,768	$440,454	$349,156	$226,383	$2,009	$0	$800,191	$89,702	$74,466,515	$0	$0	$0	$0	$0	$0	$0
1845-5	Underground Conductors and Devices - Secondary	$40,994,363	$95,222,012	$92,314,996	$39,253,725	$24,538,433	$0	$1,406,677	$912,050	$0	$0	$3,223,804	$0	$297,866,061	$0	$0	$0	$0	$0	$0	$0
1850	Line Transformers	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1850-1	TRF-LV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$2,384,265	$0	$0	$2,384,265	$0	$0	$0	$0	$0	$0	$0

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USoA Account #	Accounts	UR	R1	R2	Seasonal	GSe	GSd	St Lgt	Sen Lgt	Dgen	ST	UGe	UGd	Total - Customer	UR	R1	R2	Seasonal	GSe	GSd	St Lgt
1850-2	TRF-Rural	$84,031,654	$236,378,793	$303,567,488	$91,845,247	$65,345,125	$4,977,253	$3,763,414	$2,440,092	$21,657	$0	$0	$0	$792,370,723	$0	$0	$0	$0	$0	$0	$0
1855	Services	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1860	Meters	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1860-1	Mtr-Single	$1,688,100	$4,020,245	$4,171,006	$1,800,451	$1,233,555	$0	$0	$0	$0	$0	$167,665	$0	$13,081,021	$0	$0	$0	$0	$0	$0	$0
1860-2	Mtr-Poly	$0	$0	$0	$0	$0	$4,456,956	$0	$0	$81,830	$0	$0	$840,262	$5,379,048	$0	$0	$0	$0	$0	$0	$0
1860-3	Mtr-LV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$6,689,107	$0	$0	$6,689,107	$0	$0	$0	$0	$0	$0	$0
1860-4	Mtr-Smart	$20,332,497	$47,228,476	$45,786,646	$19,469,171	$12,170,640	$880,120	$0	$0	$10,495	$84,437	$1,598,951	$179,243	$147,740,678	$0	$0	$0	$0	$0	$0	$0
1875	St Lgts	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1905	Land	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1906	Land Rights	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1908	Buildings and Fixtures	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1910	Leasehold Improvements	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1915	Office Furniture and Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1920	Computer Equipment - Hardware	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1925	Computer Software	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1930	Transportation Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1935	Stores Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1940	Tools, Shop and Garage Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1945	Measurement and Testing Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1950	Power Operated Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1955	Communication Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1960	Miscellaneous Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1970	Load Management Controls - Customer Premises	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1975	Load Management Controls - Utility Premises	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1980	System Supervisory Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1985	Sentinel Lgts																				
1990	Other Tangible Property	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1995	Contributions and Grants - Credit	($18,993,839)	($56,200,097)	($77,847,255)	($27,224,474)	($17,085,700)	($973,911)	($928,676)	($602,128)	($5,913)	($406,494)	($1,084,829)	($65,846)	($201,419,161)							
2005	Property Under Capital Leases	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2010	Electric Plant Purchased or Sold	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2105	Accum. Amortization of Electric Utility Plant - Property, Plant, & Equipment	($58,954,920)	($204,347,866)	($328,834,938)	($108,464,901)	($68,322,798)	($5,195,021)	($3,850,152)	($2,460,044)	($3,630)	($3,115,302)	($3,239,394)	($522,659)	($787,311,623)							
2120	Accumulated Amortization of Electric Utility Plant - Intangibles	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
3046	Balance Transferred From Income	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($8,755,327)	($32,653,228)	($53,570,424)	($11,532,830)	($15,922,528)	($18,728,636)	($1,352,746)
4080	Distribution Services Revenue	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($53,878,006)	($186,515,673)	($392,645,261)	($74,805,048)	($113,915,687)	($105,528,769)	($4,775,662)
4082	Retail Services Revenues	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4084	Service Transaction Requests (STR) Revenues	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4090	Electric Services Incidental to Energy Sales	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4205	Interdepartmental Rents	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4210	Rent from Electric Property	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4215	Other Utility Operating Income	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4220	Other Electric Revenues	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4225	Late Payment Charges	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($1,219,557)	($3,994,463)	($4,668,534)	($803,694)	($1,599,523)	($1,271,608)	($20,916)
4235	Miscellaneous Service Revenues	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($3,615,456)	($8,451,334)	($8,311,693)	($1,194,134)	($4,049,132)	($1,105,601)	($128,991)
4240	Provision for Rate Refunds	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4245	Government Assistance Directly Credited to Income	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4305	Regulatory Debits	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4310	Regulatory Credits	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4315	Revenues from Electric Plant Leased to Others	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4320	Expenses of Electric Plant Leased to Others	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4325	Revenues from Merchandise, Jobbing, Etc.	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4330	Costs and Expenses of Merchandising, Jobbing, Etc.	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4335	Profits and Losses from Financial Instrument Hedges	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4340	Profits and Losses from Financial Instrument Investments	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4345	Gains from Disposition of Future Use Utility Plant	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4350	Losses from Disposition of Future Use Utility Plant	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4355	Gain on Disposition of Utility and Other Property	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4360	Loss on Disposition of Utility and Other Property	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4365	Gains from Disposition of Allowances for Emission	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4370	Losses from Disposition of Allowances for Emission	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4390	Miscellaneous Non-Operating Income	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4395	Rate-Payer Benefit Including Interest	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4398	Foreign Exchange Gains and Losses, Including Amortization	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

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USoA Account #	Accounts	UR	R1	R2	Seasonal	GSe	GSd	St Lgt	Sen Lgt	Dgen	ST	UGe	UGd	Total - Customer	UR	R1	R2	Seasonal	GSe	GSd	St Lgt
4405	Interest and Dividend Incom	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4415	Equity in Earnings of Subsidiary Companies	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4705	Power Purchased	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4708	Charges-WMS	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4710	Cost of Power Adjustments	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4712	Charges-One-Time	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4714	Charges-NW	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4715	System Control and Load Dispatching	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4716	Charges-CN	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4730	Rural Rate Assistance Expense	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5005	Operation Supervision and Engineerin	$97,315	$323,502	$502,058	$166,215	$105,386	$8,686	$5,779	$3,702	$28	$5,786	$4,961	$896	$1,224,314	$0	$0	$0	$0	$0	$0	$0
5010	Load Dispatching	$37,007	$123,021	$190,922	$63,208	$40,076	$3,303	$2,197	$1,408	$11	$2,200	$1,887	$341	$465,581	$0	$0	$0	$0	$0	$0	$0
5012	Station Buildings and Fixtures Expens	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5014	Transformer Station Equipment - Operation Labour	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5015	Transformer Station Equipment - Operation Supplies and Expenses	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5016	Distribution Station Equipment - Operation Labour	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5017	Distribution Station Equipment - Operation Supplies and Expenses	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5020	Overhead Distribution Lines and Feeders - Operation Labour	$155,107	$761,105	$1,528,009	$504,156	$295,093	$18,152	$15,547	$10,080	$73	$3,002	$13,599	$993	$3,304,917	$0	$0	$0	$0	$0	$0	$0
5025	Overhead Distribution Lines & Feeders - Operation Supplies and Expenses	$25,401	$124,640	$250,231	$82,562	$48,325	$2,973	$2,546	$1,651	$12	$492	$2,227	$163	$541,221	$0	$0	$0	$0	$0	$0	$0
5030	Overhead Subtransmission Feeders - Operation	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5035	Overhead Distribution Transformers- Operation	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5040	Underground Distribution Lines and Feeders Operation Labour	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5045	Underground Distribution Lines & Feeders - Operation Supplies & Expenses	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5050	Underground Subtransmission Feeders - Operation	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5055	Underground Distribution Transformers - Operation	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5065	Meter Expense	$971,111	$2,312,720	$2,399,449	$1,035,743	$709,625	$123,597	$0	$0	$2,269	$482,781	$96,452	$23,302	$8,157,050	$0	$0	$0	$0	$0	$0	$0
5070	Customer Premises - Operation Labou	$2,094,637	$4,865,439	$4,716,903	$2,005,698	$1,253,809	$90,669	$71,875	$46,602	$1,081	$8,699	$164,723	$18,465	$15,338,600	$0	$0	$0	$0	$0	$0	$0
5075	Customer Premises - Materials and Expenses	$317,611	$737,749	$715,226	$304,125	$190,116	$13,748	$10,898	$7,066	$164	$1,319	$24,977	$2,800	$2,325,800	$0	$0	$0	$0	$0	$0	$0
5085	Miscellaneous Distribution Expens	$486,507	$1,617,282	$2,509,938	$830,961	$526,858	$43,423	$28,889	$18,509	$141	$28,924	$24,803	$4,480	$6,120,716	$0	$0	$0	$0	$0	$0	$0
5090	Underground Distribution Lines and Feeders Rental Paid	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5095	Overhead Distribution Lines and Feeders - Rental Paid	$4,171	$20,465	$41,086	$13,556	$7,935	$488	$418	$271	$2	$81	$366	$27	$88,864	$0	$0	$0	$0	$0	$0	$0
5096	Other Rent	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5105	Maintenance Supervision and Engineering	$490,358	$1,630,084	$2,529,806	$837,539	$531,029	$43,767	$29,118	$18,656	$142	$29,153	$24,999	$4,516	$6,169,165	$0	$0	$0	$0	$0	$0	$0
5110	Maintenance of Buildings and Fixtures - Distribution Stations	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5112	Maintenance of Transformer Station Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5114	Maintenance of Distribution Station Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5120	Maintenance of Poles, Towers and Fixtures	$457,838	$2,246,593	$4,510,308	$1,488,145	$871,042	$53,581	$45,890	$29,754	$214	$8,861	$40,142	$2,931	$9,755,301	$0	$0	$0	$0	$0	$0	$0
5125	Maintenance of Overhead Conductors and Devices	$1,317,743	$6,466,108	$12,981,495	$4,283,155	$2,507,020	$154,216	$132,080	$85,637	$617	$25,505	$115,537	$8,436	$28,077,547	$0	$0	$0	$0	$0	$0	$0
5130	Maintenance of Overhead Service	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5135	Overhead Distribution Lines and Feeders - Right of Way	$3,115,970	$15,289,937	$30,696,399	$10,128,065	$5,928,168	$364,663	$312,320	$202,499	$1,459	$60,310	$273,202	$19,947	$66,392,940	$0	$0	$0	$0	$0	$0	$0
5145	Maintenance of Underground Condu	$19,998	$46,452	$45,034	$19,149	$11,971	$172	$686	$445	$1	$0	$1,573	$35	$145,516	$0	$0	$0	$0	$0	$0	$0
5150	Maintenance of Underground Conductors an Devices	$85,102	$197,676	$191,641	$81,489	$50,941	$733	$2,920	$1,893	$3	$0	$6,692	$149	$619,240	$0	$0	$0	$0	$0	$0	$0
5155	Maintenance of Underground Service	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5160	Maintenance of Line Transformer	$209,231	$588,562	$755,856	$228,686	$162,704	$12,393	$9,371	$6,076	$54	$5,937	$0	$0	$1,978,869	$0	$0	$0	$0	$0	$0	$0
5175	Maintenance of Meter	$235,146	$547,258	$533,472	$227,127	$143,136	$56,992	$0	$0	$986	$72,331	$18,865	$10,887	$1,846,200	$0	$0	$0	$0	$0	$0	$0
5305	Supervisior	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5310	Meter Reading Expens	$2,329,176	$6,805,728	$10,709,244	$1,442,426	$1,630,202	$354,613	$0	$0	$0	$0	$185,839	$56,621	$23,513,850	$0	$0	$0	$0	$0	$0	$0
5315	Customer Billing	$4,659,594	$10,892,068	$10,712,098	$1,538,998	$5,218,516	$1,424,898	$166,243	$10,779	$4,843	$169,058	$743,555	$287,951	$35,828,600	$0	$0	$0	$0	$0	$0	$0
5320	Collecting	$1,121,875	$2,622,446	$2,579,115	$370,539	$1,256,444	$343,068	$40,026	$2,595	$1,166	$40,703	$179,023	$69,329	$8,626,330	$0	$0	$0	$0	$0	$0	$0
5325	Collecting- Cash Over and Shor	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5330	Collection Charges	$113,122	$264,429	$260,060	$37,363	$126,691	$34,593	$4,036	$262	$118	$4,104	$18,051	$6,991	$869,820	$0	$0	$0	$0	$0	$0	$0
5335	Bad Debt Expense	$1,993,660	$5,507,458	$5,594,679	$419,343	$1,327,286	$1,473,243	$110,533	$20,546	$1,014	$473,480	$157,608	$317,551	$17,396,400	$0	$0	$0	$0	$0	$0	$0
5340	Miscellaneous Customer Accounts Expenses	$619,546	$1,448,224	$1,424,295	$204,627	$693,861	$189,456	$22,104	$1,433	$644	$22,478	$98,864	$38,286	$4,763,820	$0	$0	$0	$0	$0	$0	$0
5405	Supervision	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5410	Community Relations - Sundr	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5415	Energy Conservatior	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

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USoA Account #	Accounts	UR	R1	R2	Seasonal	GSe	GSd	St Lgt	Sen Lgt	Dgen	ST	UGe	UGd	Total - Customer	UR	R1	R2	Seasonal	GSe	GSd	St Lgt
5420	Community Safety Progran	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5425	Miscellaneous Customer Service and Informational Expenses	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5505	Supervisior	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5510	Demonstrating and Selling Expens	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5515	Advertising Expense	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5520	Miscellaneous Sales Expens	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5605	Executive Salaries and Expense	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5610	Management Salaries and Expense	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5615	General Administrative Salaries and Expenses	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5620	Office Supplies and Expenses	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5625	Administrative Expense Transferred Credit	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5630	Outside Services Employec	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5635	Property Insurance	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5640	Injuries and Damages	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5645	Employee Pensions and Benefit	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5650	Franchise Requirements	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5655	Regulatory Expenses	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5660	General Advertising Expense:	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5665	Miscellaneous General Expense	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5670	Rent	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5675	Maintenance of General Plar	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5680	Electrical Safety Authority Fee:	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5685	Independent Market Operator Fees and Penalties	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5705	Amortization Expense - Property, Plant, and Equipment	$7,034,157	$21,013,105	$29,397,310	$10,173,107	$6,502,669	$956,761	$294,312	$186,911	$9,395	$943,276	$425,770	$147,084	$77,083,856							
5710	Amortization of Limited Term Electric Plant	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
5715	Amortization of Intangibles and Other Electric Plant	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
5720	Amortization of Electric Plant Acquisition Adjustments	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0							
5730	Amortization of Unrecovered Plant and Regulatory Study Costs														$0	$0	$0	$0	$0	$0	$0
5735	Amortization of Deferred Development Costs														$0	$0	$0	$0	$0	$0	$0
5740	Amortization of Deferred Charge:														$0	$0	$0	$0	$0	$0	$0
6005	Interest on Long Term Deb	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
6105	Taxes Other Than Income Taxe:	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
6110	Income Taxes	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
6205	Donations	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
6210	Life Insurance	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
6215	Penalties	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
6225	Other Deductions	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
		$173,204,577	$545,902,878	$807,009,770	$265,395,875	$176,161,340	$23,310,475	$8,488,038	$5,242,063	$165,544	$17,698,434	$10,357,717	$3,363,321	$2,036,300,033	($67,468,346)	($231,614,699)	($459,195,913)	($88,335,705)	($135,486,870)	($126,634,615)	($6,278,315)

Hydro One Networks - Distribution

Output Sheet Summarizing All Allocators by Accounts by Cl

Uniform System of Accounts - Detail Accounts:

								Allocation of General Plant and Administration												
		8	12	13	14	15		1	2	3	4	5	6	7	8	12	13	14	15	
USoA Account #	Accounts	Sen Lgt	Dgen	ST	UGe	UGd	Total - Mis	UR	R1	R2	Seasonal	GSe	GSd	St Lgt	Sen Lgt	Dgen	ST	UGe	UGd	Total - A&G
1565	Conservation and Demand Management Expenditures and Recoveries	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1608	Franchises and Consents	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1805	Land	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1805-1	Land Station >50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1805-2	Land Station <50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1806	Land Rights	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1806-1	Land Rights Station >50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1806-2	Land Rights Station <50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1808	Buildings and Fixtures	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1808-1	Buildings and Fixtures > 50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1808-2	Buildings and Fixtures < 50 KV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1810	Leasehold Improvements	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1810-1	Leasehold Improvements >50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1810-2	Leasehold Improvements <50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1815	Transformer Station Equipment - Normally Primary above 50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1815-1	HVDS - Rural	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1815-2	HVDS - lo LV Specific	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1815-3	HVDS - hi LV Specific	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1815-4	HVDS - lo LV Shared	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1815-5	HVDS - hi LV Shared	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1820	Distribution Station Equipment - Normally Primary below 50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1820-1	Distribution Station Equipment - Normally Primary below 50 kV (Bulk)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1820-2	Distribution Station Equipment - Normally Primary below 50 kV (Primary)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1820-3	Distribution Station Equipment - Normally Primary below 50 kV (Wholesale Meters)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1825	Storage Battery Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1825-1	Storage Battery Equipment > 50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1825-2	Storage Battery Equipment <50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1830	Poles, Towers and Fixtures	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1830-3	Poles, Towers and Fixtures - Subtransmission Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1830-3A	Bulk-LV Fixtures	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1830-3B	Bulk-Retail Fixtures	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1830-4	Poles, Towers and Fixtures - Primary	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1830-4A	Primary-LV Fixtures	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1830-4B	Primary-Retail Fixtures	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1830-5	Poles, Towers and Fixtures - Secondary	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1835	Overhead Conductors and Devices	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1835-3	Overhead Conductors and Devices - Subtransmission Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1835-3A	Bulk-LV Conductors	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1835-3B	Bulk-Retail Conductors	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1835-4	Overhead Conductors and Devices - Primary	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1835-4A	Primary-LV Conductors	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1835-4B	Primary-Retail Conductors	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1835-5	Overhead Conductors and Devices - Secondary	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1840	Underground Conduit	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1840-3	Underground Conduit - Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1840-4	Underground Conduit - Primary	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1840-5	Underground Conduit - Secondary	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1845	Underground Conductors and Devices	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1845-3	Underground Conductors and Devices - Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1845-4	Underground Conductors and Devices - Primary	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1845-5	Underground Conductors and Devices - Secondary	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1850	Line Transformers	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1850-1	TRF-LV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

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USoA Account #	Accounts	Sen Lgt	Dgen	ST	UGe	UGd	Total - Mis	UR	R1	R2	Seasonal	GSe	GSd	St Lgt	Sen Lgt	Dgen	ST	UGe	UGd	Total - A&G
1850-2	TRF-Rural	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1855	Services	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1860	Meters	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1860-1	Mtr-Single	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1860-2	Mtr-Poly	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1860-3	Mtr-LV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1860-4	Mtr-Smart	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1875	St Lgts	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1905	Land	$0	$0	$0	$0	$0	$0	$192,583	$713,421	$1,163,073	$251,105	$346,017	$399,590	$29,502	$6,400	$193	$83,411	$29,853	$68,649	$3,283,798
1906	Land Rights	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1908	Buildings and Fixtures	$0	$0	$0	$0	$0	$0	$5,565,598	$20,617,724	$33,612,566	$7,256,892	$9,999,812	$11,548,056	$852,612	$184,956	$5,580	$2,410,569	$862,750	$1,983,937	$94,901,052
1910	Leasehold Improvements	$0	$0	$0	$0	$0	$0	$270,980	$1,003,844	$1,636,543	$353,327	$486,875	$562,257	$41,512	$9,005	$272	$117,367	$42,006	$96,595	$4,620,582
1915	Office Furniture and Equipment	$0	$0	$0	$0	$0	$0	$148,777	$551,144	$898,516	$193,988	$267,311	$308,697	$22,792	$4,944	$149	$64,438	$23,063	$53,034	$2,536,853
1920	Computer Equipment - Hardware	$0	$0	$0	$0	$0	$0	$3,260,364	$12,077,999	$19,690,463	$4,251,135	$5,857,956	$6,764,928	$499,466	$108,348	$3,269	$1,412,127	$505,405	$1,162,204	$55,593,665
1925	Computer Software	$0	$0	$0	$0	$0	$0	$12,055,975	$44,661,288	$72,810,194	$15,719,589	$21,661,193	$25,014,937	$1,846,895	$400,643	$12,087	$5,221,678	$1,868,855	$4,297,526	$205,570,861
1930	Transportation Equipment	$0	$0	$0	$0	$0	$0	$11,683,524	$43,281,548	$70,560,838	$15,233,958	$20,992,005	$24,242,140	$1,789,838	$388,266	$11,714	$5,060,363	$1,811,119	$4,164,760	$199,220,074
1935	Stores Equipment	$0	$0	$0	$0	$0	$0	$386,314	$1,431,098	$2,333,083	$503,708	$694,097	$801,563	$59,181	$12,838	$387	$167,320	$59,884	$137,707	$6,587,180
1940	Tools, Shop and Garage Equipment	$0	$0	$0	$0	$0	$0	$133,832	$495,781	$808,259	$174,502	$240,459	$277,688	$20,502	$4,448	$134	$57,965	$20,746	$47,706	$2,282,022
1945	Measurement and Testing Equipment	$0	$0	$0	$0	$0	$0	$179,832	$666,188	$1,086,070	$234,480	$323,108	$373,134	$27,549	$5,976	$180	$77,889	$27,877	$64,104	$3,066,387
1950	Power Operated Equipment	$0	$0	$0	$0	$0	$0	$4,988,171	$18,478,649	$30,125,285	$6,503,995	$8,962,339	$10,349,953	$764,154	$165,767	$5,001	$2,160,474	$773,240	$1,778,105	$85,055,133
1955	Communication Equipment	$0	$0	$0	$0	$0	$0	$1,651,532	$6,118,092	$9,974,175	$2,153,406	$2,967,339	$3,426,764	$253,004	$54,884	$1,656	$715,311	$256,012	$588,712	$28,160,887
1960	Miscellaneous Equipment	$0	$0	$0	$0	$0	$0	$175,862	$651,481	$1,062,094	$229,304	$315,975	$364,897	$26,941	$5,844	$176	$76,169	$27,261	$62,689	$2,998,695
1970	Load Management Controls - Customer Premises	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1975	Load Management Controls - Utility Premises	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1980	System Supervisory Equipment	$0	$0	$0	$0	$0	$0	$1,282,544	$4,751,177	$7,745,727	$1,672,288	$2,304,371	$2,661,150	$196,477	$42,621	$1,286	$555,495	$198,813	$457,181	$21,869,131
1985	Sentinel Lgts						$0													
1990	Other Tangible Property	$0	$0	$0	$0	$0	$0	$309,353	$1,145,995	$1,868,287	$403,360	$555,820	$641,876	$47,391	$10,280	$310	$133,987	$47,954	$110,273	$5,274,886
1995	Contributions and Grants - Credit							($36,854)	($136,524)	($222,572)	($48,053)	($66,216)	($76,468)	($5,646)	($302,314)	($37)	($15,962)	($5,713)	($13,137)	($929,494)
2005	Property Under Capital Leases	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2010	Electric Plant Purchased or Sold	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2105	Accum. Amortization of Electric Utility Plant - Property, Plant, & Equipment							($23,008,973)	($85,236,606)	($138,959,133)	($30,001,026)	($41,340,648)	($47,741,309)	($3,524,821)	($12,658,354)	($23,069)	($9,965,636)	($3,566,731)	($8,201,879)	($404,228,185)
2120	Accumulated Amortization of Electric Utility Plant - Intangibles							$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
3046	Balance Transferred From Income	($290,776)	($9,359)	($3,994,232)	($1,362,237)	($3,227,677)	($151,400,000)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4080	Distribution Services Revenue	($887,720)	($627,466)	($63,422,672)	($11,607,755)	($15,665,873)	($1,024,275,593)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4082	Retail Services Revenues	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4084	Service Transaction Requests (STR) Revenues	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4090	Electric Services Incidental to Energy Sales	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4205	Interdepartmental Rents	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4210	Rent from Electric Property	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4215	Other Utility Operating Income	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4220	Other Electric Revenues	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4225	Late Payment Charges	($5,379)	($3,199)	($476,654)	($257,149)	($179,324)	($14,500,000)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4235	Miscellaneous Service Revenues	($8,363)	($3,758)	($131,175)	($576,936)	($223,426)	($27,800,000)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4240	Provision for Rate Refunds	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4245	Government Assistance Directly Credited to Income	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4305	Regulatory Debits	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4310	Regulatory Credits	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4315	Revenues from Electric Plant Leased to Others	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4320	Expenses of Electric Plant Leased to Others	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4325	Revenues from Merchandise, Jobbing, Etc.	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4330	Costs and Expenses of Merchandising, Jobbing, Etc.	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4335	Profits and Losses from Financial Instrument Hedges	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4340	Profits and Losses from Financial Instrument Investments	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4345	Gains from Disposition of Future Use Utility Plant	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4350	Losses from Disposition of Future Use Utility Plant	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4355	Gain on Disposition of Utility and Other Property	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4360	Loss on Disposition of Utility and Other Property	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4365	Gains from Disposition of Allowances for Emission	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4370	Losses from Disposition of Allowances for Emission	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4390	Miscellaneous Non-Operating Income	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4395	Rate-Payer Benefit Including Interest	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4398	Foreign Exchange Gains and Losses, Including Amortization	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

O5 Details by Class & Accounts

USoA Account #	Accounts	Sen Lgt	Dgen	ST	UGe	UGd	Total - Mis	UR	R1	R2	Seasonal	GSe	GSd	St Lgt	Sen Lgt	Dgen	ST	UGe	UGd	Total - A&G
4405	Interest and Dividend Income	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4415	Equity in Earnings of Subsidiary Companies	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4705	Power Purchased	$0	$0	$0	$0	$0	$0	$120,640,405	$355,856,506	$454,120,215	$57,060,824	$185,646,555	$261,384,838	$9,737,031	$1,809,959	$273,686	$411,443,278	$34,246,845	$67,079,857	$1,959,300,000
4708	Charges-WMS	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4710	Cost of Power Adjustments	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4712	Charges-One-Time	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4714	Charges-NW	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4715	System Control and Load Dispatching	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4716	Charges-CN	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4730	Rural Rate Assistance Expense	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5005	Operation Supervision and Engineerin	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5010	Load Dispatching	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5012	Station Buildings and Fixtures Expens	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5014	Transformer Station Equipment - Operation Labour	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5015	Transformer Station Equipment - Operation Supplies and Expenses	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5016	Distribution Station Equipment - Operation Labour	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5017	Distribution Station Equipment - Operation Supplies and Expenses	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5020	Overhead Distribution Lines and Feeders - Operation Labour	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5025	Overhead Distribution Lines & Feeders - Operation Supplies and Expenses	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5030	Overhead Subtransmission Feeders - Operation	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5035	Overhead Distribution Transformers- Operation	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5040	Underground Distribution Lines and Feeders Operation Labour	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5045	Underground Distribution Lines & Feeders - Operation Supplies & Expenses	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5050	Underground Subtransmission Feeders - Operation	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5055	Underground Distribution Transformers - Operation	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5065	Meter Expense	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5070	Customer Premises - Operation Labou	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5075	Customer Premises - Materials and Expenses	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5085	Miscellaneous Distribution Expense	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5090	Underground Distribution Lines and Feeders Rental Paid	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5095	Overhead Distribution Lines and Feeders - Rental Paid	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5096	Other Rent	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5105	Maintenance Supervision and Engineering	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5110	Maintenance of Buildings and Fixtures - Distribution Stations	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5112	Maintenance of Transformer Station Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5114	Maintenance of Distribution Station Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5120	Maintenance of Poles, Towers and Fixtures	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5125	Maintenance of Overhead Conductors and Devices	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5130	Maintenance of Overhead Service	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5135	Overhead Distribution Lines and Feeders - Right of Way	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5145	Maintenance of Underground Condu	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5150	Maintenance of Underground Conductors and Devices	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5155	Maintenance of Underground Service	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5160	Maintenance of Line Transformers	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5175	Maintenance of Meters	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5305	Supervision	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5310	Meter Reading Expense	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5315	Customer Billing	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5320	Collecting	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5325	Collecting- Cash Over and Shor	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5330	Collection Charges	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5335	Bad Debt Expense	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5340	Miscellaneous Customer Accounts Expenses	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5405	Supervision	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5410	Community Relations - Sundry	$0	$0	$0	$0	$0	$0	$45,493	$161,842	$261,086	$54,263	$70,557	$48,376	$4,294	$1,213	$37	$13,195	$6,234	$6,491	$673,080
5415	Energy Conservation	$0	$0	$0	$0	$0	$0	$67,589	$240,450	$387,897	$80,618	$104,827	$71,873	$6,379	$1,802	$54	$19,604	$9,263	$9,643	$1,000,000

USoA Account #	Accounts	Sen Lgt	Dgen	ST	UGe	UGd	Total - Mis	UR	R1	R2	Seasonal	GSe	GSd	St Lgt	Sen Lgt	Dgen	ST	UGe	UGd	Total - A&G
5420	Community Safety Progran	$0	$0	$0	$0	$0	$0	$50,689	$187,777	$306,129	$66,093	$91,074	$105,175	$7,765	$1,684	$51	$21,954	$7,858	$18,069	$864,318
5425	Miscellaneous Customer Service and Informational Expenses	$0	$0	$0	$0	$0	$0	$689	$2,453	$3,957	$822	$1,069	$733	$65	$18	$1	$200	$94	$98	$10,200
5505	Supervisior	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5510	Demonstrating and Selling Expens	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5515	Advertising Expense	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5520	Miscellaneous Sales Expens	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5605	Executive Salaries and Expense	$0	$0	$0	$0	$0	$0	$391,606	$1,393,142	$2,247,435	$467,093	$607,357	$416,425	$36,962	$10,440	$315	$113,582	$53,666	$55,871	$5,793,895
5610	Management Salaries and Expense	$0	$0	$0	$0	$0	$0	$1,459,900	$5,193,613	$8,378,406	$1,741,318	$2,264,220	$1,552,428	$137,794	$38,921	$1,175	$423,430	$200,066	$208,288	$21,599,559
5615	General Administrative Salaries and Expenses	$0	$0	$0	$0	$0	$0	$2,148,963	$7,644,963	$12,332,956	$2,563,208	$3,332,916	$2,285,164	$202,832	$57,292	$1,730	$623,287	$294,496	$306,598	$31,794,404
5620	Office Supplies and Expenses	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5625	Administrative Expense Transferred Credit	$0	$0	$0	$0	$0	$0	($3,332,220)	($11,854,412)	($19,123,695)	($3,974,555)	($5,168,077)	($3,543,414)	($314,515)	($88,837)	($2,683)	($966,479)	($456,650)	($475,416)	($49,300,954)
5630	Outside Services Employed	$0	$0	$0	$0	$0	$0	$442,578	$1,574,477	$2,539,967	$527,892	$686,412	$470,628	$41,773	$11,799	$356	$128,366	$60,651	$63,144	$6,548,043
5635	Property Insurance	$0	$0	$0	$0	$0	$0	$159,251	$589,944	$961,771	$207,645	$286,129	$330,430	$24,396	$5,292	$160	$68,975	$24,686	$56,767	$2,715,447
5640	Injuries and Damages	$0	$0	$0	$0	$0	$0	$114,502	$407,342	$657,129	$136,574	$177,586	$121,759	$10,807	$3,053	$92	$33,210	$15,691	$16,336	$1,694,082
5645	Employee Pensions and Benefit	$0	$0	$0	$0	$0	$0	$1,594,568	$5,672,695	$9,151,267	$1,901,945	$2,473,081	$1,695,631	$150,505	$42,511	$1,284	$462,490	$218,521	$227,501	$23,592,000
5650	Franchise Requirements	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5655	Regulatory Expenses	$0	$0	$0	$0	$0	$0	$337,509	$1,200,694	$1,936,975	$402,569	$523,457	$358,901	$31,856	$8,998	$272	$97,891	$46,253	$48,153	$4,993,529
5660	General Advertising Expenses	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5665	Miscellaneous General Expense	$0	$0	$0	$0	$0	$0	($27,939)	($99,395)	($160,345)	($33,325)	($43,332)	($29,710)	($2,637)	($745)	($22)	($8,104)	($3,829)	($3,986)	($413,370)
5670	Rent	$0	$0	$0	$0	$0	$0	$523,175	$1,861,200	$3,002,512	$624,024	$811,413	$556,333	$49,380	$13,948	$421	$151,742	$71,696	$74,643	$7,740,487
5675	Maintenance of General Plar	$0	$0	$0	$0	$0	$0	$3,941,271	$14,021,120	$22,619,057	$4,701,010	$6,112,680	$4,191,067	$372,001	$105,075	$3,173	$1,143,129	$540,115	$562,311	$58,312,009
5680	Electrical Safety Authority Fees	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5685	Independent Market Operator Fees and Penalties	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5705	Amortization Expense - Property, Plant, and Equipment							$3,129,910	$11,594,733	$18,902,607	$4,081,039	$5,623,567	$6,494,249	$479,481	$586,414	$3,138	$1,355,625	$485,182	$1,115,701	$53,851,648
5710	Amortization of Limited Term Electric Plant							$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5715	Amortization of Intangibles and Other Electric Plant							$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5720	Amortization of Electric Plant Acquisition Adjustments							$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5730	Amortization of Unrecovered Plant and Regulatory Study Costs	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5735	Amortization of Deferred Development Costs	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5740	Amortization of Deferred Charges	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
6005	Interest on Long Term Deb	$0	$0	$0	$0	$0	$0	$8,587,623	$32,027,770	$52,544,306	$11,311,923	$15,617,539	$18,369,897	$1,326,835	$285,207	$9,180	$3,917,724	$1,336,144	$3,165,852	$148,500,000
6105	Taxes Other Than Income Taxes	$0	$0	$0	$0	$0	$0	$258,149	$962,774	$1,579,514	$340,043	$469,473	$552,210	$39,885	$8,573	$276	$117,769	$40,165	$95,167	$4,464,000
6110	Income Taxes	$0	$0	$0	$0	$0	$0	$2,897,238	$10,805,328	$17,727,069	$3,816,346	$5,268,947	$6,197,521	$447,639	$96,221	$3,097	$1,321,737	$450,780	$1,068,075	$50,100,000
6205	Donations	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
6210	Life Insurance	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
6215	Penalties	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
6225	Other Deductions	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
		($1,192,239)	($643,783)	($68,024,732)	($13,804,077)	($19,296,300)	($1,217,975,593)	$162,670,365	$510,717,315	$706,569,683	$111,163,330	$259,525,263	$341,550,369	$15,737,882	($8,556,609)	$315,083	$428,815,571	$40,630,322	$80,557,330	$2,649,695,903

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Exhibit G2-1-1
Attachment A
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Output Sheet to Show How Various Composite Allocators are Derived

Hydro One Distribution: 12 Rate Classes

Demand Allocators: Columns C to W
Customer Allocators: Columns X to AM

		Demand Allocators	1	2	3	4	5	6	7	8	12	13	14	15	Customer Allocators	1
		Demand Total	UR	R1	R2	Seasonal	GSe	GSd	St Lgt	Sen Lgt	Dgen	ST	UGe	UGd	Customer Total	UR
Composite allocators																
Rate Base		**Vlookup sheet O5 by accounts based on Column A in this spreadsheet, extract demand figures from columns D to W and Customer Data from Y to AR**														
1565	Conservation and Demand Management	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$6,400,000	$432,572
1805-1	Land Station >50 kV		$278,391	$842,156	$1,017,848	$127,359	$309,614	$447,137	$12,742	$2,513	$463	$2,910,894	$58,355	$114,448	$0	$0
1805-2	Land Station <50 kV		$4,646,748	$14,056,812	$16,989,369	$2,125,804	$5,167,913	$7,463,364	$212,688	$41,940	$7,720	$1,500,596	$974,026	$1,910,298	$0	$0
1805	Total	$61,219,197	$4,925,139	$14,898,968	$18,007,217	$2,253,163	$5,477,528	$7,910,501	$225,430	$44,452	$8,182	$4,411,490	$1,032,380	$2,024,746	$0	$0
1806-1	Land Rights Station >50 kV		$1,089,013	$3,294,358	$3,981,633	$498,204	$1,211,153	$1,749,116	$49,846	$9,829	$1,809	$11,386,873	$228,273	$447,698	$0	$0
1806-2	Land Rights Station <50 kV		$18,177,210	$54,987,620	$66,459,232	$8,315,748	$20,215,910	$29,195,284	$831,994	$164,060	$30,199	$5,870,049	$3,810,206	$7,472,730	$0	$0
1806	Total	$239,478,047	$19,266,223	$58,281,978	$70,440,865	$8,813,952	$21,427,064	$30,944,400	$881,840	$173,889	$32,008	$17,256,922	$4,038,479	$7,920,428	$0	$0
1808-1	Buildings and Fixtures > 50 kV		$123,640	$374,023	$452,052	$56,563	$137,507	$198,585	$5,659	$1,116	$205	$1,292,800	$25,917	$50,829	$0	$0
1808-2	Buildings and Fixtures < 50 KV		$229,304	$693,664	$838,378	$104,902	$255,022	$368,296	$10,496	$2,070	$381	$74,050	$48,065	$94,268	$0	$0
1808	Total	$5,437,793	$352,944	$1,067,687	$1,290,430	$161,466	$392,530	$566,881	$16,155	$3,186	$586	$1,366,851	$73,982	$145,097	$0	$0
1810-1	Leasehold Improvements >50 kV		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1810-2	Leasehold Improvements <50 kV		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1810	Total	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1815	Transformer Station Equipment - Normally Primary above 50 kV	$107,852,474	$7,499,214	$22,685,764	$27,418,508	$3,430,756	$8,340,302	$12,044,845	$343,249	$67,685	$12,459	$21,354,790	$1,571,943	$3,082,959	$0	$0
1815-1	HVDS - Rural	$86,497,684	$7,499,214	$22,685,764	$27,418,508	$3,430,756	$8,340,302	$12,044,845	$343,249	$67,685	$12,459	$0	$1,571,943	$3,082,959	$0	$0
1815-2	HVDS - lo LV Specific	$571,618	$0	$0	$0	$0	$0	$0	$0	$0	$0	$571,618	$0	$0	$0	$0
1815-3	HVDS - hi LV Specific	$1,908,989	$0	$0	$0	$0	$0	$0	$0	$0	$0	$1,908,989	$0	$0	$0	$0
1815-4	HVDS - lo LV Shared	$9,437,091	$0	$0	$0	$0	$0	$0	$0	$0	$0	$9,437,091	$0	$0	$0	$0
1815-5	HVDS - hi LV Shared	$9,437,091	$0	$0	$0	$0	$0	$0	$0	$0	$0	$9,437,091	$0	$0	$0	$0
1820-1	Distribution Station Equipment - Normally Primary below 50 kV (Bulk)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1820-2	Distribution Station Equipment - Normally Primary below 50 kV (Primary)	$287,412,402	$20,219,742	$70,423,968	$83,975,568	$4,953,917	$31,528,052	$46,707,891	$3,317,828	$531,403	$3,242	$8,235,782	$5,521,428	$11,993,581	$0	$0
1820-3	Distribution Station Equipment - Normally Primary below 50 kV (Wholesale Meters)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$39,824,763	$2,452,139
1820	Total	$287,412,402	$20,219,742	$70,423,968	$83,975,568	$4,953,917	$31,528,052	$46,707,891	$3,317,828	$531,403	$3,242	$8,235,782	$5,521,428	$11,993,581	$39,824,763	$2,452,139
1815 & 1820	Total	$395,264,876	$27,718,956	$93,109,733	$111,394,076	$8,384,673	$39,868,354	$58,752,735	$3,661,077	$599,088	$15,701	$29,590,572	$7,093,372	$15,076,541	$39,824,763	$2,452,139
1825-1	Storage Battery Equipment > 50 kV		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1825-2	Storage Battery Equipment <50 kV		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1825	Total	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1830-3	Poles, Towers and Fixtures - Subtransmission Bul Delivery	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1830-3A	Bulk-LV Fixtures	$50,225,910	$0	$0	$0	$0	$0	$0	$0	$0	$0	$50,225,910	$0	$0	$0	$0
1830-3B	Bulk-Retail Fixtures	$336,127,241	$5,386,505	$56,940,804	$152,648,853	$21,503,857	$37,661,735	$55,547,736	$1,346,281	$265,472	$48,866	$0	$1,127,010	$3,650,121	$0	$0
1830-4	Poles, Towers and Fixtures - Primary	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1830-4A	Primary-LV Fixtures	$732,791	$0	$0	$0	$0	$0	$0	$0	$0	$0	$732,791	$0	$0	$671,023	$0
1830-4B	Primary-Retail Fixtures	$654,715,329	$8,796,968	$107,067,273	$283,184,021	$18,807,947	$86,234,634	$130,473,253	$7,882,189	$1,262,458	$7,701	$0	$2,397,775	$8,601,110	$599,528,596	$15,606,832
1830-5	Poles, Towers and Fixtures - Secondary	$151,257,258	$13,809,425	$48,314,814	$57,709,087	$3,249,753	$21,712,775	$0	$2,290,303	$363,687	$0	$0	$3,807,414	$0	$138,507,604	$19,062,363
1830	Total	$1,193,058,529	$27,992,898	$212,322,892	$493,541,961	$43,561,557	$145,609,144	$186,020,989	$11,518,773	$1,891,617	$56,568	$50,958,701	$7,332,199	$12,251,231	$738,707,224	$34,669,195
1835-3	Overhead Conductors and Devices - Subtransmission Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1835-3A	Bulk-LV Conductors	$33,587,887	$0	$0	$0	$0	$0	$0	$0	$0	$0	$33,587,887	$0	$0	$0	$0
1835-3B	Bulk-Retail Conductors	$224,780,475	$3,602,151	$38,078,381	$102,081,823	$14,380,409	$25,185,768	$37,146,786	$900,307	$177,531	$32,679	$0	$753,673	$2,440,969	$0	$0

			1	2	3	4	5	6	7	8	12	13	14	15		1
		Demand Total	**UR**	**R1**	**R2**	**Seasonal**	**GSe**	**GSd**	**St Lgt**	**Sen Lgt**	**Dgen**	**ST**	**UGe**	**UGd**	**Customer Total**	**UR**
1835-4	Overhead Conductors and Devices - Primary	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1835-4A	Primary-LV Conductors	$424,329	$0	$0	$0	$0	$0	$0	$0	$0	$0	$424,329	$0	$0	$514,452	$0
1835-4B	Primary-Retail Conductors	$379,118,794	$5,093,963	$61,998,267	$163,980,252	$10,890,910	$49,934,940	$75,551,710	$4,564,252	$731,038	$4,460	$0	$1,388,453	$4,980,550	$459,639,600	$11,965,264
1835-5	Overhead Conductors and Devices - Secondary	$87,586,875	$7,996,471	$27,977,127	$33,416,966	$1,881,799	$12,572,977	$0	$1,326,221	$210,596	$0	$0	$2,204,717	$0	$106,189,397	$14,614,511
1835	Total	$725,498,360	$16,692,586	$128,053,775	$299,479,041	$27,153,118	$87,693,685	$112,698,495	$6,790,780	$1,119,165	$37,138	$34,012,216	$4,346,843	$7,421,518	$566,343,449	$26,579,775
1830 & 1835	Total	$1,918,556,888	$44,685,484	$340,376,667	$793,021,002	$70,714,675	$233,302,829	$298,719,484	$18,309,552	$3,010,781	$93,706	$84,970,917	$11,679,042	$19,672,749	$1,305,050,672	$61,248,970
1840-3	Underground Conduit - Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1840-4	Underground Conduit - Primary	$2,168,189	$157,034	$546,939	$652,185	$38,474	$244,859	$362,751	$25,767	$4,127	$25	$0	$42,881	$93,147	$2,628,689	$359,193
1840-5	Underground Conduit - Secondary	$8,672,755	$791,802	$2,770,264	$3,308,911	$186,334	$1,244,962	$0	$131,321	$20,853	$0	$0	$218,309	$0	$10,514,756	$1,447,113
1840	Total	$10,840,944	$948,836	$3,317,203	$3,961,096	$224,808	$1,489,821	$362,751	$157,088	$24,980	$25	$0	$261,190	$93,147	$13,143,445	$1,806,305
1845-3	Underground Conductors and Devices - Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1845-4	Underground Conductors and Devices - Primary	$61,421,286	$4,448,519	$15,493,886	$18,475,356	$1,089,905	$6,936,446	$10,276,142	$729,951	$116,913	$713	$0	$1,214,762	$2,638,692	$74,466,515	$10,175,351
1845-5	Underground Conductors and Devices - Secondary	$245,685,145	$22,430,464	$78,477,108	$93,736,100	$5,278,530	$35,267,770	$0	$3,720,109	$590,732	$0	$0	$6,184,332	$0	$297,866,061	$40,994,363
1845	Total	$307,106,431	$26,878,983	$93,970,994	$112,211,456	$6,368,435	$42,204,216	$10,276,142	$4,450,060	$707,646	$713	$0	$7,399,094	$2,638,692	$372,332,576	$51,169,714
1840 & 1845	Total	$317,947,375	$27,827,819	$97,288,197	$116,172,552	$6,593,243	$43,694,037	$10,638,893	$4,607,148	$732,626	$738	$0	$7,660,284	$2,731,839	$385,476,022	$52,976,019
1850	Line Transformers	$489,178,757	$0	$0	$235,113	$0	$73,972,976	$310,995,284	$15,757,133	$0	$0	$1,467,536	$12,014,848	$74,735,867	$794,754,988	$84,031,654
1850-1	TRF-LV	$1,467,536	$0	$0	$0	$0	$0	$0	$0	$0	$0	$1,467,536	$0	$0	$2,384,265	$0
1850-2	TRF-Rural	$487,711,220	$0	$0	$235,113	$0	$73,972,976	$310,995,284	$15,757,133	$0	$0	$0	$12,014,848	$74,735,867	$792,370,723	$84,031,654
1815- 1850	Total	$3,120,947,897	$100,232,259	$530,774,596	$1,020,822,743	$85,692,591	$390,838,196	$679,106,396	$42,334,910	$4,342,495	$110,145	$116,029,025	$38,447,545	$112,216,995	$2,525,106,445	$200,708,782
1855	Services	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1815- 1855	Total	$3,120,947,897	$100,232,259	$530,774,596	$1,020,822,743	$85,692,591	$390,838,196	$679,106,396	$42,334,910	$4,342,495	$110,145	$116,029,025	$38,447,545	$112,216,995	$2,525,106,445	$200,708,782
1860	Meters	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$172,889,855	$22,020,598
1860-1	Mtr-Single	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$13,081,021	$1,688,100
1860-2	Mtr-Poly	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$5,379,048	$0
1860-3	Mtr-LV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$6,689,107	$0
1860-4	Mtr-Smart	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$147,740,678	$20,332,497
1815-1860	Total	$3,120,947,897	$100,232,259	$530,774,596	$1,020,822,743	$85,692,591	$390,838,196	$679,106,396	$42,334,910	$4,342,495	$110,145	$116,029,025	$38,447,545	$112,216,995	$2,697,996,299	$222,729,380
1565-1860	Total	$3,427,082,933 $2,704,396,299	$124,776,566	$605,023,229	$1,110,561,255	$96,921,171	$418,135,317	$718,528,177	$43,458,334	$4,564,022	$150,922	$139,064,288	$43,592,386	$122,307,266	$2,704,396,299	$223,161,952
1875	St Lfts	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
		$6,131,479,233	**check from I4**													
	Total Demand And Customer	$6,131,479,233	$347,938,518	$1,325,022,017	$2,198,478,584	$461,520,438	$649,566,251	$742,239,398	$55,417,412	$12,211,481	$301,573	$157,896,039	$55,650,611	$125,236,912		
	Accum Depreication - NFA	($2,378,186,551)	($130,888,944)	($515,529,805)	($870,437,099)	($175,614,986)	($254,837,677)	($277,945,788)	($21,882,053)	($5,002,968)	($69,546)	($58,876,752)	($21,879,978)	($45,220,954)		
	Accum Depreication - NFA ECC	($1,960,411,404)	($103,320,734)	($418,836,867)	($721,147,323)	($142,567,287)	($210,056,946)	($234,682,052)	($17,943,605)	($4,082,359)	($56,317)	($51,947,294)	($17,731,234)	($38,039,384)		
NFA	Net Fixed Assets	$3,753,292,682	$217,049,574	$809,492,211	$1,328,041,485	$285,905,452	$394,728,573	$464,293,609	$33,535,359	$7,208,513	$232,026	$99,019,286	$33,770,633	$80,015,958		
NFA ECC	Net Fixed Assets Excluding Capital Contribution	$4,171,067,829	$244,617,784	$906,185,150	$1,477,331,261	$318,953,150	$439,509,305	$507,557,346	$37,473,807	$8,129,121	$245,256	$105,948,744	$37,919,377	$87,197,527		
			5.8%	21.6%	35.4%	7.6%	10.5%	12.4%	0.9%	0.2%	0.0%	2.6%	0.9%	2.1%	0.0%	

Operating and Maintenance

Allocate all the costs to the O and M expenses before using it as a composite allocator.

Acccounts

5005	Operation Supervision and Engineering	$1,009,836	$32,432	$171,741	$330,305	$27,727	$126,462	$219,736	$13,698	$1,405	$36	$37,543	$12,440	$36,310	$1,089,090	$97,315
5010	Load Dispatching	$384,019	$12,333	$65,310	$125,608	$10,544	$48,091	$83,561	$5,209	$534	$14	$14,277	$4,731	$13,808	$414,158	$37,007
5012	Station Buildings and Fixtures Expense	$396,000	$25,703	$77,753	$93,974	$11,759	$28,585	$41,282	$1,176	$232	$43	$99,539	$5,388	$10,566	$0	$0
5014	Transformer Station Equipment - Operation Labour	$590,000	$41,024	$124,101	$149,991	$18,768	$45,625	$65,891	$1,878	$370	$68	$116,820	$8,599	$16,865	$0	$0
5015	Transformer Station Equipment - Operation Supplies and Expenses	$290,000	$20,164	$60,999	$73,724	$9,225	$22,426	$32,387	$923	$182	$34	$57,420	$4,227	$8,290	$0	$0

			1	2	3	4	5	6	7	8	12	13	14	15		1
		Demand Total	**UR**	**R1**	**R2**	**Seasonal**	**GSe**	**GSd**	**St Lgt**	**Sen Lgt**	**Dgen**	**ST**	**UGe**	**UGd**	**Customer Total**	**UR**
5016	Distribution Station Equipment - Operation Labour	$6,620,000	$465,723	$1,622,083	$1,934,218	$114,104	$726,189	$1,075,828	$76,420	$12,240	$75	$189,696	$127,176	$276,249	$0	$0
5017	Distribution Station Equipment - Operation Supplies and Expenses	$2,500,000	$175,877	$612,569	$730,445	$43,091	$274,241	$406,279	$28,859	$4,622	$28	$71,637	$48,027	$104,324	$0	$0
5020	Overhead Distribution Lines and Feeders - Operation Labour	$2,725,953	$63,491	$483,619	$1,126,752	$100,474	$331,485	$424,431	$26,015	$4,278	$133	$120,730	$16,594	$27,952	$2,948,377	$155,107
5025	Overhead Distribution Lines & Feeders - Operatioı Supplies and Expenses	$446,409	$10,397	$79,199	$184,520	$16,454	$54,285	$69,506	$4,260	$701	$22	$19,771	$2,717	$4,577	$482,833	$25,401
5030	Overhead Subtransmission Feeders - Operation	$564,400	$13,146	$100,132	$233,290	$20,803	$68,633	$87,877	$5,386	$886	$28	$24,997	$3,436	$5,787	$0	$0
5035	Overhead Distribution Transformers- Operation	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5040	Underground Distribution Lines and Feeders - Operation Labour	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5045	Underground Distribution Lines & Feeders - Operation Supplies & Expenses	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5050	Underground Subtransmission Feeders - Operation	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5055	Underground Distribution Transformers - Operation	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5065	Meter Expense	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$6,719,023	$971,111
5070	Customer Premises - Operation Labour	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$13,682,676	$2,094,637
5075	Customer Premises - Materials and Expenses	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$2,074,711	$317,611
5085	Miscellaneous Distribution Expense	$5,048,474	$162,137	$858,586	$1,651,292	$138,617	$632,223	$1,098,529	$68,481	$7,024	$178	$187,690	$62,193	$181,523	$5,444,689	$486,507
5090	Underground Distribution Lines and Feeders - Rental Paid	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5095	Overhead Distribution Lines and Feeders - Rental Paid	$73,296	$1,707	$13,004	$30,296	$2,702	$8,913	$11,412	$699	$115	$4	$3,246	$446	$752	$79,277	$4,171
5096	Other Rent	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5105	Maintenance Supervision and Engineering	$5,088,435	$163,420	$865,382	$1,664,363	$139,714	$637,228	$1,107,224	$69,023	$7,080	$180	$189,175	$62,685	$182,960	$5,487,786	$490,358
5110	Maintenance of Buildings and Fixtures - Distribution Stations	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5112	Maintenance of Transformer Station Equipment	$1,895,500	$131,798	$398,701	$481,878	$60,295	$146,580	$211,687	$6,033	$1,190	$219	$375,309	$27,627	$54,183	$0	$0
5114	Maintenance of Distribution Station Equipment	$18,339,300	$1,290,188	$4,493,634	$5,358,339	$316,101	$2,011,752	$2,980,352	$211,705	$33,908	$207	$525,511	$352,313	$765,290	$0	$0
5120	Maintenance of Poles, Towers and Fixtures	$10,653,279	$249,959	$1,895,913	$4,407,026	$388,978	$1,300,200	$1,661,053	$102,856	$16,891	$505	$455,030	$65,472	$109,396	$8,702,885	$457,838
5125	Maintenance of Overhead Conductors and Devices	$23,158,853	$532,849	$4,087,643	$9,559,761	$866,763	$2,799,297	$3,597,483	$216,771	$35,725	$1,185	$1,085,714	$138,757	$236,905	$25,048,500	$1,317,743
5130	Maintenance of Overhead Services	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5135	Overhead Distribution Lines and Feeders - Right c Way	$54,762,060	$1,275,474	$9,715,494	$22,635,484	$2,018,434	$6,659,247	$8,526,458	$522,616	$85,938	$2,675	$2,425,355	$333,359	$561,526	$59,230,372	$3,115,970
5145	Maintenance of Underground Conduit	$120,024	$10,505	$36,726	$43,855	$2,489	$16,494	$4,016	$1,739	$277	$0	$0	$2,892	$1,031	$130,634	$19,998
5150	Maintenance of Underground Conductors and Devices	$510,760	$44,703	$156,287	$186,623	$10,592	$70,191	$17,091	$7,401	$1,177	$1	$0	$12,306	$4,389	$555,908	$85,102
5155	Maintenance of Underground Services	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5160	Maintenance of Line Transformers	$1,218,011	$0	$0	$585	$0	$184,186	$774,350	$39,234	$0	$0	$3,654	$29,916	$186,086	$1,782,336	$209,231
5175	Maintenance of Meters	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$1,543,003	$235,146
5305	Supervision	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5310	Meter Reading Expense	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$21,286,574	$2,329,176
5315	Customer Billing	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$27,802,758	$4,659,594
5320	Collecting	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$6,693,975	$1,121,875
5325	Collecting- Cash Over and Short	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5330	Collection Charges	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$674,975	$113,122
5335	Bad Debt Expense	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$13,515,140	$1,993,660
5340	Miscellaneous Customer Accounts Expenses	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$3,696,693	$619,546
O&M DC	Total	$136,394,609	$4,723,031	$25,918,874	$51,002,331	$4,317,633	$16,192,333	$22,496,433	$1,410,383	$214,774	$5,633	$6,003,114	$1,321,300	$2,788,769	$209,086,374	$20,957,227
O&M	Total Demand and Customer	$379,945,270	$25,680,258	$91,357,822	$147,379,654	$30,630,509	$39,828,568	$27,307,859	$2,423,859	$684,638	$20,673	$7,448,318	$3,519,246	$3,663,865		
Acccounts																
4705	Power Purchased	$1,959,300,000	$120,640,405	$355,856,506	$454,120,215	$57,060,824	$185,646,555	$261,384,838	$9,737,031	$1,809,959	$273,686	$411,443,278	$34,246,845	$67,079,857	$1,959,300,000	
4708	Charges-WMS	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
4710	Cost of Power Adjustments	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
4712	Charges-One-Time	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	

			1	2	3	4	5	6	7	8	12	13	14	15		1
		Demand Total	**UR**	**R1**	**R2**	**Seasonal**	**GSe**	**GSd**	**St Lgt**	**Sen Lgt**	**Dgen**	**ST**	**UGe**	**UGd**	**Customer Total**	**UR**
4714	Charges-NW	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
4716	Charges-CN	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
4730	Rural Rate Assistance Expense	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5685	Independent Market Operator Fees and Penalties	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
COP	Cost of Power	$1,959,300,000	$120,640,405	$355,856,506	$454,120,215	$57,060,824	$185,646,555	$261,384,838	$9,737,031	$1,809,959	$273,686	$411,443,278	$34,246,845	$67,079,857	$1,959,300,000	
Acccounts																
5005	Operation Supervision and Engineering	$2,234,150	$129,747	$495,243	$832,362	$193,943	$231,849	$228,422	$19,477	$5,107	$64	$43,329	$17,402	$37,206	$2,234,150	
5010	Load Dispatching	$849,600	$49,340	$188,330	$316,530	$73,752	$88,167	$86,864	$7,407	$1,942	$24	$16,477	$6,617	$14,149	$849,600	
5012	Station Buildings and Fixtures Expense	$396,000	$25,703	$77,753	$93,974	$11,759	$28,585	$41,282	$1,176	$232	$43	$99,539	$5,388	$10,566	$396,000	
5014	Transformer Station Equipment - Operation Labour	$590,000	$41,024	$124,101	$149,991	$18,768	$45,625	$65,891	$1,878	$370	$68	$116,820	$8,599	$16,865	$590,000	
5015	Transformer Station Equipment - Operation Supplies and Expenses	$290,000	$20,164	$60,999	$73,724	$9,225	$22,426	$32,387	$923	$182	$34	$57,420	$4,227	$8,290	$290,000	
5016	Distribution Station Equipment - Operation Labour	$6,620,000	$465,723	$1,622,083	$1,934,218	$114,104	$726,189	$1,075,828	$76,420	$12,240	$75	$189,696	$127,176	$276,249	$6,620,000	
5017	Distribution Station Equipment - Operation Supplies and Expenses	$2,500,000	$175,877	$612,569	$730,445	$43,091	$274,241	$406,279	$28,859	$4,622	$28	$71,637	$48,027	$104,324	$2,500,000	
5020	Overhead Distribution Lines and Feeders - Operation Labour	$6,030,870	$218,598	$1,244,724	$2,654,762	$604,630	$626,578	$442,583	$41,562	$14,358	$206	$123,732	$30,193	$28,945	$6,030,870	
5025	Overhead Distribution Lines & Feeders - Operatioı Supplies and Expenses	$987,630	$35,798	$203,839	$434,750	$99,016	$102,610	$72,479	$6,806	$2,351	$34	$20,263	$4,945	$4,740	$987,630	
5030	Overhead Subtransmission Feeders - Operation	$564,400	$13,146	$100,132	$233,290	$20,803	$68,633	$87,877	$5,386	$886	$28	$24,997	$3,436	$5,787	$564,400	
5035	Overhead Distribution Transformers- Operation	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5040	Underground Distribution Lines and Feeders - Operation Labour	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5045	Underground Distribution Lines & Feeders - Operation Supplies & Expenses	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5050	Underground Subtransmission Feeders - Operation	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5055	Underground Distribution Transformers - Operation	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5065	Meter Expense	$8,157,050	$971,111	$2,312,720	$2,399,449	$1,035,743	$709,625	$123,597	$0	$0	$2,269	$482,781	$96,452	$23,302	$8,157,050	
5070	Customer Premises - Operation Labour	$15,338,600	$2,094,637	$4,865,439	$4,716,903	$2,005,698	$1,253,809	$90,669	$71,875	$46,602	$1,081	$8,699	$164,723	$18,465	$15,338,600	
5075	Customer Premises - Materials and Expenses	$2,325,800	$317,611	$737,749	$715,226	$304,125	$190,116	$13,748	$10,898	$7,066	$164	$1,319	$24,977	$2,800	$2,325,800	
5085	Miscellaneous Distribution Expense	$11,169,190	$648,643	$2,475,868	$4,161,231	$969,578	$1,159,082	$1,141,952	$97,371	$25,534	$319	$216,614	$86,996	$186,004	$11,169,190	
5090	Underground Distribution Lines and Feeders - Rental Paid	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5095	Overhead Distribution Lines and Feeders - Rental Paid	$162,160	$5,878	$33,469	$71,382	$16,257	$16,848	$11,900	$1,118	$386	$6	$3,327	$812	$778	$162,160	
5096	Other Rent	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5105	Maintenance Supervision and Engineering	$11,257,600	$653,778	$2,495,466	$4,194,169	$977,253	$1,168,257	$1,150,991	$98,141	$25,736	$321	$218,329	$87,684	$187,476	$11,257,600	
5110	Maintenance of Buildings and Fixtures - Distribution Stations	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5112	Maintenance of Transformer Station Equipment	$1,895,500	$131,798	$398,701	$481,878	$60,295	$146,580	$211,687	$6,033	$1,190	$219	$375,309	$27,627	$54,183	$1,895,500	
5114	Maintenance of Distribution Station Equipment	$18,339,300	$1,290,188	$4,493,634	$5,358,339	$316,101	$2,011,752	$2,980,352	$211,705	$33,908	$207	$525,511	$352,313	$765,290	$18,339,300	
5120	Maintenance of Poles, Towers and Fixtures	$20,408,580	$707,798	$4,142,506	$8,917,334	$1,877,123	$2,171,242	$1,714,634	$148,746	$46,645	$719	$463,891	$105,614	$112,327	$20,408,580	
5125	Maintenance of Overhead Conductors and Devices	$51,236,400	$1,850,592	$10,553,752	$22,541,256	$5,149,918	$5,306,317	$3,751,699	$348,850	$121,362	$1,802	$1,111,219	$254,294	$245,340	$51,236,400	
5130	Maintenance of Overhead Services	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5135	Overhead Distribution Lines and Feeders - Right c Way	$121,155,000	$4,391,444	$25,005,431	$53,331,883	$12,146,500	$12,587,415	$8,891,121	$834,936	$288,437	$4,134	$2,485,665	$606,561	$581,473	$121,155,000	
5145	Maintenance of Underground Conduit	$265,540	$30,503	$83,178	$88,889	$21,638	$28,465	$4,188	$2,425	$721	$1	$0	$4,464	$1,066	$265,540	
5150	Maintenance of Underground Conductors and Devices	$1,130,000	$129,806	$353,963	$378,264	$92,080	$121,132	$17,823	$10,321	$3,070	$5	$0	$18,998	$4,538	$1,130,000	
5155	Maintenance of Underground Services	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5160	Maintenance of Line Transformers	$3,196,880	$209,231	$588,562	$756,441	$228,686	$346,890	$786,743	$48,604	$6,076	$54	$9,591	$29,916	$186,086	$3,196,880	
5175	Maintenance of Meters	$1,846,200	$235,146	$547,258	$533,472	$227,127	$143,136	$56,992	$0	$0	$986	$72,331	$18,865	$10,887	$1,846,200	
5305	Supervision	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5310	Meter Reading Expense	$23,513,850	$2,329,176	$6,805,728	$10,709,244	$1,442,426	$1,630,202	$354,613	$0	$0	$0	$0	$185,839	$56,621	$23,513,850	
5315	Customer Billing	$35,828,600	$4,659,594	$10,892,068	$10,712,098	$1,538,998	$5,218,516	$1,424,898	$166,243	$10,779	$4,843	$169,058	$743,555	$287,951	$35,828,600	
5320	Collecting	$8,626,330	$1,121,875	$2,622,446	$2,579,115	$370,539	$1,256,444	$343,068	$40,026	$2,595	$1,166	$40,703	$179,023	$69,329	$8,626,330	

			1	2	3	4	5	6	7	8	12	13	14	15		1
		Demand Total	**UR**	**R1**	**R2**	**Seasonal**	**GSe**	**GSd**	**St Lgt**	**Sen Lgt**	**Dgen**	**ST**	**UGe**	**UGd**	**Customer Total**	**UR**
5325	Collecting- Cash Over and Short	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5330	Collection Charges	$869,820	$113,122	$264,429	$260,060	$37,363	$126,691	$34,593	$4,036	$262	$118	$4,104	$18,051	$6,991	$869,820	
5335	Bad Debt Expense	$17,396,400	$1,993,660	$5,507,458	$5,594,679	$419,343	$1,327,286	$1,473,243	$110,533	$20,546	$1,014	$473,480	$157,608	$317,551	$17,396,400	
5340	Miscellaneous Customer Accounts Expenses	$4,763,820	$619,546	$1,448,224	$1,424,295	$204,627	$693,861	$189,456	$22,104	$1,433	$644	$22,478	$98,864	$38,286	$4,763,820	
5405	Supervision	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5410	Community Relations - Sundry	$673,080	$45,493	$161,842	$261,086	$54,263	$70,557	$48,376	$4,294	$1,213	$37	$13,195	$6,234	$6,491	$673,080	
5415	Energy Conservation	$1,000,000	$67,589	$240,450	$387,897	$80,618	$104,827	$71,873	$6,379	$1,802	$54	$19,604	$9,263	$9,643	$1,000,000	
5420	Community Safety Program	$864,318	$50,689	$187,777	$306,129	$66,093	$91,074	$105,175	$7,765	$1,684	$51	$21,954	$7,858	$18,069	$864,318	
5425	Miscellaneous Customer Service and Informationa Expenses	$10,200	$689	$2,453	$3,957	$822	$1,069	$733	$65	$18	$1	$200	$94	$98	$10,200	
5505	Supervision	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5510	Demonstrating and Selling Expense	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5515	Advertising Expense	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5520	Miscellaneous Sales Expense	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5605	Executive Salaries and Expenses	$5,793,895	$391,606	$1,393,142	$2,247,435	$467,093	$607,357	$416,425	$36,962	$10,440	$315	$113,582	$53,666	$55,871	$5,793,895	
5610	Management Salaries and Expenses	$21,599,559	$1,459,900	$5,193,613	$8,378,406	$1,741,318	$2,264,220	$1,552,428	$137,794	$38,921	$1,175	$423,430	$200,066	$208,288	$21,599,559	
5615	General Administrative Salaries and Expenses	$31,794,404	$2,148,963	$7,644,963	$12,332,956	$2,563,208	$3,332,916	$2,285,164	$202,832	$57,292	$1,730	$623,287	$294,496	$306,598	$31,794,404	
5620	Office Supplies and Expenses	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5625	Administrative Expense Transferred Credit	($49,300,954)	($3,332,220)	($11,854,412)	($19,123,695)	($3,974,555)	($5,168,077)	($3,543,414)	($314,515)	($88,837)	($2,683)	($966,479)	($456,650)	($475,416)	($49,300,954)	
5630	Outside Services Employed	$6,548,043	$442,578	$1,574,477	$2,539,967	$527,892	$686,412	$470,628	$41,773	$11,799	$356	$128,366	$60,651	$63,144	$6,548,043	
5635	Property Insurance	$2,715,447	$159,251	$589,944	$961,771	$207,645	$286,129	$330,430	$24,396	$5,292	$160	$68,975	$24,686	$56,767	$2,715,447	
5640	Injuries and Damages	$1,694,082	$114,502	$407,342	$657,129	$136,574	$177,586	$121,759	$10,807	$3,053	$92	$33,210	$15,691	$16,336	$1,694,082	
5645	Employee Pensions and Benefits	$23,592,000	$1,594,568	$5,672,695	$9,151,267	$1,901,945	$2,473,081	$1,695,631	$150,505	$42,511	$1,284	$462,490	$218,521	$227,501	$23,592,000	
5650	Franchise Requirements	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5655	Regulatory Expenses	$4,993,529	$337,509	$1,200,694	$1,936,975	$402,569	$523,457	$358,901	$31,856	$8,998	$272	$97,891	$46,253	$48,153	$4,993,529	
5660	General Advertising Expenses	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5665	Miscellaneous General Expenses	($413,370)	($27,939)	($99,395)	($160,345)	($33,325)	($43,332)	($29,710)	($2,637)	($745)	($22)	($8,104)	($3,829)	($3,986)	($413,370)	
5670	Rent	$7,740,487	$523,175	$1,861,200	$3,002,512	$624,024	$811,413	$556,333	$49,380	$13,948	$421	$151,742	$71,696	$74,643	$7,740,487	
5675	Maintenance of General Plant	$58,312,009	$3,941,271	$14,021,120	$22,619,057	$4,701,010	$6,112,680	$4,191,067	$372,001	$105,075	$3,173	$1,143,129	$540,115	$562,311	$58,312,009	
5680	Electrical Safety Authority Fees	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
6105	Taxes Other Than Income Taxes	$4,464,000	$258,149	$962,774	$1,579,514	$340,043	$469,473	$552,210	$39,885	$8,573	$276	$117,769	$40,165	$95,167	$4,464,000	
6205	Donations	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
6210	Life Insurance	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
6215	Penalties	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
6225	Other Deductions	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
	OM&A Expenses	$502,025,997	$33,856,032	$120,518,500	$194,461,671	$40,437,746	$52,629,410	$36,491,868	$3,223,404	$905,676	$27,365	$9,892,558	$4,648,223	$4,933,543	$502,025,997	

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Exhibit G2-1-1
Attachment A
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Output Sheet to Show How Various Composite Allocators are Derived

Demand Allocators: Columns C to W
Customer Allocators: Columns X to AM

		2	3	4	5	6	7	8	12	13	14	15	
		R1	R2	Seasonal	GSe	GSd	St Lgt	Sen Lgt	Dgen	ST	UGe	UGd	Total
Composite allocators													
Rate Base													
1565	Conservation and Demand Management	$1,538,880	$2,482,541	$515,957	$670,894	$459,988	$40,829	$11,532	$348	$125,463	$59,280	$61,716	$6,400,000
1805-1	Land Station >50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1805-2	Land Station <50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1805	Total	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$61,219,197
1806-1	Land Rights Station >50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1806-2	Land Rights Station <50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1806	Total	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$239,478,047
1808-1	Buildings and Fixtures > 50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1808-2	Buildings and Fixtures < 50 KV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1808	Total	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$5,437,793
1810-1	Leasehold Improvements >50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1810-2	Leasehold Improvements <50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1810	Total	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1815	Transformer Station Equipment - Normally Primary above 50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$107,852,474
1815-1	HVDS - Rural	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$86,497,684
1815-2	HVDS - lo LV Specific	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$571,618
1815-3	HVDS - hi LV Specific	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$1,908,989
1815-4	HVDS - lo LV Shared	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$9,437,091
1815-5	HVDS - hi LV Shared	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$9,437,091
1820-1	Distribution Station Equipment - Normally Primary below 50 kV (Bulk)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1820-2	Distribution Station Equipment - Normally Primary below 50 kV (Primary)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$287,412,402
1820-3	Distribution Station Equipment - Normally Primary below 50 kV (Wholesale Meters)	$7,233,145	$9,230,455	$1,159,819	$3,773,455	$5,312,912	$197,915	$36,789	$5,563	$8,363,003	$696,102	$1,363,466	$39,824,763
1820	Total	$7,233,145	$9,230,455	$1,159,819	$3,773,455	$5,312,912	$197,915	$36,789	$5,563	$8,363,003	$696,102	$1,363,466	$327,237,165
1815 & 1820	Total	$7,233,145	$9,230,455	$1,159,819	$3,773,455	$5,312,912	$197,915	$36,789	$5,563	$8,363,003	$696,102	$1,363,466	$435,089,639
1825-1	Storage Battery Equipment > 50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1825-2	Storage Battery Equipment <50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1825	Total	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1830-3	Poles, Towers and Fixtures - Subtransmission Bul Delivery	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1830-3A	Bulk-LV Fixtures	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$50,225,910
1830-3B	Bulk-Retail Fixtures	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$336,127,241
1830-4	Poles, Towers and Fixtures - Primary	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1830-4A	Primary-LV Fixtures	$0	$0	$0	$0	$0	$0	$0	$0	$671,023	$0	$0	$1,403,814
1830-4B	Primary-Retail Fixtures	$125,842,105	$298,610,653	$94,434,843	$54,548,167	$4,057,348	$2,820,858	$1,828,965	$16,233	$0	$1,540,656	$221,937	$1,254,243,925
1830-5	Poles, Towers and Fixtures - Secondary	$44,278,199	$42,926,438	$18,252,967	$11,410,362	$0	$654,104	$424,103	$0	$0	$1,499,068	$0	$289,764,863
1830	Total	$170,120,304	$341,537,090	$112,687,810	$65,958,529	$4,057,348	$3,474,962	$2,253,068	$16,233	$671,023	$3,039,723	$221,937	$1,931,765,752
1835-3	Overhead Conductors and Devices - Subtransmission Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1835-3A	Bulk-LV Conductors	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$33,587,887
1835-3B	Bulk-Retail Conductors	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$224,780,475

		2	3	4	5	6	7	8	12	13	14	15	
		R1	**R2**	**Seasonal**	**GSe**	**GSd**	**St Lgt**	**Sen Lgt**	**Dgen**	**ST**	**UGe**	**UGd**	**Total**
1835-4	Overhead Conductors and Devices - Primary	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1835-4A	Primary-LV Conductors	$0	$0	$0	$0	$0	$0	$0	$0	$514,452	$0	$0	$938,781
1835-4B	Primary-Retail Conductors	$96,479,159	$228,935,336	$72,400,205	$41,820,353	$3,110,641	$2,162,662	$1,402,210	$12,445	$0	$1,181,172	$170,152	$838,758,394
1835-5	Overhead Conductors and Devices - Secondary	$33,946,694	$32,910,341	$13,993,972	$8,747,963	$0	$501,481	$325,146	$0	$0	$1,149,288	$0	$193,776,271
1835	Total	$130,425,853	$261,845,678	$86,394,177	$50,568,316	$3,110,641	$2,664,143	$1,727,356	$12,445	$514,452	$2,330,460	$170,152	$1,291,841,808
1830 & 1835	Total	$300,546,157	$603,382,768	$199,081,987	$116,526,845	$7,167,989	$6,139,105	$3,980,425	$28,678	$1,185,475	$5,370,183	$392,090	$3,223,607,561
1840-3	Underground Conduit - Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1840-4	Underground Conduit - Primary	$834,336	$808,864	$343,941	$215,006	$15,548	$12,325	$7,991	$71	$0	$28,247	$3,167	$4,796,878
1840-5	Underground Conduit - Secondary	$3,361,364	$3,258,746	$1,385,668	$866,214	$0	$49,656	$32,196	$0	$0	$113,801	$0	$19,187,512
1840	Total	$4,195,700	$4,067,610	$1,729,609	$1,081,219	$15,548	$61,981	$40,187	$71	$0	$142,048	$3,167	$23,984,390
1845-3	Underground Conductors and Devices - Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1845-4	Underground Conductors and Devices - Primary	$23,635,380	$22,913,820	$9,743,301	$6,090,768	$440,454	$349,156	$226,383	$2,009	$0	$800,191	$89,702	$135,887,801
1845-5	Underground Conductors and Devices - Secondary	$95,222,012	$92,314,996	$39,253,725	$24,538,433	$0	$1,406,677	$912,050	$0	$0	$3,223,804	$0	$543,551,206
1845	Total	$118,857,393	$115,228,816	$48,997,026	$30,629,201	$440,454	$1,755,833	$1,138,433	$2,009	$0	$4,023,995	$89,702	$679,439,007
1840 & 1845	Total	$123,053,092	$119,296,425	$50,726,635	$31,710,420	$456,002	$1,817,815	$1,178,620	$2,080	$0	$4,166,044	$92,868	$703,423,397
1850	Line Transformers	$236,378,793	$303,567,488	$91,845,247	$65,345,125	$4,977,253	$3,763,414	$2,440,092	$21,657	$2,384,265	$0	$0	$1,283,933,745
1850-1	TRF-LV	$0	$0	$0	$0	$0	$0	$0	$0	$2,384,265	$0	$0	$3,851,801
1850-2	TRF-Rural	$236,378,793	$303,567,488	$91,845,247	$65,345,125	$4,977,253	$3,763,414	$2,440,092	$21,657	$0	$0	$0	$1,280,081,943
1815- 1850	Total	$667,211,187	$1,035,477,136	$342,813,688	$217,355,846	$17,914,156	$11,918,249	$7,635,927	$57,977	$11,932,743	$10,232,329	$1,848,424	$5,646,054,341
1855	Services	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1815- 1855	Total	$667,211,187	$1,035,477,136	$342,813,688	$217,355,846	$17,914,156	$11,918,249	$7,635,927	$57,977	$11,932,743	$10,232,329	$1,848,424	$5,646,054,341
1860	Meters	$51,248,721	$49,957,652	$21,269,622	$13,404,195	$5,337,076	$0	$0	$92,325	$6,773,545	$1,766,616	$1,019,505	$172,889,855
1860-1	Mtr-Single	$4,020,245	$4,171,006	$1,800,451	$1,233,555	$0	$0	$0	$0	$0	$167,665	$0	$13,081,021
1860-2	Mtr-Poly	$0	$0	$0	$0	$4,456,956	$0	$0	$81,830	$0	$0	$840,262	$5,379,048
1860-3	Mtr-LV	$0	$0	$0	$0	$0	$0	$0	$0	$6,689,107	$0	$0	$6,689,107
1860-4	Mtr-Smart	$47,228,476	$45,786,646	$19,469,171	$12,170,640	$880,120	$0	$0	$10,495	$84,437	$1,598,951	$179,243	$147,740,678
1815-1860	Total	$718,459,908	$1,085,434,788	$364,083,310	$230,760,040	$23,251,232	$11,918,249	$7,635,927	$150,303	$18,706,288	$11,998,945	$2,867,929	$5,818,944,196
1565-1860	Total	$719,998,788	$1,087,917,329	$364,599,267	$231,430,934	$23,711,221	$11,959,078	$7,647,459	$150,651	$18,831,751	$12,058,225	$2,929,645	$6,131,479,233
1875	St Lfts	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Total Demand And Customer												
	Accum Depreication - NFA												
	Accum Depreication - NFA ECC												
NFA	Net Fixed Assets												
NFA ECC	Net Fixed Assets Excluding Capital Contribution												

Operating and Maintenance

Acccounts

		R1	R2	Seasonal	GSe	GSd	St Lgt	Sen Lgt	Dgen	ST	UGe	UGd
5005	Operation Supervision and Engineering	$323,502	$502,058	$166,215	$105,386	$8,686	$5,779	$3,702	$28	$5,786	$4,961	$896
5010	Load Dispatching	$123,021	$190,922	$63,208	$40,076	$3,303	$2,197	$1,408	$11	$2,200	$1,887	$341
5012	Station Buildings and Fixtures Expense	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5014	Transformer Station Equipment - Operation Labour	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5015	Transformer Station Equipment - Operation Supplies and Expenses	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

		2	3	4	5	6	7	8	12	13	14	15	
		R1	R2	Seasonal	GSe	GSd	St Lgt	Sen Lgt	Dgen	ST	UGe	UGd	Total
5016	Distribution Station Equipment - Operation Labour	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5017	Distribution Station Equipment - Operation Supplies and Expenses	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5020	Overhead Distribution Lines and Feeders - Operation Labour	$761,105	$1,528,009	$504,156	$295,093	$18,152	$15,547	$10,080	$73	$3,002	$13,599	$993	
5025	Overhead Distribution Lines & Feeders - Operatio Supplies and Expenses	$124,640	$250,231	$82,562	$48,325	$2,973	$2,546	$1,651	$12	$492	$2,227	$163	
5030	Overhead Subtransmission Feeders - Operation	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5035	Overhead Distribution Transformers- Operation	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5040	Underground Distribution Lines and Feeders - Operation Labour	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5045	Underground Distribution Lines & Feeders - Operation Supplies & Expenses	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5050	Underground Subtransmission Feeders - Operation	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5055	Underground Distribution Transformers - Operation	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5065	Meter Expense	$2,312,720	$2,399,449	$1,035,743	$709,625	$123,597	$0	$0	$2,269	$482,781	$96,452	$23,302	
5070	Customer Premises - Operation Labour	$4,865,439	$4,716,903	$2,005,698	$1,253,809	$90,669	$71,875	$46,602	$1,081	$8,699	$164,723	$18,465	
5075	Customer Premises - Materials and Expenses	$737,749	$715,226	$304,125	$190,116	$13,748	$10,898	$7,066	$164	$1,319	$24,977	$2,800	
5085	Miscellaneous Distribution Expense	$1,617,282	$2,509,938	$830,961	$526,858	$43,423	$28,889	$18,509	$141	$28,924	$24,803	$4,480	
5090	Underground Distribution Lines and Feeders - Rental Paid	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5095	Overhead Distribution Lines and Feeders - Rental Paid	$20,465	$41,086	$13,556	$7,935	$488	$418	$271	$2	$81	$366	$27	
5096	Other Rent	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5105	Maintenance Supervision and Engineering	$1,630,084	$2,529,806	$837,539	$531,029	$43,767	$29,118	$18,656	$142	$29,153	$24,999	$4,516	
5110	Maintenance of Buildings and Fixtures - Distribution Stations	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5112	Maintenance of Transformer Station Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5114	Maintenance of Distribution Station Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5120	Maintenance of Poles, Towers and Fixtures	$2,246,593	$4,510,308	$1,488,145	$871,042	$53,581	$45,890	$29,754	$214	$8,861	$40,142	$2,931	
5125	Maintenance of Overhead Conductors and Devices	$6,466,108	$12,981,495	$4,283,155	$2,507,020	$154,216	$132,080	$85,637	$617	$25,505	$115,537	$8,436	
5130	Maintenance of Overhead Services	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5135	Overhead Distribution Lines and Feeders - Right c Way	$15,289,937	$30,696,399	$10,128,065	$5,928,168	$364,663	$312,320	$202,499	$1,459	$60,310	$273,202	$19,947	
5145	Maintenance of Underground Conduit	$46,452	$45,034	$19,149	$11,971	$172	$686	$445	$1	$0	$1,573	$35	
5150	Maintenance of Underground Conductors and Devices	$197,676	$191,641	$81,489	$50,941	$733	$2,920	$1,893	$3	$0	$6,692	$149	
5155	Maintenance of Underground Services	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5160	Maintenance of Line Transformers	$588,562	$755,856	$228,686	$162,704	$12,393	$9,371	$6,076	$54	$5,937	$0	$0	
5175	Maintenance of Meters	$547,258	$533,472	$227,127	$143,136	$56,992	$0	$0	$986	$72,331	$18,865	$10,887	
5305	Supervision	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5310	Meter Reading Expense	$6,805,728	$10,709,244	$1,442,426	$1,630,202	$354,613	$0	$0	$0	$0	$185,839	$56,621	
5315	Customer Billing	$10,892,068	$10,712,098	$1,538,998	$5,218,516	$1,424,898	$166,243	$10,779	$4,843	$169,058	$743,555	$287,951	
5320	Collecting	$2,622,446	$2,579,115	$370,539	$1,256,444	$343,068	$40,026	$2,595	$1,166	$40,703	$179,023	$69,329	
5325	Collecting- Cash Over and Short	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5330	Collection Charges	$264,429	$260,060	$37,363	$126,691	$34,593	$4,036	$262	$118	$4,104	$18,051	$6,991	
5335	Bad Debt Expense	$5,507,458	$5,594,679	$419,343	$1,327,286	$1,473,243	$110,533	$20,546	$1,014	$473,480	$157,608	$317,551	
5340	Miscellaneous Customer Accounts Expenses	$1,448,224	$1,424,295	$204,627	$693,861	$189,456	$22,104	$1,433	$644	$22,478	$98,864	$38,286	
O&M DC	Total	$65,438,948	$96,377,323	$26,312,876	$23,636,235	$4,811,426	$1,013,476	$469,864	$15,041	$1,445,203	$2,197,946	$875,097	
O&M	Total Demand and Customer												

Acccounts	
4705	Power Purchased
4708	Charges-WMS
4710	Cost of Power Adjustments
4712	Charges-One-Time

		2	3	4	5	6	7	8	12	13	14	15	
		R1	R2	Seasonal	GSe	GSd	St Lgt	Sen Lgt	Dgen	ST	UGe	UGd	Total
4714	Charges-NW												
4716	Charges-CN												
4730	Rural Rate Assistance Expense												
5685	Independent Market Operator Fees and Penalties												
COP	Cost of Power												
Acccounts													
5005	Operation Supervision and Engineering												
5010	Load Dispatching												
5012	Station Buildings and Fixtures Expense												
5014	Transformer Station Equipment - Operation Labour												
5015	Transformer Station Equipment - Operation Supplies and Expenses												
5016	Distribution Station Equipment - Operation Labour												
5017	Distribution Station Equipment - Operation Supplies and Expenses												
5020	Overhead Distribution Lines and Feeders - Operation Labour												
5025	Overhead Distribution Lines & Feeders - Operatio Supplies and Expenses												
5030	Overhead Subtransmission Feeders - Operation												
5035	Overhead Distribution Transformers- Operation												
5040	Underground Distribution Lines and Feeders - Operation Labour												
5045	Underground Distribution Lines & Feeders - Operation Supplies & Expenses												
5050	Underground Subtransmission Feeders - Operation												
5055	Underground Distribution Transformers - Operation												
5065	Meter Expense												
5070	Customer Premises - Operation Labour												
5075	Customer Premises - Materials and Expenses												
5085	Miscellaneous Distribution Expense												
5090	Underground Distribution Lines and Feeders - Rental Paid												
5095	Overhead Distribution Lines and Feeders - Rental Paid												
5096	Other Rent												
5105	Maintenance Supervision and Engineering												
5110	Maintenance of Buildings and Fixtures - Distribution Stations												
5112	Maintenance of Transformer Station Equipment												
5114	Maintenance of Distribution Station Equipment												
5120	Maintenance of Poles, Towers and Fixtures												
5125	Maintenance of Overhead Conductors and Devices												
5130	Maintenance of Overhead Services												
5135	Overhead Distribution Lines and Feeders - Right c Way												
5145	Maintenance of Underground Conduit												
5150	Maintenance of Underground Conductors and Devices												
5155	Maintenance of Underground Services												
5160	Maintenance of Line Transformers												
5175	Maintenance of Meters												
5305	Supervision												
5310	Meter Reading Expense												
5315	Customer Billing												
5320	Collecting												

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		2	3	4	5	6	7	8	12	13	14	15	
		R1	R2	Seasonal	GSe	GSd	St Lgt	Sen Lgt	Dgen	ST	UGe	UGd	Total
5325	Collecting- Cash Over and Short												
5330	Collection Charges												
5335	Bad Debt Expense												
5340	Miscellaneous Customer Accounts Expenses												
5405	Supervision												
5410	Community Relations - Sundry												
5415	Energy Conservation												
5420	Community Safety Program												
5425	Miscellaneous Customer Service and Informationa Expenses												
5505	Supervision												
5510	Demonstrating and Selling Expense												
5515	Advertising Expense												
5520	Miscellaneous Sales Expense												
5605	Executive Salaries and Expenses												
5610	Management Salaries and Expenses												
5615	General Administrative Salaries and Expenses												
5620	Office Supplies and Expenses												
5625	Administrative Expense Transferred Credit												
5630	Outside Services Employed												
5635	Property Insurance												
5640	Injuries and Damages												
5645	Employee Pensions and Benefits												
5650	Franchise Requirements												
5655	Regulatory Expenses												
5660	General Advertising Expenses												
5665	Miscellaneous General Expenses												
5670	Rent												
5675	Maintenance of General Plant												
5680	Electrical Safety Authority Fees												
6105	Taxes Other Than Income Taxes												
6205	Donations												
6210	Life Insurance												
6215	Penalties												
6225	Other Deductions												
	OM&A Expenses												

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Hydro One Networks - Distribution

Hydro One Distribution: 12 Rate Classes

Output sheet for Amortization

Categorization and Allocation of Contributed Capital

Contributed Capital - 1995

Account	Description	Contributed Capital	Demand	Customer	Total	Demand Allocation 1 UR	2 R1	3 R2	4 Seasonal	5 GSe	6 GSd	7 St Lgt	8 Sen Lgt	12 Dgen	13 ST	14 UGe	15 UGd	Sub -total Total	Customer Allocation 1 UR	2 R1	3 R2
1565	Conservation and Demand Management	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1805	Land	($443,615)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1805-1	Land Station >50 kV	($44,362)	($44,362)	$0	($44,362)	($2,017)	($6,103)	($7,376)	($923)	($2,244)	($3,240)	($92)	($18)	($3)	($21,093)	($423)	($829)	($44,362)	$0	$0	$0
1805-2	Land Station <50 kV	($399,254)	($399,254)	$0	($399,254)	($33,672)	($101,860)	($123,111)	($15,404)	($37,448)	($54,082)	($1,541)	($304)	($56)	($10,874)	($7,058)	($13,843)	($399,254)	$0	$0	$0
1806	Land Rights	($8,619,326)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1806-1	Land Rights Station >50 kV	($861,933)	($861,933)	$0	($861,933)	($39,196)	($118,571)	($143,307)	($17,931)	($43,592)	($62,954)	($1,794)	($354)	($65)	($409,838)	($8,216)	($16,114)	($861,933)	$0	$0	$0
1806-2	Land Rights Station <50 kV	($7,757,394)	($7,757,394)	$0	($7,757,394)	($654,237)	($1,979,122)	($2,392,010)	($299,302)	($727,614)	($1,050,801)	($29,945)	($5,905)	($1,087)	($211,276)	($137,137)	($268,960)	($7,757,394)	$0	$0	$0
1808	Buildings and Fixtures	($80,204)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1808-1	Buildings and Fixtures > 50 kV	($40,102)	($40,102)	$0	($40,102)	($1,824)	($5,517)	($6,667)	($834)	($2,028)	($2,929)	($83)	($16)	($3)	($19,068)	($382)	($750)	($40,102)	$0	$0	$0
1808-2	Buildings and Fixtures < 50 KV	($40,102)	($40,102)	$0	($40,102)	($3,382)	($10,231)	($12,366)	($1,547)	($3,761)	($5,432)	($155)	($31)	($6)	($1,092)	($709)	($1,390)	($40,102)	$0	$0	$0
1810	Leasehold Improvements	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1810-1	Leasehold Improvements >50 kV (Wholesale)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1810-2	Leasehold Improvements <50 kV (Other)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1815	Transformer Station Equipment - Normally Primary above 50 kV	($3,354,573)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1815-1	HVDS - Rural	($2,690,367)	($2,690,367)	$0	($2,690,367)	($233,251)	($705,603)	($852,807)	($106,708)	($259,411)	($374,635)	($10,676)	($2,105)	($388)	$0	($48,893)	($95,890)	($2,690,367)	$0	$0	$0
1815-2	HVDS - lo LV Specific	($17,779)	($17,779)	$0	($17,779)	$0	$0	$0	$0	$0	$0	$0	$0	$0	($17,779)	$0	$0	($17,779)	$0	$0	$0
1815-3	HVDS - hi LV Specific	($59,376)	($59,376)	$0	($59,376)	$0	$0	$0	$0	$0	$0	$0	$0	$0	($59,376)	$0	$0	($59,376)	$0	$0	$0
1815-4	HVDS - lo LV Shared	($293,525)	($293,525)	$0	($293,525)	$0	$0	$0	$0	$0	$0	$0	$0	$0	($293,525)	$0	$0	($293,525)	$0	$0	$0
1815-5	HVDS - hi LV Shared	($293,525)	($293,525)	$0	($293,525)	$0	$0	$0	$0	$0	$0	$0	$0	$0	($293,525)	$0	$0	($293,525)	$0	$0	$0
1820	Distribution Station Equipment - Normally Primary below 50 kV	($1,648,708)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1820-1	Distribution Station Equipment - Normally Primary below 50 kV (Bulk)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1820-2	Distribution Station Equipment - Normally Primary below 50 kV (Primary)	($1,648,708)	($1,648,708)	$0	($1,648,708)	($115,988)	($403,979)	($481,716)	($28,418)	($180,857)	($267,934)	($19,032)	($3,048)	($19)	($47,244)	($31,673)	($68,800)	($1,648,708)	$0	$0	$0
1820-3	Distribution Station Equipment - Normally Primary below 50 kV (Wholesale Meters)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1825	Storage Battery Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1825-1	Storage Battery Equipment > 50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1825-2	Storage Battery Equipment <50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1830	Poles, Towers and Fixtures	($124,290,053)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1830-3	Poles, Towers and Fixtures - Subtransmission Bulk Delivery	($24,858,011)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1830-3A	Bulk-LV Fixtures	($3,231,541)	($3,231,541)	$0	($3,231,541)	$0	$0	$0	$0	$0	$0	$0	$0	$0	($3,231,541)	$0	$0	($3,231,541)	$0	$0	$0
1830-3B	Bulk-Retail Fixtures	($21,626,469)	($21,626,469)	$0	($21,626,469)	($346,568)	($3,663,579)	($9,821,446)	($1,383,561)	($2,423,161)	($3,573,948)	($86,620)	($17,080)	($3,144)	$0	($72,512)	($234,849)	($21,626,469)	$0	$0	$0
1830-4	Poles, Towers and Fixtures - Primary	($80,788,534)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1830-4A	Primary-LV Fixtures	($90,322)	($47,148)	($43,174)	($90,322)	$0	$0	$0	$0	$0	$0	$0	$0	$0	($47,148)	$0	$0	($47,148)	$0	$0	$0
1830-4B	Primary-Retail Fixtures	($80,698,213)	($42,124,467)	($38,573,746)	($80,698,213)	($565,998)	($6,888,722)	($18,220,096)	($1,210,106)	($5,548,347)	($8,394,666)	($507,141)	($81,227)	($496)	$0	($154,273)	($553,396)	($42,124,467)	($1,004,146)	($8,096,697)	($19,212,647)
1830-5	Poles, Towers and Fixtures - Secondary	($18,643,508)	($9,731,911)	($8,911,597)	($18,643,508)	($888,500)	($3,108,581)	($3,713,010)	($209,090)	($1,397,003)	$0	($147,358)	($23,400)	$0	$0	($244,970)	$0	($9,731,911)	($1,226,475)	($2,848,865)	($2,761,892)
1835	Overhead Conductors and Devices	($66,898,941)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

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Account	Description	Contributed Capital	Demand	Customer	Total	UR	R1	R2	Seasonal	GSe	GSd	St Lgt	Sen Lgt	Dgen	ST	UGe	UGd	Total	UR	R1	R2
1835-3	Overhead Conductors and Devices - Subtransmission Bulk Delivery	($13,379,788)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1835-3A	Bulk-LV Conductors	($1,739,372)	($1,739,372)	$0	($1,739,372)	$0	$0	$0	$0	$0	$0	$0	$0	$0	($1,739,372)	$0	$0	($1,739,372)	$0	$0	$0
1835-3B	Bulk-Retail Conductors	($11,640,416)	($11,640,416)	$0	($11,640,416)	($186,540)	($1,971,916)	($5,286,379)	($744,700)	($1,304,263)	($1,923,673)	($46,623)	($9,194)	($1,692)	$0	($39,029)	($126,407)	($11,640,416)	$0	$0	$0
1835-4	Overhead Conductors and Devices - Primary	($43,484,312)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1835-4A	Primary-LV Conductors	($48,615)	($21,974)	($26,641)	($48,615)	$0	$0	$0	$0	$0	$0	$0	$0	$0	($21,974)	$0	$0	($21,974)	$0	$0	$0
1835-4B	Primary-Retail Conductors	($43,435,696)	($19,632,935)	($23,802,762)	($43,435,696)	($263,794)	($3,210,624)	($8,491,833)	($563,993)	($2,585,916)	($3,912,499)	($236,363)	($37,857)	($231)	$0	($71,902)	($257,921)	($19,632,935)	($619,630)	($4,996,241)	($11,855,578)
1835-5	Overhead Conductors and Devices - Secondary	($10,034,841)	($4,535,748)	($5,499,093)	($10,034,841)	($414,103)	($1,448,815)	($1,730,521)	($97,450)	($651,101)	$0	($68,679)	($10,906)	$0	$0	($114,173)	$0	($4,535,748)	($756,823)	($1,757,954)	($1,704,285)
1840	Underground Conduit	($1,089,202)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1840-3	Underground Conduit - Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1840-4	Underground Conduit - Primary	($217,840)	($98,464)	($119,377)	($217,840)	($7,131)	($24,838)	($29,618)	($1,747)	($11,120)	($16,474)	($1,170)	($187)	($1)	$0	($1,947)	($4,230)	($98,464)	($16,312)	($37,890)	($36,733)
1840-5	Underground Conduit - Secondary	($871,362)	($393,856)	($477,506)	($871,362)	($35,958)	($125,806)	($150,267)	($8,462)	($56,537)	$0	($5,964)	($947)	$0	$0	($9,914)	$0	($393,856)	($65,718)	($152,650)	($147,989)
1845	Underground Conductors and Devices	($120,883,300)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1845-3	Underground Conductors and Devices - Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1845-4	Underground Conductors and Devices - Primary	($24,176,660)	($10,927,850)	($13,248,810)	($24,176,660)	($791,464)	($2,756,615)	($3,287,068)	($193,912)	($1,234,107)	($1,828,294)	($129,870)	($20,801)	($127)	$0	($216,126)	($469,466)	($10,927,850)	($1,810,361)	($4,205,120)	($4,076,743)
1845-5	Underground Conductors and Devices - Secondary	($96,706,640)	($43,711,401)	($52,995,239)	($96,706,640)	($3,990,746)	($13,962,360)	($16,677,184)	($939,137)	($6,274,713)	$0	($661,868)	($105,101)	$0	$0	($1,100,294)	$0	($43,711,401)	($7,293,567)	($16,941,552)	($16,424,346)
1850	Line Transformers	($85,947,524)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1850-1	TRF-LV	($257,843)	($98,238)	($159,605)	($257,843)	$0	$0	$0	$0	$0	$0	$0	$0	$0	($98,238)	$0	$0	($98,238)	$0	$0	$0
1850-2	TRF-Rural	($85,689,681)	($32,647,768)	($53,041,913)	($85,689,681)	$0	$0	($15,739)	$0	($4,951,809)	($20,818,266)	($1,054,795)	$0	$0	$0	($804,283)	($5,002,877)	($32,647,768)	($5,625,144)	($15,823,380)	($20,321,044)
1855	Services	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1860	Meters	($4,519,700)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1860-1	Mtr-Single	($341,965)	$0	($341,965)	($341,965)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($44,130)	($105,098)	($109,039)
1860-2	Mtr-Poly	($140,620)	$0	($140,620)	($140,620)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1860-3	Mtr-LV	($174,867)	$0	($174,867)	($174,867)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1860-4	Mtr-Smart	($3,862,249)	$0	($3,862,249)	($3,862,249)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($531,534)	($1,234,651)	($1,196,958)
1875	St Lgts	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Sub - Total	($417,775,147)	($216,355,986)	($201,419,161)	($417,775,147)	($8,574,370)	($40,492,842)	($71,442,521)	($5,823,225)	($27,695,031)	($42,289,826)	($3,009,771)	($318,481)	($7,317)	($6,522,964)	($3,063,915)	($7,115,723)	($216,355,986)	($18,993,839)	($56,200,097)	($77,847,255)
General Plant																					
1905	Land	$0																			
1906	Land Rights	$0																			
1908	Buildings and Fixtures	($124,317)																			
1910	Leasehold Improvements	$0																			
1915	Office Furniture and Equipment	$0																			
1920	Computer Equipment - Hardware	($6,399)																			
1925	Computer Software	($2,133)																			
1930	Transportation Equipment	$0																			
1935	Stores Equipment	$0																			
1940	Tools, Shop and Garage Equipment	$0																			
1945	Measurement and Testing Equipment	$0																			
1950	Power Operated Equipment	$0																			
1955	Communication Equipment	($83,530)																			
1960	Miscellaneous Equipment	$0																			
1970	Load Management Controls Customer Premises	$0																			
1975	Load Management Controls Utility Premises	$0																			
1980	System Supervisory Equipment	($412,025)																			
1985	Sentinel Lgts	($301,089)																			
1990	Other Tangible Property	$0																			
2005	Property Under Capital Leases	$0																			
2010	Electric Plant Purchased or Sold	$0																			
	Sub - Total	($929,494)																			

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Account	Description	Contributed Capital	Demand	Customer	Total	UR	R1	R2	Seasonal	GSe	GSd	St Lgt	Sen Lgt	Dgen	ST	UGe	UGd	Total	UR	R1	R2
	TOTAL - 1995	($418,704,641)	($216,355,986)	($201,419,161)	($417,775,147)	($8,574,370)	($40,492,842)	($71,442,521)	($5,823,225)	($27,695,031)	($42,289,826)	($3,009,771)	($318,481)	($7,317)	($6,522,964)	($3,063,915)	($7,115,723)	($216,355,986)	($18,993,839)	($56,200,097)	($77,847,255)

Accumulated Depreciation - 2105 Captial Contribution

						Demand Allocation 1	2	3	4	5	6	7	8	12	13	14	15	Sub -total	Customer Allocation 1	2	3
Account	Description	Accumulated Depreciation	Demand	Customer	Total	UR	R1	R2	Seasonal	GSe	GSd	St Lgt	Sen Lgt	Dgen	ST	UGe	UGd	Sub -total	UR	R1	R2
1565	Conservation and Demand Management	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1805	Land	($137,823)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1805-1	Land Station >50 kV	($13,782)	($13,782)	$0	($13,782)	($627)	($1,896)	($2,291)	($287)	($697)	($1,007)	($29)	($6)	($1)	($6,553)	($131)	($258)	($13,782)	$0	$0	$0
1805-2	Land Station <50 kV	($124,040)	($124,040)	$0	($124,040)	($10,461)	($31,646)	($38,248)	($4,786)	($11,635)	($16,802)	($479)	($94)	($17)	($3,378)	($2,193)	($4,301)	($124,040)	$0	$0	$0
1806	Land Rights	($2,130,226)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1806-1	Land Rights Station >50 kV	($213,023)	($213,023)	$0	($213,023)	($9,687)	($29,304)	($35,418)	($4,432)	($10,774)	($15,559)	($443)	($87)	($16)	($101,289)	($2,031)	($3,982)	($213,023)	$0	$0	$0
1806-2	Land Rights Station <50 kV	($1,917,203)	($1,917,203)	$0	($1,917,203)	($161,691)	($489,131)	($591,174)	($73,971)	($179,826)	($259,700)	($7,401)	($1,459)	($269)	($52,216)	($33,893)	($66,472)	($1,917,203)	$0	$0	$0
1808	Buildings and Fixtures	($32,787)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1808-1	Buildings and Fixtures > 50 kV	($16,393)	($16,393)	$0	($16,393)	($745)	($2,255)	($2,726)	($341)	($829)	($1,197)	($34)	($7)	($1)	($7,795)	($156)	($306)	($16,393)	$0	$0	$0
1808-2	Buildings and Fixtures < 50 KV	($16,393)	($16,393)	$0	($16,393)	($1,383)	($4,182)	($5,055)	($632)	($1,538)	($2,221)	($63)	($12)	($2)	($446)	($290)	($568)	($16,393)	$0	$0	$0
1810	Leasehold Improvements	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1810-1	Leasehold Improvements >50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1810-2	Leasehold Improvements <50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1815	Transformer Station Equipment - Normally Primary above 50 kV	($1,257,888)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1815-1	HVDS - Rural	($1,008,827)	($1,008,827)	$0	($1,008,827)	($87,464)	($264,585)	($319,783)	($40,013)	($97,273)	($140,480)	($4,003)	($789)	($145)	$0	($18,334)	($35,957)	($1,008,827)	$0	$0	$0
1815-2	HVDS - lo LV Specific	($6,667)	($6,667)	$0	($6,667)	$0	$0	$0	$0	$0	$0	$0	$0	$0	($6,667)	$0	$0	($6,667)	$0	$0	$0
1815-3	HVDS - hi LV Specific	($22,265)	($22,265)	$0	($22,265)	$0	$0	$0	$0	$0	$0	$0	$0	$0	($22,265)	$0	$0	($22,265)	$0	$0	$0
1815-4	HVDS - lo LV Shared	($110,065)	($110,065)	$0	($110,065)	$0	$0	$0	$0	$0	$0	$0	$0	$0	($110,065)	$0	$0	($110,065)	$0	$0	$0
1815-5	HVDS - hi LV Shared	($110,065)	($110,065)	$0	($110,065)	$0	$0	$0	$0	$0	$0	$0	$0	$0	($110,065)	$0	$0	($110,065)	$0	$0	$0
1820	Distribution Station Equipment - Normally Primary below 50 kV	($1,088,478)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1820-1	Distribution Station Equipment - Normally Primary below 50 kV (Bulk)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1820-2	Distribution Station Equipment - Normally Primary below 50 kV (Primary)	($1,088,478)	($1,088,478)	$0	($1,088,478)	($76,576)	($266,707)	($318,029)	($18,761)	($119,402)	($176,891)	($12,565)	($2,013)	($12)	($31,190)	($20,911)	($45,422)	($1,088,478)	$0	$0	$0
1820-3	Distribution Station Equipment - Normally Primary below 50 kV (Wholesale Meters)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1825	Storage Battery Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1825-1	Storage Battery Equipment > 50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1825-2	Storage Battery Equipment <50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1830	Poles, Towers and Fixtures	($30,945,903)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1830-3	Poles, Towers and Fixtures - Subtransmission Bulk Delivery	($6,189,181)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1830-3A	Bulk-LV Fixtures	($804,593)	($804,593)	$0	($804,593)	$0	$0	$0	$0	$0	$0	$0	$0	$0	($804,593)	$0	$0	($804,593)	$0	$0	$0
1830-3B	Bulk-Retail Fixtures	($5,384,587)	($5,384,587)	$0	($5,384,587)	($86,289)	($912,163)	($2,445,357)	($344,481)	($603,322)	($889,846)	($21,567)	($4,253)	($783)	$0	($18,054)	($58,473)	($5,384,587)	$0	$0	$0
1830-4	Poles, Towers and Fixtures - Primary	($20,114,837)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1830-4A	Primary-LV Fixtures	($22,488)	($11,739)	($10,749)	($22,488)	$0	$0	$0	$0	$0	$0	$0	$0	$0	($11,739)	$0	$0	($11,739)	$0	$0	$0
1830-4B	Primary-Retail Fixtures	($20,092,349)	($10,488,206)	($9,604,143)	($20,092,349)	($140,923)	($1,715,163)	($4,536,464)	($301,294)	($1,381,435)	($2,090,115)	($126,269)	($20,224)	($123)	$0	($38,411)	($137,785)	($10,488,206)	($250,014)	($2,015,926)	($4,783,591)
1830-5	Poles, Towers and Fixtures - Secondary	($4,641,885)	($2,423,064)	($2,218,821)	($4,641,885)	($221,220)	($773,979)	($924,470)	($52,059)	($347,828)	$0	($36,689)	($5,826)	$0	$0	($60,993)	$0	($2,423,064)	($305,369)	($709,314)	($687,660)
1835	Overhead Conductors and Devices	($14,870,323)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1835-3	Overhead Conductors and Devices - Subtransmission Bulk Delivery	($2,974,065)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1835-3A	Bulk-LV Conductors	($386,628)	($386,628)	$0	($386,628)	$0	$0	$0	$0	$0	$0	$0	$0	$0	($386,628)	$0	$0	($386,628)	$0	$0	$0
1835-3B	Bulk-Retail Conductors	($2,587,436)	($2,587,436)	$0	($2,587,436)	($41,464)	($438,318)	($1,175,058)	($165,532)	($289,912)	($427,595)	($10,363)	($2,044)	($376)	$0	($8,675)	($28,098)	($2,587,436)	$0	$0	$0
1835-4	Overhead Conductors and Devices - Primary	($9,665,710)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

Account	Description	Contributed Capital	Demand	Customer	Total	UR	R1	R2	Seasonal	GSe	GSd	St Lgt	Sen Lgt	Dgen	ST	UGe	UGd	Total	UR	R1	R2
1835-4A	Primary-LV Conductors	($10,806)	($4,884)	($5,922)	($10,806)	$0	$0	$0	$0	$0	$0	$0	$0	$0	($4,884)	$0	$0	($4,884)	$0	$0	$0
1835-4B	Primary-Retail Conductors	($9,654,903)	($4,364,016)	($5,290,887)	($9,654,903)	($58,636)	($713,659)	($1,887,568)	($125,365)	($574,798)	($869,672)	($52,539)	($8,415)	($51)	$0	($15,982)	($57,331)	($4,364,016)	($137,732)	($1,110,566)	($2,635,263)
1835-5	Overhead Conductors and Devices - Secondary	($2,230,548)	($1,008,208)	($1,222,341)	($2,230,548)	($92,047)	($322,043)	($384,661)	($21,661)	($144,727)	$0	($15,266)	($2,424)	$0	$0	($25,378)	$0	($1,008,208)	($168,227)	($390,759)	($378,829)
1840	Underground Conduit	($476,947)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1840-3	Underground Conduit - Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1840-4	Underground Conduit - Primary	($95,389)	($43,116)	($52,273)	($95,389)	($3,123)	($10,876)	($12,969)	($765)	($4,869)	($7,214)	($512)	($82)	($1)	$0	($853)	($1,852)	($43,116)	($7,143)	($16,591)	($16,085)
1840-5	Underground Conduit - Secondary	($381,557)	($172,464)	($209,093)	($381,557)	($15,746)	($55,089)	($65,800)	($3,705)	($24,757)	$0	($2,611)	($415)	$0	$0	($4,341)	$0	($172,464)	($28,777)	($66,843)	($64,802)
1845	Underground Conductors and Devices	($46,698,712)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1845-3	Underground Conductors and Devices - Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1845-4	Underground Conductors and Devices - Primary	($9,339,742)	($4,221,564)	($5,118,179)	($9,339,742)	($305,752)	($1,064,915)	($1,269,835)	($74,911)	($476,751)	($706,292)	($50,170)	($8,036)	($49)	$0	($83,492)	($181,361)	($4,221,564)	($699,365)	($1,624,490)	($1,574,896)
1845-5	Underground Conductors and Devices - Secondary	($37,358,969)	($16,886,254)	($20,472,715)	($37,358,969)	($1,541,674)	($5,393,832)	($6,442,602)	($362,800)	($2,423,999)	$0	($255,688)	($40,602)	$0	$0	($425,057)	$0	($16,886,254)	($2,817,595)	($6,544,731)	($6,344,928)
1850	Line Transformers	($14,256,721)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1850-1	TRF-LV	($42,770)	($16,295)	($26,475)	($42,770)	$0	$0	$0	$0	$0	$0	$0	$0	$0	($16,295)	$0	$0	($16,295)	$0	$0	$0
1850-2	TRF-Rural	($14,213,951)	($5,415,515)	($8,798,436)	($14,213,951)	$0	$0	($2,611)	$0	($821,391)	($3,453,272)	($174,966)	$0	$0	$0	($133,412)	($829,862)	($5,415,515)	($933,082)	($2,624,736)	($3,370,795)
1855	Services	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1860	Meters	($2,745,536)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1860-1	Mtr-Single	($207,730)	$0	($207,730)	($207,730)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($26,807)	($63,843)	($66,237)
1860-2	Mtr-Poly	($85,421)	$0	($85,421)	($85,421)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1860-3	Mtr-LV	($106,225)	$0	($106,225)	($106,225)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1860-4	Mtr-Smart	($2,346,160)	$0	($2,346,160)	($2,346,160)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($322,885)	($750,001)	($727,104)
1875	St Lgts	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Sub - Total	($114,641,343)	($58,865,773)	($55,775,570)	($114,641,343)	($2,855,508)	($12,489,743)	($20,460,119)	($1,595,796)	($7,515,762)	($9,057,862)	($771,659)	($96,788)	($1,847)	($1,676,071)	($892,588)	($1,452,029)	($58,865,773)	($5,696,996)	($15,917,799)	($20,650,188)
General Plant																					
1905	Land	$0																			
1906	Land Rights	$0																			
1908	Buildings and Fixtures	($22,732)																			
1910	Leasehold Improvements	$0																			
1915	Office Furniture and Equipment	$0																			
1920	Computer Equipment - Hardware	($2,918)																			
1925	Computer Software	($1,044)																			
1930	Transportation Equipment	$0																			
1935	Stores Equipment	$0																			
1940	Tools, Shop and Garage Equipment	$0																			
1945	Measurement and Testing Equipment	$0																			
1950	Power Operated Equipment	$0																			
1955	Communication Equipment	($19,830)																			
1960	Miscellaneous Equipment	$0																			
1970	Load Management Controls Customer Premises	$0																			
1975	Load Management Controls Utility Premises	$0																			
1980	System Supervisory Equipment	($129,134)																			
1985	Sentinel Lgts	($170,254)																			
1990	Other Tangible Property	$0																			
2005	Property Under Capital Leases	$0																			
2010	Electric Plant Purchased or Sold	$0																			
	Sub - Total	($345,912)																			
	TOTAL - 2105 CC	($114,987,255)	($58,865,773)	($55,775,570)	($114,641,343)	($2,855,508)	($12,489,743)	($20,460,119)	($1,595,796)	($7,515,762)	($9,057,862)	($771,659)	($96,788)	($1,847)	($1,676,071)	($892,588)	($1,452,029)	($58,865,773)	($5,696,996)	($15,917,799)	($20,650,188)

Accumulated Depreciation - 2105 Fixed Assets Only

Demand Allocation													**Customer Allocation**		
1	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**12**	**13**	**14**	**15**	**Sub -total**	**1**	**2**	**3**

Account	Description	Contributed Capital	Demand	Customer	Total	UR	R1	R2	Seasonal	GSe	GSd	St Lgt	Sen Lgt	Dgen	ST	UGe	UGd	Total	UR	R1	R2
Account	Description	Accumulated Depreciation	Demand	Customer	Total	UR	R1	R2	Seasonal	GSe	GSd	St Lgt	Sen Lgt	Dgen	ST	UGe	UGd	Sub -total	UR	R1	R2
1565	Conservation and Demand Management	($775,688)	$0	($775,688)	($775,688)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($52,428)	($186,514)	($300,887)
1805	Land	($31,082,664)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1805-1	Land Station >50 kV	($3,108,266)	($3,108,266)	$0	($3,108,266)	($141,347)	($427,586)	($516,790)	($64,664)	($157,200)	($227,024)	($6,470)	($1,276)	($235)	($1,477,941)	($29,628)	($58,108)	($3,108,266)	$0	$0	$0
1805-2	Land Station <50 kV	($27,974,398)	($27,974,398)	$0	($27,974,398)	($2,359,281)	($7,137,029)	($8,625,968)	($1,079,329)	($2,623,891)	($3,789,354)	($107,987)	($21,294)	($3,920)	($761,894)	($494,539)	($969,911)	($27,974,398)	$0	$0	$0
1806	Land Rights	($69,491,518)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1806-1	Land Rights Station >50 kV	($6,949,152)	($6,949,152)	$0	($6,949,152)	($316,009)	($955,954)	($1,155,386)	($144,568)	($351,451)	($507,557)	($14,464)	($2,852)	($525)	($3,304,232)	($66,240)	($129,913)	($6,949,152)	$0	$0	$0
1806-2	Land Rights Station <50 kV	($62,542,366)	($62,542,366)	$0	($62,542,366)	($5,274,646)	($15,956,257)	($19,285,079)	($2,413,056)	($5,866,234)	($8,471,860)	($241,427)	($47,607)	($8,763)	($1,703,365)	($1,105,642)	($2,168,430)	($62,542,366)	$0	$0	$0
1808	Buildings and Fixtures	($1,916,304)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1808-1	Buildings and Fixtures > 50 kV	($958,152)	($958,152)	$0	($958,152)	($43,571)	($131,807)	($159,305)	($19,933)	($48,458)	($69,982)	($1,994)	($393)	($72)	($455,589)	($9,133)	($17,912)	($958,152)	$0	$0	$0
1808-2	Buildings and Fixtures < 50 KV	($958,152)	($958,152)	$0	($958,152)	($80,808)	($244,451)	($295,448)	($36,968)	($89,871)	($129,789)	($3,699)	($729)	($134)	($26,096)	($16,938)	($33,220)	($958,152)	$0	$0	$0
1810	Leasehold Improvements	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1810-1	Leasehold Improvements >50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1810-2	Leasehold Improvements <50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1815	Transformer Station Equipment - Normally Primary above 50 kV	($35,001,013)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1815-1	HVDS - Rural	($28,077,231)	($28,077,231)	$0	($28,077,231)	($2,434,252)	($7,363,821)	($8,900,074)	($1,113,627)	($2,707,270)	($3,909,768)	($111,419)	($21,971)	($4,044)	$0	($510,254)	($1,000,732)	($28,077,231)	$0	$0	$0
1815-2	HVDS - lo LV Specific	($244,283)	($244,283)	$0	($244,283)	$0	$0	$0	$0	$0	$0	$0	$0	$0	($244,283)	$0	$0	($244,283)	$0	$0	$0
1815-3	HVDS - hi LV Specific	($554,322)	($554,322)	$0	($554,322)	$0	$0	$0	$0	$0	$0	$0	$0	$0	($554,322)	$0	$0	($554,322)	$0	$0	$0
1815-4	HVDS - lo LV Shared	($3,062,589)	($3,062,589)	$0	($3,062,589)	$0	$0	$0	$0	$0	$0	$0	$0	$0	($3,062,589)	$0	$0	($3,062,589)	$0	$0	$0
1815-5	HVDS - hi LV Shared	($3,062,589)	($3,062,589)	$0	($3,062,589)	$0	$0	$0	$0	$0	$0	$0	$0	$0	($3,062,589)	$0	$0	($3,062,589)	$0	$0	$0
1820	Distribution Station Equipment - Normally Primary below 50 kV	($136,355,247)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1820-1	Distribution Station Equipment - Normally Primary below 50 kV (Bulk)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1820-2	Distribution Station Equipment - Normally Primary below 50 kV (Primary)	($121,355,247)	($121,355,247)	$0	($121,355,247)	($8,537,460)	($29,735,384)	($35,457,328)	($2,091,712)	($13,312,211)	($19,721,653)	($1,400,899)	($224,376)	($1,369)	($3,477,426)	($2,331,334)	($5,064,096)	($121,355,247)	$0	$0	$0
1820-3	Distribution Station Equipment - Normally Primary below 50 kV (Wholesale Meters)	($15,000,000)	$0	($15,000,000)	($15,000,000)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($923,598)	($2,724,365)	($3,476,651)
1825	Storage Battery Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1825-1	Storage Battery Equipment > 50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1825-2	Storage Battery Equipment <50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1830	Poles, Towers and Fixtures	($635,754,791)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1830-3	Poles, Towers and Fixtures - Subtransmission Bulk Delivery	($127,150,958)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1830-3A	Bulk-LV Fixtures	($16,529,625)	($16,529,625)	$0	($16,529,625)	$0	$0	$0	$0	$0	$0	$0	$0	$0	($16,529,625)	$0	$0	($16,529,625)	$0	$0	$0
1830-3B	Bulk-Retail Fixtures	($110,621,334)	($110,621,334)	$0	($110,621,334)	($1,772,729)	($18,739,534)	($50,237,582)	($7,077,038)	($12,394,685)	($18,281,067)	($443,068)	($87,368)	($16,082)	$0	($370,905)	($1,201,275)	($110,621,334)	$0	$0	$0
1830-4	Poles, Towers and Fixtures - Primary	($413,240,614)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1830-4A	Primary-LV Fixtures	($462,003)	($241,166)	($220,837)	($462,003)	$0	$0	$0	$0	$0	$0	$0	$0	$0	($241,166)	$0	$0	($241,166)	$0	$0	$0
1830-4B	Primary-Retail Fixtures	($412,778,611)	($215,470,435)	($197,308,176)	($412,778,611)	($2,895,131)	($35,236,432)	($93,197,427)	($6,189,799)	($28,380,295)	($42,939,469)	($2,594,072)	($415,482)	($2,535)	$0	($789,121)	($2,830,673)	($215,470,435)	($5,136,295)	($41,415,332)	($98,274,417)
1830-5	Poles, Towers and Fixtures - Secondary	($95,363,219)	($49,779,600)	($45,583,619)	($95,363,219)	($4,544,758)	($15,900,673)	($18,992,380)	($1,069,512)	($7,145,794)	$0	($753,751)	($119,691)	$0	$0	($1,253,041)	$0	($49,779,600)	($6,273,529)	($14,572,200)	($14,127,328)
1835	Overhead Conductors and Devices	($451,075,879)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1835-3	Overhead Conductors and Devices - Subtransmission Bulk Delivery	($90,215,176)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1835-3A	Bulk-LV Conductors	($11,727,973)	($11,727,973)	$0	($11,727,973)	$0	$0	$0	$0	$0	$0	$0	$0	$0	($11,727,973)	$0	$0	($11,727,973)	$0	$0	$0
1835-3B	Bulk-Retail Conductors	($78,487,203)	($78,487,203)	$0	($78,487,203)	($1,257,773)	($13,295,931)	($35,644,185)	($5,021,246)	($8,794,182)	($12,970,643)	($314,363)	($61,989)	($11,410)	$0	($263,162)	($852,320)	($78,487,203)	$0	$0	$0
1835-4	Overhead Conductors and Devices - Primary	($293,199,321)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1835-4A	Primary-LV Conductors	($327,797)	($148,164)	($179,633)	($327,797)	$0	$0	$0	$0	$0	$0	$0	$0	$0	($148,164)	$0	$0	($148,164)	$0	$0	$0
1835-4B	Primary-Retail Conductors	($292,871,525)	($132,377,929)	($160,493,595)	($292,871,525)	($1,778,673)	($21,648,102)	($57,257,426)	($3,802,809)	($17,435,917)	($26,380,594)	($1,593,712)	($255,258)	($1,557)	$0	($484,810)	($1,739,072)	($132,377,929)	($4,177,944)	($33,687,887)	($79,937,967)
1835-5	Overhead Conductors and Devices - Secondary	($67,661,382)	($30,582,945)	($37,078,437)	($67,661,382)	($2,792,149)	($9,768,849)	($11,668,292)	($657,073)	($4,390,140)	$0	($463,080)	($73,534)	$0	$0	($769,827)	$0	($30,582,945)	($5,102,988)	($11,853,258)	($11,491,392)
1840	Underground Conduit	($9,630,326)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

Account	Description	Contributed Capital	Demand	Customer	Total	UR	R1	R2	Seasonal	GSe	GSd	St Lgt	Sen Lgt	Dgen	ST	UGe	UGd	Total	UR	R1	R2
1840-3	Underground Conduit - Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1840-4	Underground Conduit - Primary	($1,926,065)	($870,581)	($1,055,484)	($1,926,065)	($63,053)	($219,609)	($261,869)	($15,448)	($98,317)	($145,653)	($10,346)	($1,657)	($10)	$0	($17,218)	($37,401)	($870,581)	($144,225)	($335,006)	($324,779)
1840-5	Underground Conduit - Secondary	($7,704,261)	($3,482,326)	($4,221,935)	($7,704,261)	($317,928)	($1,112,330)	($1,328,610)	($74,818)	($499,883)	$0	($52,729)	($8,373)	$0	$0	($87,656)	$0	($3,482,326)	($581,052)	($1,349,671)	($1,308,467)
1845	Underground Conductors and Devices	($174,434,832)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1845-3	Underground Conductors and Devices - Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1845-4	Underground Conductors and Devices - Primary	($34,886,966)	($15,768,909)	($19,118,058)	($34,886,966)	($1,142,084)	($3,977,801)	($4,743,245)	($279,815)	($1,780,819)	($2,638,231)	($187,403)	($30,016)	($183)	$0	($311,870)	($677,441)	($15,768,909)	($2,612,355)	($6,067,997)	($5,882,748)
1845-5	Underground Conductors and Devices - Secondary	($139,547,865)	($63,075,635)	($76,472,230)	($139,547,865)	($5,758,654)	($20,147,712)	($24,065,208)	($1,355,176)	($9,054,422)	$0	($955,077)	($151,661)	$0	$0	($1,587,726)	$0	($63,075,635)	($10,524,631)	($24,446,691)	($23,700,362)
1850	Line Transformers	($331,295,116)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1850-1	TRF-LV	($993,885)	($378,670)	($615,215)	($993,885)	$0	$0	$0	$0	$0	$0	$0	$0	$0	($378,670)	$0	$0	($378,670)	$0	$0	$0
1850-2	TRF-Rural	($330,301,230)	($125,844,769)	($204,456,462)	($330,301,230)	$0	$0	($60,667)	$0	($19,087,345)	($80,246,523)	($4,065,834)	$0	$0	$0	($3,100,207)	($19,284,194)	($125,844,769)	($21,682,798)	($60,993,131)	($78,329,919)
1855	Services	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1860	Meters	$31,043,316	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1860-1	Mtr-Single	$2,348,769	$0	$2,348,769	$2,348,769	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$303,108	$721,857	$748,927
1860-2	Mtr-Poly	$965,837	$0	$965,837	$965,837	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1860-3	Mtr-LV	$1,201,066	$0	$1,201,066	$1,201,066	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1860-4	Mtr-Smart	$26,527,644	$0	$26,527,644	$26,527,644	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$3,650,811	$8,480,130	$8,221,242
1875	St Lgts	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Sub - Total	($1,845,770,061)	($1,114,234,008)	($731,536,053)	($1,845,770,061)	($41,510,306)	($201,999,258)	($371,852,266)	($32,506,590)	($134,218,386)	($220,429,168)	($13,321,795)	($1,525,528)	($50,840)	($47,155,922)	($13,599,253)	($36,064,697)	($1,114,234,008)	($53,257,924)	($188,430,067)	($308,184,749)
General Plant																					
1905	Land	($20,263)																			
1906	Land Rights	$0																			
1908	Buildings and Fixtures	($44,386,901)																			
1910	Leasehold Improvements	($3,700,025)																			
1915	Office Furniture and Equipment	($671,827)																			
1920	Computer Equipment - Hardware	($25,231,142)																			
1925	Computer Software	($107,402,562)																			
1930	Transportation Equipment	($101,991,639)																			
1935	Stores Equipment	($3,308,717)																			
1940	Tools, Shop and Garage Equipment	($1,024,244)																			
1945	Measurement and Testing Equipment	($1,034,519)																			
1950	Power Operated Equipment	($71,517,234)																			
1955	Communication Equipment	($20,908,064)																			
1960	Miscellaneous Equipment	($1,155,954)																			
1970	Load Management Controls Customer Premises	$0																			
1975	Load Management Controls Utility Premises	$0																			
1980	System Supervisory Equipment	($6,426,248)																			
1985	Sentinel Lgts	($11,723,467)																			
1990	Other Tangible Property	($3,379,466)																			
2005	Property Under Capital Leases	$0																			
2010	Electric Plant Purchased or Sold	$0																			
	Sub - Total	($403,882,273)																			
	TOTAL - 2105 FA	($2,249,652,334)	($1,114,234,008)	($731,536,053)	($1,845,770,061)	($41,510,306)	($201,999,258)	($371,852,266)	($32,506,590)	($134,218,386)	($220,429,168)	($13,321,795)	($1,525,528)	($50,840)	($47,155,922)	($13,599,253)	($36,064,697)	($1,114,234,008)	($53,257,924)	($188,430,067)	($308,184,749)

Accumulated Depreciation - 2120

						Demand Allocation													Customer Allocation		
						1	2	3	4	5	6	7	8	12	13	14	15	Sub -total	1	2	3
Account	Description	Accumulated Depreciation	Demand	Customer	Total	UR	R1	R2	Seasonal	GSe	GSd	St Lgt	Sen Lgt	Dgen	ST	UGe	UGd	Sub -total	UR	R1	R2
1565	Conservation and Demand Management	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1805	Land	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

Account	Description	Contributed Capital	Demand	Customer	Total	UR	R1	R2	Seasonal	GSe	GSd	St Lgt	Sen Lgt	Dgen	ST	UGe	UGd	Total	UR	R1	R2
1805-1	Land Station >50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1805-2	Land Station <50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1806	Land Rights	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1806-1	Land Rights Station >50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1806-2	Land Rights Station <50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1808	Buildings and Fixtures	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1808-1	Buildings and Fixtures > 50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1808-2	Buildings and Fixtures < 50 KV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1810	Leasehold Improvements	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1810-1	Leasehold Improvements >50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1810-2	Leasehold Improvements <50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1815	Transformer Station Equipment - Normally Primary above 50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1815-1	HVDS - Rural	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1815-2	HVDS - lo LV Specific	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1815-3	HVDS - hi LV Specific	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1815-4	HVDS - lo LV Shared	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1815-5	HVDS - hi LV Shared	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1820	Distribution Station Equipment - Normally Primary below 50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1820-1	Distribution Station Equipment - Normally Primary below 50 kV (Bulk)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1820-2	Distribution Station Equipment - Normally Primary below 50 kV (Primary)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1820-3	Distribution Station Equipment - Normally Primary below 50 kV (Wholesale Meters)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1825	Storage Battery Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1825-1	Storage Battery Equipment > 50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1825-2	Storage Battery Equipment <50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1830	Poles, Towers and Fixtures	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1830-3	Poles, Towers and Fixtures - Subtransmission Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1830-3A	Bulk-LV Fixtures	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1830-3B	Bulk-Retail Fixtures	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1830-4	Poles, Towers and Fixtures - Primary	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1830-4A	Primary-LV Fixtures	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1830-4B	Primary-Retail Fixtures	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1830-5	Poles, Towers and Fixtures - Secondary	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1835	Overhead Conductors and Devices	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1835-3	Overhead Conductors and Devices - Subtransmission Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1835-3A	Bulk-LV Conductors	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1835-3B	Bulk-Retail Conductors	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1835-4	Overhead Conductors and Devices - Primary	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1835-4A	Primary-LV Conductors	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1835-4B	Primary-Retail Conductors	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1835-5	Overhead Conductors and Devices - Secondary	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1840	Underground Conduit	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1840-3	Underground Conduit - Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1840-4	Underground Conduit - Primary	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1840-5	Underground Conduit - Secondary	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1845	Underground Conductors and Devices	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

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Account	Description	Contributed Capital	Demand	Customer	Total	UR	R1	R2	Seasonal	GSe	GSd	St Lgt	Sen Lgt	Dgen	ST	UGe	UGd	Total	UR	R1	R2
1845-3	Underground Conductors and Devices - Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1845-4	Underground Conductors and Devices - Primary	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1845-5	Underground Conductors and Devices - Secondary	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1850	Line Transformers	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1850-1	TRF-LV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1850-2	TRF-Rural	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1855	Services	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1860	Meters	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1860-1	Mtr-Single	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1860-2	Mtr-Poly	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1860-3	Mtr-LV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1860-4	Mtr-Smart	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1875	St Lgts	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Sub - Total	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
General Plant																					
1905	Land	$0																			
1906	Land Rights	$0																			
1908	Buildings and Fixtures	$0																			
1910	Leasehold Improvements	$0																			
1915	Office Furniture and Equipment	$0																			
1920	Computer Equipment - Hardware	$0																			
1925	Computer Software	$0																			
1930	Transportation Equipment	$0																			
1935	Stores Equipment	$0																			
1940	Tools, Shop and Garage Equipment	$0																			
1945	Measurement and Testing Equipment	$0																			
1950	Power Operated Equipment	$0																			
1955	Communication Equipment	$0																			
1960	Miscellaneous Equipment	$0																			
1970	Load Management Controls Customer Premises	$0																			
1975	Load Management Controls Utility Premises	$0																			
1980	System Supervisory Equipment	$0																			
1985	Sentinel Lgts	$0																			
1990	Other Tangible Property	$0																			
2005	Property Under Capital Leases	$0																			
2010	Electric Plant Purchased or Sold	$0																			
	Sub - Total	$0				$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	TOTAL - 2120	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

Categorization and Allocation of Amortization Expense - Property, Plant and Equipment - 5705

						Demand Allocation													Customer Allocation		
						1	2	3	4	5	6	7	8	12	13	14	15	Sub -total	1	2	3
Account	Description	Depreciation	Demand	Customer	Total	UR	R1	R2	Seasonal	GSe	GSd	St Lgt	Sen Lgt	Dgen	ST	UGe	UGd	Sub -total	UR	R1	R2
1565	Conservation and Demand Management	$426,880	$0	$426,880	$426,880	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$28,853	$102,643	$165,585
1805	Land	$473,420	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1805-1	Land Station >50 kV	$47,342	$47,342	$0	$47,342	$2,153	$6,513	$7,871	$985	$2,394	$3,458	$99	$19	$4	$22,511	$451	$885	$47,342	$0	$0	$0
1805-2	Land Station <50 kV	$426,078	$426,078	$0	$426,078	$35,934	$108,704	$131,382	$16,439	$39,965	$57,716	$1,645	$324	$60	$11,604	$7,532	$14,773	$426,078	$0	$0	$0
1806	Land Rights	$2,818,534	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1806-1	Land Rights Station >50 kV	$281,853	$281,853	$0	$281,853	$12,817	$38,773	$46,862	$5,864	$14,255	$20,586	$587	$116	$21	$134,018	$2,687	$5,269	$281,853	$0	$0	$0

Account	Description	Contributed Capital	Demand	Customer	Total	UR	R1	R2	Seasonal	GSe	GSd	St Lgt	Sen Lgt	Dgen	ST	UGe	UGd	Total	UR	R1	R2
1806-2	Land Rights Station <50 kV	$2,536,680	$2,536,680	$0	$2,536,680	$213,936	$647,176	$782,191	$97,872	$237,931	$343,613	$9,792	$1,931	$355	$69,087	$44,844	$87,950	$2,536,680	$0	$0	$0
1808	Buildings and Fixtures	$95,977	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1808-1	Buildings and Fixtures > 50 kV	$47,989	$47,989	$0	$47,989	$2,182	$6,602	$7,979	$998	$2,427	$3,505	$100	$20	$4	$22,818	$457	$897	$47,989	$0	$0	$0
1808-2	Buildings and Fixtures < 50 KV	$47,989	$47,989	$0	$47,989	$4,047	$12,243	$14,797	$1,852	$4,501	$6,500	$185	$37	$7	$1,307	$848	$1,664	$47,989	$0	$0	$0
1810	Leasehold Improvements	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1810-1	Leasehold Improvements >50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1810-2	Leasehold Improvements <50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1815	Transformer Station Equipment - Normally Primary above 50 kV	$2,207,159	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1815-1	HVDS - Rural	$1,770,142	$1,770,142	$0	$1,770,142	$153,469	$464,255	$561,109	$70,209	$170,681	$246,493	$7,024	$1,385	$255	$0	$32,169	$63,092	$1,770,142	$0	$0	$0
1815-2	HVDS - lo LV Specific	$11,698	$11,698	$0	$11,698	$0	$0	$0	$0	$0	$0	$0	$0	$0	$11,698	$0	$0	$11,698	$0	$0	$0
1815-3	HVDS - hi LV Specific	$39,067	$39,067	$0	$39,067	$0	$0	$0	$0	$0	$0	$0	$0	$0	$39,067	$0	$0	$39,067	$0	$0	$0
1815-4	HVDS - lo LV Shared	$193,126	$193,126	$0	$193,126	$0	$0	$0	$0	$0	$0	$0	$0	$0	$193,126	$0	$0	$193,126	$0	$0	$0
1815-5	HVDS - hi LV Shared	$193,126	$193,126	$0	$193,126	$0	$0	$0	$0	$0	$0	$0	$0	$0	$193,126	$0	$0	$193,126	$0	$0	$0
1820	Distribution Station Equipment - Normally Primary below 50 kV	$7,452,285	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1820-1	Distribution Station Equipment - Normally Primary below 50 kV (Bulk)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1820-2	Distribution Station Equipment - Normally Primary below 50 kV (Primary)	$6,183,733	$6,183,733	$0	$6,183,733	$435,032	$1,515,185	$1,806,751	$106,584	$678,332	$1,004,929	$71,384	$11,433	$70	$177,194	$118,795	$258,044	$6,183,733	$0	$0	$0
1820-3	Distribution Station Equipment - Normally Primary below 50 kV (Wholesale Meters)	$1,268,552	$0	$1,268,552	$1,268,552	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$78,109	$230,400	$294,021
1825	Storage Battery Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1825-1	Storage Battery Equipment > 50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1825-2	Storage Battery Equipment <50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1830	Poles, Towers and Fixtures	$41,901,515	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1830-3	Poles, Towers and Fixtures - Subtransmission Bulk Delivery	$8,380,303	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1830-3A	Bulk-LV Fixtures	$1,089,439	$1,089,439	$0	$1,089,439	$0	$0	$0	$0	$0	$0	$0	$0	$0	$1,089,439	$0	$0	$1,089,439	$0	$0	$0
1830-3B	Bulk-Retail Fixtures	$7,290,864	$7,290,864	$0	$7,290,864	$116,838	$1,235,091	$3,311,073	$466,436	$816,913	$1,204,874	$29,202	$5,758	$1,060	$0	$24,446	$79,174	$7,290,864	$0	$0	$0
1830-4	Poles, Towers and Fixtures - Primary	$27,235,985	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1830-4A	Primary-LV Fixtures	$30,450	$15,895	$14,555	$30,450	$0	$0	$0	$0	$0	$0	$0	$0	$0	$15,895	$0	$0	$15,895	$0	$0	$0
1830-4B	Primary-Retail Fixtures	$27,205,535	$14,201,289	$13,004,246	$27,205,535	$190,813	$2,322,373	$6,142,484	$407,959	$1,870,497	$2,830,067	$170,971	$27,384	$167	$0	$52,010	$186,565	$14,201,289	$338,524	$2,729,614	$6,477,099
1830-5	Poles, Towers and Fixtures - Secondary	$6,285,227	$3,280,889	$3,004,339	$6,285,227	$299,537	$1,047,986	$1,251,755	$70,490	$470,967	$0	$49,678	$7,889	$0	$0	$82,586	$0	$3,280,889	$413,478	$960,429	$931,108
1835	Overhead Conductors and Devices	$30,777,374	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1835-3	Overhead Conductors and Devices - Subtransmission Bulk Delivery	$6,155,475	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1835-3A	Bulk-LV Conductors	$800,212	$800,212	$0	$800,212	$0	$0	$0	$0	$0	$0	$0	$0	$0	$800,212	$0	$0	$800,212	$0	$0	$0
1835-3B	Bulk-Retail Conductors	$5,355,263	$5,355,263	$0	$5,355,263	$85,819	$907,195	$2,432,040	$342,605	$600,036	$885,000	$21,449	$4,230	$779	$0	$17,956	$58,155	$5,355,263	$0	$0	$0
1835-4	Overhead Conductors and Devices - Primary	$20,005,293	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1835-4A	Primary-LV Conductors	$22,366	$10,109	$12,257	$22,366	$0	$0	$0	$0	$0	$0	$0	$0	$0	$10,109	$0	$0	$10,109	$0	$0	$0
1835-4B	Primary-Retail Conductors	$19,982,927	$9,032,283	$10,950,644	$19,982,927	$121,361	$1,477,072	$3,906,733	$259,470	$1,189,671	$1,799,975	$108,741	$17,417	$106	$0	$33,079	$118,659	$9,032,283	$285,065	$2,298,559	$5,454,250
1835-5	Overhead Conductors and Devices - Secondary	$4,616,606	$2,086,706	$2,529,900	$4,616,606	$190,511	$666,539	$796,140	$44,833	$299,544	$0	$31,596	$5,017	$0	$0	$52,526	$0	$2,086,706	$348,182	$808,760	$784,070
1840	Underground Conduit	$451,035	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1840-3	Underground Conduit - Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1840-4	Underground Conduit - Primary	$90,207	$40,774	$49,433	$90,207	$2,953	$10,285	$12,265	$724	$4,605	$6,822	$485	$78	$0	$0	$806	$1,752	$40,774	$6,755	$15,690	$15,211
1840-5	Underground Conduit - Secondary	$360,828	$163,094	$197,734	$360,828	$14,890	$52,096	$62,225	$3,504	$23,412	$0	$2,470	$392	$0	$0	$4,105	$0	$163,094	$27,213	$63,212	$61,282
1845	Underground Conductors and Devices	$20,813,363	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1845-3	Underground Conductors and Devices - Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

Account	Description	Contributed Capital	Demand	Customer	Total	UR	R1	R2	Seasonal	GSe	GSd	St Lgt	Sen Lgt	Dgen	ST	UGe	UGd	Total	UR	R1	R2
1845-4	Underground Conductors and Devices - Primary	$4,162,673	$1,881,528	$2,281,145	$4,162,673	$136,272	$474,627	$565,959	$33,387	$212,485	$314,791	$22,361	$3,581	$22	$0	$37,212	$80,831	$1,881,528	$311,703	$724,026	$701,923
1845-5	Underground Conductors and Devices - Secondary	$16,650,691	$7,526,112	$9,124,579	$16,650,691	$687,116	$2,404,002	$2,871,433	$161,698	$1,080,363	$0	$113,959	$18,096	$0	$0	$189,446	$0	$7,526,112	$1,255,787	$2,916,951	$2,827,900
1850	Line Transformers	$31,211,446	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1850-1	TRF-LV	$93,634	$35,675	$57,960	$93,634	$0	$0	$0	$0	$0	$0	$0	$0	$0	$35,675	$0	$0	$35,675	$0	$0	$0
1850-2	TRF-Rural	$31,117,811	$11,855,886	$19,261,925	$31,117,811	$0	$0	$5,715	$0	$1,798,226	$7,560,057	$383,044	$0	$0	$0	$292,072	$1,816,772	$11,855,886	$2,042,745	$5,746,187	$7,379,493
1855	Services	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1860	Meters	$14,899,710	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1860-1	Mtr-Single	$1,127,327	$0	$1,127,327	$1,127,327	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$145,481	$346,466	$359,459
1860-2	Mtr-Poly	$463,568	$0	$463,568	$463,568	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1860-3	Mtr-LV	$576,470	$0	$576,470	$576,470	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1860-4	Mtr-Smart	$12,732,345	$0	$12,732,345	$12,732,345	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$1,752,262	$4,070,167	$3,945,910
1875	St Lgts	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Sub - Total	$153,528,698	$76,444,841	$77,083,856	$153,528,698	$2,705,681	$13,396,717	$24,716,764	$2,091,908	$9,517,204	$16,288,387	$1,024,770	$105,106	$2,909	$2,826,887	$994,027	$2,774,481	$76,444,841	$7,034,157	$21,013,105	$29,397,310
General Plant																					
1905	Land	$0																			
1906	Land Rights	$0																			
1908	Buildings and Fixtures	$1,948,322																			
1910	Leasehold Improvements	$389,149																			
1915	Office Furniture and Equipment	$362,408																			
1920	Computer Equipment - Hardware	$8,103,834																			
1925	Computer Software	$20,793,821																			
1930	Transportation Equipment	$12,052,905																			
1935	Stores Equipment	$823,398																			
1940	Tools, Shop and Garage Equipment	$188,948																			
1945	Measurement and Testing Equipment	$613,277																			
1950	Power Operated Equipment	$2,876,786																			
1955	Communication Equipment	$2,706,386																			
1960	Miscellaneous Equipment	$599,739																			
1970	Load Management Controls Customer Premises	$0																			
1975	Load Management Controls Utility Premises	$0																			
1980	System Supervisory Equipment	$1,760,833																			
1985	Sentinel Lgts	$482,401																			
1990	Other Tangible Property	$149,442																			
2005	Property Under Capital Leases	$0																			
2010	Electric Plant Purchased or Sold	$0																			
	Sub - Total	$53,851,648				$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	TOTAL - 5705	$207,380,346	$76,444,841	$77,083,856	$153,528,698	$2,705,681	$13,396,717	$24,716,764	$2,091,908	$9,517,204	$16,288,387	$1,024,770	$105,106	$2,909	$2,826,887	$994,027	$2,774,481	$76,444,841	$7,034,157	$21,013,105	$29,397,310

Categorization and Allocation of Amortization of Limited Term Electric Plant - 5710

						Demand Allocation													Customer Allocation		
						1	2	3	4	5	6	7	8	12	13	14	15	Sub -total	1	2	3
Account	**Description**	**Depreciation**	**Demand**	**Customer**	**Total**	**UR**	**R1**	**R2**	**Seasonal**	**GSe**	**GSd**	**St Lgt**	**Sen Lgt**	**Dgen**	**ST**	**UGe**	**UGd**	**Sub -total**	**UR**	**R1**	**R2**
1565	Conservation and Demand Management	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1805	Land	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1805-1	Land Station >50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1805-2	Land Station <50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1806	Land Rights	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1806-1	Land Rights Station >50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1806-2	Land Rights Station <50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1808	Buildings and Fixtures	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

Account	Description	Contributed Capital	Demand	Customer	Total	UR	R1	R2	Seasonal	GSe	GSd	St Lgt	Sen Lgt	Dgen	ST	UGe	UGd	Total	UR	R1	R2
1808-1	Buildings and Fixtures > 50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1808-2	Buildings and Fixtures < 50 KV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1810	Leasehold Improvements	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1810-1	Leasehold Improvements >50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1810-2	Leasehold Improvements <50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1815	Transformer Station Equipment - Normally Primary above 50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1815-1	HVDS - Rural	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1815-2	HVDS - lo LV Specific	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1815-3	HVDS - hi LV Specific	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1815-4	HVDS - lo LV Shared	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1815-5	HVDS - hi LV Shared	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1820	Distribution Station Equipment - Normally Primary below 50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1820-1	Distribution Station Equipment - Normally Primary below 50 kV (Bulk)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1820-2	Distribution Station Equipment - Normally Primary below 50 kV (Primary)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1820-3	Distribution Station Equipment - Normally Primary below 50 kV (Wholesale Meters)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1825	Storage Battery Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1825-1	Storage Battery Equipment > 50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1825-2	Storage Battery Equipment <50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1830	Poles, Towers and Fixtures	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1830-3	Poles, Towers and Fixtures - Subtransmission Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1830-3A	Bulk-LV Fixtures	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1830-3B	Bulk-Retail Fixtures	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1830-4	Poles, Towers and Fixtures - Primary	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1830-4A	Primary-LV Fixtures	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1830-4B	Primary-Retail Fixtures	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1830-5	Poles, Towers and Fixtures - Secondary	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1835	Overhead Conductors and Devices	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1835-3	Overhead Conductors and Devices - Subtransmission Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1835-3A	Bulk-LV Conductors	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1835-3B	Bulk-Retail Conductors	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1835-4	Overhead Conductors and Devices - Primary	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1835-4A	Primary-LV Conductors	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1835-4B	Primary-Retail Conductors	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1835-5	Overhead Conductors and Devices - Secondary	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1840	Underground Condui	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1840-3	Underground Conduit - Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1840-4	Underground Conduit - Primary	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1840-5	Underground Conduit - Secondary	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1845	Underground Conductors and Devices	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1845-3	Underground Conductors and Devices - Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1845-4	Underground Conductors and Devices - Primary	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

Account	Description	Contributed Capital	Demand	Customer	Total	UR	R1	R2	Seasonal	GSe	GSd	St Lgt	Sen Lgt	Dgen	ST	UGe	UGd	Total	UR	R1	R2
1845-5	Underground Conductors and Devices - Secondary	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1850	Line Transformers	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1850-1	TRF-LV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1850-2	TRF-Rural	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1855	Services	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1860	Meters	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1860-1	Mtr-Single	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1860-2	Mtr-Poly	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1860-3	Mtr-LV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1860-4	Mtr-Smart	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1875	St Lgts	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Sub - Total	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
General Plant																					
1905	Land	$0																			
1906	Land Rights	$0																			
1908	Buildings and Fixtures	$0																			
1910	Leasehold Improvements	$0																			
1915	Office Furniture and Equipment	$0																			
1920	Computer Equipment - Hardware	$0																			
1925	Computer Software	$0																			
1930	Transportation Equipment	$0																			
1935	Stores Equipment	$0																			
1940	Tools, Shop and Garage Equipment	$0																			
1945	Measurement and Testing Equipment	$0																			
1950	Power Operated Equipment	$0																			
1955	Communication Equipment	$0																			
1960	Miscellaneous Equipment	$0																			
1970	Load Management Controls Customer Premises	$0																			
1975	Load Management Controls Utility Premises	$0																			
1980	System Supervisory Equipment	$0																			
1985	Sentinel Lgts	$0																			
1990	Other Tangible Property	$0																			
2005	Property Under Capital Leases	$0																			
2010	Electric Plant Purchased or Sold	$0																			
	Sub - Total	$0				$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	TOTAL - 5710	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

Categorization and Allocation of Accumulated Amortization of Electric Utility Plant - Intangibles - 5715

						Demand Allocation													**Customer Allocation**		
						1	2	3	4	5	6	7	8	12	13	14	15	Sub -total	1	2	3
Account	Description	Depreciation	Demand	Customer	Total	UR	R1	R2	Seasonal	GSe	GSd	St Lgt	Sen Lgt	Dgen	ST	UGe	UGd	Sub -total	UR	R1	R2
1565	Conservation and Demand Management	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1805	Land	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1805-1	Land Station >50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1805-2	Land Station <50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1806	Land Rights	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1806-1	Land Rights Station >50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1806-2	Land Rights Station <50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1808	Buildings and Fixtures	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1808-1	Buildings and Fixtures > 50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

Account	Description	Contributed Capital	Demand	Customer	Total	UR	R1	R2	Seasonal	GSe	GSd	St Lgt	Sen Lgt	Dgen	ST	UGe	UGd	Total	UR	R1	R2
1808-2	Buildings and Fixtures < 50 KV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1810	Leasehold Improvements	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1810-1	Leasehold Improvements >50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1810-2	Leasehold Improvements <50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1815	Transformer Station Equipment - Normally Primary above 50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1815-1	HVDS - Rural	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1815-2	HVDS - lo LV Specific	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1815-3	HVDS - hi LV Specific	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1815-4	HVDS - lo LV Shared	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1815-5	HVDS - hi LV Shared	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1820	Distribution Station Equipment - Normally Primary below 50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1820-1	Distribution Station Equipment - Normally Primary below 50 kV (Bulk)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1820-2	Distribution Station Equipment - Normally Primary below 50 kV (Primary)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1820-3	Distribution Station Equipment - Normally Primary below 50 kV (Wholesale Meters)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1825	Storage Battery Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1825-1	Storage Battery Equipment > 50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1825-2	Storage Battery Equipment <50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1830	Poles, Towers and Fixtures	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1830-3	Poles, Towers and Fixtures - Subtransmission Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1830-3A	Bulk-LV Fixtures	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1830-3B	Bulk-Retail Fixtures	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1830-4	Poles, Towers and Fixtures - Primary	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1830-4A	Primary-LV Fixtures	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1830-4B	Primary-Retail Fixtures	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1830-5	Poles, Towers and Fixtures - Secondary	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1835	Overhead Conductors and Devices	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1835-3	Overhead Conductors and Devices - Subtransmission Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1835-3A	Bulk-LV Conductors	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1835-3B	Bulk-Retail Conductors	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1835-4	Overhead Conductors and Devices - Primary	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1835-4A	Primary-LV Conductors	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1835-4B	Primary-Retail Conductors	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1835-5	Overhead Conductors and Devices - Secondary	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1840	Underground Conduit	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1840-3	Underground Conduit - Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1840-4	Underground Conduit - Primary	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1840-5	Underground Conduit - Secondary	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1845	Underground Conductors and Devices	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1845-3	Underground Conductors and Devices - Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1845-4	Underground Conductors and Devices - Primary	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1845-5	Underground Conductors and Devices - Secondary	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1850	Line Transformers	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

Account	Description	Contributed Capital	Demand	Customer	Total	UR	R1	R2	Seasonal	GSe	GSd	St Lgt	Sen Lgt	Dgen	ST	UGe	UGd	Total	UR	R1	R2
1850-1	TRF-LV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1850-2	TRF-Rural	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1855	Services	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1860	Meters	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1860-1	Mtr-Single	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1860-2	Mtr-Poly	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1860-3	Mtr-LV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1860-4	Mtr-Smart	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1875	St Lgts	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Sub - Total	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
General Plant																					
1905	Land	$0																			
1906	Land Rights	$0																			
1908	Buildings and Fixtures	$0																			
1910	Leasehold Improvements	$0																			
1915	Office Furniture and Equipment	$0																			
1920	Computer Equipment - Hardware	$0																			
1925	Computer Software	$0																			
1930	Transportation Equipment	$0																			
1935	Stores Equipment	$0																			
1940	Tools, Shop and Garage Equipment	$0																			
1945	Measurement and Testing Equipment	$0																			
1950	Power Operated Equipment	$0																			
1955	Communication Equipment	$0																			
1960	Miscellaneous Equipment	$0																			
1970	Load Management Controls Customer Premises	$0																			
1975	Load Management Controls Utility Premises	$0																			
1980	System Supervisory Equipment	$0																			
1985	Sentinel Lgts	$0																			
1990	Other Tangible Property	$0																			
2005	Property Under Capital Leases	$0																			
2010	Electric Plant Purchased or Sold	$0																			
	Sub - Total	$0				$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	TOTAL - 5715	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

Categorization and Allocation of Accum. Amortization of Electric Utility Plant- Property, Plant & Equipment - 5720

						Demand Allocation													**Customer Allocation**		
						1	2	3	4	5	6	7	8	12	13	14	15	Sub -total	1	2	3
Account	Description	Depreciation	Demand	Customer	Total	UR	R1	R2	Seasonal	GSe	GSd	St Lgt	Sen Lgt	Dgen	ST	UGe	UGd	Sub -total	UR	R1	R2
1565	Conservation and Demand Management	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1805	Land	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1805-1	Land Station >50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1805-2	Land Station <50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1806	Land Rights	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1806-1	Land Rights Station >50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1806-2	Land Rights Station <50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1808	Buildings and Fixtures	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1808-1	Buildings and Fixtures > 50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1808-2	Buildings and Fixtures < 50 KV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1810	Leasehold Improvements	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

Account	Description	Contributed Capital	Demand	Customer	Total	UR	R1	R2	Seasonal	GSe	GSd	St Lgt	Sen Lgt	Dgen	ST	UGe	UGd	Total	UR	R1	R2
1810-1	Leasehold Improvements >50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1810-2	Leasehold Improvements <50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1815	Transformer Station Equipment - Normally Primary above 50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1815-1	HVDS - Rural	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1815-2	HVDS - lo LV Specific	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1815-3	HVDS - hi LV Specific	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1815-4	HVDS - lo LV Shared	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1815-5	HVDS - hi LV Shared	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1820	Distribution Station Equipment - Normally Primary below 50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1820-1	Distribution Station Equipment - Normally Primary below 50 kV (Bulk)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1820-2	Distribution Station Equipment - Normally Primary below 50 kV (Primary)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1820-3	Distribution Station Equipment - Normally Primary below 50 kV (Wholesale Meters)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1825	Storage Battery Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1825-1	Storage Battery Equipment > 50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1825-2	Storage Battery Equipment <50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1830	Poles, Towers and Fixtures	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1830-3	Poles, Towers and Fixtures - Subtransmission Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1830-3A	Bulk-LV Fixtures	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1830-3B	Bulk-Retail Fixtures	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1830-4	Poles, Towers and Fixtures - Primary	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1830-4A	Primary-LV Fixtures	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1830-4B	Primary-Retail Fixtures	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1830-5	Poles, Towers and Fixtures - Secondary	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1835	Overhead Conductors and Devices	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1835-3	Overhead Conductors and Devices - Subtransmission Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1835-3A	Bulk-LV Conductors	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1835-3B	Bulk-Retail Conductors	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1835-4	Overhead Conductors and Devices - Primary	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1835-4A	Primary-LV Conductors	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1835-4B	Primary-Retail Conductors	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1835-5	Overhead Conductors and Devices - Secondary	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1840	Underground Condui	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1840-3	Underground Conduit - Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1840-4	Underground Conduit - Primary	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1840-5	Underground Conduit - Secondary	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1845	Underground Conductors and Devices	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1845-3	Underground Conductors and Devices - Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1845-4	Underground Conductors and Devices - Primary	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1845-5	Underground Conductors and Devices - Secondary	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1850	Line Transformers	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1850-1	TRF-LV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1850-2	TRF-Rural	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1855	Services	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1860	Meters	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

Account	Description	Contributed Capital	Demand	Customer	Total	UR	R1	R2	Seasonal	GSe	GSd	St Lgt	Sen Lgt	Dgen	ST	UGe	UGd	Total	UR	R1	R2
1860-1	Mtr-Single	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1860-2	Mtr-Poly	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1860-3	Mtr-LV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1860-4	Mtr-Smart	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1875	St Lgts	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Sub - Total	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
General Plant																					
1905	Land	$0																			
1906	Land Rights	$0																			
1908	Buildings and Fixtures	$0																			
1910	Leasehold Improvements	$0																			
1915	Office Furniture and Equipment	$0																			
1920	Computer Equipment - Hardware	$0																			
1925	Computer Software	$0																			
1930	Transportation Equipment	$0																			
1935	Stores Equipment	$0																			
1940	Tools, Shop and Garage Equipment	$0																			
1945	Measurement and Testing Equipment	$0																			
1950	Power Operated Equipment	$0																			
1955	Communication Equipment	$0																			
1960	Miscellaneous Equipment	$0																			
1970	Load Management Controls Customer Premises	$0																			
1975	Load Management Controls Utility Premises	$0																			
1980	System Supervisory Equipment	$0																			
1985	Sentinel Lgts	$0																			
1990	Other Tangible Property	$0																			
2005	Property Under Capital Leases	$0																			
2010	Electric Plant Purchased or Sold	$0																			
	Sub - Total	$0				$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	TOTAL - 5720	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

						Demand Allocation 1	2	3	4	5	6	7	8	12	13	14	15	Sub -total	Customer Allocation 1	2	3
Account	**Description**		**Demand**	**Customer**	**Total**	**UR**	**R1**	**R2**	**Seasonal**	**GSe**	**GSd**	**St Lgt**	**Sen Lgt**	**Dgen**	**ST**	**UGe**	**UGd**	**Sub -total**	**UR**	**R1**	**R2**
1565	Conservation and Demand Management	100%	0%	100%	100%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	6.76%	24.04%	38.79%
1805	Land					0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
1805-1	Land Station >50 kV	100%	100%	0%	100%	4.55%	13.76%	16.63%	2.08%	5.06%	7.30%	0.21%	0.04%	0.01%	47.55%	0.95%	1.87%	100.00%	0.00%	0.00%	0.00%
1805-2	Land Station <50 kV	100%	100%	0%	100%	8.43%	25.51%	30.84%	3.86%	9.38%	13.55%	0.39%	0.08%	0.01%	2.72%	1.77%	3.47%	100.00%	0.00%	0.00%	0.00%
1806	Land Rights					0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
1806-1	Land Rights Station >50 kV	100%	100%	0%	100%	4.55%	13.76%	16.63%	2.08%	5.06%	7.30%	0.21%	0.04%	0.01%	47.55%	0.95%	1.87%	100.00%	0.00%	0.00%	0.00%
1806-2	Land Rights Station <50 kV	100%	100%	0%	100%	8.43%	25.51%	30.84%	3.86%	9.38%	13.55%	0.39%	0.08%	0.01%	2.72%	1.77%	3.47%	100.00%	0.00%	0.00%	0.00%
1808	Buildings and Fixtures					0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
1808-1	Buildings and Fixtures > 50 kV	100%	100%	0%	100%	4.55%	13.76%	16.63%	2.08%	5.06%	7.30%	0.21%	0.04%	0.01%	47.55%	0.95%	1.87%	100.00%	0.00%	0.00%	0.00%
1808-2	Buildings and Fixtures < 50 KV	100%	100%	0%	100%	8.43%	25.51%	30.84%	3.86%	9.38%	13.55%	0.39%	0.08%	0.01%	2.72%	1.77%	3.47%	100.00%	0.00%	0.00%	0.00%
1810	Leasehold Improvements					0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
1810-1	Leasehold Improvements >50 kV	100%	100%	0%	100%	4.55%	13.76%	16.63%	2.08%	5.06%	7.30%	0.21%	0.04%	0.01%	47.55%	0.95%	1.87%	100.00%	0.00%	0.00%	0.00%
1810-2	Leasehold Improvements <50 kV	100%	100%	0%	100%	8.43%	25.51%	30.84%	3.86%	9.38%	13.55%	0.39%	0.08%	0.01%	2.72%	1.77%	3.47%	100.00%	0.00%	0.00%	0.00%
1815	Transformer Station Equipment - Normally Primary above 50 kV	0%	0%	0%	0%	4.55%	13.76%	16.63%	2.08%	5.06%	7.30%	0.21%	0.04%	0.01%	47.55%	0.95%	1.87%	100.00%	0.00%	0.00%	0.00%
1815-1	HVDS - Rural	100%	100%	0%	100%	8.67%	26.23%	31.70%	3.97%	9.64%	13.93%	0.40%	0.08%	0.01%	0.00%	1.82%	3.56%	100.00%	0.00%	0.00%	0.00%
1815-2	HVDS - lo LV Specific	100%	100%	0%	100%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%	0.00%	0.00%	100.00%	0.00%	0.00%	0.00%
1815-3	HVDS - hi LV Specific	100%	100%	0%	100%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%	0.00%	0.00%	100.00%	0.00%	0.00%	0.00%

Account	Description	Contributed Capital	Demand	Customer	Total	UR	R1	R2	Seasonal	GSe	GSd	St Lgt	Sen Lgt	Dgen	ST	UGe	UGd	Total	UR	R1	R2
1815-4	HVDS - lo LV Shared	100%	100%	0%	100%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%	0.00%	0.00%	100.00%	0.00%	0.00%	0.00%
1815-5	HVDS - hi LV Shared	100%	100%	0%	100%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%	0.00%	0.00%	100.00%	0.00%	0.00%	0.00%
1820	Distribution Station Equipment - Normally Primary below 50 kV					4.55%	13.76%	16.63%	2.08%	5.06%	7.30%	0.21%	0.04%	0.01%	47.55%	0.95%	1.87%	100.00%	0.00%	0.00%	0.00%
1820-1	Distribution Station Equipment - Normally Primary below 50 kV (Bulk)	100%	100%	0%	100%	4.55%	13.76%	16.63%	2.08%	5.06%	7.30%	0.21%	0.04%	0.01%	47.55%	0.95%	1.87%	100.00%	0.00%	0.00%	0.00%
1820-2	Distribution Station Equipment - Normally Primary below 50 kV (Primary)	100%	100%	0%	100%	7.04%	24.50%	29.22%	1.72%	10.97%	16.25%	1.15%	0.18%	0.00%	2.87%	1.92%	4.17%	100.00%	0.00%	0.00%	0.00%
1820-3	Distribution Station Equipment - Normally Primary below 50 kV (Wholesale Meters)	100%	0%	100%	100%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	6.16%	18.16%	23.18%
1825	Storage Battery Equipment					0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
1825-1	Storage Battery Equipment > 50 kV	100%	100%	0%	100%	4.55%	13.76%	16.63%	2.08%	5.06%	7.30%	0.21%	0.04%	0.01%	47.55%	0.95%	1.87%	100.00%	0.00%	0.00%	0.00%
1825-2	Storage Battery Equipment <50 kV	100%	100%	0%	100%	4.55%	13.76%	16.63%	2.08%	5.06%	7.30%	0.21%	0.04%	0.01%	47.55%	0.95%	1.87%	100.00%	0.00%	0.00%	0.00%
1830	Poles, Towers and Fixtures					0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
1830-3	Poles, Towers and Fixtures - Subtransmission Bulk Delivery	0%	0%	0%	0%	4.55%	13.76%	16.63%	2.08%	5.06%	7.30%	0.21%	0.04%	0.01%	47.55%	0.95%	1.87%	100.00%	0.00%	0.00%	0.00%
1830-3A	Bulk-LV Fixtures	100%	100%	0%	100%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%	0.00%	0.00%	100.00%	0.00%	0.00%	0.00%
1830-3B	Bulk-Retail Fixtures	100%	100%	0%	100%	1.60%	16.94%	45.41%	6.40%	11.20%	16.53%	0.40%	0.08%	0.01%	0.00%	0.34%	1.09%	100.00%	0.00%	0.00%	0.00%
1830-4	Poles, Towers and Fixtures - Primary	0%	0%	0%	0%	7.05%	24.54%	29.26%	1.73%	10.99%	16.28%	1.16%	0.19%	0.00%	2.72%	1.92%	4.18%	100.00%	13.66%	31.74%	30.77%
1830-4A	Primary-LV Fixtures	100%	52%	48%	100%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%	0.00%	0.00%	100.00%	0.00%	0.00%	0.00%
1830-4B	Primary-Retail Fixtures	100%	52%	48%	100%	1.34%	16.35%	43.25%	2.87%	13.17%	19.93%	1.20%	0.19%	0.00%	0.00%	0.37%	1.31%	100.00%	2.60%	20.99%	49.81%
1830-5	Poles, Towers and Fixtures - Secondary	100%	52%	48%	100%	9.13%	31.94%	38.15%	2.15%	14.35%	0.00%	1.51%	0.24%	0.00%	0.00%	2.52%	0.00%	100.00%	13.76%	31.97%	30.99%
1835	Overhead Conductors and Devices					0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
1835-3	Overhead Conductors and Devices - Subtransmission Bulk Delivery	0%	0%	0%	0%	4.55%	13.76%	16.63%	2.08%	5.06%	7.30%	0.21%	0.04%	0.01%	47.55%	0.95%	1.87%	100.00%	0.00%	0.00%	0.00%
1835-3A	Bulk-LV Conductors	100%	100%	0%	100%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%	0.00%	0.00%	100.00%	0.00%	0.00%	0.00%
1835-3B	Bulk-Retail Conductors	100%	100%	0%	100%	1.60%	16.94%	45.41%	6.40%	11.20%	16.53%	0.40%	0.08%	0.01%	0.00%	0.34%	1.09%	100.00%	0.00%	0.00%	0.00%
1835-4	Overhead Conductors and Devices - Primary	0%	0%	0%	0%	7.05%	24.54%	29.26%	1.73%	10.99%	16.28%	1.16%	0.19%	0.00%	2.72%	1.92%	4.18%	100.00%	13.66%	31.74%	30.77%
1835-4A	Primary-LV Conductors	100%	45%	55%	100%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%	0.00%	0.00%	100.00%	0.00%	0.00%	0.00%
1835-4B	Primary-Retail Conductors	100%	45%	55%	100%	1.34%	16.35%	43.25%	2.87%	13.17%	19.93%	1.20%	0.19%	0.00%	0.00%	0.37%	1.31%	100.00%	2.60%	20.99%	49.81%
1835-5	Overhead Conductors and Devices - Secondary	100%	45%	55%	100%	9.13%	31.94%	38.15%	2.15%	14.35%	0.00%	1.51%	0.24%	0.00%	0.00%	2.52%	0.00%	100.00%	13.76%	31.97%	30.99%
1840	Underground Conduit					0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
1840-3	Underground Conduit - Bulk Delivery	100%	100%	0%	100%	4.55%	13.76%	16.63%	2.08%	5.06%	7.30%	0.21%	0.04%	0.01%	47.55%	0.95%	1.87%	100.00%	0.00%	0.00%	0.00%
1840-4	Underground Conduit - Primary	100%	45%	55%	100%	7.24%	25.23%	30.08%	1.77%	11.29%	16.73%	1.19%	0.19%	0.00%	0.00%	1.98%	4.30%	100.00%	13.66%	31.74%	30.77%
1840-5	Underground Conduit - Secondary	100%	45%	55%	100%	9.13%	31.94%	38.15%	2.15%	14.35%	0.00%	1.51%	0.24%	0.00%	0.00%	2.52%	0.00%	100.00%	13.76%	31.97%	30.99%
1845	Underground Conductors and Devices					0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
1845-3	Underground Conductors and Devices - Bulk Delivery	100%	100%	0%	100%	4.55%	13.76%	16.63%	2.08%	5.06%	7.30%	0.21%	0.04%	0.01%	47.55%	0.95%	1.87%	100.00%	0.00%	0.00%	0.00%
1845-4	Underground Conductors and Devices - Primary	100%	45%	55%	100%	7.24%	25.23%	30.08%	1.77%	11.29%	16.73%	1.19%	0.19%	0.00%	0.00%	1.98%	4.30%	100.00%	13.66%	31.74%	30.77%
1845-5	Underground Conductors and Devices - Secondary	100%	45%	55%	100%	9.13%	31.94%	38.15%	2.15%	14.35%	0.00%	1.51%	0.24%	0.00%	0.00%	2.52%	0.00%	100.00%	13.76%	31.97%	30.99%
1850	Line Transformers	0%	0%	0%	0%	0.00%	0.00%	0.04%	0.00%	14.59%	62.78%	3.23%	0.00%	0.00%	0.00%	3.11%	16.25%	100.00%	13.66%	31.74%	30.77%
1850-1	TRF-LV	100%	38%	62%	100%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%	0.00%	0.00%	100.00%	0.00%	0.00%	0.00%
1850-2	TRF-Rural	100%	38%	62%	100%	0.00%	0.00%	0.05%	0.00%	15.17%	63.77%	3.23%	0.00%	0.00%	0.00%	2.46%	15.32%	100.00%	10.61%	29.83%	38.31%
1855	Services	0%	0%	0%	0%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	12.59%	29.24%	28.35%
1860	Meters	0%	0%	0%	0%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	11.91%	28.35%	29.42%
1860-1	Mtr-Single	100%	0%	100%	100%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	12.90%	30.73%	31.89%
1860-2	Mtr-Poly	100%	0%	100%	100%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
1860-3	Mtr-LV	100%	0%	100%	100%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
1860-4	Mtr-Smart	100%	0%	100%	100%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	13.76%	31.97%	30.99%
1875	St Lgts	100%	100%	0%	100%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%	0.00%	0.00%	0.00%
General Plant																					
1905	Land	100%																			
1906	Land Rights	100%																			
1908	Buildings and Fixtures	100%																			

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Account	Description	Contributed Capital	Demand	Customer	Total	UR	R1	R2	Seasonal	GSe	GSd	St Lgt	Sen Lgt	Dgen	ST	UGe	UGd	Total	UR	R1	R2
1910	Leasehold Improvements	100%																			
1915	Office Furniture and Equipment	100%																			
1920	Computer Equipment - Hardware	100%																			
1925	Computer Software	100%																			
1930	Transportation Equipment	100%																			
1935	Stores Equipment	100%																			
1940	Tools, Shop and Garage Equipment	100%																			
1945	Measurement and Testing Equipment	100%																			
1950	Power Operated Equipment	100%																			
1955	Communication Equipment	100%																			
1960	Miscellaneous Equipment	100%																			
1970	Load Management Controls Customer Premises	100%																			
1975	Load Management Controls Utility Premises	100%																			
1980	System Supervisory Equipment	100%																			
1985	Sentinel Lgts	100%																			
1990	Other Tangible Property	100%																			
2005	Property Under Capital Leases	100%																			
2010	Electric Plant Purchased or Sold	100%																			

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Hydro One Networks - Distribution

Output sheet for Amortization

Categorization and Allocation of Contril

Contributed Capital - 1995

Account	Description	4 Seasonal	5 GSe	6 GSd	7 St Lgt	8 Sen Lgt	12 Dgen	13 ST	14 UGe	15 UGd	Sub -total Sub -total
1565	Conservation and Demand Management	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1805	Land	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1805-1	Land Station >50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1805-2	Land Station <50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1806	Land Rights	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1806-1	Land Rights Station >50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1806-2	Land Rights Station <50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1808	Buildings and Fixtures	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1808-1	Buildings and Fixtures > 50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1808-2	Buildings and Fixtures < 50 KV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1810	Leasehold Improvements	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1810-1	Leasehold Improvements >50 kV (Wholesale)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1810-2	Leasehold Improvements <50 kV (Other)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1815	Transformer Station Equipment - Normally Primary above 50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1815-1	HVDS - Rural	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1815-2	HVDS - lo LV Specific	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1815-3	HVDS - hi LV Specific	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1815-4	HVDS - lo LV Shared	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1815-5	HVDS - hi LV Shared	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1820	Distribution Station Equipment - Normally Primary below 50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1820-1	Distribution Station Equipment - Normally Primary below 50 kV (Bulk)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1820-2	Distribution Station Equipment - Normally Primary below 50 kV (Primary)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1820-3	Distribution Station Equipment - Normally Primary below 50 kV (Wholesale Meters)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1825	Storage Battery Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1825-1	Storage Battery Equipment > 50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1825-2	Storage Battery Equipment <50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1830	Poles, Towers and Fixtures	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1830-3	Poles, Towers and Fixtures - Subtransmission Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1830-3A	Bulk-LV Fixtures	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1830-3B	Bulk-Retail Fixtures	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1830-4	Poles, Towers and Fixtures - Primary	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1830-4A	Primary-LV Fixtures	$0	$0	$0	$0	$0	$0	($43,174)	$0	$0	($43,174)
1830-4B	Primary-Retail Fixtures	($6,075,950)	($3,509,636)	($261,050)	($181,494)	($117,676)	($1,044)	$0	($99,126)	($14,279)	($38,573,746)
1830-5	Poles, Towers and Fixtures - Secondary	($1,174,398)	($734,144)	$0	($42,085)	($27,287)	$0	$0	($96,450)	$0	($8,911,597)
1835	Overhead Conductors and Devices	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

A & G Allocation 1 UR	2 R1	3 R2	4 Seasonal	5 GSe	6 GSd	7 St Lgt	8 Sen Lgt	12 Dgen	13 ST	14 UGe	15 UGd	Sub -total Sub -total

Account	Description	Seasonal	GSe	GSd	St Lgt	Sen Lgt	Dgen	ST	UGe	UGd	Sub -total
1835-3	Overhead Conductors and Devices - Subtransmission Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1835-3A	Bulk-LV Conductors	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1835-3B	Bulk-Retail Conductors	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1835-4	Overhead Conductors and Devices - Primary	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1835-4A	Primary-LV Conductors	$0	$0	$0	$0	$0	$0	($26,641)	$0	$0	($26,641)
1835-4B	Primary-Retail Conductors	($3,749,296)	($2,165,697)	($161,087)	($111,995)	($72,614)	($644)	$0	($61,168)	($8,811)	($23,802,762)
1835-5	Overhead Conductors and Devices - Secondary	($724,688)	($453,019)	$0	($25,970)	($16,838)	$0	$0	($59,517)	$0	($5,499,093)
1840	Underground Conduit	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1840-3	Underground Conduit - Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1840-4	Underground Conduit - Primary	($15,619)	($9,764)	($706)	($560)	($363)	($3)	$0	($1,283)	($144)	($119,377)
1840-5	Underground Conduit - Secondary	($62,927)	($39,337)	$0	($2,255)	($1,462)	$0	$0	($5,168)	$0	($477,506)
1845	Underground Conductors and Devices	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1845-3	Underground Conductors and Devices - Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1845-4	Underground Conductors and Devices - Primary	($1,733,492)	($1,083,647)	($78,364)	($62,121)	($40,277)	($357)	$0	($142,367)	($15,959)	($13,248,810)
1845-5	Underground Conductors and Devices - Secondary	($6,983,879)	($4,365,788)	$0	($250,271)	($162,269)	$0	$0	($573,567)	$0	($52,995,239)
1850	Line Transformers	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1850-1	TRF-LV	$0	$0	$0	$0	$0	$0	($159,605)	$0	$0	($159,605)
1850-2	TRF-Rural	($6,148,192)	($4,374,254)	($333,181)	($251,926)	($163,342)	($1,450)	$0	$0	$0	($53,041,913)
1855	Services	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1860	Meters	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1860-1	Mtr-Single	($47,068)	($32,248)	$0	$0	$0	$0	$0	($4,383)	$0	($341,965)
1860-2	Mtr-Poly	$0	$0	($116,514)	$0	$0	($2,139)	$0	$0	($21,966)	($140,620)
1860-3	Mtr-LV	$0	$0	$0	$0	$0	$0	($174,867)	$0	$0	($174,867)
1860-4	Mtr-Smart	($508,965)	($318,166)	($23,008)	$0	$0	($274)	($2,207)	($41,800)	($4,686)	($3,862,249)
1875	St Lgts	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Sub - Total	($27,224,474)	($17,085,700)	($973,911)	($928,676)	($602,128)	($5,913)	($406,494)	($1,084,829)	($65,846)	($201,419,161)

Account	Description	UR	R1	R2	Seasonal	GSe	GSd	St Lgt	Sen Lgt	Dgen	ST	UGe	UGd	Sub -total
General Plant														
1905	Land	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1906	Land Rights	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1908	Buildings and Fixtures	($7,291)	($27,008)	($44,031)	($9,506)	($13,099)	($15,128)	($1,117)	($242)	($7)	($3,158)	($1,130)	($2,599)	($124,317)
1910	Leasehold Improvements	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1915	Office Furniture and Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1920	Computer Equipment - Hardware	($375)	($1,390)	($2,266)	($489)	($674)	($779)	($57)	($12)	($0)	($163)	($58)	($134)	($6,399)
1925	Computer Software	($125)	($463)	($755)	($163)	($225)	($260)	($19)	($4)	($0)	($54)	($19)	($45)	($2,133)
1930	Transportation Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1935	Stores Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1940	Tools, Shop and Garage Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1945	Measurement and Testing Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1950	Power Operated Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1955	Communication Equipment	($4,899)	($18,147)	($29,585)	($6,387)	($8,802)	($10,164)	($750)	($163)	($5)	($2,122)	($759)	($1,746)	($83,530)
1960	Miscellaneous Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1970	Load Management Controls Customer Premises	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1975	Load Management Controls Utility Premises	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1980	System Supervisory Equipment	($24,164)	($89,515)	($145,933)	($31,507)	($43,416)	($50,137)	($3,702)	($803)	($24)	($10,466)	($3,746)	($8,614)	($412,025)
1985	Sentinel Lgts	$0	$0	$0	$0	$0	$0	$0	($301,089)	$0	$0	$0	$0	($301,089)
1990	Other Tangible Property	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2005	Property Under Capital Leases	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2010	Electric Plant Purchased or Sold	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Sub - Total	($36,854)	($136,524)	($222,572)	($48,053)	($66,216)	($76,468)	($5,646)	($302,314)	($37)	($15,962)	($5,713)	($13,137)	($929,494)

Account	Description	Seasonal	GSe	GSd	St Lgt	Sen Lgt	Dgen	ST	UGe	UGd	Sub -total	UR	R1	R2	Seasonal	GSe	GSd	St Lgt	Sen Lgt	Dgen	ST	UGe	UGd	Sub -total
	TOTAL - 1995	($27,224,474)	($17,085,700)	($973,911)	($928,676)	($602,128)	($5,913)	($406,494)	($1,084,829)	($65,846)	($201,419,161)	($36,854)	($136,524)	($222,572)	($48,053)	($66,216)	($76,468)	($5,646)	($302,314)	($37)	($15,962)	($5,713)	($13,137)	($929,494)

Accumulated Depreciation - 2105 Capti

		4	5	6	7	8	12	13	14	15	Sub -total
Account	Description	Seasonal	GSe	GSd	St Lgt	Sen Lgt	Dgen	ST	UGe	UGd	Sub -total
1565	Conservation and Demand Management	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1805	Land	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1805-1	Land Station >50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1805-2	Land Station <50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1806	Land Rights	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1806-1	Land Rights Station >50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1806-2	Land Rights Station <50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1808	Buildings and Fixtures	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1808-1	Buildings and Fixtures > 50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1808-2	Buildings and Fixtures < 50 KV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1810	Leasehold Improvements	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1810-1	Leasehold Improvements >50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1810-2	Leasehold Improvements <50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1815	Transformer Station Equipment - Normally Primary above 50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1815-1	HVDS - Rural	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1815-2	HVDS - lo LV Specific	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1815-3	HVDS - hi LV Specific	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1815-4	HVDS - lo LV Shared	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1815-5	HVDS - hi LV Shared	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1820	Distribution Station Equipment - Normally Primary below 50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1820-1	Distribution Station Equipment - Normally Primary below 50 kV (Bulk)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1820-2	Distribution Station Equipment - Normally Primary below 50 kV (Primary)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1820-3	Distribution Station Equipment - Normally Primary below 50 kV (Wholesale Meters)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1825	Storage Battery Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1825-1	Storage Battery Equipment > 50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1825-2	Storage Battery Equipment <50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1830	Poles, Towers and Fixtures	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1830-3	Poles, Towers and Fixtures - Subtransmission Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1830-3A	Bulk-LV Fixtures	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1830-3B	Bulk-Retail Fixtures	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1830-4	Poles, Towers and Fixtures - Primary	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1830-4A	Primary-LV Fixtures	$0	$0	$0	$0	$0	$0	($10,749)	$0	$0	($10,749)
1830-4B	Primary-Retail Fixtures	($1,512,798)	($873,834)	($64,997)	($45,189)	($29,299)	($260)	$0	($24,681)	($3,555)	($9,604,143)
1830-5	Poles, Towers and Fixtures - Secondary	($292,403)	($182,788)	$0	($10,478)	($6,794)	$0	$0	($24,014)	$0	($2,218,821)
1835	Overhead Conductors and Devices	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1835-3	Overhead Conductors and Devices - Subtransmission Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1835-3A	Bulk-LV Conductors	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1835-3B	Bulk-Retail Conductors	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1835-4	Overhead Conductors and Devices - Primary	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

A & G Allocation												
1	2	3	4	5	6	7	8	12	13	14	15	Sub -total
UR	R1	R2	Seasonal	GSe	GSd	St Lgt	Sen Lgt	Dgen	ST	UGe	UGd	Sub -total

Account	Description	Seasonal	GSe	GSd	St Lgt	Sen Lgt	Dgen	ST	UGe	UGd	Sub -total	UR	R1	R2	Seasonal	GSe	GSd	St Lgt	Sen Lgt	Dgen	ST	UGe	UGd	Sub -total
1835-4A	Primary-LV Conductors	$0	$0	$0	$0	$0	$0	($5,922)	$0	$0	($5,922)													
1835-4B	Primary-Retail Conductors	($833,395)	($481,392)	($35,806)	($24,894)	($16,141)	($143)	$0	($13,596)	($1,959)	($5,290,887)													
1835-5	Overhead Conductors and Devices - Secondary	($161,084)	($100,697)	$0	($5,773)	($3,743)	$0	$0	($13,229)	$0	($1,222,341)													
1840	Underground Conduit	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1840-3	Underground Conduit - Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1840-4	Underground Conduit - Primary	($6,840)	($4,276)	($309)	($245)	($159)	($1)	$0	($562)	($63)	($52,273)													
1840-5	Underground Conduit - Secondary	($27,555)	($17,225)	$0	($987)	($640)	$0	$0	($2,263)	$0	($209,093)													
1845	Underground Conductors and Devices	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1845-3	Underground Conductors and Devices - Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1845-4	Underground Conductors and Devices - Primary	($669,670)	($418,626)	($30,273)	($23,998)	($15,560)	($138)	$0	($54,998)	($6,165)	($5,118,179)													
1845-5	Underground Conductors and Devices - Secondary	($2,697,959)	($1,686,558)	$0	($96,683)	($62,686)	$0	$0	($221,576)	$0	($20,472,715)													
1850	Line Transformers	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1850-1	TRF-LV	$0	$0	$0	$0	$0	$0	($26,475)	$0	$0	($26,475)													
1850-2	TRF-Rural	($1,019,844)	($725,588)	($55,267)	($41,789)	($27,095)	($240)	$0	$0	$0	($8,798,436)													
1855	Services	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1860	Meters	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1860-1	Mtr-Single	($28,592)	($19,589)	$0	$0	$0	$0	$0	($2,663)	$0	($207,730)													
1860-2	Mtr-Poly	$0	$0	($70,778)	$0	$0	($1,299)	$0	$0	($13,344)	($85,421)													
1860-3	Mtr-LV	$0	$0	$0	$0	$0	$0	($106,225)	$0	$0	($106,225)													
1860-4	Mtr-Smart	($309,176)	($193,273)	($13,977)	$0	$0	($167)	($1,341)	($25,392)	($2,846)	($2,346,160)													
1875	St Lgts	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
	Sub - Total	($7,559,314)	($4,703,847)	($271,406)	($250,036)	($162,116)	($2,249)	($150,712)	($382,974)	($27,932)	($55,775,570)													
General Plant																								
1905	Land											$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1906	Land Rights											$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1908	Buildings and Fixtures											($1,333)	($4,939)	($8,051)	($1,738)	($2,395)	($2,766)	($204)	($44)	($1)	($577)	($207)	($475)	($22,732)
1910	Leasehold Improvements											$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1915	Office Furniture and Equipment											$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1920	Computer Equipment - Hardware											($171)	($634)	($1,034)	($223)	($308)	($355)	($26)	($6)	($0)	($74)	($27)	($61)	($2,918)
1925	Computer Software											($61)	($227)	($370)	($80)	($110)	($127)	($9)	($2)	($0)	($27)	($9)	($22)	($1,044)
1930	Transportation Equipment											$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1935	Stores Equipment											$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1940	Tools, Shop and Garage Equipment											$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1945	Measurement and Testing Equipment											$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1950	Power Operated Equipment											$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1955	Communication Equipment											($1,163)	($4,308)	($7,024)	($1,516)	($2,090)	($2,413)	($178)	($39)	($1)	($504)	($180)	($415)	($19,830)
1960	Miscellaneous Equipment											$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1970	Load Management Controls Customer Premises											$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1975	Load Management Controls Utility Premises											$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1980	System Supervisory Equipment											($7,573)	($28,055)	($45,737)	($9,875)	($13,607)	($15,714)	($1,160)	($252)	($8)	($3,280)	($1,174)	($2,700)	($129,134)
1985	Sentinel Lgts											$0	$0	$0	$0	$0	$0	$0	($170,254)	$0	$0	$0	$0	$0
1990	Other Tangible Property											$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2005	Property Under Capital Leases											$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2010	Electric Plant Purchased or Sold											$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Sub - Total											($10,302)	($38,163)	($62,216)	($13,432)	($18,509)	($21,375)	($1,578)	($170,596)	($10)	($4,462)	($1,597)	($3,672)	($175,659)
	TOTAL - 2105 CC	($7,559,314)	($4,703,847)	($271,406)	($250,036)	($162,116)	($2,249)	($150,712)	($382,974)	($27,932)	($55,775,570)	($10,302)	($38,163)	($62,216)	($13,432)	($18,509)	($21,375)	($1,578)	($170,596)	($10)	($4,462)	($1,597)	($3,672)	($175,659)

Accumulated Depreciation - 2105 Fixed

									A & G Allocation													
4	**5**	**6**	**7**	**8**	**12**	**13**	**14**	**15**	**Sub -total**	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**12**	**13**	**14**	**15**	**Sub -total**

Account	Description	Seasonal	GSe	GSd	St Lgt	Sen Lgt	Dgen	ST	UGe	UGd	Sub -total	UR	R1	R2	Seasonal	GSe	GSd	St Lgt	Sen Lgt	Dgen	ST	UGe	UGd	Sub -total
Account	Description	Seasonal	GSe	GSd	St Lgt	Sen Lgt	Dgen	ST	UGe	UGd	Sub -total	UR	R1	R2	Seasonal	GSe	GSd	St Lgt	Sen Lgt	Dgen	ST	UGe	UGd	Sub -total
1565	Conservation and Demand Management	($62,535)	($81,313)	($55,751)	($4,948)	($1,398)	($42)	($15,206)	($7,185)	($7,480)	($775,688)													
1805	Land	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1805-1	Land Station >50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1805-2	Land Station <50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1806	Land Rights	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1806-1	Land Rights Station >50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1806-2	Land Rights Station <50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1808	Buildings and Fixtures	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1808-1	Buildings and Fixtures > 50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1808-2	Buildings and Fixtures < 50 KV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1810	Leasehold Improvements	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1810-1	Leasehold Improvements >50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1810-2	Leasehold Improvements <50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1815	Transformer Station Equipment - Normally Primary above 50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1815-1	HVDS - Rural	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1815-2	HVDS - lo LV Specific	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1815-3	HVDS - hi LV Specific	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1815-4	HVDS - lo LV Shared	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1815-5	HVDS - hi LV Shared	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1820	Distribution Station Equipment - Normally Primary below 50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1820-1	Distribution Station Equipment - Normally Primary below 50 kV (Bulk)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1820-2	Distribution Station Equipment - Normally Primary below 50 kV (Primary)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1820-3	Distribution Station Equipment - Normally Primary below 50 kV (Wholesale Meters)	($436,846)	($1,421,272)	($2,001,109)	($74,545)	($13,857)	($2,095)	($3,149,926)	($262,187)	($513,550)	($15,000,000)													
1825	Storage Battery Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1825-1	Storage Battery Equipment > 50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1825-2	Storage Battery Equipment <50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1830	Poles, Towers and Fixtures	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1830-3	Poles, Towers and Fixtures - Subtransmission Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1830-3A	Bulk-LV Fixtures	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1830-3B	Bulk-Retail Fixtures	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1830-4	Poles, Towers and Fixtures - Primary	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1830-4A	Primary-LV Fixtures	$0	$0	$0	$0	$0	$0	($220,837)	$0	$0	($220,837)													
1830-4B	Primary-Retail Fixtures	($31,079,029)	($17,952,103)	($1,335,296)	($928,360)	($601,923)	($5,342)	$0	($507,038)	($73,041)	($197,308,176)													
1830-5	Poles, Towers and Fixtures - Secondary	($6,007,152)	($3,755,213)	$0	($215,269)	($139,575)	$0	$0	($493,351)	$0	($45,583,619)													
1835	Overhead Conductors and Devices	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1835-3	Overhead Conductors and Devices - Subtransmission Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1835-3A	Bulk-LV Conductors	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1835-3B	Bulk-Retail Conductors	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1835-4	Overhead Conductors and Devices - Primary	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1835-4A	Primary-LV Conductors	$0	$0	$0	$0	$0	$0	($179,633)	$0	$0	($179,633)													
1835-4B	Primary-Retail Conductors	($25,280,174)	($14,602,525)	($1,086,151)	($755,143)	($489,613)	($4,345)	$0	($412,433)	($59,413)	($160,493,595)													
1835-5	Overhead Conductors and Devices - Secondary	($4,886,313)	($3,054,550)	$0	($175,104)	($113,532)	$0	$0	($401,300)	$0	($37,078,437)													
1840	Underground Condui	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													

Account	Description	Seasonal	GSe	GSd	St Lgt	Sen Lgt	Dgen	ST	UGe	UGd	Sub -total
1840-3	Underground Conduit - Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1840-4	Underground Conduit - Primary	($138,101)	($86,330)	($6,243)	($4,949)	($3,209)	($28)	$0	($11,342)	($1,271)	($1,055,484)
1840-5	Underground Conduit - Secondary	($556,380)	($347,806)	$0	($19,938)	($12,927)	$0	$0	($45,694)	$0	($4,221,935)
1845	Underground Conductors and Devices	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1845-3	Underground Conductors and Devices - Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1845-4	Underground Conductors and Devices - Primary	($2,501,433)	($1,563,705)	($113,079)	($89,640)	($58,120)	($516)	$0	($205,436)	($23,029)	($19,118,058)
1845-5	Underground Conductors and Devices - Secondary	($10,077,751)	($6,299,841)	$0	($361,141)	($234,154)	$0	$0	($827,659)	$0	($76,472,230)
1850	Line Transformers	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1850-1	TRF-LV	$0	$0	$0	$0	$0	$0	($615,215)	$0	$0	($615,215)
1850-2	TRF-Rural	($23,698,950)	($16,861,089)	($1,284,287)	($971,079)	($629,620)	($5,588)	$0	$0	$0	($204,456,462)
1855	Services	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1860	Meters	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1860-1	Mtr-Single	$323,281	$221,492	$0	$0	$0	$0	$0	$30,105	$0	$2,348,769
1860-2	Mtr-Poly	$0	$0	$800,271	$0	$0	$14,693	$0	$0	$150,874	$965,837
1860-3	Mtr-LV	$0	$0	$0	$0	$0	$0	$1,201,066	$0	$0	$1,201,066
1860-4	Mtr-Smart	$3,495,796	$2,185,305	$158,030	$0	$0	$1,884	$15,161	$287,100	$32,184	$26,527,644
1875	St Lgts	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Sub - Total	($100,905,587)	($63,618,951)	($4,923,615)	($3,600,116)	($2,297,928)	($1,380)	($2,964,590)	($2,856,420)	($494,726)	($731,536,053)
	TOTAL - 2105 FA	($100,905,587)	($63,618,951)	($4,923,615)	($3,600,116)	($2,297,928)	($1,380)	($2,964,590)	($2,856,420)	($494,726)	($731,536,053)

Account	Description	UR	R1	R2	Seasonal	GSe	GSd	St Lgt	Sen Lgt	Dgen	ST	UGe	UGd	Sub -total
	Sub - Total	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
General Plant														
1905	Land	($1,188)	($4,402)	($7,177)	($1,549)	($2,135)	($2,466)	($182)	($39)	($1)	($515)	($184)	($424)	($20,263)
1906	Land Rights	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1908	Buildings and Fixtures	($2,603,128)	($9,643,274)	($15,721,192)	($3,394,177)	($4,677,089)	($5,401,230)	($398,782)	($86,507)	($2,610)	($1,127,466)	($403,523)	($927,923)	($44,386,901)
1910	Leasehold Improvements	($216,993)	($803,849)	($1,310,495)	($282,933)	($389,875)	($450,238)	($33,242)	($7,211)	($218)	($93,984)	($33,637)	($77,350)	($3,700,025)
1915	Office Furniture and Equipment	($39,400)	($145,958)	($237,951)	($51,373)	($70,791)	($81,751)	($6,036)	($1,309)	($40)	($17,065)	($6,108)	($14,045)	($671,827)
1920	Computer Equipment - Hardware	($1,479,714)	($5,481,591)	($8,936,502)	($1,929,375)	($2,658,629)	($3,070,257)	($226,682)	($49,174)	($1,484)	($640,893)	($229,378)	($527,465)	($25,231,142)
1925	Computer Software	($6,298,765)	($23,333,739)	($38,040,418)	($8,212,857)	($11,317,108)	($13,069,305)	($964,929)	($209,320)	($6,315)	($2,728,118)	($976,402)	($2,245,285)	($107,402,562)
1930	Transportation Equipment	($5,981,434)	($22,158,189)	($36,123,948)	($7,799,095)	($10,746,954)	($12,410,876)	($916,316)	($198,775)	($5,997)	($2,590,676)	($927,211)	($2,132,168)	($101,991,639)
1935	Stores Equipment	($194,044)	($718,835)	($1,171,899)	($253,011)	($348,643)	($402,622)	($29,726)	($6,448)	($195)	($84,044)	($30,080)	($69,170)	($3,308,717)
1940	Tools, Shop and Garage Equipment	($60,068)	($222,522)	($362,772)	($78,322)	($107,926)	($124,635)	($9,202)	($1,996)	($60)	($26,017)	($9,311)	($21,412)	($1,024,244)
1945	Measurement and Testing Equipment	($60,671)	($224,754)	($366,411)	($79,108)	($109,008)	($125,886)	($9,294)	($2,016)	($61)	($26,278)	($9,405)	($21,627)	($1,034,519)
1950	Power Operated Equipment	($4,194,223)	($15,537,473)	($25,330,359)	($5,468,779)	($7,535,838)	($8,702,591)	($642,527)	($139,382)	($4,205)	($1,816,600)	($650,167)	($1,495,091)	($71,517,234)
1955	Communication Equipment	($1,226,181)	($4,542,380)	($7,405,331)	($1,598,798)	($2,203,102)	($2,544,203)	($187,843)	($40,748)	($1,229)	($531,083)	($190,076)	($437,090)	($20,908,064)
1960	Miscellaneous Equipment	($67,792)	($251,137)	($409,422)	($88,393)	($121,804)	($140,663)	($10,385)	($2,253)	($68)	($29,362)	($10,509)	($24,166)	($1,155,954)
1970	Load Management Controls Customer Premises	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1975	Load Management Controls Utility Premises	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1980	System Supervisory Equipment	($376,876)	($1,396,134)	($2,276,083)	($491,402)	($677,140)	($781,979)	($57,735)	($12,524)	($378)	($163,232)	($58,421)	($134,343)	($6,426,248)
1985	Sentinel Lgts	$0	$0	$0	$0	$0	$0	$0	($11,723,467)	$0	$0	$0	$0	$0
1990	Other Tangible Property	($198,193)	($734,206)	($1,196,958)	($258,421)	($356,098)	($411,231)	($30,362)	($6,586)	($199)	($85,841)	($30,723)	($70,649)	($3,379,466)
2005	Property Under Capital Leases	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2010	Electric Plant Purchased or Sold	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Sub - Total	($22,998,671)	($85,198,443)	($138,896,917)	($29,987,593)	($41,322,139)	($47,719,934)	($3,523,242)	($12,487,758)	($23,059)	($9,961,174)	($3,565,134)	($8,198,207)	($392,158,805)
	TOTAL - 2105 FA	($22,998,671)	($85,198,443)	($138,896,917)	($29,987,593)	($41,322,139)	($47,719,934)	($3,523,242)	($12,487,758)	($23,059)	($9,961,174)	($3,565,134)	($8,198,207)	($392,158,805)

Accumulated Depreciation - 2120

												A & G Allocation												
		4	5	6	7	8	12	13	14	15	Sub -total	1	2	3	4	5	6	7	8	12	13	14	15	Sub -total
Account	**Description**	**Seasonal**	**GSe**	**GSd**	**St Lgt**	**Sen Lgt**	**Dgen**	**ST**	**UGe**	**UGd**	**Sub -total**	**UR**	**R1**	**R2**	**Seasonal**	**GSe**	**GSd**	**St Lgt**	**Sen Lgt**	**Dgen**	**ST**	**UGe**	**UGd**	**Sub -total**
1565	Conservation and Demand Management	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1805	Land	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													

Account	Description	Seasonal	GSe	GSd	St Lgt	Sen Lgt	Dgen	ST	UGe	UGd	Sub -total	UR	R1	R2	Seasonal	GSe	GSd	St Lgt	Sen Lgt	Dgen	ST	UGe	UGd	Sub -total
1805-1	Land Station >50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1805-2	Land Station <50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1806	Land Rights	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1806-1	Land Rights Station >50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1806-2	Land Rights Station <50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1808	Buildings and Fixtures	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1808-1	Buildings and Fixtures > 50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1808-2	Buildings and Fixtures < 50 KV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1810	Leasehold Improvements	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1810-1	Leasehold Improvements >50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1810-2	Leasehold Improvements <50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1815	Transformer Station Equipment - Normally Primary above 50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1815-1	HVDS - Rural	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1815-2	HVDS - lo LV Specific	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1815-3	HVDS - hi LV Specific	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1815-4	HVDS - lo LV Shared	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1815-5	HVDS - hi LV Shared	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1820	Distribution Station Equipment - Normally Primary below 50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1820-1	Distribution Station Equipment - Normally Primary below 50 kV (Bulk)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1820-2	Distribution Station Equipment - Normally Primary below 50 kV (Primary)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1820-3	Distribution Station Equipment - Normally Primary below 50 kV (Wholesale Meters)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1825	Storage Battery Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1825-1	Storage Battery Equipment > 50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1825-2	Storage Battery Equipment <50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1830	Poles, Towers and Fixtures	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1830-3	Poles, Towers and Fixtures - Subtransmission Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1830-3A	Bulk-LV Fixtures	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1830-3B	Bulk-Retail Fixtures	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1830-4	Poles, Towers and Fixtures - Primary	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1830-4A	Primary-LV Fixtures	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1830-4B	Primary-Retail Fixtures	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1830-5	Poles, Towers and Fixtures - Secondary	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1835	Overhead Conductors and Devices	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1835-3	Overhead Conductors and Devices - Subtransmission Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1835-3A	Bulk-LV Conductors	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1835-3B	Bulk-Retail Conductors	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1835-4	Overhead Conductors and Devices - Primary	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1835-4A	Primary-LV Conductors	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1835-4B	Primary-Retail Conductors	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1835-5	Overhead Conductors and Devices - Secondary	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1840	Underground Conduit	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1840-3	Underground Conduit - Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1840-4	Underground Conduit - Primary	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1840-5	Underground Conduit - Secondary	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1845	Underground Conductors and Devices	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													

Account	Description	Seasonal	GSe	GSd	St Lgt	Sen Lgt	Dgen	ST	UGe	UGd	Sub -total	UR	R1	R2	Seasonal	GSe	GSd	St Lgt	Sen Lgt	Dgen	ST	UGe	UGd	Sub -total
1845-3	Underground Conductors and Devices - Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1845-4	Underground Conductors and Devices - Primary	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1845-5	Underground Conductors and Devices - Secondary	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1850	Line Transformers	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1850-1	TRF-LV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1850-2	TRF-Rural	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1855	Services	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1860	Meters	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1860-1	Mtr-Single	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1860-2	Mtr-Poly	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1860-3	Mtr-LV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1860-4	Mtr-Smart	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1875	St Lgts	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
	Sub - Total	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
General Plant																								
1905	Land											$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1906	Land Rights											$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1908	Buildings and Fixtures											$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1910	Leasehold Improvements											$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1915	Office Furniture and Equipment											$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1920	Computer Equipment - Hardware											$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1925	Computer Software											$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1930	Transportation Equipment											$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1935	Stores Equipment											$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1940	Tools, Shop and Garage Equipment											$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1945	Measurement and Testing Equipment											$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1950	Power Operated Equipment											$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1955	Communication Equipment											$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1960	Miscellaneous Equipment											$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1970	Load Management Controls Customer Premises											$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1975	Load Management Controls Utility Premises											$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1980	System Supervisory Equipment											$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1985	Sentinel Lgts											$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1990	Other Tangible Property											$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2005	Property Under Capital Leases											$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2010	Electric Plant Purchased or Sold											$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Sub - Total	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	TOTAL - 2120	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

Categorization and Allocation of Amorti

											A & G Allocation													
		4	5	6	7	8	12	13	14	15	Sub -total	1	2	3	4	5	6	7	8	12	13	14	15	Sub -total
Account	Description	Seasonal	GSe	GSd	St Lgt	Sen Lgt	Dgen	ST	UGe	UGd	Sub -total	UR	R1	R2	Seasonal	GSe	GSd	St Lgt	Sen Lgt	Dgen	ST	UGe	UGd	Sub -total
1565	Conservation and Demand Management	$34,414	$44,749	$30,681	$2,723	$769	$23	$8,368	$3,954	$4,116	$426,880													
1805	Land	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1805-1	Land Station >50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1805-2	Land Station <50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1806	Land Rights	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1806-1	Land Rights Station >50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													

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Account	Description	Seasonal	GSe	GSd	St Lgt	Sen Lgt	Dgen	ST	UGe	UGd	Sub -total	UR	R1	R2	Seasonal	GSe	GSd	St Lgt	Sen Lgt	Dgen	ST	UGe	UGd	Sub -total
1806-2	Land Rights Station <50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1808	Buildings and Fixtures	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1808-1	Buildings and Fixtures > 50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1808-2	Buildings and Fixtures < 50 KV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1810	Leasehold Improvements	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1810-1	Leasehold Improvements >50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1810-2	Leasehold Improvements <50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1815	Transformer Station Equipment - Normally Primary above 50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1815-1	HVDS - Rural	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1815-2	HVDS - lo LV Specific	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1815-3	HVDS - hi LV Specific	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1815-4	HVDS - lo LV Shared	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1815-5	HVDS - hi LV Shared	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1820	Distribution Station Equipment - Normally Primary below 50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1820-1	Distribution Station Equipment - Normally Primary below 50 kV (Bulk)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1820-2	Distribution Station Equipment - Normally Primary below 50 kV (Primary)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1820-3	Distribution Station Equipment - Normally Primary below 50 kV (Wholesale Meters)	$36,944	$120,197	$169,234	$6,304	$1,172	$177	$266,390	$22,173	$43,431	$1,268,552													
1825	Storage Battery Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1825-1	Storage Battery Equipment > 50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1825-2	Storage Battery Equipment <50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1830	Poles, Towers and Fixtures	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1830-3	Poles, Towers and Fixtures - Subtransmission Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1830-3A	Bulk-LV Fixtures	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1830-3B	Bulk-Retail Fixtures	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1830-4	Poles, Towers and Fixtures - Primary	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1830-4A	Primary-LV Fixtures	$0	$0	$0	$0	$0	$0	$14,555	$0	$0	$14,555													
1830-4B	Primary-Retail Fixtures	$2,048,366	$1,183,193	$88,007	$61,187	$39,672	$352	$0	$33,418	$4,814	$13,004,246													
1830-5	Poles, Towers and Fixtures - Secondary	$395,921	$247,500	$0	$14,188	$9,199	$0	$0	$32,516	$0	$3,004,339													
1835	Overhead Conductors and Devices	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1835-3	Overhead Conductors and Devices - Subtransmission Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1835-3A	Bulk-LV Conductors	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1835-3B	Bulk-Retail Conductors	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1835-4	Overhead Conductors and Devices - Primary	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1835-4A	Primary-LV Conductors	$0	$0	$0	$0	$0	$0	$12,257	$0	$0	$12,257													
1835-4B	Primary-Retail Conductors	$1,724,892	$996,345	$74,109	$51,524	$33,407	$296	$0	$28,141	$4,054	$10,950,644													
1835-5	Overhead Conductors and Devices - Secondary	$333,398	$208,415	$0	$11,947	$7,746	$0	$0	$27,381	$0	$2,529,900													
1840	Underground Condui	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1840-3	Underground Conduit - Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1840-4	Underground Conduit - Primary	$6,468	$4,043	$292	$232	$150	$1	$0	$531	$60	$49,433													
1840-5	Underground Conduit - Secondary	$26,058	$16,289	$0	$934	$605	$0	$0	$2,140	$0	$197,734													
1845	Underground Conductors and Devices	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1845-3	Underground Conductors and Devices - Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													

Account	Description	Seasonal	GSe	GSd	St Lgt	Sen Lgt	Dgen	ST	UGe	UGd	Sub -total	UR	R1	R2	Seasonal	GSe	GSd	St Lgt	Sen Lgt	Dgen	ST	UGe	UGd	Sub -total
1845-4	Underground Conductors and Devices - Primary	$298,468	$186,579	$13,492	$10,696	$6,935	$62	$0	$24,512	$2,748	$2,281,145													
1845-5	Underground Conductors and Devices - Secondary	$1,202,466	$751,690	$0	$43,091	$27,939	$0	$0	$98,755	$0	$9,124,579													
1850	Line Transformers	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1850-1	TRF-LV	$0	$0	$0	$0	$0	$0	$57,960	$0	$0	$57,960													
1850-2	TRF-Rural	$2,232,688	$1,588,490	$120,993	$91,486	$59,317	$526	$0	$0	$0	$19,261,925													
1855	Services	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1860	Meters	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1860-1	Mtr-Single	$155,164	$106,308	$0	$0	$0	$0	$0	$14,449	$0	$1,127,327													
1860-2	Mtr-Poly	$0	$0	$384,102	$0	$0	$7,052	$0	$0	$72,414	$463,568													
1860-3	Mtr-LV	$0	$0	$0	$0	$0	$0	$576,470	$0	$0	$576,470													
1860-4	Mtr-Smart	$1,677,860	$1,048,870	$75,849	$0	$0	$904	$7,277	$137,798	$15,447	$12,732,345													
1875	St Lgts	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
	Sub - Total	$10,173,107	$6,502,669	$956,761	$294,312	$186,911	$9,395	$943,276	$425,770	$147,084	$77,083,856	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
General Plant																								
1905	Land											$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1906	Land Rights											$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1908	Buildings and Fixtures											$114,262	$423,283	$690,067	$148,984	$205,297	$237,082	$17,504	$3,797	$115	$49,489	$17,712	$40,730	$1,948,322
1910	Leasehold Improvements											$22,822	$84,544	$137,831	$29,757	$41,005	$47,354	$3,496	$758	$23	$9,885	$3,538	$8,135	$389,149
1915	Office Furniture and Equipment											$21,254	$78,735	$128,359	$27,713	$38,187	$44,100	$3,256	$706	$21	$9,205	$3,295	$7,576	$362,408
1920	Computer Equipment - Hardware											$475,260	$1,760,598	$2,870,260	$619,684	$853,909	$986,117	$72,807	$15,794	$477	$205,844	$73,672	$169,413	$8,103,834
1925	Computer Software											$1,219,481	$4,517,561	$7,364,867	$1,590,062	$2,191,064	$2,530,301	$186,816	$40,526	$1,223	$528,181	$189,038	$434,702	$20,793,821
1930	Transportation Equipment											$706,859	$2,618,553	$4,268,963	$921,661	$1,270,026	$1,466,661	$108,286	$23,490	$709	$306,154	$109,574	$251,970	$12,052,905
1935	Stores Equipment											$48,289	$178,887	$291,635	$62,964	$86,762	$100,195	$7,398	$1,605	$48	$20,915	$7,486	$17,213	$823,398
1940	Tools, Shop and Garage Equipment											$11,081	$41,050	$66,923	$14,448	$19,910	$22,992	$1,698	$368	$11	$4,799	$1,718	$3,950	$188,948
1945	Measurement and Testing Equipment											$35,966	$133,238	$217,214	$46,896	$64,622	$74,627	$5,510	$1,195	$36	$15,578	$5,575	$12,821	$613,277
1950	Power Operated Equipment											$168,713	$624,996	$1,018,916	$219,982	$303,130	$350,062	$25,846	$5,607	$169	$73,073	$26,153	$60,140	$2,876,786
1955	Communication Equipment											$158,720	$587,976	$958,562	$206,952	$285,174	$329,327	$24,315	$5,275	$159	$68,745	$24,604	$56,578	$2,706,386
1960	Miscellaneous Equipment											$35,172	$130,296	$212,419	$45,861	$63,195	$72,979	$5,388	$1,169	$35	$15,234	$5,452	$12,538	$599,739
1970	Load Management Controls Customer Premises											$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1975	Load Management Controls Utility Premises											$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1980	System Supervisory Equipment											$103,266	$382,550	$623,661	$134,647	$185,541	$214,267	$15,820	$3,432	$104	$44,727	$16,008	$36,811	$1,760,833
1985	Sentinel Lgts											$0	$0	$0	$0	$0	$0	$0	$482,401	$0	$0	$0	$0	$482,401
1990	Other Tangible Property											$8,764	$32,467	$52,930	$11,428	$15,747	$18,185	$1,343	$291	$9	$3,796	$1,359	$3,124	$149,442
2005	Property Under Capital Leases											$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2010	Electric Plant Purchased or Sold											$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Sub - Total	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$3,129,910	$11,594,733	$18,902,607	$4,081,039	$5,623,567	$6,494,249	$479,481	$586,414	$3,138	$1,355,625	$485,182	$1,115,701	$53,851,648
	TOTAL - 5705	$10,173,107	$6,502,669	$956,761	$294,312	$186,911	$9,395	$943,276	$425,770	$147,084	$77,083,856	$3,129,910	$11,594,733	$18,902,607	$4,081,039	$5,623,567	$6,494,249	$479,481	$586,414	$3,138	$1,355,625	$485,182	$1,115,701	$53,851,648

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											A & G Allocation													
		4	5	6	7	8	12	13	14	15	Sub -total	1	2	3	4	5	6	7	8	12	13	14	15	Sub -total
Account	**Description**	**Seasonal**	**GSe**	**GSd**	**St Lgt**	**Sen Lgt**	**Dgen**	**ST**	**UGe**	**UGd**	**Sub -total**	**UR**	**R1**	**R2**	**Seasonal**	**GSe**	**GSd**	**St Lgt**	**Sen Lgt**	**Dgen**	**ST**	**UGe**	**UGd**	**Sub -total**
1565	Conservation and Demand Management	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1805	Land	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1805-1	Land Station >50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1805-2	Land Station <50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1806	Land Rights	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1806-1	Land Rights Station >50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1806-2	Land Rights Station <50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1808	Buildings and Fixtures	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													

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Account	Description	Seasonal	GSe	GSd	St Lgt	Sen Lgt	Dgen	ST	UGe	UGd	Sub -total	UR	R1	R2	Seasonal	GSe	GSd	St Lgt	Sen Lgt	Dgen	ST	UGe	UGd	Sub -total
1808-1	Buildings and Fixtures > 50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1808-2	Buildings and Fixtures < 50 KV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1810	Leasehold Improvements	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1810-1	Leasehold Improvements >50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1810-2	Leasehold Improvements <50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1815	Transformer Station Equipment - Normally Primary above 50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1815-1	HVDS - Rural	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1815-2	HVDS - lo LV Specific	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1815-3	HVDS - hi LV Specific	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1815-4	HVDS - lo LV Shared	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1815-5	HVDS - hi LV Shared	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1820	Distribution Station Equipment - Normally Primary below 50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1820-1	Distribution Station Equipment - Normally Primary below 50 kV (Bulk)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1820-2	Distribution Station Equipment - Normally Primary below 50 kV (Primary)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1820-3	Distribution Station Equipment - Normally Primary below 50 kV (Wholesale Meters)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1825	Storage Battery Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1825-1	Storage Battery Equipment > 50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1825-2	Storage Battery Equipment <50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1830	Poles, Towers and Fixtures	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1830-3	Poles, Towers and Fixtures - Subtransmission Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1830-3A	Bulk-LV Fixtures	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1830-3B	Bulk-Retail Fixtures	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1830-4	Poles, Towers and Fixtures - Primary	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1830-4A	Primary-LV Fixtures	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1830-4B	Primary-Retail Fixtures	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1830-5	Poles, Towers and Fixtures - Secondary	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1835	Overhead Conductors and Devices	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1835-3	Overhead Conductors and Devices - Subtransmission Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1835-3A	Bulk-LV Conductors	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1835-3B	Bulk-Retail Conductors	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1835-4	Overhead Conductors and Devices - Primary	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1835-4A	Primary-LV Conductors	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1835-4B	Primary-Retail Conductors	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1835-5	Overhead Conductors and Devices - Secondary	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1840	Underground Conduit	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1840-3	Underground Conduit - Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1840-4	Underground Conduit - Primary	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1840-5	Underground Conduit - Secondary	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1845	Underground Conductors and Devices	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1845-3	Underground Conductors and Devices - Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1845-4	Underground Conductors and Devices - Primary	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													

Account	Description	Seasonal	GSe	GSd	St Lgt	Sen Lgt	Dgen	ST	UGe	UGd	Sub -total	UR	R1	R2	Seasonal	GSe	GSd	St Lgt	Sen Lgt	Dgen	ST	UGe	UGd	Sub -total
1845-5	Underground Conductors and Devices - Secondary	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1850	Line Transformers	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1850-1	TRF-LV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1850-2	TRF-Rural	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1855	Services	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1860	Meters	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1860-1	Mtr-Single	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1860-2	Mtr-Poly	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1860-3	Mtr-LV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1860-4	Mtr-Smart	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1875	St Lgts	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
	Sub - Total	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
General Plant																								
1905	Land											$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1906	Land Rights											$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1908	Buildings and Fixtures											$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1910	Leasehold Improvements											$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1915	Office Furniture and Equipment											$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1920	Computer Equipment - Hardware											$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1925	Computer Software											$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1930	Transportation Equipment											$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1935	Stores Equipment											$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1940	Tools, Shop and Garage Equipment											$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1945	Measurement and Testing Equipment											$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1950	Power Operated Equipment											$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1955	Communication Equipment											$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1960	Miscellaneous Equipment											$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1970	Load Management Controls Customer Premises											$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1975	Load Management Controls Utility Premises											$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1980	System Supervisory Equipment											$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1985	Sentinel Lgts											$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1990	Other Tangible Property											$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2005	Property Under Capital Leases											$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2010	Electric Plant Purchased or Sold											$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Sub - Total	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	TOTAL - 5710	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

Categorization and Allocation of Accum

										A & G Allocation														
		4	5	6	7	8	12	13	14	15	Sub -total	1	2	3	4	5	6	7	8	12	13	14	15	Sub -total
Account	**Description**	**Seasonal**	**GSe**	**GSd**	**St Lgt**	**Sen Lgt**	**Dgen**	**ST**	**UGe**	**UGd**	**Sub -total**	**UR**	**R1**	**R2**	**Seasonal**	**GSe**	**GSd**	**St Lgt**	**Sen Lgt**	**Dgen**	**ST**	**UGe**	**UGd**	**Sub -total**
1565	Conservation and Demand Management	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1805	Land	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1805-1	Land Station >50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1805-2	Land Station <50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1806	Land Rights	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1806-1	Land Rights Station >50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1806-2	Land Rights Station <50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1808	Buildings and Fixtures	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1808-1	Buildings and Fixtures > 50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													

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Account	Description	Seasonal	GSe	GSd	St Lgt	Sen Lgt	Dgen	ST	UGe	UGd	Sub -total	UR	R1	R2	Seasonal	GSe	GSd	St Lgt	Sen Lgt	Dgen	ST	UGe	UGd	Sub -total
1808-2	Buildings and Fixtures < 50 KV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1810	Leasehold Improvements	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1810-1	Leasehold Improvements >50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1810-2	Leasehold Improvements <50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1815	Transformer Station Equipment - Normally Primary above 50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1815-1	HVDS - Rural	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1815-2	HVDS - lo LV Specific	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1815-3	HVDS - hi LV Specific	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1815-4	HVDS - lo LV Shared	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1815-5	HVDS - hi LV Shared	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1820	Distribution Station Equipment - Normally Primary below 50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1820-1	Distribution Station Equipment - Normally Primary below 50 kV (Bulk)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1820-2	Distribution Station Equipment - Normally Primary below 50 kV (Primary)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1820-3	Distribution Station Equipment - Normally Primary below 50 kV (Wholesale Meters)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1825	Storage Battery Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1825-1	Storage Battery Equipment > 50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1825-2	Storage Battery Equipment <50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1830	Poles, Towers and Fixtures	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1830-3	Poles, Towers and Fixtures - Subtransmission Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1830-3A	Bulk-LV Fixtures	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1830-3B	Bulk-Retail Fixtures	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1830-4	Poles, Towers and Fixtures - Primary	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1830-4A	Primary-LV Fixtures	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1830-4B	Primary-Retail Fixtures	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1830-5	Poles, Towers and Fixtures - Secondary	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1835	Overhead Conductors and Devices	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1835-3	Overhead Conductors and Devices - Subtransmission Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1835-3A	Bulk-LV Conductors	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1835-3B	Bulk-Retail Conductors	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1835-4	Overhead Conductors and Devices - Primary	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1835-4A	Primary-LV Conductors	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1835-4B	Primary-Retail Conductors	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1835-5	Overhead Conductors and Devices - Secondary	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1840	Underground Condui	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1840-3	Underground Conduit - Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1840-4	Underground Conduit - Primary	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1840-5	Underground Conduit - Secondary	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1845	Underground Conductors and Devices	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1845-3	Underground Conductors and Devices - Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1845-4	Underground Conductors and Devices - Primary	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1845-5	Underground Conductors and Devices - Secondary	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1850	Line Transformers	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													

Account	Description	Seasonal	GSe	GSd	St Lgt	Sen Lgt	Dgen	ST	UGe	UGd	Sub -total	UR	R1	R2	Seasonal	GSe	GSd	St Lgt	Sen Lgt	Dgen	ST	UGe	UGd	Sub -total
1850-1	TRF-LV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1850-2	TRF-Rural	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1855	Services	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1860	Meters	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1860-1	Mtr-Single	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1860-2	Mtr-Poly	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1860-3	Mtr-LV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1860-4	Mtr-Smart	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1875	St Lgts	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
	Sub - Total	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
General Plant																								
1905	Land											$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1906	Land Rights											$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1908	Buildings and Fixtures											$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1910	Leasehold Improvements											$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1915	Office Furniture and Equipment											$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1920	Computer Equipment - Hardware											$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1925	Computer Software											$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1930	Transportation Equipment											$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1935	Stores Equipment											$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1940	Tools, Shop and Garage Equipment											$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1945	Measurement and Testing Equipment											$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1950	Power Operated Equipment											$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1955	Communication Equipment											$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1960	Miscellaneous Equipment											$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1970	Load Management Controls Customer Premises											$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1975	Load Management Controls Utility Premises											$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1980	System Supervisory Equipment											$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1985	Sentinel Lgts											$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1990	Other Tangible Property											$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2005	Property Under Capital Leases											$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2010	Electric Plant Purchased or Sold											$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Sub - Total	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	TOTAL - 5715	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

Categorization and Allocation of Accur

											A & G Allocation													
		4	5	6	7	8	12	13	14	15	Sub -total	1	2	3	4	5	6	7	8	12	13	14	15	Sub -total
Account	Description	Seasonal	GSe	GSd	St Lgt	Sen Lgt	Dgen	ST	UGe	UGd	Sub -total	UR	R1	R2	Seasonal	GSe	GSd	St Lgt	Sen Lgt	Dgen	ST	UGe	UGd	Sub -total
1565	Conservation and Demand Management	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1805	Land	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1805-1	Land Station >50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1805-2	Land Station <50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1806	Land Rights	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1806-1	Land Rights Station >50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1806-2	Land Rights Station <50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1808	Buildings and Fixtures	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1808-1	Buildings and Fixtures > 50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1808-2	Buildings and Fixtures < 50 KV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1810	Leasehold Improvements	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													

Account	Description	Seasonal	GSe	GSd	St Lgt	Sen Lgt	Dgen	ST	UGe	UGd	Sub -total	UR	R1	R2	Seasonal	GSe	GSd	St Lgt	Sen Lgt	Dgen	ST	UGe	UGd	Sub -total
1810-1	Leasehold Improvements >50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1810-2	Leasehold Improvements <50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1815	Transformer Station Equipment - Normally Primary above 50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1815-1	HVDS - Rural	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1815-2	HVDS - lo LV Specific	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1815-3	HVDS - hi LV Specific	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1815-4	HVDS - lo LV Shared	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1815-5	HVDS - hi LV Shared	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1820	Distribution Station Equipment - Normally Primary below 50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1820-1	Distribution Station Equipment - Normally Primary below 50 kV (Bulk)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1820-2	Distribution Station Equipment - Normally Primary below 50 kV (Primary)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1820-3	Distribution Station Equipment - Normally Primary below 50 kV (Wholesale Meters)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1825	Storage Battery Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1825-1	Storage Battery Equipment > 50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1825-2	Storage Battery Equipment <50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1830	Poles, Towers and Fixtures	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1830-3	Poles, Towers and Fixtures - Subtransmission Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1830-3A	Bulk-LV Fixtures	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1830-3B	Bulk-Retail Fixtures	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1830-4	Poles, Towers and Fixtures - Primary	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1830-4A	Primary-LV Fixtures	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1830-4B	Primary-Retail Fixtures	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1830-5	Poles, Towers and Fixtures - Secondary	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1835	Overhead Conductors and Devices	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1835-3	Overhead Conductors and Devices - Subtransmission Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1835-3A	Bulk-LV Conductors	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1835-3B	Bulk-Retail Conductors	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1835-4	Overhead Conductors and Devices - Primary	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1835-4A	Primary-LV Conductors	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1835-4B	Primary-Retail Conductors	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1835-5	Overhead Conductors and Devices - Secondary	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1840	Underground Conduit	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1840-3	Underground Conduit - Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1840-4	Underground Conduit - Primary	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1840-5	Underground Conduit - Secondary	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1845	Underground Conductors and Devices	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1845-3	Underground Conductors and Devices - Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1845-4	Underground Conductors and Devices - Primary	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1845-5	Underground Conductors and Devices - Secondary	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1850	Line Transformers	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1850-1	TRF-LV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1850-2	TRF-Rural	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1855	Services	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1860	Meters	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													

Account	Description	Seasonal	GSe	GSd	St Lgt	Sen Lgt	Dgen	ST	UGe	UGd	Sub -total	UR	R1	R2	Seasonal	GSe	GSd	St Lgt	Sen Lgt	Dgen	ST	UGe	UGd	Sub -total
1860-1	Mtr-Single	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1860-2	Mtr-Poly	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1860-3	Mtr-LV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1860-4	Mtr-Smart	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
1875	St Lgts	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0													
	Sub - Total	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
General Plant																								
1905	Land											$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1906	Land Rights											$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1908	Buildings and Fixtures											$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1910	Leasehold Improvements											$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1915	Office Furniture and Equipment											$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1920	Computer Equipment - Hardware											$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1925	Computer Software											$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1930	Transportation Equipment											$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1935	Stores Equipment											$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1940	Tools, Shop and Garage Equipment											$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1945	Measurement and Testing Equipment											$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1950	Power Operated Equipment											$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1955	Communication Equipment											$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1960	Miscellaneous Equipment											$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1970	Load Management Controls Customer Premises											$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1975	Load Management Controls Utility Premises											$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1980	System Supervisory Equipment											$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1985	Sentinel Lgts											$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1990	Other Tangible Property											$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2005	Property Under Capital Leases											$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2010	Electric Plant Purchased or Sold											$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Sub - Total	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	TOTAL - 5720	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

												A & G Allocation												
		4	**5**	**6**	**7**	**8**	**12**	**13**	**14**	**15**	**Sub -total**	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**12**	**13**	**14**	**15**	**Sub -total**
Account	**Description**	**Seasonal**	**GSe**	**GSd**	**St Lgt**	**Sen Lgt**	**Dgen**	**ST**	**UGe**	**UGd**	**Sub -total**	**UR**	**R1**	**R2**	**Seasonal**	**GSe**	**GSd**	**St Lgt**	**Sen Lgt**	**Dgen**	**ST**	**UGe**	**UGd**	**Sub -total**
1565	Conservation and Demand Management	8.06%	10.48%	7.19%	0.64%	0.18%	0.01%	1.96%	0.93%	0.96%	100.00%													
1805	Land	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%													
1805-1	Land Station >50 kV	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%													
1805-2	Land Station <50 kV	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%													
1806	Land Rights	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%													
1806-1	Land Rights Station >50 kV	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%													
1806-2	Land Rights Station <50 kV	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%													
1808	Buildings and Fixtures	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%													
1808-1	Buildings and Fixtures > 50 kV	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%													
1808-2	Buildings and Fixtures < 50 KV	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%													
1810	Leasehold Improvements	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%													
1810-1	Leasehold Improvements >50 kV	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%													
1810-2	Leasehold Improvements <50 kV	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%													
1815	Transformer Station Equipment - Normally Primary above 50 kV	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%													
1815-1	HVDS - Rural	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%													
1815-2	HVDS - lo LV Specific	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%													
1815-3	HVDS - hi LV Specific	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%													

Account	Description	Seasonal	GSe	GSd	St Lgt	Sen Lgt	Dgen	ST	UGe	UGd	Sub -total	UR	R1	R2	Seasonal	GSe	GSd	St Lgt	Sen Lgt	Dgen	ST	UGe	UGd	Sub -total
1815-4	HVDS - lo LV Shared	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%													
1815-5	HVDS - hi LV Shared	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%													
1820	Distribution Station Equipment - Normally Primary below 50 kV	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%													
1820-1	Distribution Station Equipment - Normally Primary below 50 kV (Bulk)	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%													
1820-2	Distribution Station Equipment - Normally Primary below 50 kV (Primary)	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%													
1820-3	Distribution Station Equipment - Normally Primary below 50 kV (Wholesale Meters)	2.91%	9.48%	13.34%	0.50%	0.09%	0.01%	21.00%	1.75%	3.42%	100.00%													
1825	Storage Battery Equipment	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%													
1825-1	Storage Battery Equipment > 50 kV	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%													
1825-2	Storage Battery Equipment <50 kV	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%													
1830	Poles, Towers and Fixtures	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%													
1830-3	Poles, Towers and Fixtures - Subtransmission Bulk Delivery	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%													
1830-3A	Bulk-LV Fixtures	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%													
1830-3B	Bulk-Retail Fixtures	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%													
1830-4	Poles, Towers and Fixtures - Primary	13.08%	8.18%	0.59%	0.47%	0.30%	0.00%	0.01%	1.07%	0.12%	100.00%													
1830-4A	Primary-LV Fixtures	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%	0.00%	0.00%	100.00%													
1830-4B	Primary-Retail Fixtures	15.75%	9.10%	0.68%	0.47%	0.31%	0.00%	0.00%	0.26%	0.04%	100.00%													
1830-5	Poles, Towers and Fixtures - Secondary	13.18%	8.24%	0.00%	0.47%	0.31%	0.00%	0.00%	1.08%	0.00%	100.00%													
1835	Overhead Conductors and Devices	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%													
1835-3	Overhead Conductors and Devices - Subtransmission Bulk Delivery	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%													
1835-3A	Bulk-LV Conductors	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%													
1835-3B	Bulk-Retail Conductors	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%													
1835-4	Overhead Conductors and Devices - Primary	13.08%	8.18%	0.59%	0.47%	0.30%	0.00%	0.01%	1.07%	0.12%	100.00%													
1835-4A	Primary-LV Conductors	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%	0.00%	0.00%	100.00%													
1835-4B	Primary-Retail Conductors	15.75%	9.10%	0.68%	0.47%	0.31%	0.00%	0.00%	0.26%	0.04%	100.00%													
1835-5	Overhead Conductors and Devices - Secondary	13.18%	8.24%	0.00%	0.47%	0.31%	0.00%	0.00%	1.08%	0.00%	100.00%													
1840	Underground Condui	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%													
1840-3	Underground Conduit - Bulk Delivery	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%													
1840-4	Underground Conduit - Primary	13.08%	8.18%	0.59%	0.47%	0.30%	0.00%	0.00%	1.07%	0.12%	100.00%													
1840-5	Underground Conduit - Secondary	13.18%	8.24%	0.00%	0.47%	0.31%	0.00%	0.00%	1.08%	0.00%	100.00%													
1845	Underground Conductors and Devices	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%													
1845-3	Underground Conductors and Devices - Bulk Delivery	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%													
1845-4	Underground Conductors and Devices - Primary	13.08%	8.18%	0.59%	0.47%	0.30%	0.00%	0.00%	1.07%	0.12%	100.00%													
1845-5	Underground Conductors and Devices - Secondary	13.18%	8.24%	0.00%	0.47%	0.31%	0.00%	0.00%	1.08%	0.00%	100.00%													
1850	Line Transformers	13.08%	8.18%	0.59%	0.47%	0.30%	0.00%	0.00%	1.07%	0.12%	100.00%													
1850-1	TRF-LV	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%	0.00%	0.00%	100.00%													
1850-2	TRF-Rural	11.59%	8.25%	0.63%	0.47%	0.31%	0.00%	0.00%	0.00%	0.00%	100.00%													
1855	Services	12.05%	15.07%	0.00%	0.43%	0.28%	0.00%	0.00%	1.98%	0.00%	100.00%													
1860	Meters	12.70%	8.70%	1.52%	0.00%	0.00%	0.03%	5.92%	1.18%	0.29%	100.00%													
1860-1	Mtr-Single	13.76%	9.43%	0.00%	0.00%	0.00%	0.00%	0.00%	1.28%	0.00%	100.00%													
1860-2	Mtr-Poly	0.00%	0.00%	82.86%	0.00%	0.00%	1.52%	0.00%	0.00%	15.62%	100.00%													
1860-3	Mtr-LV	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%	0.00%	0.00%	100.00%													
1860-4	Mtr-Smart	13.18%	8.24%	0.60%	0.00%	0.00%	0.01%	0.06%	1.08%	0.12%	100.00%													
1875	St Lgts	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%													
General Plant																								
1905	Land											6%	22%	35%	8%	11%	12%	1%	0%	0%	3%	1%	2%	100%
1906	Land Rights											6%	22%	35%	8%	11%	12%	1%	0%	0%	3%	1%	2%	100%
1908	Buildings and Fixtures											6%	22%	35%	8%	11%	12%	1%	0%	0%	3%	1%	2%	100%

Account	Description	Seasonal	GSe	GSd	St Lgt	Sen Lgt	Dgen	ST	UGe	UGd	Sub -total	UR	R1	R2	Seasonal	GSe	GSd	St Lgt	Sen Lgt	Dgen	ST	UGe	UGd	Sub -total
1910	Leasehold Improvements											6%	22%	35%	8%	11%	12%	1%	0%	0%	3%	1%	2%	100%
1915	Office Furniture and Equipment											6%	22%	35%	8%	11%	12%	1%	0%	0%	3%	1%	2%	100%
1920	Computer Equipment - Hardware											6%	22%	35%	8%	11%	12%	1%	0%	0%	3%	1%	2%	100%
1925	Computer Software											6%	22%	35%	8%	11%	12%	1%	0%	0%	3%	1%	2%	100%
1930	Transportation Equipment											6%	22%	35%	8%	11%	12%	1%	0%	0%	3%	1%	2%	100%
1935	Stores Equipment											6%	22%	35%	8%	11%	12%	1%	0%	0%	3%	1%	2%	100%
1940	Tools, Shop and Garage Equipment											6%	22%	35%	8%	11%	12%	1%	0%	0%	3%	1%	2%	100%
1945	Measurement and Testing Equipment											6%	22%	35%	8%	11%	12%	1%	0%	0%	3%	1%	2%	100%
1950	Power Operated Equipment											6%	22%	35%	8%	11%	12%	1%	0%	0%	3%	1%	2%	100%
1955	Communication Equipment											6%	22%	35%	8%	11%	12%	1%	0%	0%	3%	1%	2%	100%
1960	Miscellaneous Equipment											6%	22%	35%	8%	11%	12%	1%	0%	0%	3%	1%	2%	100%
1970	Load Management Controls Customer Premises											6%	22%	35%	8%	11%	12%	1%	0%	0%	3%	1%	2%	100%
1975	Load Management Controls Utility Premises											6%	22%	35%	8%	11%	12%	1%	0%	0%	3%	1%	2%	100%
1980	System Supervisory Equipment											6%	22%	35%	8%	11%	12%	1%	0%	0%	3%	1%	2%	100%
1985	Sentinel Lgts											0%	0%	0%	0%	0%	0%	0%	100%	0%	0%	0%	0%	100%
1990	Other Tangible Property											6%	22%	35%	8%	11%	12%	1%	0%	0%	3%	1%	2%	100%
2005	Property Under Capital Leases											6%	22%	35%	8%	11%	12%	1%	0%	0%	3%	1%	2%	100%
2010	Electric Plant Purchased or Sold											6%	22%	35%	8%	11%	12%	1%	0%	0%	3%	1%	2%	100%

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Data Sheet to Show How Density is Derived and How Costs are Categorized

Hydro One Distribution: 12 Rate Classes

Density of Utility

Density	Number of Customers	kM of Lines
9.8	1177552	119900

Dx Lines	0.548
0	1
Old	New
0.6	0.548

Fixtures	0.478
0	1
Old	New
0.6	0.478

Deemed Customer Cost Component based on Survey Results

		Customer Component	
If Density is < 30 customers per kM of lines then	LOW	0.548	All
If Density is Between 30 and 60 customers per kM of	MEDIUM	0.4	All
If Density is Between > 60 customers per kM of lines t	HIGH	0.35	Distribution
If Density is Between > 60 customers per kM of lines t	HIGH	0.3	Transformers

Rtransf	0.619
0	1
Old	New
0.6	0.619

Categorization and Demand Allocation for Distribution Assets Accounts

USoA A/C #	Accounts	Categorization		
		Demand	Customer	Customer Component
	Distribution Plant			
1805	Land	DCP		0%
1805-1	Land Station >50 kV	TCP		0%
1805-2	Land Station <50 kV	BCPA		0%
1806	Land Rights	DCP		0%
1806-1	Land Rights Station >50 kV	TCP		0%
1806-2	Land Rights Station <50 kV	DCP		0%
1808	Buildings and Fixtures	DCP		0%
1808-1	Buildings and Fixtures > 50 kV	TCP		0%
1808-2	Buildings and Fixtures < 50 KV	DCP		0%
1810	Leasehold Improvements	DCP		0%
1810-1	Leasehold Improvements >50 kV	TCP		0%
1810-2	Leasehold Improvements <50 kV	DCP		0%
1815	Transformer Station Equipment - Normally Primary above 50 kV	TCP		0%

USoA A/C #	Accounts	Categorization		
		Demand	Customer	Customer Component
1815-1	HVDS - Rural	TCP		0%
1815-2	HVDS - lo LV Specific	1815-2D		0%
1815-3	HVDS - hi LV Specific	1815-3D		0%
1815-4	HVDS - lo LV Shared	1815-4D		0%
1815-5	HVDS - hi LV Shared	1816-5D		0%
1820	Distribution Station Equipment - Normally Primary below 50 kV	DCP		0%
1820-1	Distribution Station Equipment - Normally Primary below 50 kV (Bulk)	DCP		0%
1820-2	Distribution Station Equipment - Normally Primary below 50 kV (Primary)	PNCP		0%
1820-3	Distribution Station Equipment - Normally Primary below 50 kV (Wholesale Meters)		CEN	100%
1825	Storage Battery Equipment	DCP		0%
1825-1	Storage Battery Equipment > 50 kV	TCP		0%
1825-2	Storage Battery Equipment <50 kV	DCP		0%
1830	Poles, Towers and Fixtures	DNCP	CCA	48%
1830-3	Poles, Towers and Fixtures - Subtransmission Bulk Delivery	BCP		0%
1830-3A	Bulk-LV Fixtures	1830-3A		0%
1830-3B	Bulk-Retail Fixtures	BCP		0%
1830-4	Poles, Towers and Fixtures - Primary	PNCP	CCP	48%
1830-4A	Primary-LV Fixtures	1830-4AD	1834-4AC	48%
1830-4B	Primary-Retail Fixtures	PNCP	CCP	48%
1830-5	Poles, Towers and Fixtures - Secondary	SNCP	CCS	48%
1835	Overhead Conductors and Devices	DNCP	CCA	55%
1835-3	Overhead Conductors and Devices - Subtransmission Bulk Delivery	BCP		0%
1835-3A	Bulk-LV Conductors	1835-3A		0%
1835-3B	Bulk-Retail Conductors	BCP		0%
1835-4	Overhead Conductors and Devices - Primary	PNCP	CCP	55%
1835-4A	Primary-LV Conductors	1835-4AD	1835-4AD	55%
1835-4B	Primary-Retail Conductors	PNCP	CCP	55%
1835-5	Overhead Conductors and Devices - Secondary	SNCP	CCS	55%
1840	Underground Conduit	DNCP	CCA	55%

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USoA A/C #	Accounts	Categorization		
		Demand	Customer	Customer Component
1840-3	Underground Conduit - Bulk Delivery	BCP		0%
1840-4	Underground Conduit - Primary	PNCP	CCP	55%
1840-5	Underground Conduit - Secondary	SNCP	CCS	55%
1845	Underground Conductors and Devices	DNCP	CCA	55%
1845-3	Underground Conductors and Devices - Bulk Delivery	BCP		0%
1845-4	Underground Conductors and Devices - Primary	PNCP	CCP	55%
1845-5	Underground Conductors and Devices - Secondary	SNCP	CCS	55%
1850	Line Transformers	LTNCP	CCLT	62%
1850-1	TRF-LV	1850-1D	1850-1C	62%
1850-2	TRF-Rural	LTNCP	CCLT	62%
1855	Services		CWCS	100%
1860	Meters		CWMC	100%
1860-1	Mtr-Single		CWMC1	100%
1860-2	Mtr-Poly		CWMC2	100%
1860-3	Mtr-LV		CWMC3	100%
1860-4	Mtr-Smart		CWMC4	100%
1875	Street Lights	TCP		0%
1985	Sentinel Lgts	TCP		0%
1565	Conservation and Demand Management Expenditures and Recoveries		CDMPP	100%
	Accumulated Amortization			
2105	Accum. Amortization of Electric Utility Plant - Property, Plant, & Equipment	See I4 BO Assets		
	Operation			
5005	Operation Supervision and Engineering	1815-1855 D	1815-1855 C	55%
5010	Load Dispatching	1815-1855 D	1815-1855 C	55%
5012	Station Buildings and Fixtures Expense	1808 D		0%
5014	Transformer Station Equipment - Operation Labour	1815 D		0%
5015	Transformer Station Equipment - Operation Supplies and Expenses	1815 D		0%
5016	Distribution Station Equipment - Operation Labour	1820 D		0%

USoA A/C #	Accounts	Categorization		
		Demand	Customer	Customer Component
5017	Distribution Station Equipment - Operation Supplies and Expenses	1820 D		0%
5020	Overhead Distribution Lines and Feeders - Operation Labour	1830 & 1835 D	1830 & 1835 C	55%
5025	Overhead Distribution Lines & Feeders - Operation Supplies and Expenses	1830 & 1835 D	1830 & 1835 C	55%
5030	Overhead Subtransmission Feeders - Operation	1830 & 1835 D		0%
5035	Overhead Distribution Transformers- Operation	1850 D	1850 C	62%
5040	Underground Distribution Lines and Feeders - Operation Labour	1840 & 1845 D	1840 & 1845 C	55%
5045	Underground Distribution Lines & Feeders - Operation Supplies & Expenses	1840 & 1845 D	1840 & 1845 C	55%
5050	Underground Subtransmission Feeders - Operation	1840 & 1845 D		0%
5055	Underground Distribution Transformers - Operation	1850 D	1850 C	62%
5065	Meter Expense		CWMC	100%
5070	Customer Premises - Operation Labour		CCA	100%
5075	Customer Premises - Materials and Expenses		CCA	100%
5085	Miscellaneous Distribution Expense	1815-1855 D	1815-1855 C	55%
5090	Underground Distribution Lines and Feeders - Rental Paid	1840 & 1845 D	1840 & 1845 C	55%
5095	Overhead Distribution Lines and Feeders - Rental Paid	1830 & 1835 D	1830 & 1835 C	55%
	Maintenance			
5105	Maintenance Supervision and Engineering	1815-1855 D	1815-1855 C	55%
5110	Maintenance of Buildings and Fixtures - Distribution Stations	1808 D		0%
5112	Maintenance of Transformer Station Equipment	1815 D		0%
5114	Maintenance of Distribution Station Equipment	1820 D		0%
5120	Maintenance of Poles, Towers and Fixtures	1830 D	1830 C	48%
5125	Maintenance of Overhead Conductors and Devices	1835 D	1835 C	55%
5130	Maintenance of Overhead Services		1855 C	100%
5135	Overhead Distribution Lines and Feeders - Right of Way	1830 & 1835 D	1830 & 1835 C	55%
5145	Maintenance of Underground Conduit	1840 D	1840 C	55%
5150	Maintenance of Underground Conductors and Devices	1845 D	1845 C	55%
5155	Maintenance of Underground Services		1855 C	100%
5160	Maintenance of Line Transformers	1850 D	1850 C	62%

USoA A/C #	Accounts	Categorization		
		Demand	Customer	Customer Component
5175	Maintenance of Meters		1860 C	100%
5305	Supervision		CWNB	100%
5310	Meter Reading Expense		CWMR	100%
5315	Customer Billing		CWNB	100%
5320	Collecting		CWNB	100%
5325	Collecting- Cash Over and Short		CWNB	100%
5330	Collection Charges		CWNB	100%
5335	Bad Debt Expense		BDHA	100%
5340	Miscellaneous Customer Accounts Expenses		CWNB	100%

Hydro One Distribution: 12 Rate Classes

This sheet picks up the data from I7 and translate the figures into percentages to allow easier programing and simplier analysis.

			1	2	3	4	5	6	7	8	12	13	14	15
Explanation	**ID and Factors**	**Total**	**UR**	**R1**	**R2**	**Seasonal**	**GSe**	**GSd**	**St Lgt**	**Sen Lgt**	**Dgen**	**ST**	**UGe**	**UGd**
Demand Allocators														
1 cp														
Transformation CP	**TCP1**	**100.00%**	**5.06%**	**15.59%**	**17.99%**	**1.69%**	**5.08%**	**7.02%**	**0.39%**	**0.08%**	**0.01%**	**44.33%**	**0.93%**	**1.82%**
Bulk Delivery (SubTransmission) CP	**BCP1**	**100.00%**	**5.06%**	**15.59%**	**17.99%**	**1.69%**	**5.08%**	**7.02%**	**0.39%**	**0.08%**	**0.01%**	**44.33%**	**0.93%**	**1.82%**
Distribution CP (Total System)	**DCP1**	**100.00%**	**5.06%**	**15.59%**	**17.99%**	**1.69%**	**5.08%**	**7.02%**	**0.39%**	**0.08%**	**0.01%**	**44.33%**	**0.93%**	**1.82%**
4 cp														
Transformation CP	**TCP4**	**100.00%**	**4.87%**	**15.42%**	**18.27%**	**1.80%**	**4.88%**	**7.02%**	**0.42%**	**0.08%**	**0.01%**	**44.54%**	**0.91%**	**1.80%**
Bulk Delivery (SubTransmission) CP	**BCP4**	**100.00%**	**4.87%**	**15.42%**	**18.27%**	**1.80%**	**4.88%**	**7.02%**	**0.42%**	**0.08%**	**0.01%**	**44.54%**	**0.91%**	**1.80%**
Distribution CP (Total System)	**DCP4**	**100.00%**	**4.87%**	**15.42%**	**18.27%**	**1.80%**	**4.88%**	**7.02%**	**0.42%**	**0.08%**	**0.01%**	**44.54%**	**0.91%**	**1.80%**
12 cp														
Transformation CP	**TCP12**	**100.00%**	**4.55%**	**13.76%**	**16.63%**	**2.08%**	**5.06%**	**7.30%**	**0.21%**	**0.04%**	**0.01%**	**47.55%**	**0.95%**	**1.87%**
Bulk Delivery (SubTransmission) CP	**BCP12**	**100.00%**	**4.55%**	**13.76%**	**16.63%**	**2.08%**	**5.06%**	**7.30%**	**0.21%**	**0.04%**	**0.01%**	**47.55%**	**0.95%**	**1.87%**
Distribution CP (Total System)	**DCP12**	**100.00%**	**4.55%**	**13.76%**	**16.63%**	**2.08%**	**5.06%**	**7.30%**	**0.21%**	**0.04%**	**0.01%**	**47.55%**	**0.95%**	**1.87%**
NON CO_INCIDENT PEAK														
1 NCP														
Distribution NCP (Total System)	**DNCP1**	**100.00%**	**3.99%**	**13.23%**	**16.16%**	**1.06%**	**6.11%**	**8.73%**	**0.62%**	**0.10%**	**0.01%**	**46.75%**	**1.03%**	**2.21%**
Primary NCP	**PNCP1**	**100.00%**	**7.22%**	**24.11%**	**29.53%**	**1.81%**	**11.21%**	**16.15%**	**1.13%**	**0.18%**	**0.00%**	**2.67%**	**1.89%**	**4.10%**
Line Transformer NCP	**LTNCP1**	**100.00%**	**0.00%**	**0.00%**	**5.92%**	**0.00%**	**15.69%**	**57.73%**	**2.97%**	**0.00%**	**0.00%**	**0.00%**	**2.95%**	**14.75%**
Secondary NCP	**SNCP1**	**100.00%**	**9.33%**	**31.27%**	**38.37%**	**2.25%**	**14.59%**	**0.00%**	**1.48%**	**0.24%**	**0.00%**	**0.00%**	**2.47%**	**0.00%**
4 NCP														
Distribution NCP (Total System)	**DNCP4**	**100.00%**	**3.87%**	**13.36%**	**15.88%**	**1.01%**	**5.94%**	**8.72%**	**0.62%**	**0.10%**	**0.01%**	**47.21%**	**1.04%**	**2.24%**
Primary NCP	**PNCP4**	**100.00%**	**7.05%**	**24.54%**	**29.26%**	**1.73%**	**10.99%**	**16.28%**	**1.16%**	**0.19%**	**0.00%**	**2.72%**	**1.92%**	**4.18%**
Line Transformer NCP	**LTNCP4**	**100.00%**	**0.00%**	**0.00%**	**0.04%**	**0.00%**	**14.59%**	**62.78%**	**3.23%**	**0.00%**	**0.00%**	**0.00%**	**3.11%**	**16.25%**
Secondary NCP	**SNCP4**	**100.00%**	**9.13%**	**31.94%**	**38.15%**	**2.15%**	**14.35%**	**0.00%**	**1.51%**	**0.24%**	**0.00%**	**0.00%**	**2.52%**	**0.00%**
12 NCP														
Distribution NCP (Total System)	**DNCP12**	**100.00%**	**3.54%**	**11.68%**	**14.24%**	**0.92%**	**5.98%**	**9.18%**	**0.55%**	**0.08%**	**0.01%**	**50.38%**	**1.09%**	**2.36%**
Primary NCP	**PNCP12**	**100.00%**	**6.82%**	**22.69%**	**27.78%**	**1.63%**	**11.74%**	**18.20%**	**1.08%**	**0.16%**	**0.00%**	**3.08%**	**2.14%**	**4.68%**
Line Transformer NCP	**LTNCP12**	**100.00%**	**0.00%**	**0.00%**	**0.00%**	**0.00%**	**10.10%**	**67.30%**	**2.35%**	**0.00%**	**0.00%**	**0.00%**	**2.81%**	**17.43%**
Secondary NCP	**SNCP12**	**100.00%**	**9.16%**	**30.63%**	**37.60%**	**2.07%**	**15.94%**	**0.00%**	**1.47%**	**0.22%**	**0.00%**	**0.00%**	**2.92%**	**0.00%**
Demand Allocators - Composite														
DEMAND 1815-1855	**1815-1855 D**	**100.00%**	**3.21%**	**17.01%**	**32.71%**	**2.75%**	**12.52%**	**21.76%**	**1.36%**	**0.14%**	**0.00%**	**3.72%**	**1.23%**	**3.60%**
DEMAND 1808	**1808 D**	**100.00%**	**6.49%**	**19.63%**	**23.73%**	**2.97%**	**7.22%**	**10.42%**	**0.30%**	**0.06%**	**0.01%**	**25.14%**	**1.36%**	**2.67%**
DEMAND 1815	**1815 D**	**100.00%**	**6.95%**	**21.03%**	**25.42%**	**3.18%**	**7.73%**	**11.17%**	**0.32%**	**0.06%**	**0.01%**	**19.80%**	**1.46%**	**2.86%**
DEMAND 1820	**1820 D**	**100.00%**	**7.04%**	**24.50%**	**29.22%**	**1.72%**	**10.97%**	**16.25%**	**1.15%**	**0.18%**	**0.00%**	**2.87%**	**1.92%**	**4.17%**
DEMAND 1815 & 1820	**1815 & 1820 D**	**100.00%**	**7.01%**	**23.56%**	**28.18%**	**2.12%**	**10.09%**	**14.86%**	**0.93%**	**0.15%**	**0.00%**	**7.49%**	**1.79%**	**3.81%**
DEMAND 1830	**1830 D**	**100.00%**	**2.35%**	**17.80%**	**41.37%**	**3.65%**	**12.20%**	**15.59%**	**0.97%**	**0.16%**	**0.00%**	**4.27%**	**0.61%**	**1.03%**
DEMAND 1835	**1835 D**	**100.00%**	**2.30%**	**17.65%**	**41.28%**	**3.74%**	**12.09%**	**15.53%**	**0.94%**	**0.15%**	**0.01%**	**4.69%**	**0.60%**	**1.02%**
DEMAND 1830 & 1835	**1830 & 1835 D**	**100.00%**	**2.33%**	**17.74%**	**41.33%**	**3.69%**	**12.16%**	**15.57%**	**0.95%**	**0.16%**	**0.00%**	**4.43%**	**0.61%**	**1.03%**
DEMAND 1840	**1840 D**	**100.00%**	**8.75%**	**30.60%**	**36.54%**	**2.07%**	**13.74%**	**3.35%**	**1.45%**	**0.23%**	**0.00%**	**0.00%**	**2.41%**	**0.86%**
DEMAND 1845	**1845 D**	**100.00%**	**8.75%**	**30.60%**	**36.54%**	**2.07%**	**13.74%**	**3.35%**	**1.45%**	**0.23%**	**0.00%**	**0.00%**	**2.41%**	**0.86%**
DEMAND 1840 & 1845	**1840 & 1845 D**	**100.00%**	**8.75%**	**30.60%**	**36.54%**	**2.07%**	**13.74%**	**3.35%**	**1.45%**	**0.23%**	**0.00%**	**0.00%**	**2.41%**	**0.86%**
DEMAND 1850	**1850 D**	**100.00%**	**0.00%**	**0.00%**	**0.05%**	**0.00%**	**15.12%**	**63.57%**	**3.22%**	**0.00%**	**0.00%**	**0.30%**	**2.46%**	**15.28%**
DEMAND 1855	**1855 D**		**0.00%**	**0.00%**	**0.00%**	**0.00%**	**0.00%**	**0.00%**	**0.00%**	**0.00%**	**0.00%**	**0.00%**	**0.00%**	**0.00%**
DEMAND 1860	**1860 D**		**0.00%**	**0.00%**	**0.00%**	**0.00%**	**0.00%**	**0.00%**	**0.00%**	**0.00%**	**0.00%**	**0.00%**	**0.00%**	**0.00%**
CUSTOMER ALLOCATORS														
Billing Data														
kWh	**CEN**	**100.00%**	**3.89%**	**11.47%**	**14.64%**	**1.84%**	**5.99%**	**8.43%**	**0.31%**	**0.06%**	**0.01%**	**50.09%**	**1.10%**	**2.16%**
kW	**CDEM**	**100.00%**	**0.00%**	**0.00%**	**0.12%**	**0.00%**	**0.90%**	**19.35%**	**0.00%**	**0.00%**	**0.09%**	**75.55%**	**0.12%**	**3.87%**
kWh - Excl WMP	**CEN EWMP**	**100.00%**	**6.16%**	**18.16%**	**23.18%**	**2.91%**	**9.48%**	**13.34%**	**0.50%**	**0.09%**	**0.01%**	**21.00%**	**1.75%**	**3.42%**
Dollar Billed (per 2006 EDR)	**CREV**	**100.00%**	**5.26%**	**18.21%**	**38.33%**	**7.30%**	**11.12%**	**10.30%**	**0.47%**	**0.09%**	**0.06%**	**6.19%**	**1.13%**	**1.53%**

			1	2	3	4	5	6	7	8	12	13	14	15
Explanation	**ID and Factors**	**Total**	**UR**	**R1**	**R2**	**Seasonal**	**GSe**	**GSd**	**St Lgt**	**Sen Lgt**	**Dgen**	**ST**	**UGe**	**UGd**
Bad Debt 3 Year Historical Average	**BDHA**	**100.00%**	**11.46%**	**31.66%**	**32.16%**	**2.41%**	**7.63%**	**8.47%**	**0.64%**	**0.12%**	**0.01%**	**2.72%**	**0.91%**	**1.83%**
Late Payment 3 Year Historical Average	**LPHA**	**100.00%**	**8.41%**	**27.55%**	**32.20%**	**5.54%**	**11.03%**	**8.77%**	**0.14%**	**0.04%**	**0.02%**	**3.29%**	**1.77%**	**1.24%**
Number of Bills	**CNB**	**100.00%**	**14.88%**	**34.78%**	**34.21%**	**4.91%**	**8.33%**	**0.65%**	**0.53%**	**0.34%**	**0.01%**	**0.04%**	**1.19%**	**0.13%**
Number of Connections (Unmetered)	**CCON**	**100.00%**	**0.00%**	**0.00%**	**0.00%**	**0.00%**	**0.00%**	**0.00%**	**60.67%**	**39.33%**	**0.00%**	**0.00%**	**0.00%**	**0.00%**
CDM Participtant Percentage	**CDMPP**													
Total Number of Customer	**CCA**	**100.00%**	**13.66%**	**31.72%**	**30.75%**	**13.08%**	**8.17%**	**0.59%**	**0.47%**	**0.30%**	**0.01%**	**0.06%**	**1.07%**	**0.12%**
Subtransmission Customer Base	**CCB**	**100.00%**	**13.66%**	**31.72%**	**30.75%**	**13.08%**	**8.17%**	**0.59%**	**0.47%**	**0.30%**	**0.01%**	**0.06%**	**1.07%**	**0.12%**
Primary Feeder Customer Base	**CCP**	**100.00%**	**13.66%**	**31.74%**	**30.77%**	**13.08%**	**8.18%**	**0.59%**	**0.47%**	**0.30%**	**0.00%**	**0.01%**	**1.07%**	**0.12%**
Line Transformer Customer Base	**CCLT**	**100.00%**	**13.66%**	**31.74%**	**30.77%**	**13.08%**	**8.18%**	**0.59%**	**0.47%**	**0.30%**	**0.00%**	**0.00%**	**1.07%**	**0.12%**
Secondary Feeder Customer Base	**CCS**	**100.00%**	**13.76%**	**31.97%**	**30.99%**	**13.18%**	**8.24%**	**0.00%**	**0.47%**	**0.31%**	**0.00%**	**0.00%**	**1.08%**	**0.00%**
Weighted - Services	**CWCS**	**100.00%**	**12.59%**	**29.24%**	**28.35%**	**12.05%**	**15.07%**	**0.00%**	**0.43%**	**0.28%**	**0.00%**	**0.00%**	**1.98%**	**0.00%**
Weighted Meter -Capital	**CWMC**	**100.00%**	**11.91%**	**28.35%**	**29.42%**	**12.70%**	**8.70%**	**1.52%**	**0.00%**	**0.00%**	**0.03%**	**5.92%**	**1.18%**	**0.29%**
Weighted Meter Reading	**CWMR**	**100.00%**	**9.91%**	**28.94%**	**45.54%**	**6.13%**	**6.93%**	**1.51%**	**0.00%**	**0.00%**	**0.00%**	**0.00%**	**0.79%**	**0.24%**
Weighted Bills	**CWNB**	**100.00%**	**13.01%**	**30.40%**	**29.90%**	**4.30%**	**14.57%**	**3.98%**	**0.46%**	**0.03%**	**0.01%**	**0.47%**	**2.08%**	**0.80%**
CUSTOMER ALLOCATORS - Composite														
CUSTOMER 1815-1855	**1815-1855 C**	**100.00%**	**7.95%**	**26.42%**	**41.01%**	**13.58%**	**8.61%**	**0.71%**	**0.47%**	**0.30%**	**0.00%**	**0.47%**	**0.41%**	**0.07%**
CUSTOMER 1808	**1808 C**		**0.00%**	**0.00%**	**0.00%**	**0.00%**	**0.00%**	**0.00%**	**0.00%**	**0.00%**	**0.00%**	**0.00%**	**0.00%**	**0.00%**
CUSTOMER 1815	**1815 C**		**0.00%**	**0.00%**	**0.00%**	**0.00%**	**0.00%**	**0.00%**	**0.00%**	**0.00%**	**0.00%**	**0.00%**	**0.00%**	**0.00%**
CUSTOMER 1820	**1820 C**	**100.00%**	**6.16%**	**18.16%**	**23.18%**	**2.91%**	**9.48%**	**13.34%**	**0.50%**	**0.09%**	**0.01%**	**21.00%**	**1.75%**	**3.42%**
CUSTOMER 1815 & 1820	**1815 & 1820 C**	**100.00%**	**6.16%**	**18.16%**	**23.18%**	**2.91%**	**9.48%**	**13.34%**	**0.50%**	**0.09%**	**0.01%**	**21.00%**	**1.75%**	**3.42%**
CUSTOMER 1830	**1830 C**	**100.00%**	**4.69%**	**23.03%**	**46.23%**	**15.25%**	**8.93%**	**0.55%**	**0.47%**	**0.31%**	**0.00%**	**0.09%**	**0.41%**	**0.03%**
CUSTOMER 1835	**1835 C**	**100.00%**	**4.69%**	**23.03%**	**46.23%**	**15.25%**	**8.93%**	**0.55%**	**0.47%**	**0.31%**	**0.00%**	**0.09%**	**0.41%**	**0.03%**
CUSTOMER 1830 & 1835	**1830 & 1835 C**	**100.00%**	**4.69%**	**23.03%**	**46.23%**	**15.25%**	**8.93%**	**0.55%**	**0.47%**	**0.31%**	**0.00%**	**0.09%**	**0.41%**	**0.03%**
CUSTOMER 1840	**1840 C**	**100.00%**	**13.74%**	**31.92%**	**30.95%**	**13.16%**	**8.23%**	**0.12%**	**0.47%**	**0.31%**	**0.00%**	**0.00%**	**1.08%**	**0.02%**
CUSTOMER 1845	**1845 C**	**100.00%**	**13.74%**	**31.92%**	**30.95%**	**13.16%**	**8.23%**	**0.12%**	**0.47%**	**0.31%**	**0.00%**	**0.00%**	**1.08%**	**0.02%**
CUSTOMER 1840 & 1845	**1840 & 1845 C**	**100.00%**	**13.74%**	**31.92%**	**30.95%**	**13.16%**	**8.23%**	**0.12%**	**0.47%**	**0.31%**	**0.00%**	**0.00%**	**1.08%**	**0.02%**
CUSTOMER 1850	**1850 C**	**100.00%**	**10.57%**	**29.74%**	**38.20%**	**11.56%**	**8.22%**	**0.63%**	**0.47%**	**0.31%**	**0.00%**	**0.30%**	**0.00%**	**0.00%**
CUSTOMER 1855	**1855 C**		**0.00%**	**0.00%**	**0.00%**	**0.00%**	**0.00%**	**0.00%**	**0.00%**	**0.00%**	**0.00%**	**0.00%**	**0.00%**	**0.00%**
CUSTOMER 1860	**1860 C**	**100.00%**	**12.74%**	**29.64%**	**28.90%**	**12.30%**	**7.75%**	**3.09%**	**0.00%**	**0.00%**	**0.05%**	**3.92%**	**1.02%**	**0.59%**
Composite Allocators														
Net Fixed Assets	**NFA**	**100.00%**	**5.78%**	**21.57%**	**35.38%**	**7.62%**	**10.52%**	**12.37%**	**0.89%**	**0.19%**	**0.01%**	**2.64%**	**0.90%**	**2.13%**
Net Fixed Assets Excluding Capital Contribution	**NFA ECC**	**100.00%**	**5.86%**	**21.73%**	**35.42%**	**7.65%**	**10.54%**	**12.17%**	**0.90%**	**0.19%**	**0.01%**	**2.54%**	**0.91%**	**2.09%**
5005-5340	**O&M**	**100.00%**	**6.76%**	**24.04%**	**38.79%**	**8.06%**	**10.48%**	**7.19%**	**0.64%**	**0.18%**	**0.01%**	**1.96%**	**0.93%**	**0.96%**
New Allocators employed for H1N-Dx														
New Connections	**Connects**	100%	**17.2%**	**33.6%**	**18.4%**	**2.1%**	**27.1%**	**0.6%**	**0.0%**	**0.0%**	**0.0%**	**0.0%**	**0.9%**	**0.1%**
Meters	**CWMC**	274,283,678	32,653,951	77,766,040	80,682,304	34,827,221	23,861,405	4,156,006	-	-	76,305	16,233,676	3,243,245	783,524
Mtr-Single	CWMC-1	253,034,166	**32,653,951**	**77,766,040**	**80,682,304**	**34,827,221**	**23,861,405**			**-**			**3,243,245**	
Mtr-Poly	CWMC-2	5,015,836						**4,156,006**	**-**		**76,305**			**783,524**
Mtr-LV	CWMC-3	16,233,676										**16,233,676**		
Mtr-Smart	Cust	1,177,552	**162,058**	**376,430**	**364,938**	**155,177**	**97,005**	**7,015**	**-**	**-**	**84**	**673**	**12,744**	**1,429**
	IM Cust	1,419	**-**	**-**	**-**	**-**	**8.00**	**481.00**	**-**	**-**	**81.00**	**736.00**	**-**	**113.00**

Explanation	ID and Factors	Total	UR	R1	R2	Seasonal	GSe	GSd	St Lgt	Sen Lgt	Dgen	ST	UGe	UGd
			1	2	3	4	5	6	7	8	12	13	14	15
		100%	**0.00%**	**0.00%**	**0.00%**	**0.00%**	**0.56%**	**33.90%**	**0.00%**	**0.00%**	**5.71%**	**51.87%**	**0.00%**	**7.96%**
Mtr-Single	CWMC1	100%	**12.9%**	**30.7%**	**31.9%**	**13.8%**	**9.4%**	**0.0%**	**0.0%**	**0.0%**	**0.0%**	**0.0%**	**1.3%**	**0.0%**
Mtr-Poly	CWMC2	100%	**0.0%**	**0.0%**	**0.0%**	**0.0%**	**0.0%**	**82.9%**	**0.0%**	**0.0%**	**1.5%**	**0.0%**	**0.0%**	**15.6%**
Mtr-LV	CWMC3	100%	**0.0%**	**0.0%**	**0.0%**	**0.0%**	**0.0%**	**0.0%**	**0.0%**	**0.0%**	**0.0%**	**100.0%**	**0.0%**	**0.0%**
Mtr-Smart	CWMC4	100%	**13.8%**	**32.0%**	**31.0%**	**13.2%**	**8.2%**	**0.6%**	**0.0%**	**0.0%**	**0.0%**	**0.1%**	**1.1%**	**0.1%**
1855-D														
1815-1														
1815-2	**1815-2D**	100%	0%	0%	0%	0%	0%	0%	0%	0%	0%	100%	0%	0%
1815-3	**1815-3D**	100%	0%	0%	0%	0%	0%	0%	0%	0%	0%	100%	0%	0%
1815-4	**1815-4D**	100%	0%	0%	0%	0%	0%	0%	0%	0%	0%	100%	0%	0%
1815-5	**1815-5D**	100%	0%	0%	0%	0%	0%	0%	0%	0%	0%	100%	0%	0%
1830-3A	**1830-3A**	100%	0%	0%	0%	0%	0%	0%	0%	0%	0%	100%	0%	0%
1830-3B														
1830-4AC	**1830-4AC**	100%	0%	0%	0%	0%	0%	0%	0%	0%	0%	100%	0%	0%
1830-4AD	**1830-4AD**	100%	0%	0%	0%	0%	0%	0%	0%	0%	0%	100%	0%	0%
1830-4B														
1835-3A	**1835-3A**	100%	0%	0%	0%	0%	0%	0%	0%	0%	0%	100%	0%	0%
1835-3B														
1835-4AC	**1835-4AC**	100%	0%	0%	0%	0%	0%	0%	0%	0%	0%	100%	0%	0%
1835-4AD	**1835-4AD**	100%	0%	0%	0%	0%	0%	0%	0%	0%	0%	100%	0%	0%
1835-4B														
1850-1C	**1850-1C**	100%	0%	0%	0%	0%	0%	0%	0%	0%	0%	100%	0%	0%
1850-1D	**1850-1D**	100%	0%	0%	0%	0%	0%	0%	0%	0%	0%	100%	0%	0%
TCP1		6,716,619	339,882	1,047,380	1,208,430	113,585	341,335	471,767	25,967	5,120	461	2,977,680	62,625	122,387
TCP4		26,078,514	1,270,911	4,020,290	4,765,830	468,705	1,271,553	1,829,931	108,260	21,348	1,827	11,614,299	237,141	468,420
TCP12		70,226,697	3,193,520	9,660,672	11,676,098	1,460,978	3,551,695	5,129,265	146,171	28,823	5,306	33,391,892	669,408	1,312,870
DCP1		6,716,619	339,882	1,047,380	1,208,430	113,585	341,335	471,767	25,967	5,120	461	2,977,680	62,625	122,387
DCP4		26,078,514	1,270,911	4,020,290	4,765,830	468,705	1,271,553	1,829,931	108,260	21,348	1,827	11,614,299	237,141	468,420
DCP12		70,226,697	3,193,520	9,660,672	11,676,098	1,460,978	3,551,695	5,129,265	146,171	28,823	5,306	33,391,892	669,408	1,312,870
BCP1		6,488,254	328,326	1,011,769	1,167,343	109,723	329,729	455,727	25,084	4,946	445	2,876,439	60,496	118,226
BCP4		25,191,845	1,227,700	3,883,600	4,603,791	452,769	1,228,321	1,767,713	104,579	20,622	1,765	11,219,412	229,078	452,494
BCP12		67,838,990	3,084,940	9,332,209	11,279,111	1,411,305	3,430,938	4,954,870	141,202	27,843	5,125	32,256,567	646,648	1,268,232
DNCP1		6,535,864	260,679	864,894	1,055,978	69,364	399,314	570,806	40,271	6,576	544	3,055,390	67,292	144,756
DNCP4		25,354,741	979,964	3,386,569	4,026,379	256,418	1,506,021	2,211,803	157,828	25,662	2,094	11,970,968	263,146	567,891
DNCP12		66,695,243	2,361,176	7,787,782	9,495,658	613,012	3,987,157	6,123,796	365,215	55,638	5,782	33,600,362	726,259	1,573,406
PNCP1		3,316,851	239,400	799,644	979,454	59,984	371,737	535,754	37,630	6,055	38	88,513	62,764	135,878
PNCP4		12,754,912	898,675	3,130,023	3,732,329	220,179	1,401,277	2,075,952	147,462	23,618	144	346,791	245,402	533,060
PNCP12		31,572,146	2,152,612	7,162,830	8,771,102	513,825	3,705,312	5,747,451	340,722	50,808	385	973,357	676,883	1,476,859
LTNCP1		788,987	-	-	46,672	-	123,793	455,476	23,416	-	-	-	23,257	116,374
LTNCP4		2,807,466	-	-	1,204	-	409,500	1,762,586	90,608	-	-	-	87,373	456,195
LTNCP12		7,225,558	-	-	-	-	729,979	4,862,866	170,160	-	-	-	202,795	1,259,758
SNCP1		2,451,114	228,586	766,484	940,564	55,216	357,722	-	36,288	5,791	-	-	60,463	-
SNCP4		9,390,873	857,364	2,999,647	3,582,894	201,762	1,348,047	-	142,194	22,580	-	-	236,385	-
SNCP12		22,348,653	2,046,620	6,845,232	8,402,885	463,419	3,562,079	-	328,275	48,354	-	-	651,790	-
excl ST	**BCP1A**	100.0000%	9.09%	28.01%	32.32%	3.04%	9.13%	12.62%	0.69%	0.14%	0.01%		1.67%	3.27%
	BCP4A	100.0000%	8.79%	27.79%	32.95%	3.24%	8.79%	12.65%	0.75%	0.15%	0.01%		1.64%	3.24%
	BCP12A	100.0000%	8.67%	26.23%	31.70%	3.97%	9.64%	13.93%	0.40%	0.08%	0.01%		1.82%	3.56%

			1	2	3	4	5	6	7	8	12	13	14	15
Explanation	**ID and Factors**	**Total**	**UR**	**R1**	**R2**	**Seasonal**	**GSe**	**GSd**	**St Lgt**	**Sen Lgt**	**Dgen**	**ST**	**UGe**	**UGd**
excl ST	**BCP1B**	100.0000%	9.09%	28.01%	32.32%	3.04%	9.13%	12.62%	0.69%	0.14%	0.01%		1.67%	3.27%
	BCP4B	100.0000%	8.79%	27.79%	32.95%	3.24%	8.79%	12.65%	0.75%	0.15%	0.01%		1.64%	3.24%
	BCP12B	100.0000%	8.67%	26.23%	31.70%	3.97%	9.64%	13.93%	0.40%	0.08%	0.01%		1.82%	3.56%
excl ST	**PNCP1A**	100.0000%	7.4%	24.8%	30.3%	1.9%	11.5%	16.6%	1.2%	0.2%	0.0%		1.9%	4.2%
	PNCP4A	100.0000%	7.2%	25.2%	30.1%	1.8%	11.3%	16.7%	1.2%	0.2%	0.0%		2.0%	4.3%
	PNCP12A	100.0000%	7.0%	23.4%	28.7%	1.7%	12.1%	18.8%	1.1%	0.2%	0.0%		2.2%	4.8%
excl ST	**PNCP1B**	100.0000%	7.4%	24.8%	30.3%	1.9%	11.5%	16.6%	1.2%	0.2%	0.0%		1.9%	4.2%
	PNCP4B	100.0000%	7.2%	25.2%	30.1%	1.8%	11.3%	16.7%	1.2%	0.2%	0.0%		2.0%	4.3%
	PNCP12B	100.0000%	7.0%	23.4%	28.7%	1.7%	12.1%	18.8%	1.1%	0.2%	0.0%		2.2%	4.8%
excl ST	**PNCP1C**	100.0000%	7.4%	24.8%	30.3%	1.9%	11.5%	16.6%	1.2%	0.2%	0.0%		1.9%	4.2%
excl LV+LU+F3+T+F1+Stdby	**PNCP4C**	100.0000%	7.2%	25.2%	30.1%	1.8%	11.3%	16.7%	1.2%	0.2%	0.0%		2.0%	4.3%
excl LV+LU+F3+T+F1+Stdby	**PNCP12C**	100.0000%	7.0%	23.4%	28.7%	1.7%	12.1%	18.8%	1.1%	0.2%	0.0%		2.2%	4.8%
excl ST	**SNCP1C**	100.0000%	9.33%	31.27%	38.37%	2.25%	14.59%	0.00%	1.48%	0.24%	0.00%	0.00%	2.47%	0.00%
excl F1,F3	**SNCP4C**	100.0000%	9.13%	31.94%	38.15%	2.15%	14.35%	0.00%	1.51%	0.24%	0.00%	0.00%	2.52%	0.00%
excl F1,F3	**SNCP12C**	100.0000%	9.16%	30.63%	37.60%	2.07%	15.94%	0.00%	1.47%	0.22%	0.00%	0.00%	2.92%	0.00%
		1,185,994	162,058	376,430	364,938	155,177	97,005	7,015	5,561	3,606	32		12,744	1,429
excl ST	**CCP-C**	100.000%	13.7%	31.7%	30.8%	13.1%	8.2%	0.6%	0.5%	0.3%	0.0%	0.0%	1.1%	0.1%
		1,177,518	162,058	376,430	364,938	155,177	97,005	-	5,561	3,606	-	-	12,744	-
excl ST	**CCS-C**	100.000%	13.8%	32.0%	31.0%	13.2%	8.2%	0.0%	0.5%	0.3%	0.0%	0.0%	1.1%	0.0%
Density Wts for Dlines + Rural Transformers														
Dlines cust			**0.190**	**0.659**	**1.613**	**1.200**	**1.109**	**1.140**	**1.000**	**1.000**	**1.000**	**1.000**	**0.238**	**0.306**
Dlines energy			**0.183**	**0.640**	**1.419**	**1.598**	**1.151**	**1.176**	**1.000**	**1.000**	**1.000**	**1.000**	**0.183**	**0.302**
Rural Transf cust			**0.766**	**0.928**	**1.229**	**0.875**	**0.995**	**1.048**	**1.000**	**1.000**	**1.000**	**1.000**	**1.033**	**0.760**
Rural Transf energy			**0.746**	**0.882**	**1.123**	**1.282**	**1.039**	**1.015**	**1.000**	**1.000**	**1.000**	**1.000**	**0.791**	**0.942**
	BCP1-DLines	6,409,078	60,127	647,478	1,656,996	175,346	379,620	535,850	25,084	4,946	445	2,876,439	11,058	35,688
	BCP4-DLines	24,986,102	224,831	2,485,294	6,534,893	723,564	1,414,176	2,078,500	104,579	20,622	1,765	11,219,412	41,874	136,592
	BCP12-DLines	67,510,523	564,952	5,972,109	16,010,234	2,255,384	3,950,067	5,826,000	141,202	27,843	5,125	32,256,567	118,204	382,835
		-												
	PNCP1-DLines	3,284,381	43,842	511,729	1,390,294	95,859	427,984	629,947	37,630	6,055	38	88,513	11,473	41,017
	PNCP4-DLines	12,595,393	164,576	2,003,045	5,297,888	351,864	1,613,302	2,440,931	147,462	23,618	144	346,791	44,858	160,912
	PNCP12-DLines	31,208,090	394,212	4,583,824	12,450,219	821,136	4,265,956	6,757,928	340,722	50,808	385	973,357	123,731	445,812
		-												
	SNCP1-DLines	2,420,682	41,861	490,508	1,335,092	88,240	411,849	-	36,288	5,791	-	-	11,052	-
	SNCP4-DLines	9,244,829	157,011	1,919,612	5,085,771	322,433	1,552,018	-	142,194	22,580	-	-	43,210	-
	SNCP12-DLines	22,020,337	374,802	4,380,578	11,927,550	740,583	4,101,051	-	328,275	48,354	-	-	119,144	-
		-												
	BCP1-RTransf	6,459,867	245,057	892,452	1,310,643	140,707	342,505	462,379	25,084	4,946	445	2,876,439	47,836	111,373
	BCP4-RTransf	25,114,722	916,333	3,425,608	5,168,939	580,627	1,275,913	1,793,516	104,579	20,622	1,765	11,219,412	181,140	426,267
	BCP12-RTransf	67,735,609	2,302,545	8,231,664	12,663,700	1,809,844	3,563,874	5,027,193	141,202	27,843	5,125	32,256,567	511,327	1,194,724
		-												
	PNCP1-RTransf	3,300,220	178,684	705,342	1,099,688	76,922	386,140	543,574	37,630	6,055	38	88,513	49,630	128,002
	PNCP4-RTransf	12,680,561	670,755	2,760,900	4,190,499	282,355	1,455,572	2,106,253	147,462	23,618	144	346,791	194,048	502,163
	PNCP12-RTransf	31,403,519	1,606,671	6,318,120	9,847,816	658,925	3,848,879	5,831,343	340,722	50,808	385	973,357	535,234	1,391,259
		-												
	SNCP1-RTransf	2,435,010	170,612	676,093	1,056,025	70,809	371,583	-	36,288	5,791	-	-	47,810	-
	SNCP4-RTransf	9,319,249	639,921	2,645,899	4,022,719	258,738	1,400,279	-	142,194	22,580	-	-	186,918	-
	SNCP12-RTransf	22,186,336	1,527,561	6,037,975	9,434,398	594,285	3,700,097	-	328,275	48,354	-	-	515,392	-
	LTNCP1-Rtransf	794,549	-	-	52,402	-	128,589	462,124	23,416	-	-	-	18,390	109,628
	LTNCP4-Rtransf	2,804,482	-	-	1,352	-	425,366	1,788,314	90,608	-	-	-	69,089	429,753
	LTNCP12-Rtransf	7,209,368	-	-	-	-	758,263	4,933,847	170,160	-	-	-	160,357	1,186,741

Dlines

Explanation	ID and Factors	Total	1 UR	2 R1	3 R2	4 Seasonal	5 GSe	6 GSd	7 St Lgt	8 Sen Lgt	12 Dgen	13 ST	14 UGe	15 UGd
excl ST	**BCP1-DLinesB**	100.00%	1.70%	18.33%	46.91%	4.96%	10.75%	15.17%	0.71%	0.14%	0.01%		0.31%	1.01%
	BCP4-DLinesB	100.00%	1.63%	18.05%	47.47%	5.26%	10.27%	15.10%	0.76%	0.15%	0.01%		0.30%	0.99%
	BCP12-DLinesB	100.00%	1.60%	16.94%	45.41%	6.40%	11.20%	16.53%	0.40%	0.08%	0.01%		0.34%	1.09%
excl ST	**PNCP1-DLinesB**	100.0%	1.37%	16.01%	43.50%	3.00%	13.39%	19.71%	1.18%	0.19%	0.00%		0.36%	1.28%
	PNCP4-DLinesB	100.0%	1.34%	16.35%	43.25%	2.87%	13.17%	19.93%	1.20%	0.19%	0.00%		0.37%	1.31%
	PNCP12-DLinesB	100.0%	1.30%	15.16%	41.18%	2.72%	14.11%	22.35%	1.13%	0.17%	0.00%		0.41%	1.47%
	SNCP1-DLinesB	100%	1.73%	20.26%	55.15%	3.65%	17.01%	0.00%	1.50%	0.24%	0.00%	0.00%	0.46%	0.00%
	SNCP4-DLinesB	100%	1.70%	20.76%	55.01%	3.49%	16.79%	0.00%	1.54%	0.24%	0.00%	0.00%	0.47%	0.00%
	SNCP12-DLinesB	100%	1.70%	19.89%	54.17%	3.36%	18.62%	0.00%	1.49%	0.22%	0.00%	0.00%	0.54%	0.00%
	SNCP1-DLinesC	100.0%	1.73%	20.26%	55.15%	3.65%	17.01%	0.00%	1.50%	0.24%	0.00%	0.00%	0.46%	0.00%
	SNCP4-DLinesC	100.0%	1.70%	20.76%	55.01%	3.49%	16.79%	0.00%	1.54%	0.24%	0.00%	0.00%	0.47%	0.00%
	SNCP12-DLinesC	100.0%	1.70%	19.89%	54.17%	3.36%	18.62%	0.00%	1.49%	0.22%	0.00%	0.00%	0.54%	0.00%
	PNCP1-DLinesC	100.0%	1.33%	15.58%	42.33%	2.92%	13.03%	19.18%	1.15%	0.18%	0.00%	2.69%	0.35%	1.25%
	PNCP4-DLinesC	100.0%	1.31%	15.90%	42.06%	2.79%	12.81%	19.38%	1.17%	0.19%	0.00%	2.75%	0.36%	1.28%
	PNCP12-DLinesC	100.0%	1.26%	14.69%	39.89%	2.63%	13.67%	21.65%	1.09%	0.16%	0.00%	3.12%	0.40%	1.43%
CCP		1,186,072	162,058	376,430	364,938	155,177	97,005	7,015	5,561	3,606	32	78	12,744	1,429
CCLT		1,185,994	162,058	376,430	364,938	155,177	97,005	7,015	5,561	3,606	32	-	12,744	1,429
CCS		1,177,518	162,058	376,430	364,938	155,177	97,005	-	5,561	3,606	-	-	12,744	-
CCP-Dlines Wted		1,181,949	30,766	248,077	588,661	186,163	107,533	7,998	5,561	3,606	32	78	3,037	438
CCS-Dlines Wted		1,173,403	30,766	248,077	588,661	186,163	107,533	-	5,561	3,606	-	-	3,037	-
	CCP-Dlines	100.0%	2.60%	20.99%	49.80%	15.75%	9.10%	0.68%	0.47%	0.31%	0.00%	0.01%	0.26%	0.04%
	CCS_Dlines	100.0%	2.62%	21.14%	50.17%	15.87%	9.16%	0.00%	0.47%	0.31%	0.00%	0.00%	0.26%	0.00%
excl ST	**CCP-DlinesC**	100.0%	2.60%	20.99%	49.81%	15.75%	9.10%	0.68%	0.47%	0.31%	0.00%		0.26%	0.04%
	CCS_DlinesC	100.0%	2.62%	21.14%	50.17%	15.87%	9.16%	0.00%	0.47%	0.31%	0.00%		0.26%	0.00%
Rtransf														
excl ST	**BCP1-RTransfB**	100.0%	6.84%	24.90%	36.58%	3.93%	9.56%	12.90%	0.70%	0.14%	0.01%		1.33%	3.11%
	BCP4-RTransfB	100.0%	6.59%	24.65%	37.20%	4.18%	9.18%	12.91%	0.75%	0.15%	0.01%		1.30%	3.07%
	BCP12-RTransfB	100.0%	6.49%	23.20%	35.69%	5.10%	10.05%	14.17%	0.40%	0.08%	0.01%		1.44%	3.37%
excl ST	**PNCP1-RTransfB**	100.0%	5.56%	21.96%	34.24%	2.40%	12.02%	16.92%	1.17%	0.19%	0.00%		1.55%	3.99%
	PNCP4-RTransfB	100.0%	5.44%	22.38%	33.98%	2.29%	11.80%	17.08%	1.20%	0.19%	0.00%		1.57%	4.07%
	PNCP12-RTransfB	100.0%	5.28%	20.76%	32.36%	2.17%	12.65%	19.16%	1.12%	0.17%	0.00%		1.76%	4.57%
	SNCP1-RTransfB	100.0%	7.01%	27.77%	43.37%	2.91%	15.26%	0.00%	1.49%	0.24%	0.00%	0.00%	1.96%	0.00%
	SNCP4-RTransfB	100.0%	6.87%	28.39%	43.17%	2.78%	15.03%	0.00%	1.53%	0.24%	0.00%	0.00%	2.01%	0.00%
	SNCP12-RTransfB	100.0%	6.89%	27.21%	42.52%	2.68%	16.68%	0.00%	1.48%	0.22%	0.00%	0.00%	2.32%	0.00%
	LTNCP1-RtransfB	100.0%	0.00%	0.00%	6.60%	0.00%	16.18%	58.16%	2.95%	0.00%	0.00%	0.00%	2.31%	13.80%
	LTNCP4-RtransfB	100.0%	0.00%	0.00%	0.05%	0.00%	15.17%	63.77%	3.23%	0.00%	0.00%	0.00%	2.46%	15.32%
	LTNCP12-RtransfB	100.0%	0.00%	0.00%	0.00%	0.00%	10.52%	68.44%	2.36%	0.00%	0.00%	0.00%	2.22%	16.46%
	SNCP1-RTransfC	100.0%	7.01%	27.77%	43.37%	2.91%	15.26%	0.00%	1.49%	0.24%	0.00%	0.00%	1.96%	0.00%
	SNCP4-RTransfC	100.0%	6.87%	28.39%	43.17%	2.78%	15.03%	0.00%	1.53%	0.24%	0.00%	0.00%	2.01%	0.00%
	SNCP12-RTransfC	100.0%	6.89%	27.21%	42.52%	2.68%	16.68%	0.00%	1.48%	0.22%	0.00%	0.00%	2.32%	0.00%
excl ST	**PNCP1-RTransfC**	101.0%	5.56%	21.96%	34.24%	2.40%	12.02%	16.92%	1.17%	0.19%	0.00%		1.83%	4.71%
	PNCP4-RTransfC	101.0%	5.44%	22.38%	33.98%	2.29%	11.80%	17.08%	1.20%	0.19%	0.00%		1.86%	4.82%
	PNCP12-RTransfC	101.3%	5.28%	20.76%	32.36%	2.17%	12.65%	19.16%	1.12%	0.17%	0.00%		2.12%	5.51%
CCP-Rtransf Wted		1,185,137	124,166	349,275	448,554	135,711	96,554	7,354	5,561	3,606	32	78	13,160	1,086
CCLT-Rtransf Wted		1,170,813	124,166	349,275	448,554	135,711	96,554	7,354	5,561	3,606	32	-		
CCS-RTransf Wted		1,176,586	124,166	349,275	448,554	135,711	96,554	-	5,561	3,606	-	-	13,160	-
excl St	**CCP-Rtransf**	100.000%	10.48%	29.47%	37.85%	11.45%	8.15%	0.62%	0.47%	0.30%	0.00%		1.11%	0.09%
	CCLT-Rtransf	100.000%	10.61%	29.83%	38.31%	11.59%	8.25%	0.63%	0.47%	0.31%	0.00%		0.00%	0.00%

Explanation	ID and Factors	Total	UR	R1	R2	Seasonal	GSe	GSd	St Lgt	Sen Lgt	Dgen	ST	UGe	UGd
			1	2	3	4	5	6	7	8	12	13	14	15
	CCS-Rtransf	100.000%	10.55%	29.69%	38.12%	11.53%	8.21%	0.00%	0.47%	0.31%	0.00%		1.12%	0.00%
	StLgt	100.000%	0%	0%	0%	0%	0%	0%	100%	0%	0%	0%	0%	0%
	SenLgt	100.000%	0%	0%	0%	0%	0%	0%	0%	100%	0%	0%	0%	0%
excl WMP	**CEN2 GWH**	24,267	1,494	4,407	5,624	707	2,299	3,237	121	22	3	5,096	424	831
	CEN2		**6.2%**	**18.2%**	**23.2%**	**2.9%**	**9.5%**	**13.3%**	**0.5%**	**0.1%**	**0.0%**	**21.0%**	**1.7%**	**3.4%**
Separate Out RCD from ST														
	RCD											RCD		
BCP1 incl RCD	89,931	3,701,747	328,326	1,011,769	1,167,343	109,723	329,729	455,727	25,084	4,946	445	89,931	60,496	118,226
BCP4	355,914	14,328,347	1,227,700	3,883,600	4,603,791	452,769	1,228,321	1,767,713	104,579	20,622	1,765	355,914	229,078	452,494
BCP12	996,234	36,578,656	3,084,940	9,332,209	11,279,111	1,411,305	3,430,938	4,954,870	141,202	27,843	5,125	996,234	646,648	1,268,232
	BCP1AA	100.000%	8.9%	27.3%	31.5%	3.0%	8.9%	12.3%	0.7%	0.1%	0.0%	2.43%	1.6%	3.2%
	BCP4AA	100.000%	8.6%	27.1%	32.1%	3.2%	8.6%	12.3%	0.7%	0.1%	0.0%	2.48%	1.6%	3.2%
	BCP12AA	100.000%	8.4%	25.5%	30.8%	3.9%	9.4%	13.5%	0.4%	0.1%	0.0%	2.72%	1.8%	3.5%
	RCD											RCD		
PNCP1 incl RCD	93,909	3,322,247	239,400	799,644	979,454	59,984	371,737	535,754	37,630	6,055	38	93,909	62,764	135,878
PNCP4	366,043	12,774,164	898,675	3,130,023	3,732,329	220,179	1,401,277	2,075,952	147,462	23,618	144	366,043	245,402	533,060
PNCP12	1,006,298	31,605,087	2,152,612	7,162,830	8,771,102	513,825	3,705,312	5,747,451	340,722	50,808	385	1,006,298	676,883	1,476,859
	PNCP1AA	100.000%	7.2%	24.1%	29.5%	1.8%	11.2%	16.1%	1.1%	0.2%	0.0%	2.8%	1.9%	4.1%
	PNCP4AA	100.000%	7.0%	24.5%	29.2%	1.7%	11.0%	16.3%	1.2%	0.2%	0.0%	2.9%	1.9%	4.2%
	PNCP12AA	100.000%	6.8%	22.7%	27.8%	1.6%	11.7%	18.2%	1.1%	0.2%	0.0%	3.2%	2.1%	4.7%
BCP1 incl RCD w Density		3,622,570	60,127	647,478	1,656,996	175,346	379,620	535,850	25,084	4,946	445	89,931	11,058	35,688
BCP4		14,122,604	224,831	2,485,294	6,534,893	723,564	1,414,176	2,078,500	104,579	20,622	1,765	355,914	41,874	136,592
BCP12		36,250,189	564,952	5,972,109	16,010,234	2,255,384	3,950,067	5,826,000	141,202	27,843	5,125	996,234	118,204	382,835
	BCP1-DlinesBB	100.000%	1.7%	17.9%	45.7%	4.8%	10.5%	14.8%	0.7%	0.1%	0.0%	2.5%	0.3%	1.0%
	BCP4-DlinesBB	100.000%	1.6%	17.6%	46.3%	5.1%	10.0%	14.7%	0.7%	0.1%	0.0%	2.5%	0.3%	1.0%
	BCP12-DlinesBB	100.000%	1.6%	16.5%	44.2%	6.2%	10.9%	16.1%	0.4%	0.1%	0.0%	2.7%	0.3%	1.1%

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Attachment A
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Hydro One Distribution: 12 Rate Classes

- 1		1
Ref	Conductors	Rural Transformers
PLCC WATTS 400	PLCC WATTS 544	PLCC WATTS 3100

Customer Classes	Total	UR	R1	R2	Seasonal	GSe	GSd	St Lgt	Sen Lgt	Dgen	ST	UGe	UGd
		1	2	3	4	5	6	7	8	12	13	14	15
CCA	**1,186,719**	162,058	376,430	364,938	155,177	97,005	7,015	5,561	3,606	84	673	12,744	1,429
CCB	**1,186,719**	162,058	376,430	364,938	155,177	97,005	7,015	5,561	3,606	84	673	12,744	1,429
CCP	**1,186,072**	162,058	376,430	364,938	155,177	97,005	7,015	5,561	3,606	32	78	12,744	1,429
CCLT	**1,185,994**	162,058	376,430	364,938	155,177	97,005	7,015	5,561	3,606	32	0	12,744	1,429
CCS	**1,177,518**	162,058	376,430	364,938	155,177	97,005	0	5,561	3,606	0	0	12,744	0
PLCC-CCA	**645,575**	88,160	204,778	198,526	84,416	52,771	3,816	3,025	1,961	46	366	6,933	777
PLCC-CCB	**645,575**	88,160	204,778	198,526	84,416	52,771	3,816	3,025	1,961	46	366	6,933	777
PLCC-CCP	**645,223**	88,160	204,778	198,526	84,416	52,771	3,816	3,025	1,961	17	42	6,933	777
PLCC-CCLT	**3,684,291**	502,380	1,166,933	1,131,307	481,049	300,715	21,746	17,239	11,177	99	0	46,440	5,206
PLCC-CCS	**640,570**	88,160	204,778	198,526	84,416	52,771	0	3,025	1,961	0	0	6,933	0
1NCP													
DNCP1	**7,181,439**	348,839	1,069,672	1,254,505	153,781	452,085	574,622	43,296	8,537	589	3,055,756	74,224	145,533
PNCP1	**3,962,074**	327,559	1,004,422	1,177,980	144,400	424,508	539,570	40,655	8,017	55	88,556	69,697	136,655
LTNCP1	**3,796,059**	327,559	1,004,422	1,177,980	144,400	424,508	477,222	40,655	8,017	21	0	69,697	121,579
SNCP1	**3,091,684**	316,745	971,262	1,139,090	139,633	410,493	0	39,313	7,752	0	0	67,396	0
PLCC - 1NCP													
DNCP1A	**6,535,864**	260,679	864,894	1,055,978	69,364	399,314	570,806	40,271	6,576	544	3,055,390	67,292	144,756
PNCP1A	**3,316,851**	239,400	799,644	979,454	59,984	371,737	535,754	37,630	6,055	38	88,513	62,764	135,878
LTNCP1A	**788,987**	0	0	46,672	0	123,793	455,476	23,416	0	0	0	23,257	116,374
SNCP1A	**2,451,114**	228,586	766,484	940,564	55,216	357,722	0	36,288	5,791	0	0	60,463	0
4 NCP													
DNCP4	**27,937,041**	1,332,602	4,205,680	4,820,483	594,083	1,717,103	2,227,067	169,928	33,508	2,276	11,972,432	290,877	570,999
PNCP4	**15,335,805**	1,251,313	3,949,134	4,526,434	557,844	1,612,360	2,091,216	159,563	31,464	214	346,961	273,134	536,168
LTNCP4	**14,687,915**	1,251,313	3,949,134	4,526,434	557,844	1,612,360	1,849,571	159,563	31,464	79	0	273,134	477,018
SNCP4	**11,953,154**	1,210,003	3,818,758	4,376,999	539,428	1,559,130	0	154,295	30,425	0	0	264,117	0
PLCC - 4NCP													
DNCP4A	**25,354,741**	979,964	3,386,569	4,026,379	256,418	1,506,021	2,211,803	157,828	25,662	2,094	11,970,968	263,146	567,891
PNCP4A	**12,754,912**	898,675	3,130,023	3,732,329	220,179	1,401,277	2,075,952	147,462	23,618	144	346,791	245,402	533,060
LTNCP4A	**2,807,466**	0	0	1,204	0	409,500	1,762,586	90,608	0	0	0	87,373	456,195
SNCP4A	**9,390,873**	857,364	2,999,647	3,582,894	201,762	1,348,047	0	142,194	22,580	0	0	236,385	0
12NCP													
DNCP12	**74,442,142**	3,419,092	10,245,116	11,877,973	1,626,008	4,620,404	6,169,589	401,516	79,175	6,328	33,604,756	809,454	1,582,732
PNCP12	**39,314,824**	3,210,527	9,620,164	11,153,416	1,526,821	4,338,560	5,793,244	377,024	74,345	594	973,866	760,077	1,486,185
LTNCP12	**37,507,206**	3,210,527	9,620,164	11,153,416	1,526,821	4,338,560	5,123,821	377,024	74,345	221	0	760,077	1,322,230
SNCP12	**30,035,493**	3,104,535	9,302,566	10,785,199	1,476,415	4,195,327	0	364,577	71,890	0	0	734,984	0
PLCC - 12NCP													
DNCP12A	**66,695,243**	2,361,176	7,787,782	9,495,658	613,012	3,987,157	6,123,796	365,215	55,638	5,782	33,600,362	726,259	1,573,406
PNCP12A	**31,572,146**	2,152,612	7,162,830	8,771,102	513,825	3,705,312	5,747,451	340,722	50,808	385	973,357	676,883	1,476,859
LTNCP12A	**7,225,558**	0	0	0	0	729,979	4,862,866	170,160	0	0	0	202,795	1,259,758
SNCP12A	**22,348,653**	2,046,620	6,845,232	8,402,885	463,419	3,562,079	0	328,275	48,354	0	0	651,790	0

Hydro One Distribution: 12 Rate Classes

This sheet shows what accounts are included in the COSS, and how they are grouped into working capital and rate base. It shows how accounts are categorized in the customer and demand related costs. It will then show how the categorized costs are allocated to customer and demand related components. It will also show how Miscellaneous Revenue and General Plant and Administration costs are allocated. FInally, it will show how costs are being grouped together for presentation purposes.

System of Accounts -					Classification and Allocation			Demand Related	Customer Related	Allocation A&G Related	Allocation Misc Related					
USoA Account #	Accounts	Explanations	Grouping for Sheet O1 Revenue to Cost	Demand Grouping Indicator	Demand	Customer	Joint	Demand ID	Customer ID	A & G ID	Misc ID		cp	ncp	non-demand	FINAL
1565	Conservation and Demand Management Expenditures and Recoveries	CDM Expenditures and Recoveries	dp			O&M			O&M							
1608	Franchises and Consents	Other Distribution Assets	gp							NFA ECC						
1805	Land		dp	DDCP												
1805-1	Land Station >50 kV		dp	TCP	TCP12			TCP12					TCP12			TCP12
1805-2	Land Station <50 kV		dp	BCP	BCP12AA			BCP12AA				DCP	BCP12			BCP12
1806	Land Rights		dp	DDCP												
1806-1	Land Rights Station >50 kV		dp	TCP	TCP12			TCP12					TCP12			TCP12
1806-2	Land Rights Station <50 kV		dp	BCP	BCP12AA			BCP12AA				DCP	BCP12			BCP12
1808	Buildings and Fixtures		dp	DDCP												
1808-1	Buildings and Fixtures > 50 kV		dp	TCP	TCP12			TCP12					TCP12			TCP12
1808-2	Buildings and Fixtures < 50 kV		dp	BCP	BCP12AA			BCP12AA				DCP	BCP12			BCP12
1810	Leasehold Improvements		dp	DDCP												
1810-1	Leasehold Improvements >50 kV		dp	TCP	TCP12			TCP12					TCP12			TCP12
1810-2	Leasehold Improvements <50 kV		dp	BCP	BCP12AA			BCP12AA				DCP	BCP12			BCP12
1815	Transformer Station Equipment - Normally Primary above 50 kV		dp	TCP	TCP12			TCP12					TCP12			TCP12
1815-1	HVDS - Rural		dp	BCP	BCP12B			BCP12B					BCP12			BCP12
1815-2	HVDS - lo LV Specific		dp	TCP	1815-2D			1815-2D					TCP12			TCP12
1815-3	HVDS - hi LV Specific		dp	TCP	1815-3D			1815-3D					TCP12			TCP12
1815-4	HVDS - lo LV Shared		dp	TCP	1815-4D			1815-4D					TCP12			TCP12
1815-5	HVDS - hi LV Shared		dp	TCP	1815-5D			1815-5D					TCP12			TCP12
1820	Distribution Station Equipment - Normally Primary below 50 kV		dp	DCP	DCP12			DCP12					DCP12			DCP12
1820-1	Distribution Station Equipment - Normally Primary below 50 kV (Bulk)		dp	BCP	BCP12			BCP12					BCP12			BCP12

System of Accounts -					Classification and Allocation			Demand Related	Customer Related	Allocation A&G Related	Allocation Misc Related				
USoA Account #	Accounts	Explanations	Grouping for Sheet O1 Revenue to Cost	Demand Grouping Indicator	Demand	Customer	Joint	Demand ID	Customer ID	A & G ID	Misc ID	cp	ncp	non-demand	FINAL
1820-2	Distribution Station Equipment - Normally Primary below 50 kV (Primary)		dp	PNCP	PNCP4AA			PNCP4AA					PNCP4		PNCP4
1820-3	Distribution Station Equipment - Normally Primary below 50 kV (Wholesale Meters)		dp			cen2			cen2						
1825	Storage Battery Equipment		dp	DDCP											
1825-1	Storage Battery Equipment > 50 kV		dp	TCP	TCP12			TCP12				TCP12			TCP12
1825-2	Storage Battery Equipment <50 kV		dp	DCP	DCP12			DCP12				DCP12			DCP12
1830	Poles, Towers and Fixtures		dp	DDNCP											
1830-3	Poles, Towers and Fixtures - Subtransmission Bulk Delivery		dp	BCP	BCP12			BCP12				BCP12			BCP12
1830-3A	Bulk-LV Fixtures		dp	BCP	1830-3A			1830-3A				BCP12			BCP12
1830-3B	Bulk-Retail Fixtures		dp	BCP	BCP12-DlinesB			BCP12-Dlines				BCP12			BCP12
1830-4	Poles, Towers and Fixtures - Primary		dp	PNCP	PNCP4	CCP	x	PNCP4	CCP				PNCP4		PNCP4
1830-4A	Primary-LV Fixtures		dp	PNCP	1830-4AD	1830-4AC	x	1830-4AD	1830-4AC				PNCP4		PNCP4
1830-4B	Primary-Retail Fixtures		dp	PNCP	PNCP4-DlinesB	CCP-DlinesC	x	PNCP4-Dlines	CCP-DlinesC				PNCP4		PNCP4
1830-5	Poles, Towers and Fixtures - Secondary		dp	SNCP	SNCP4	CCS	x	SNCP4	CCS				SNCP4		SNCP4
1835	Overhead Conductors and Devices		dp	DDNCP											
1835-3	Overhead Conductors and Devices - Subtransmission Bulk Delivery		dp	BCP	BCP12			BCP12				BCP12			BCP12
1835-3A	Bulk-LV Conductors		dp	BCP	1835-3A			1835-3A				BCP12			BCP12
1835-3B	Bulk-Retail Conductors		dp	BCP	BCP12-DLinesB			BCP12-DLines				BCP12			BCP12
1835-4	Overhead Conductors and Devices - Primary		dp	PNCP	PNCP4	CCP	x	PNCP4	CCP				PNCP4		PNCP4
1835-4A	Primary-LV Conductors		dp	PNCP	1835-4AD	1835-4AC	x	1835-4AD	1835-4AC						
1835-4B	Primary-Retail Conductors		dp	PNCP	PNCP4-DlinesB	CCP-DlinesC	x	PNCP4-Dlines	CCP-DlinesC				PNCP4		PNCP4
1835-5	Overhead Conductors and Devices - Secondary		dp	SNCP	SNCP4	CCS	x	SNCP4	CCS				SNCP4		SNCP4
1840	Underground Conduit		dp	DDNCP											
1840-3	Underground Conduit - Bulk Delivery	Land and Buildings	dp	BCP	BCP12			BCP12				BCP12			BCP12

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USoA Account #	Accounts	Explanations	Grouping for Sheet O1 Revenue to Cost	Demand Grouping Indicator	Demand	Customer	Joint	Demand ID	Customer ID	A & G ID	Misc ID	cp	ncp	non-demand	FINAL
1840-4	Underground Conduit - Primary	Land and Buildings	dp	PNCP	PNCP4C	CCP-C	x	PNCP4C	CCP-C				PNCP4		PNCP4
1840-5	Underground Conduit - Secondary	Land and Buildings	dp	SNCP	SNCP4C	CCS-C	x	SNCP4C	CCS-C				SNCP4		SNCP4
1845	Underground Conductors and Devices	Land and Buildings	dp	DDNCP											
1845-3	Underground Conductors and Devices - Bulk Delivery	TS Primary Above 50	dp	BCP	BCP12			BCP12				BCP12			BCP12
1845-4	Underground Conductors and Devices - Primary	DS	dp	PNCP	PNCP4C	CCP-C	x	PNCP4C	CCP-C				PNCP4		PNCP4
1845-5	Underground Conductors and Devices - Secondary	Other Distribution Assets	dp	SNCP	SNCP4C	CCS-C	x	SNCP4C	CCS-C				SNCP4		SNCP4
1850	Line Transformers	Poles, Wires	dp	LTNCP	LTNCP4	CCLT	x	LTNCP4	CCLT				LTNCP4		LTNCP4
1850-1	TRF-LV	Poles, Wires	dp				x	1850-1D	1850-1C						
1850-2	TRF-Rural	Poles, Wires	dp	LTNCP	LTNCP4-RtransfB	CCLT-Rtransf	x	LTNCP4-Rtran	CCLT-Rtransf				LTNCP4		LTNCP4
1855	Services	Services and Meters	dp			CWCS			CWCS						
1860	Meters	Services and Meters	dp			CWMC			CWMC						
1860-1	Mtr-Single	Services and Meters	dp			CWMC1			CWMC1						
1860-2	Mtr-Poly	Services and Meters	dp			CWMC2			CWMC2						
1860-3	Mtr-LV	Services and Meters	dp			CWMC3			CWMC3						
1860-4	Mtr-Smart	Services and Meters	dp			CWMC4			CWMC4						
1875	St Lgts	Lgts	dp	SNCP	StLgt			StLgt							
1905	Land	Land and Buildings	gp							NFA ECC					
1906	Land Rights	Land and Buildings	gp							NFA ECC					
1908	Buildings and Fixtures	General Plant	gp							NFA ECC					
1910	Leasehold Improvements	General Plant	gp							NFA ECC					
1915	Office Furniture and Equipment	Equipment	gp							NFA ECC					
1920	Computer Equipment - Hardware	IT Assets	gp							NFA ECC					
1925	Computer Software	IT Assets	gp							NFA ECC					
1930	Transportation Equipment	Equipment	gp							NFA ECC					
1935	Stores Equipment	Equipment	gp							NFA ECC					
1940	Tools, Shop and Garage Equipment	Equipment	gp							NFA ECC					
1945	Measurement and Testing Equipment	Equipment	gp							NFA ECC					
1950	Power Operated Equipment	Equipment	gp							NFA ECC					
1955	Communication Equipment	Equipment	gp							NFA ECC					
1960	Miscellaneous Equipment	Equipment	gp							NFA ECC					

System of Accounts -					Classification and Allocation			Demand Related	Customer Related	Allocation A&G Related	Allocation Misc Related				
USoA Account #	Accounts	Explanations	Grouping for Sheet O1 Revenue to Cost	Demand Grouping Indicator	Demand	Customer	Joint	Demand ID	Customer ID	A & G ID	Misc ID	cp	ncp	non-demand	FINAL
1970	Load Management Controls - Customer Premises	Other Distribution Assets	gp							NFA ECC					
1975	Load Management Controls - Utility Premises	Other Distribution Assets	gp							NFA ECC					
1980	System Supervisory Equipment	Other Distribution Assets	gp							NFA ECC					
1985	Sentinel Lgts	Lgts	gp	TCP	SenLgt			SenLgt		SenLgt					
1990	Other Tangible Property	Other Distribution Assets	gp							NFA ECC					
1995	Contributions and Grants - Credit	Contributions and Grants	co		Break out	Breakout		Break out	Breakout						
2005	Property Under Capital Leases	Other Distribution Assets	gp							NFA ECC					
2010	Electric Plant Purchased or Sold	Other Distribution Assets	gp							NFA ECC					
2105	Accum. Amortization of Electric Utility Plant - Property, Plant, & Equipment	Accumulated Amortization	accum dep		Break out	Breakout		Break out	Breakout						
2120	Accumulated Amortization of Electric Utility Plant - Intangibles	Accumulated Amortization	accum dep		Break out	Breakout		Break out	Breakout						
3046	Balance Transferred From Income	Equity	NI								NFA				
4080	Distribution Services Revenue	Distribution Services Revenue	CREV								CREV				
4082	Retail Services Revenues	Other Distribution Revenue	mi								CWNB				
4084	Service Transaction Requests (STR) Revenues	Other Distribution Revenue	mi								CWNB				
4090	Electric Services Incidental to Energy Sales	Other Distribution Revenue	mi								CWNB				
4205	Interdepartmental Rents	Other Distribution Revenue	mi								NFA				
4210	Rent from Electric Property	Other Distribution Revenue	mi								NFA				
4215	Other Utility Operating Income	Other Distribution Revenue	mi								NFA				
4220	Other Electric Revenues	Other Distribution Revenue	mi								NFA				
4225	Late Payment Charges	Late Payment Charges	mi								LPHA				
4235	Miscellaneous Service Revenues	Specific Service Charges	mi								CWNB				
4240	Provision for Rate Refunds	Other Distribution Revenue	mi								NFA				
4245	Government Assistance Directly Credited to Income	Other Distribution Revenue	mi								NFA				

System of Accounts - USoA Account #	Accounts	Explanations	Grouping for Sheet O1 Revenue to Cost	Demand Grouping Indicator	Classification and Allocation Demand	Customer	Joint	Demand Related Demand ID	Customer Related Customer ID	Allocation A&G Related A & G ID	Allocation Misc Related Misc ID
4305	Regulatory Debits	Other Income & Deductions	mi								NFA
4310	Regulatory Credits	Other Income & Deductions	mi								NFA
4315	Revenues from Electric Plant Leased to Others	Other Income & Deductions	mi								NFA
4320	Expenses of Electric Plant Leased to Others	Other Income & Deductions	mi								NFA
4325	Revenues from Merchandise, Jobbing, Etc.	Other Income & Deductions	mi								NFA
4330	Costs and Expenses of Merchandising, Jobbing, Etc.	Other Income & Deductions	mi								NFA
4335	Profits and Losses from Financial Instrument Hedges	Other Income & Deductions	mi								NFA
4340	Profits and Losses from Financial Instrument Investments	Other Income & Deductions	mi								NFA
4345	Gains from Disposition of Future Use Utility Plant	Other Income & Deductions	mi								NFA
4350	Losses from Disposition of Future Use Utility Plant	Other Income & Deductions	mi								NFA
4355	Gain on Disposition of Utility and Other Property	Other Income & Deductions	mi								NFA
4360	Loss on Disposition of Utility and Other Property	Other Income & Deductions	mi								NFA
4365	Gains from Disposition of Allowances for Emission	Other Income & Deductions	mi								NFA
4370	Losses from Disposition of Allowances for Emission	Other Income & Deductions	mi								NFA
4390	Miscellaneous Non-Operating Income	Other Income & Deductions	mi								NFA
4395	Rate-Payer Benefit Including Interest	Other Income & Deductions	mi								NFA
4398	Foreign Exchange Gains and Losses, Including Amortization	Other Income & Deductions	mi								NFA
4405	Interest and Dividend Income	Other Income & Deductions	mi								NFA

cp	ncp	non-demand	FINAL

System of Accounts -					Classification and Allocation			Demand Related	Customer Related	Allocation A&G Related	Allocation Misc Related				
USoA Account #	Accounts	Explanations	Grouping for Sheet O1 Revenue to Cost	Demand Grouping Indicator	Demand	Customer	Joint	Demand ID	Customer ID	A & G ID	Misc ID	cp	ncp	non-demand	FINAL
4415	Equity in Earnings of Subsidiary Companies	Other Income & Deductions	mi								NFA				
4705	Power Purchased	Power Supply Expenses (Working Capital)	cop							CEN EWMP					
4708	Charges-WMS	Power Supply Expenses (Working Capital)	cop							CEN EWMP					
4710	Cost of Power Adjustments	Power Supply Expenses (Working Capital)	cop							CEN EWMP					
4712	Charges-One-Time	Power Supply Expenses (Working Capital)	cop							CEN EWMP					
4714	Charges-NW	Power Supply Expenses (Working Capital)	cop							CEN					
4715	System Control and Load Dispatching	Other Power Supply Expenses	cop							CEN EWMP					
4716	Charges-CN	Power Supply Expenses (Working Capital)	cop							CEN					
4730	Rural Rate Assistance Expense	Power Supply Expenses (Working Capital)	cop							CEN EWMP					
5005	Operation Supervision and Engineering	Operation (Working Capital)	di	1815-1855 D	1815-1855 D	1815-1855 C	x	1815-1855 D	1815-1855 C					1815-1855 D	1815-1855 D
5010	Load Dispatching	Operation (Working Capital)	di	1815-1855 D	1815-1855 D	1815-1855 C	x	1815-1855 D	1815-1855 C					1815-1855 D	1815-1855 D
5012	Station Buildings and Fixtures Expense	Operation (Working Capital)	di	1808 D	1808 D	1808 C		1808 D	1808 C					1808 D	1808 D
5014	Transformer Station Equipment - Operation Labour	Operation (Working Capital)	di	1815 D	1815 D	1815 C		1815 D	1815 C					1815 D	1815 D
5015	Transformer Station Equipment - Operation Supplies and Expenses	Operation (Working Capital)	di	1815 D	1815 D	1815 C		1815 D	1815 C					1815 D	1815 D
5016	Distribution Station Equipment - Operation Labour	Operation (Working Capital)	di	1820 D	1820 D	1820 C		1820 D	1820 C					1820 D	1820 D
5017	Distribution Station Equipment - Operation Supplies and Expenses	Operation (Working Capital)	di	1820 D	1820 D	1820 C		1820 D	1820 C					1820 D	1820 D
5020	Overhead Distribution Lines and Feeders - Operation Labour	Operation (Working Capital)	di	1830 & 1835 D	1830 & 1835 D	1830 & 1835 C	x	1830 & 1835 D	1830 & 1835 C					1830 & 1835 D	1830 & 1835 D

System of Accounts -					Classification and Allocation			Demand Related	Customer Related	Allocation A&G Related	Allocation Misc Related				
USoA Account #	Accounts	Explanations	Grouping for Sheet O1 Revenue to Cost	Demand Grouping Indicator	Demand	Customer	Joint	Demand ID	Customer ID	A & G ID	Misc ID	cp	ncp	non-demand	FINAL
5025	Overhead Distribution Lines & Feeders - Operation Supplies and Expenses	Operation (Working Capital)	di	1830 & 1835 D	1830 & 1835 D	1830 & 1835 C	x	1830 & 1835 D	1830 & 1835 C					1830 & 1835 D	1830 & 1835 D
5030	Overhead Subtransmission Feeders - Operation	Operation (Working Capital)	di	1830 & 1835 D	1830 & 1835 D	1830 & 1835 C		1830 & 1835 D	1830 & 1835 C					1830 & 1835 D	1830 & 1835 D
5035	Overhead Distribution Transformers- Operation	Operation (Working Capital)	di	1850 D	1850 D	1850 C	x	1850 D	1850 C					1850 D	1850 D
5040	Underground Distribution Lines and Feeders - Operation Labour	Operation (Working Capital)	di	1840 & 1845 D	1840 & 1845 D	1840 & 1845 C	x	1840 & 1845 D	1840 & 1845 C					1840 & 1845 D	1840 & 1845 D
5045	Underground Distribution Lines & Feeders - Operation Supplies & Expenses	Operation (Working Capital)	di	1840 & 1845 D	1840 & 1845 D	1840 & 1845 C	x	1840 & 1845 D	1840 & 1845 C					1840 & 1845 D	1840 & 1845 D
5050	Underground Subtransmission Feeders - Operation	Operation (Working Capital)	di	1840 & 1845 D	1840 & 1845 D	1840 & 1845 C		1840 & 1845 D	1840 & 1845 C					1840 & 1845 D	1840 & 1845 D
5055	Underground Distribution Transformers - Operation	Operation (Working Capital)	di	1850 D	1850 D	1850 C	x	1850 D	1850 C					1850 D	1850 D
5065	Meter Expense	Operation (Working Capital)	cu			CWMC			CWMC						
5070	Customer Premises - Operation Labour	Operation (Working Capital)	cu			CCA			CCA						
5075	Customer Premises - Materials and Expenses	Operation (Working Capital)	cu			CCA			CCA						
5085	Miscellaneous Distribution Expense	Operation (Working Capital)	di	1815-1855 D	1815-1855 D	1815-1855 C	x	1815-1855 D	1815-1855 C					1815-1855 D	1815-1855 D
5090	Underground Distribution Lines and Feeders - Rental Paid	Operation (Working Capital)	di	1840 & 1845 D	1840 & 1845 D	1840 & 1845 C	x	1840 & 1845 D	1840 & 1845 C					1840 & 1845 D	1840 & 1845 D
5095	Overhead Distribution Lines and Feeders - Rental Paid	Operation (Working Capital)	di	1830 & 1835 D	1830 & 1835 D	1830 & 1835 C	x	1830 & 1835 D	1830 & 1835 C					1830 & 1835 D	1830 & 1835 D
5096	Other Rent	Operation (Working Capital)	di							O&M					
5105	Maintenance Supervision and Engineering	Maintenance (Working Capital)	di	1815-1855 D	1815-1855 D	1815-1855 C	x	1815-1855 D	1815-1855 C					1815-1855 D	1815-1855 D

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USoA Account #	Accounts	Explanations	Grouping for Sheet O1 Revenue to Cost	Demand Grouping Indicator	Demand	Customer	Joint	Demand ID	Customer ID	A & G ID	Misc ID	cp	ncp	non-demand	FINAL
5110	Maintenance of Buildings and Fixtures - Distribution Stations	Maintenance (Working Capital)	di	1808 D	1808 D	1808 C		1808 D	1808 C					1808 D	1808 D
5112	Maintenance of Transformer Station Equipment	Maintenance (Working Capital)	di	1815 D	1815 D	1815 C		1815 D	1815 C					1815 D	1815 D
5114	Maintenance of Distribution Station Equipment	Maintenance (Working Capital)	di	1820 D	1820 D	1820 C		1820 D	1820 C					1820 D	1820 D
5120	Maintenance of Poles, Towers and Fixtures	Maintenance (Working Capital)	di	1830 D	1830 D	1830 C	x	1830 D	1830 C					1830 D	1830 D
5125	Maintenance of Overhead Conductors and Devices	Maintenance (Working Capital)	di	1835 D	1835 D	1835 C	x	1835 D	1835 C					1835 D	1835 D
5130	Maintenance of Overhead Services	Maintenance (Working Capital)	di	1855 D	1855 D	1855 C		1855 D	1855 C					1855 D	1855 D
5135	Overhead Distribution Lines and Feeders - Right of Way	Maintenance (Working Capital)	di	1830 & 1835 D	1830 & 1835 D	1830 & 1835 C	x	1830 & 1835 D	1830 & 1835 C					1830 & 1835 D	1830 & 1835 D
5145	Maintenance of Underground Conduit	Maintenance (Working Capital)	di	1840 D	1840 D	1840 C	x	1840 D	1840 C					1840 D	1840 D
5150	Maintenance of Underground Conductors and Devices	Maintenance (Working Capital)	di	1845 D	1845 D	1845 C	x	1845 D	1845 C					1845 D	1845 D
5155	Maintenance of Underground Services	Maintenance (Working Capital)	di	1855 D	1855 D	1855 C		1855 D	1855 C					1855 D	1855 D
5160	Maintenance of Line Transformers	Maintenance (Working Capital)	di	1850 D	1850 D	1850 C	x	1850 D	1850 C					1850 D	1850 D
5175	Maintenance of Meters	Maintenance (Working Capital)	cu	1860 D	1860 D	1860 C		1860 D	1860 C					1860 D	1860 D
5305	Supervision	Billing and Collection (Working Capital)	cu			CWNB			CWNB						
5310	Meter Reading Expense	Billing and Collection (Working Capital)	cu			CWMR			CWMR						
5315	Customer Billing	Billing and Collection (Working Capital)	cu			CWNB			CWNB						
5320	Collecting	Billing and Collection (Working Capital)	cu			CWNB			CWNB						
5325	Collecting- Cash Over and Short	Billing and Collection (Working Capital)	cu			CWNB			CWNB						
5330	Collection Charges	Billing and Collection (Working Capital)	cu			CWNB			CWNB						
5335	Bad Debt Expense	Bad Debt Expense (Working Capital)	cu			BDHA			BDHA						
5340	Miscellaneous Customer Accounts Expenses	Billing and Collection (Working Capital)	cu			CWNB			CWNB						
5405	Supervision	Community Relations (Working Capital)	ad							O&M					

System of Accounts - USoA Account #	Accounts	Explanations	Grouping for Sheet O1 Revenue to Cost	Demand Grouping Indicator	Classification and Allocation: Demand	Customer	Joint	Demand Related: Demand ID	Customer Related: Customer ID	Allocation A&G Related: A & G ID	Allocation Misc Related: Misc ID
5410	Community Relations - Sundry	Community Relations (Working Capital)	ad							O&M	
5415	Energy Conservation	Community Relations - CDM (Working Capital)	ad							O&M	
5420	Community Safety Program	Community Relations (Working Capital)	ad							NFA ECC	
5425	Miscellaneous Customer Service and Informational Expenses	Community Relations (Working Capital)	ad							O&M	
5505	Supervision	Other Distribution Expenses	ad							O&M	
5510	Demonstrating and Selling Expense	Other Distribution Expenses	ad							O&M	
5515	Advertising Expense	Advertising Expenses	ad							O&M	
5520	Miscellaneous Sales Expense	Other Distribution Expenses	ad							O&M	
5605	Executive Salaries and Expenses	Administrative and General Expenses (Working Capital)	ad							O&M	
5610	Management Salaries and Expenses	Administrative and General Expenses (Working Capital)	ad							O&M	
5615	General Administrative Salaries and Expenses	Administrative and General Expenses (Working Capital)	ad							O&M	
5620	Office Supplies and Expenses	Administrative and General Expenses (Working Capital)	ad							O&M	
5625	Administrative Expense Transferred Credit	Administrative and General Expenses (Working Capital)	ad							O&M	
5630	Outside Services Employed	Administrative and General Expenses (Working Capital)	ad							O&M	
5635	Property Insurance	Insurance Expense (Working Capital)	ad							NFA ECC	
5640	Injuries and Damages	Administrative and General Expenses (Working Capital)	ad							O&M	
5645	Employee Pensions and Benefits	Administrative and General Expenses (Working Capital)	ad							O&M	
5650	Franchise Requirements	Administrative and General Expenses (Working Capital)	ad							O&M	
5655	Regulatory Expenses	Administrative and General Expenses (Working Capital)	ad							O&M	
5660	General Advertising Expenses	Advertising Expenses	ad							O&M	

cp	ncp	non-demand	FINAL

System of Accounts -					Classification and Allocation			Demand Related	Customer Related	Allocation A&G Related	Allocation Misc Related				
USoA Account #	Accounts	Explanations	Grouping for Sheet O1 Revenue to Cost	Demand Grouping Indicator	Demand	Customer	Joint	Demand ID	Customer ID	A & G ID	Misc ID	cp	ncp	non-demand	FINAL
5665	Miscellaneous General Expenses	Administrative and General Expenses (Working Capital)	ad							O&M					
5670	Rent	Administrative and General Expenses (Working Capital)	ad							O&M					
5675	Maintenance of General Plant	Administrative and General Expenses (Working Capital)	ad							O&M					
5680	Electrical Safety Authority Fees	Administrative and General Expenses (Working Capital)	ad							O&M					
5685	Independent Market Operator Fees and Penalties	Power Supply Expenses (Working Capital)	cop							NFA ECC					
5705	Amortization Expense - Property, Plant, and Equipment	Amortization of Assets	dep	PRORATED	Break out	Breakout			Breakout					PRORATED	PRORATED
5710	Amortization of Limited Term Electric Plant	Amortization of Assets	dep	PRORATED	Break out	Breakout			Breakout					PRORATED	PRORATED
5715	Amortization of Intangibles and Other Electric Plant	Amortization of Assets	dep	PRORATED	Break out	Breakout			Breakout					PRORATED	PRORATED
5720	Amortization of Electric Plant Acquisition Adjustments	Other Amortization - Unclassified	dep	PRORATED	Break out	Breakout			Breakout					PRORATED	PRORATED
5730	Amortization of Unrecovered Plant and Regulatory Study Costs	Amortization of Assets	dep							O&M					
5735	Amortization of Deferred Development Costs	Amortization of Assets	dep							O&M					
5740	Amortization of Deferred Charges	Amortization of Assets	dep							O&M					
6005	Interest on Long Term Debt	Interest Expense - Unclassified	INT							NFA					
6105	Taxes Other Than Income Taxes	Other Distribution Expenses	ad							NFA					
6110	Income Taxes	Income Tax Expense - Unclassified	Input							NFA					
6205	Donations	Charitable Contributions	ad							O&M					
6210	Life Insurance	Insurance Expense (Working Capital)	ad							O&M					
6215	Penalties	Other Distribution Expenses	ad							O&M					
6225	Other Deductions	Other Distribution Expenses	ad							O&M					

Report to

Hydro One Networks Inc.

Regarding

Distribution Business Minimum System Study

August 20, 2007

TABLE OF CONTENTS

I. Summary

A. Background and Purpose

R. J. Rudden Associates, a unit of the Enterprise Management Solutions Division of Black & Veatch Corporation ("B&V" or "we") is pleased to submit this Report on Hydro One Networks Inc. Distribution Business Minimum System Study ("Study") to Hydro One Networks Inc. ("Hydro One").

BV was engaged by Hydro One to perform this Study for the purpose of computing the minimum system components for the conductors (sometimes called feeders) and line transformers used in Hydro One's distribution system. The Study included reviewing Line Transformers (account 1850) and Distribution Feeders, which includes poles and conductors (accounts 1830 -1845), and included computation of the Peak Load Carrying Capability of the minimum system.

Hydro One intends to use the results of the Study in its class cost allocation study. The Minimum System approach was recommended by the OEB in its Cost Allocation Review report issued September 29, 2006.

In this Report we present and support our methodology for performing the Study and present the results.

B. Hydro One Distribution System

Hydro One Networks is an integrated transmission and distribution utility, regulated by the OEB. The distribution business spans roughly 75% of the area of Ontario and serves 71 Local Distribution Companies, over one million customers and 43 directly connected large users. There are over $3 billion in fixed assets consisting of over 119,600 circuit kilometers of distribution lines, operating at voltages below 50 kV, and over 1,000 distributing and regulating substations. Most of the distribution system serves areas with low customer densities. The system is mainly radial in design, with very little redundancy in supply to customers, which is consistent with other rural systems.

C. Minimum System Study

The purpose of a Minimum System Study is to determine the smallest components (i.e., transformers, overhead conductors, underground conductors, services) that is generally installed by the utility. The cost of each minimum system component is compared to the actual average cost for each component, to determine the minimum system ratio, or the portion of total costs represented by the minimum system.

The results of the Minimum System Study are used to classify Hydro One's transformers, conductors, conduits and services plant, as either demand-related or customer-related. The minimum system study identifies the hypothetical minimum system that the utility could install and uses the ratio of the hypothetical minimum system to the cost of the existing system as the basis for the customer –related classification of costs. The hypothetical minimum system created by the study has some peak load-carrying capacity ("PLCC"), and our Study also determined the PLCC for each component.

D. Results

Table 1 below summarizes the results of the Study.

TABLE 1. SUMMARY OF RESULTS

Component	Minimum Component	Minimum System Ratio	PLCC Watts Per Customer
Line transformers	10 kVA 1-phase	61.90%	3,099 W
Conductors	#2 ASCR two-wire system (one conductor, one neutral)	54.78%	544 W
Poles, Towers and Fixtures		47.80%	

The Company's prior Minimum System Study, completed in 1985 ("1985 Study"), showed a 62% minimum system ratio for transformers, based on a 3 kVA minimum component. The 1985 Study also showed a 61% minimum system ratio for Conductors, based on a minimum components of #6 Cu for the primary portion of distribution system, 1 X #4 Al plus 2 X #6 Al for the secondary portion and 2X #6 Al for services.

The Minimum System Ratios that resulted from our Study, as presented in Table 1, are reasonable based on our experience and knowledge of minimum system studies for electric distributors, and are reasonably consistent with the results of the 1985 Study.

The 1985 Study showed a transformer minimum system PLCC of 300 Watts per customer. Some of the difference is due to the higher minimum component specified for the present Study (10kVA) and the 1985 Study (3 kVA). The 1985 Study also showed a conductor minimum system PLCC of 180 Watts per customer.

E. About BV; Scope of Assignment

The Enterprise Management Solutions Division of Black & Veatch Corporation provides strategic, economic and management consulting firm specializing in energy matters. We provide assistance in areas such as economic analysis, strategy development, operational assessment, industry restructuring support, litigation and regulatory support and technical analysis. BV has assisted many electric, gas, water and telecommunications clients in hundreds of proceedings, including recent work in the area of shared services cost allocations.

Consistent with standard practice for consulting assignments, we relied on the genuineness and completeness of all documents presented to us by Hydro One and we accepted factual statements made to us by Hydro One, subject only to overall reasonableness and actual contrary knowledge, but without independent confirmation.

All amounts in this Report are in Canadian dollars.

II. MINIMUM SYSTEM STUDY APPROACH

A. Purpose and Uses

The purpose of a Minimum System Study is to determine the smallest components that is generally installed by the utility. Two separate analyses are performed; one for transformers, another for overhead conductors and underground conductors and services.

The cost of the minimum system for each component is compared to the actual cost of the existing system for each component. The ratio of the minimum system costs to the existing system cost is the minimum system ratio for each component.

The results of the Minimum System Study are used to classify Hydro One's transformers, conductors, conduits and services plant, as either demand-related or customer-related. The classification affects how the utility's costs (or revenue requirement) are allocated among the customer classes. The minimum system for each component includes some peak load-carrying capacity ("PLCC"), and our Study determined the PLCC for each component. The PLCC is used to adjust the allocators used for the demand-related component of costs.

The following definitions may be helpful:

Minimum Component- The least-cost/smallest size component that is generally installed by the utility. For example, the minimum component for line transformers was determined to be a 10 kVA transformer.

Minimum System- The system that would be installed if all existing components were replaced with the Minimum Component. For example, the minimum system for line transformers would be a system comprising all 10 kVA transformers instead of the existing mix of transformers capacities.

Minimum System Ratio- The ratio of the X) the cost of the Minimum System to Y) the cost of the existing system.

Peak load-carrying capability- The load carrying capability of each component at the time of the system peak.

In this Study we performed two analyses- One for line transformers, and one for all Conductors including overhead, underground and services.

B. Approach

Our approach for preparing a Minimum System Study is presented below. This approach is applied to each distribution system component in the study. For each component:

1. Obtain a listing of all types of the component installed on the system. 'Types' includes differentiation as to capacities, materials, sizes and other pertinent qualities. For example each transformer type is identified as to capacity (kVA), design (line or pad mount) and number of phases.

2. Compute the current replacement cost for the existing system, either by indexing historical costs or by using current replacement costs for each component type.

3. Determine the Minimum Component; i.e., the least-cost component that is generally installed by the utility, as well as the current cost of the Minimum Component.

4. Compute the current cost for the Minimum System; i.e., the system that would be installed if all existing components were replaced with the Minimum Component.

5. Compute the Minimum System Ratio; i.e., ratio of the X) current cost of Minimum System to Y) current replacement cost of existing system.

6. Compute the PLCC based on the capacity of the minimum system and the number of customers supplied

C. Components in Minimum System Study

In this Study we performed separate analyses for line transformers and for Conductors. Line Transformers included assets in Hydro One's account 1850. Conductors, or Distribution Feeders included overhead conductors (account 1835), underground conduits (account 1840) and underground conductors and devices (account 1845).

Poles, towers and fixtures (account 1830) are classified proportionately to Overhead conductors because these assets support the overhead conductors.

The amounts in the accounts included the costs of material and installation and a charge for corporate overheads.

III. LINE TRANSFORMERS

A. Types of Transformers

Table 2 below summarizes Hydro One's distribution line transformers.

TABLE 2- NUMBERS OF TRANSFORMERS					
Capacity kVA	**Overhead Transformers**		**Pad Mount Transformers**		
	1-Phase Supply	**3-Phase Supply from 1-Phase (a)**	**1-Phase Supply**	**3-Phase Supply**	**3-Phase Supply from 1-Phase (a)**
3	4,735	104	64		1
5	26,332	165	461		3
10	**73,134**	**1,300**	920		4
15	21,939	364	348		
25	**198,244**	**5,862**	**6,981**		**206**
37	7,697	370	92		22
50	**53,049**	**3,601**	**6,847**		**368**
70			20		
75	**14,421**	**1,037**	**3,520**		**109**
100	**7,728**	**1,839**	**5,603**		**525**
112	28				
150	178	38	32		3
167	**634**	**482**	**116**		
225			32		
250			41		
300			96		
500/501			52	**190**	
750			7	**174**	
900				14	
999/1000			8	**251**	
1500			2	934	
1998				31	
2250-5000			11	58	
7500-15000				13	
Total	**408,119**	**15,162**	**25,253**	**1,665**	**1,241**
Total All	**451,440**				
(a) Number of 1-phase units that would replace existing units.					

B. Current Replacement Cost for Existing System

To determine the current replacement cost for Hydro One's existing transformers, we first obtained from Hydro One the current replacement costs for the transformer types for which the costs were available. These transformer types are shown in **bold** in Table 2.

The unit transformer costs provided by Hydro One are shown in Table 3, which also shows the percentage of units and dollars represented by the costs provided by Hydro One. For the other transformer types listed in Table 2, we determined the replacement costs by extrapolation or interpolation.

A range costs were provided for each transformer type. For example, for 10 kVA 1-phase overhead transformers, Hydro One provided costs for units with high side voltages from 2.4 kV to 7.2/16 kV. Costs ranged from $1,828 to $2,354 per unit. In this Study we used the average of all costs to represent 10 kVA 1-phase overhead transformers.

TABLE 3- UNIT TRANSFORMER COSTS					
Capacity kVA	**Overhead Transformers**		**Pad Mount Transformers**		
	1-Phase Supply	**3-Phase Supply from 1-Phase**	**1-Phase Supply**	**3-Phase Supply**	**3-Phase Supply from 1-Phase**
10	$1,982	$6,466			
25	2,414	7,236	$5,134		$15,402
50	3,056	8,961	5,624		16,872
75	3,825	11,336	6,318		18,955
100	4,002	12,297	6,378		19,133
150				$16,324	
167	5,624	18,982	8,134		
300				17,508	
500/501				20,112	
750				19,992	
999/1000				30,722	
Costs Provided by Hydro One					
% of Units	85%	93%	91%	37%	97%
% of Dollars	89%	94%	93%	33%	98%
Total % of Units	**86%**				
Total % of Dollars	**88%**				

The total current replacement cost for existing transformers was $1,333,357,659.

C. Minimum Component and Minimum System

The least-cost Transformer Minimum Component was determined to be a 10 kVA 1-phase overhead transformer, with high-side voltage of 7.2 kV.

The current replacement cost of the Minimum Component is $1,828.29, as provided by Hydro One. This cost is lower than the cost in Table 3; the cost in Table 3 represents the average of costs for 10 kVA 1-phase overhead transformers with high-side voltages from 2.4 kV to 7.2/16 kV.

The current cost for the Transformer Minimum System, the system that would be installed if all existing components were replaced with the Minimum Component, is $825,363,000, equal to 451,440 transformers times $1,828.29 per transformer.

D. Minimum System Ratio

The Minimum System Ratio is the ratio of X) current cost of Minimum System to Y) current replacement cost of existing system. The Transformer Minimum System Ratio is computed in Table 4:

TABLE 4- TRANSFORMERS MINIMUM SYSTEM RATIO

	Total ($000s)
Current replacement cost:	
Existing transformers at existing capacities	$1,333,358
Minimum System Cost	$ 825,363
Transformers Minimum System Ratio	**61.90%**

E. Peak Load Carrying Capability

The Transformers Peak Load-Carrying Capability ("PLCC") is based on all existing transformers being replaced with the minimum component, 10 kVA 1-phase transformers. The Transformers PLCC was calculated as follows:

Number of existing transformers	451,440
Capacity (kVA) of Minimum Component	10
Assumed power factor	80%
Distribution system Transformers PLCC	3,611,520
Number of customers	1,165,092
Transformers PLCC (Watts Per Customer)	**3,099**

IV. CONDUCTORS

A. Types of Conductors

Hydro One's distribution system includes conductors operating at voltages 12.5 kV and under. The primary distribution system comprises voltages 12.5 kV to 4.16 kV, and the secondary distribution system, which is primarily service drops, comprises conductors operating at voltages under 750 V. Table 5 below shows the types and lengths of conductors in Hydro One's distribution system, as provided by Hydro One.

TABLE 5- CONDUCTOR TYPES AND LENGTHS

Description	Voltages	Conductors (km)	Neutrals (km)	Total (km)
Subtransmission	44 kV-13.8 kV	75,600	8,200	83,800
Primary	12.5 kV-4.16 kV	155,100	83,800	238,900
Secondary / Services	<750 V	47,800		47,800
Total		**278,500**	**92,000**	**370,500**

The Subtransmission portion of the distribution system was determined by Hydro One to be 100% capacity-related, which is consistent with generally accepted practice. The Study included the Primary and Secondary / Services portions of the distribution system.

B. Current Replacement Cost for Existing System

To compute the current replacement cost for the existing Primary Distribution system and for Secondary / Services system, we obtained the vintaged historical costs for Overhead conductors, Underground conductors and devices and Underground conduits, from Hydro One's PeopleSoft Asset Management ("PS_AM") system.

The PS_AM system provided vintaged historical costs for each of Overhead conductors, Underground conductors and devices and Underground conduits. To compute the historical cost in 2006 dollars, we indexed each year's costs for each asset category using the appropriate Handy-Whitman index, for the North Central region, which is the region used by Hydro One for planning purposes.

The PS_AM report includes the entire distribution system. To obtain the Primary distribution portion we multiplied the total by 65%, which is Hydro One's estimate of the Primary portion of the Historical costs. To obtain the Secondary / Services portion we multiplied the total by 15%, Hydro One's estimate of that portion of Historical costs.

The results are presented in Table 6 below. The Lengths and Historical Costs for Overhead conductors, Underground conductors and devices and Underground conduits are from the PS_AM Report. The Indexed Costs were computed by applying the appropriate Handy-Whitman index. The Primary and Secondary / Services portions were computed by multiplying the totals by the 65% and 15% portions respectively.

TABLE 6- CONDUCTOR SYSTEM REPLACEMENT COSTS

Description	Length (km)	Historical Cost ($000s)	Indexed Cost (a) ($000s)
Overhead conductors	363,517	$964,228	$2,377,566
Underground conductors / devices	6,183	98,321	158,871
Underground conduits		22,895	44,735
Total	**369,700**	**$1,085,444**	**$2,581,172**
Primary portion	65%	65%	65%
Primary	**238,900**	**$705,539**	**$1,677,762**
Secondary / Services portion	15%	15%	15%
Secondary / Services	**47,800**	**$162,817**	**$387,176**
(a) Indexed to 2006 dollars.			

C. Minimum Component and Minimum System

1. Primary Distribution System

The Primary distribution system comprises conductors operating at voltages from 12.5 kV to 4.16 kV.

The Minimum Component was determined to be a #2 ASCR two-wire system (one conductor and one neutral). The length of the minimum system was determined to be the length of the existing neutrals, 83,800 km. All existing conductors were deemed to be replaced with Overhead conductors in the Minimum System, because Overhead conductors are less costly than Underground conductors and there are no regions with engineering restrictions on Overhead conductors. There may be some restrictions on Overhead conductors due to local by-laws but these were deemed to be not relevant and not material for the Study.

Hydro One provided the standard current cost for a 1km installation of the Minimum Component, including a corporate overhead charge to be comparable to the values in the PS_AM Report. The current cost for the Minimum System was calculated by scaling the

1 km standard cost for a 720 meter installation, which was the average installation length reported in 2006. The current replacement cost was thus computed to be $9,109 per km.

The current cost for the Primary Minimum System, the system that would be installed if all existing Primary components were replaced with the Minimum Component, is $763,334,000 equal to 83,800 circuit km times $9,109 per km.

2. Secondary Distribution System / Services

The Secondary distribution system / Services comprises conductors operating at voltages under 750 V. The material and length, and therefore cost, for these conductors vary based on the customers' requirements, however the service installed for each customer must be selected to meet that customer's needs without the benefit of diversity. No Minimum Component was specified for the Secondary distribution system / Services.

Based on our experience and generally accepted practice, B&V determined that the Secondary distribution system / Services Minimum System Ratio was 95%. Multiplying 95% times the current replacement cost of Secondary / Services, $387,176,000 as shown in Table 6, produces a current replacement cost for Secondary / Services Minimum System of $367,817,000.

D. Minimum System Ratio

The Minimum System Ratio is the ratio of X) current cost of Minimum System to Y) current replacement cost of existing system. The Conductors Minimum System Ratio is computed as shown in Table 7:

TABLE 7- CONDUCTORS MINIMUM SYSTEM RATIO

Description	Primary ($000s)	Secondary / Services ($000s)	Total ($000s)
Current replacement cost:			
Existing conductors	$1,677,762	$387,176	$2,064,938
Minimum System Cost	763,334	367,817	1,131,151
Conductors Minimum System Ratio			**54.78%**

E. Poles, Towers and Fixtures Minimum System Ratio

Poles, towers and fixtures (account 1830) are classified proportionately to Overhead conductors because these assets support the overhead conductors. The Minimum System Ratio for Poles, towers and fixtures was computed as shown in Table 8.

TABLE 8- POLES, TOWERS AND FIXTURES MINIMUM SYSTEM RATIO

Description	Amount ($000s except per km)
Overhead conductors, Index costs	$2,377,566
Primary portion	65%
Primary	1,545,418
Replacement circuit km	81,099
Replacement cost per circuit km	$9,109
	738,726
Poles, Towers and Fixtures Minimum System Ratio	**47.80%**

F. Peak Load Carrying Capability

The Conductors Peak Load-Carrying Capability ("PLCC") is based on is based on a rating of 184 amps per feeder of #2 ASCR wire. Hydro One's system contains 1,035 distribution substations and it is assumed that (in the Minimum System) each distribution substation would supply a single feeder.

The existing system has a combination of feeders at capacities of 12.5 kV and 4.16 kV. The Transformer Minimum Component has a high-side capacity of 7.2 kV; therefore the Minimum System would operate at 4.16 kV, because 12.5 kV would exceed the capacity of the Transformer Minimum Component.

The Conductors PLCC was calculated as follows:

Rating for each distribution feeder circuit, amps (a)	184
Line-to-Neutral Voltage, kV	4.16
Circuit capacity per distribution feeder, kVA	765
Assumed power factor	80%
Circuit capacity per distribution feeder, kW	612
Number of distribution substations (b)	1,035
Distribution system Conductors PLCC, kW	633,420
Number of customers	1,165,092
Conductors PLCC (Watts Per Customer)	**544**

(a) Continuous Current Rating Under Summer 60C/40C, Sun/No Wind Condition (Amp)

(b) Assumed equal to number of distribution feeders

HARMONIZATION OF ACQUIRED LDC CUSTOMERS

1.0 INTRODUCTION

This exhibit provides numerical details in support of the proposed harmonization plan for the 88 Acquired Utilities. Included here also are the complete set of likely customer bill impacts.

Initially, a review is provided of the existing rates for each of the Acquired Utilities as of May 1st, 2007 including Regulatory Asset Rate Riders. Then the harmonization proposal supporting data is presented.

2.0 ACQUIRED LDC RATE CLASSES AND CURRENT RATES

The current individual rates and rate riders for each of the Acquired LDCs are shown in Tables 1, 2, 3 and 4 with Table 5 being a summary.

Table 1
Acquired Utility Residential Rates and Rate Riders on May 1st, 2007

	Customers 2006	2007 Rates excluding rate riders		2007 Rate Rider # 1	2007 Rate Rider # 2
		$/customer	¢/kWh	¢/kWh	¢/kWh
Ailsa Craig	348	10.51	0.82	0.35	0.11
Arkona	217	5.84	0.26	0.68	0.33
Arnprior	3134	11.54	1.47	0.49	0.18
Arran-Elderslie	1681	9.02	0.95	0.35	0.15
Artemesia	412	12.73	0.93	0.59	0.34
Bancroft	1002	13.48	0.95	0.34	0.12
Bath	737	13.38	0.86	0.68	0.38
Blandford-Blenheim	838	11.63	0.90	0.63	0.33
Blyth	382	7.19	0.91	0.54	0.27
Bobcaygeon	1641	14.47	0.97	0.28	0.10
Brighton	2320	11.61	1.07	0.37	0.11

	Customers 2006	2007 Rates excluding rate riders		2007 Rate Rider # 1	2007 Rate Rider # 2
Brockville	8337	12.33	0.93	0.48	0.16
Caledon OH 01	8794	18.52	0.57	0.42	0.16
Caledon CH 02	2118	15.19	1.02	0.28	0.08
Caledon OH 06	7266	34.85	0.50	0.25	0.11
Caledon OH 07	210	38.78	1.04	0.43	0.25
Campbellford-Seymour	1427	12.30	1.07	0.41	0.12
Carleton Place	3711	14.17	1.79	0.38	0.15
Cavan-Millbrook-North Monaghan	560	15.01	1.34	0.68	0.40
Centre Hastings	647	11.67	0.96	0.29	0.11
Chalk River	376	14.03	1.37	0.61	0.42
Champlain	1715	10.36	0.88	0.45	0.23
Cobden	469	13.07	1.76	0.68	0.41
Deep River	1741	16.62	2.29	0.38	0.25
Deseronto	664	12.89	1.12	0.37	0.11
Dryden	2633	14.28	1.65	0.43	0.18
Dundalk	687	14.47	1.08	0.39	0.13
Durham	1110	16.35	1.24	0.46	0.16
Eganville	545	13.86	1.53	0.29	0.12
Erin	904	13.13	1.90	0.83	0.40
Exeter	1986	15.10	0.96	0.45	0.15
Fenelon Falls	970	6.09	0.96	0.25	0.08
Forest	1167	15.26	0.95	0.41	0.15
Georgian Bay Energy	8012	9.68	0.95	0.46	0.13
Georgina	1132	11.72	0.98	0.31	0.09
Glencoe	850	12.90	0.77	0.89	0.43
Grand Bend	1038	13.58	0.87	0.42	0.13
Hastings	503	16.44	1.35	0.37	0.12
Havelock-Belmont-Methuen	510	15.17	1.14	0.32	0.13
Kirkfield	107	5.34	1.00	0.48	0.26
Lanark Highlands	337	11.31	1.02	0.56	0.40
Larder Lake	383	15.84	1.01	0.68	0.43
Latchford	188	13.31	0.88	1.04	0.45
Lindsay	6514	15.81	1.01	0.41	0.14
Lucan Granton	850	11.72	1.42	0.37	0.17
Malahide	243	11.17	0.87	0.78	0.34
Mapleton	722	13.47	0.92	0.65	0.39
Markdale	634	14.30	0.86	0.44	0.16

	Customers 2006	2007 Rates excluding rate riders		2007 Rate Rider # 1	2007 Rate Rider # 2
Marmora	579	11.59	0.92	0.33	0.11
McGarry	297	12.85	0.93	0.71	0.45
Meaford	2027	12.75	0.97	0.40	0.12
Middlesex Centre	398	14.19	0.78	0.65	0.40
Napanee	2036	14.70	1.02	0.43	0.14
Nipigon	728	14.23	1.42	1.27	0.72
North Dorchester	713	8.97	0.86	0.67	0.40
North Dundas	1510	11.17	0.97	0.55	0.14
North Glengarry	1901	7.74	1.02	0.52	0.22
North Grenville	1359	14.40	1.65	0.37	0.16
North Perth	2419	14.73	1.05	0.47	0.16
North Stormont	335	5.42	0.92	0.62	0.36
Omemee	508	14.99	1.50	0.36	0.14
Perth	2845	14.47	1.22	0.50	0.18
Perth East	548	5.95	0.78	0.26	0.06
Prince Edward County	3092	14.25	1.05	0.39	0.13
Quinte West	6662	6.58	0.92	0.39	0.11
Rainy River	378	15.04	1.02	0.75	0.50
Ramara	99	6.52	0.95	0.55	0.35
Red Rock	354	15.21	2.07	0.77	0.54
Clarence-Rockland	3536	9.41	0.92	0.65	0.37
Russell	847	13.11	1.44	0.28	0.11
Schreiber	593	16.32	1.84	0.68	0.44
Severn	577	10.60	0.90	0.59	0.32
Shelburne	1703	14.14	1.33	0.39	0.14
Smiths Falls	3735	12.63	1.42	0.46	0.17
South Glengarry	440	9.46	0.75	0.52	0.36
South River	473	14.22	1.25	0.63	0.41
Springwater	735	11.79	0.82	0.61	0.31
Stirling-Rawdon	808	12.55	1.03	0.38	0.12
Thedford	295	12.75	0.81	0.82	0.52
Thessalon	550	15.56	1.05	0.28	0.12
Thorndale	139	4.32	0.88	0.62	0.32
Thorold	7102	13.68	1.47	0.41	0.14
Tweed	661	4.48	0.95	0.61	0.37
Wardsville	143	9.64	0.97	0.36	0.10
Warkworth	258	15.25	1.18	0.66	0.43
West Elgin	989	13.30	1.42	0.63	0.35

	Customers 2006	2007 Rates excluding rate riders		2007 Rate Rider # 1	2007 Rate Rider # 2
Whitchurch-Stouffville	3294	10.54	1.02	0.36	0.12
South Bruce Peninsula	893	15.83	1.55	0.37	0.14
Woodville	320	3.78	0.95	0.51	0.26
Wyoming	829	11.52	0.81	0.36	0.11
Terrace Bay	1025	20.81	1.45	0.97	

Table 2
Acquired General Service Energy Billed Rates and Rate Riders on May 1st, 2007

	Customers	2007 Rates excluding rate riders		2007 Rate Rider # 1	2007 Rate Rider # 2
		$/customer	¢/kWh	¢/kWh	¢/kWh
Ailsa Craig	45	17.31	1.32	0.17	0.09
Arkona	37	3.20	0.86	0.51	0.36
Arnprior	461	21.38	1.17	0.16	0.06
Arran-Elderslie	243	8.83	1.03	0.17	0.09
Artemesia	92	19.62	1.74	0.49	0.34
Bancroft	300	24.41	1.18	0.17	0.08
Bath	53	10.65	1.47	0.29	0.24
Blandford-Blenheim	125	23.85	1.14	0.28	0.20
Blyth	73	21.63	1.05	0.26	0.20
Bobcaygeon	282	23.20	1.38	0.18	0.09
Brighton	247	22.90	1.35	0.20	0.08
Brockville	1009	21.65	0.78	0.13	0.04
Caledon CH	623	24.21	1.80	0.14	0.08
Caledon GS 05		23.34	2.19	0.22	0.20
Caledon OH	1,004	25.56	1.70	0.16	0.07
Campbellford-Seymour	295	16.19	1.19	0.17	0.05
Carleton Place	378	23.65	1.68	0.13	0.07
Cavan-Millbrook-North Monaghan	82	22.28	1.50	0.33	0.26
Centre Hastings	165	18.38	0.97	0.14	0.06
Chalk River	31	21.33	1.79	0.39	0.34
Champlain	179	20.59	0.91	0.26	0.15
Cobden	89	21.93	2.13	0.36	0.30
Deep River	168	23.94	2.26	0.15	0.14
Deseronto	70	10.14	1.35	0.13	0.05
Dryden	450	19.11	1.03	0.12	0.04

	Customers	2007 Rates excluding rate riders		2007 Rate Rider # 1	2007 Rate Rider # 2
Dundalk	98	23.56	1.64	0.23	0.09
Durham	173	24.12	1.37	0.15	0.06
Eganville	119	21.35	2.32	0.17	0.12
Erin	179	40.38	0.73	0.19	0.08
Exeter	295	11.36	1.30	0.15	0.06
Fenelon Falls	206	19.81	0.95	0.15	0.08
Forest	175	24.91	1.18	0.16	0.06
Georgian Bay Energy	1233	10.77	1.14	0.16	0.06
Georgina	207	17.40	1.62	0.16	0.08
Glencoe	138	11.37	0.81	0.22	0.14
Grand Bend	261	22.20	1.23	0.19	0.07
Hastings	90	22.89	1.69	0.23	0.09
Havelock-Belmont-Methuen	94	22.18	1.52	0.16	0.09
Kirkfield	29	14.69	1.95	0.61	0.44
Lanark Highlands	71	18.43	1.99	0.63	0.50
Larder Lake	52	20.18	1.58	0.51	0.36
Latchford	33	2.88	1.02	0.65	0.20
Lindsay	908	23.94	1.38	0.15	0.06
Lucan Granton	89	16.99	1.47	0.17	0.10
Malahide	26	15.84	1.98	0.81	0.49
Mapleton	105	21.55	1.71	0.40	0.29
Markdale	140	23.00	0.80	0.15	0.04
Marmora	116	10.02	1.05	0.15	0.05
McGarry	25	19.99	2.00	0.57	0.50
Meaford	293	24.05	1.23	0.16	0.07
Middlesex Centre	30	17.35	1.37	0.44	0.35
Napanee	440	22.17	1.28	0.16	0.06
Nipigon	146	23.32	1.05	0.34	0.21
North Dorchester	86	15.88	0.90	0.35	0.26
North Dundas	213	13.52	0.83	0.16	0.04
North Glengarry	332	17.72	0.90	0.21	0.12
North Grenville	220	20.42	1.71	0.14	0.08
North Perth	304	29.52	1.00	0.12	0.04
North Stormont	83	5.37	0.78	0.37	0.26
Omemee	66	21.28	1.47	0.18	0.09
Perth	473	19.92	0.92	0.13	0.04
Perth East	88	14.65	1.29	0.16	0.09
Prince Edward County	554	22.85	1.42	0.18	0.08

	Customers	2007 Rates excluding rate riders		2007 Rate Rider # 1	2007 Rate Rider # 2
Quinte West	857	3.74	1.05	0.14	0.06
Rainy River	88	19.29	1.76	0.45	0.36
Ramara	33	20.97	1.06	0.45	0.37
Red Rock	31	21.64	1.94	0.27	0.24
Clarence-Rockland	300	7.27	1.00	0.17	0.22
Russell	78	19.26	2.24	0.18	0.11
Schreiber	104	20.70	2.51	0.50	0.40
Severn	96	22.17	1.06	0.31	0.22
Shelburne	198	20.01	0.87	0.10	0.02
Smiths Falls	651	9.84	1.05	0.12	0.04
South Glengarry	89	17.41	0.75	0.37	0.30
South River	83	22.11	1.58	0.39	0.30
Springwater	133	20.53	1.07	0.27	0.17
Stirling-Rawdon	161	24.12	1.30	0.21	0.09
Thedford	76	17.83	1.06	0.36	0.31
Thessalon	111	18.90	1.55	0.10	0.08
Thorndale	30	14.52	1.02	0.52	0.32
Thorold	766	22.63	1.50	0.15	0.06
Tweed	143	8.26	0.97	0.43	0.31
Wardsville	55	12.32	1.00	0.25	0.08
Warkworth	50	21.31	1.52	0.46	0.35
West Elgin	152	15.40	0.70	0.17	0.07
Whitchurch-Stouffville	297	21.85	0.93	0.11	0.04
South Bruce Peninsula	204	23.78	1.89	0.19	0.09
Woodville	47	16.89	1.57	0.67	0.48
Wyoming	102	17.36	1.45	0.16	0.07
Terrace Bay	108	41.34	1.18	0.82	

Table 3
Acquired General Service Demand Billed Rates and Rate Riders on May 1st, 2007

	Customers	2007 Rates excluding rate riders		2007 Rate Rider # 1	2007 Rate Rider # 2
		$/customer	$/kW	$/kW	$/kW
Ailsa Craig	4	17.31	4.19	0.52	0.27
Arkona	0	3.20	1.98	1.62	0.83
Arnprior	54	21.38	3.70	0.50	0.20
Arran-Elderslie	17	8.83	3.28	0.55	0.28
Artemesia	3	19.62	5.49	1.55	1.08

	Customers	2007 Rates excluding rate riders		2007 Rate Rider # 1	2007 Rate Rider # 2
Bancroft	27	24.41	3.70	0.54	0.24
Bath	6	10.65	3.77	0.93	0.63
Blandford-Blenheim	8	23.85	3.63	0.91	0.65
Blyth	7	21.63	3.37	0.82	0.64
Bobcaygeon	10	23.20	4.35	0.58	0.27
Brighton	20	22.90	4.24	0.65	0.25
Brockville	168	21.65	2.49	0.41	0.12
Caledon CH	103	24.21	5.73	0.45	0.27
Caledon GS 05		23.34	6.96	0.69	0.64
Caledon OH	158	25.56	5.35	0.51	0.24
Campbellford-Seymour	28	16.19	3.77	0.53	0.17
Carleton Place	34	23.65	5.31	0.42	0.22
Cavan-Millbrook-North Monaghan	4	22.28	4.67	1.06	0.81
Centre Hastings	5	18.38	3.07	0.45	0.20
Chalk River	1	21.33	5.70	1.23	1.07
Champlain	12	20.59	2.88	0.84	0.49
Cobden	3	21.93	6.49	1.16	0.90
Deep River	23	23.94	7.18	0.46	0.46
Deseronto	6	10.14	3.85	0.41	0.14
Dryden	50	19.11	3.29	0.38	0.13
Dundalk	8	23.56	5.17	0.74	0.28
Durham	10	24.12	4.31	0.48	0.18
Eganville	7	21.35	7.35	0.55	0.37
Erin	16	40.38	2.36	0.59	0.25
Exeter	27	11.36	4.11	0.49	0.18
Fenelon Falls	11	19.81	3.02	0.47	0.24
Forest	20	24.91	3.74	0.50	0.20
Georgian Bay Energy	122	10.77	3.64	0.49	0.19
Georgina	10	17.40	5.10	0.51	0.25
Glencoe	9	11.37	2.55	0.69	0.44
Grand Bend	11	22.20	3.90	0.59	0.23
Hastings	4	22.89	5.32	0.74	0.29
Havelock-Belmont-Methuen	2	22.18	4.82	0.50	0.28
Kirkfield	1	14.69	5.92	1.95	1.34
Lanark Highlands	1	18.43	5.26	1.99	1.32
Larder Lake	2	20.18	4.30	1.61	0.99
Latchford	1	2.88	2.44	2.06	0.48

	Customers	2007 Rates excluding rate riders		2007 Rate Rider # 1	2007 Rate Rider # 2
Lindsay	116	23.94	4.36	0.49	0.19
Lucan Granton	7	16.99	4.61	0.53	0.30
Malahide	1	15.99	5.42	2.57	1.32
Mapleton	12	21.55	5.42	1.26	0.93
Markdale	15	23.00	2.54	0.49	0.13
Marmora	6	10.02	3.33	0.49	0.16
McGarry	1	20.18	5.68	1.80	1.42
Meaford	20	24.05	3.90	0.50	0.21
Middlesex Centre	1	17.35	3.29	1.39	0.84
Napanee	33	22.17	4.04	0.52	0.20
Nipigon	7	23.32	3.38	1.07	0.68
North Dorchester	5	15.88	2.85	1.12	0.81
North Dundas	21	13.52	2.42	0.52	0.11
North Glengarry	36	17.72	2.82	0.69	0.39
North Grenville	28	20.42	5.41	0.45	0.25
North Perth	33	29.52	3.16	0.36	0.13
North Stormont	0	5.37	2.52	1.17	0.82
Omemee	5	21.28	4.64	0.55	0.27
Perth	50	19.92	2.87	0.42	0.12
Perth East	9	14.65	4.08	0.52	0.27
Prince Edward County	38	22.85	4.45	0.58	0.24
Quinte West	112	3.74	3.32	0.46	0.18
Rainy River	6	19.29	5.59	1.44	1.14
Ramara	1	20.97	3.35	1.43	1.16
Red Rock	5	21.64	6.15	0.86	0.75
Clarence-Rockland	35	7.27	2.59	0.53	0.57
Russell	5	19.26	7.10	0.58	0.36
Schreiber	9	20.70	7.36	1.57	1.17
Severn	8	22.17	3.35	0.98	0.69
Shelburne	21	20.01	2.78	0.32	0.08
Smiths Falls	56	9.84	3.33	0.39	0.13
South Glengarry	2	17.41	2.37	1.18	0.94
South River	3	22.11	4.87	1.22	0.92
Springwater	11	20.53	3.42	0.85	0.53
Stirling-Rawdon	6	24.12	4.11	0.67	0.30
Thedford	5	17.83	3.38	1.14	1.00
Thessalon	1	18.90	3.22	0.21	0.17

	Customers	**2007 Rates excluding rate riders**		**2007 Rate Rider # 1**	**2007 Rate Rider # 2**
Thorndale	2	14.52	3.25	1.67	1.03
Thorold	72	22.63	4.76	0.46	0.20
Tweed	6	8.26	3.11	1.35	0.99
Wardsville	1	12.32	3.16	0.81	0.26
Warkworth	2	21.31	4.47	1.44	1.03
West Elgin	13	15.40	2.21	0.54	0.21
Whitchurch-Stouffville	26	21.85	2.93	0.35	0.13
South Bruce Peninsula	9	23.78	5.99	0.59	0.29
Woodville	3	16.89	4.34	2.12	1.35
Wyoming	9	17.36	4.57	0.52	0.23
Terrace Bay	12	293.24	4.00	2.27	

Table 4
Acquired Large User Rates and Rate Riders for 2007

	2007 Rates excluding rate riders		2007 Rate Rider # 1	2007 Rate Rider # 2
	$/customer	$/kW	$/kW	$/kW
Arnprior	3,844	3.6	0.29	0.09
Brockville	2,608	3.9	0.33	0.21
Caledon	4,279	5.2	0.2	0.16
GBE	3,242	4.4	0.36	0.17
Quinte West	2,305	3.6	0.37	0.11

Table 5
Acquired Utility Basic Distribution Rates Statistics 2007

Acquired LDC	Residential	General Service Energy	General Service Demand	Large User	Street and Sentinel Lights
Min	$3.78/month 0.26 ¢/kWh	$2.88/month 0.70 ¢/kWh	$2.88/month $1.98/kW	$2,305/month $3.60/kW	Harmonized with Retail
Max	$38.78/month 2.29 ¢/kWh	$41.34/month 2.51 ¢/kWh	$293.24/month $7.36 /kW	$4,279/month $5.22/kW	Harmonized with Retail
Average	$12.89/month 1.10 ¢/kWh	$19.10/month 1.35 ¢/kWh	$21.90/month $4.13 /kW	$3,256/month $4.14/kW	Harmonized with Retail

4.0 STEPS TO DEVELOP HARMONIZED RATES

The following Tables show examples of the development of harmonized rates.

Table 6
Examples of Development of Harmonized Residential group rates
Urban and R 1

Residential - Urban	**LDC 1**	**LDC 2**
Target rates	$14.32/month & 2.29 ¢/kWh	$14.32/month & 2.29 ¢/kWh
LDC 2007 rate	$6.58/month	$18.52/month
LDC increase/(decrease)	$7.74/month	$(4.20)/month
LDC Yearly increase/(decrease)	$1.94/month	$(1.05)/month
LDC year 1 rate	$6.00 + $1.94 = $7.94/month & 2.40 ¢/kWh	$18.00 - $1.05 = $16.95/month & 2.40 ¢/kWh
LDC Year 2 rate	$7.94 + $1.94 = $9.88/month & 2.38 ¢/kWh	$16.95 - $1.05 = $15.90/month & 2.38 ¢/kWh
LDC Year 3 rate	$9.88 + $1.94 = $11.82/month & 2.36 ¢/kWh	$15.90 - $1.05 = $14.85/month & 2.36 ¢/kWh
LDC year 4 rate	$14.32/month & 2.29 ¢/kWh	$14.32/month & 2.29 ¢/kWh

Residential – R1	**LDC 1**	**LDC 2**
Target rates	$19.04/month & 2.60 ¢/kWh	$19.04/month & 2.60 ¢/kWh
LDC 2007 rate	$3.78/month	$20.81/month
LDC increase/(decrease)	$15.26/month	$(1.77)/month
LDC Yearly increase/(decrease)	$3.82/month	$(0.44)/month
LDC year 1 rates	$3.00 + $3.82 = $6.82/month & 2.71 ¢/kWh	$20.00 - $0.44 = $19.56/month & 2.71 ¢/kWh
LDC year 2 rates	$6.82 + $3.82 = $10.64/month & 2.68 ¢/kWh	$19.56 - $0.44 = $19.12/month & 2.68 ¢/kWh
LDC year 3 rates	$10.64 + $3.82 = $14.46/month & 2.65 ¢/kWh	$19.12 - $0.44 = $18.68/month & 2.65 ¢/kWh
LDC year 4 rates	$19.04/month & 2.60 ¢/kWh	$19.04/month & 2.60 ¢/kWh

Table 7
Examples of Development of Harmonized General Service group rates
General Service and Urban General Service

General Service - Energy	**LDC 1**	**LDC 2**
Target rates	$30.97/month & 3.39 ¢/kWh	$30.97/month & 3.39 ¢/kWh
LDC 2007 rate	$2.88/month	$41.34/month
LDC increase/(decrease)	$28.09/month	$(10.37)/month
LDC Yearly increase/(decrease)	$7.02/month	$(2.59)/month
LDC year 1 rates	$2.00 + $7.02 = $9.02/month & 3.21 ¢/kWh	$41.00 - $2.59 = $38.41/month & 3.21 ¢/kWh
LDC year 2 rates	$9.02 + $7.02 = $16.04/month & 3.27 ¢/kWh	$38.41 - $2.59 = $35.82/month & 3.27 ¢/kWh
LDC year 3 rates	$16.04 + $7.02 = $23.06/month & 3.34 ¢/kWh	$35.82 - $2.59 = $33.23/month & 3.34 ¢/kWh
LDC year 4 rates	$30.97/month & 3.39 ¢/kWh	$30.97/month & 3.39 ¢/kWh

General Service - Demand	**LDC 1**	**LDC 2**
Target rates	$46.75/month & $9.22/kW	$46.75/month & $9.22/kW
LDC 2007 rate	$2.88/month	$293.24/month
LDC increase/(decrease)	$43.87/month	$(246.49)/month
LDC Yearly increase/(decrease)	$10.97/month	$(61.62)/month
LDC year 1 rates	$2.00 + $10.97 = $12.97/month & $9.22/kW	$293.00 - $61.62 = $231.38/month & $9.22/kW
LDC year 2 rates	$12.97 + $10.97 = $23.94/month & $9.22/kW	$231.38 - $61.62 = $169.76/month & $9.22/kW
LDC year 3 rates	$33.94 + $10.97 = $34.91/month & $9.22/kW	$169.76 - $61.62 = $108.14/month & $9.22/kW
LDC year 4 rates	$46.75/month & $9.22/kW	$46.75/month & $9.22/kW

Urban General Service - Energy	**LDC 1**	**LDC 2**
Target rates	$12.33/month & 2.09 ¢/kWh	$12.33/month & 2.09 ¢/kWh
LDC 2007 rate	$3.74/month	$23.65/month
LDC increase/(decrease)	$8.59/month	$(11.32)/month
LDC Yearly increase/(decrease)	$2.15/month	$(2.83)/month
LDC year 1 rates	$3.00 + $2.15 = $5.15/month & 2.00 ¢/kWh	$23.00 - $2.83 = $20.17/month & 2.00 ¢/kWh
LDC year 2 rates	$5.15 + $2.15 = $7.30/month & 2.04 ¢/kWh	$20.17 - $2.83 = $17.34/month & 2.04 ¢/kWh
LDC year 3 rates	$7.30 + $2.15 = $9.45/month & 2.07 ¢/kWh	$17.34 - $2.83 = $14.51/month & 2.07 ¢/kWh
LDC year 4 rates	$12.33/month & 2.09 ¢/kWh	$12.33/month & 2.09 ¢/kWh

Urban General Service - Demand	**LDC 1**	**LDC 2**
Target rates	$29.19/month & $7.25/kW	$29.19/month & $7.25/kW
LDC 2007 rate	$3.74/month	$23.65/month
LDC increase/(decrease)	$25.45/month	$5.54/month
LDC Yearly increase/(decrease)	$6.36/month	$1.39
LDC year 1 rates	$3.00 + $6.36 = $9.36/month & $7.33/kW	$23.00 + $1.39 = $24.39/month & $7.33/kW
LDC year 2 rates	$9.36 + $6.36 = $15.72/month & $7.31/kW	$24.39 + $1.39 = $25.78/month & $7.31/kW
LDC year 3 rates	$15.72 + $6.36 = $22.08/month & $7.28/kW	$25.78 + $1.39 = $27.17/month & $7.28/kW
LDC year 4 rates	$29.19/month & $7.25/kW	$29.19/month & $7.25/kW

5.0 ACQUIRED CUSTOMER CLASSES HARMONIZATION IMPACT

The following tables show the range of impacts for Residential and General Service customer classes resulting from achieving the target rates.

Table 8
Range of impacts as a result of Harmonization of Residential customers of Acquired

Urban Residential			Residential [R1]		
# LDCs	# Cust	Impact Range	# LDCs	# Cust	Impact Range
0	-	-5 to 0	2	2,095	0 to 3
1	3,618	0 to 2	3	2,225	3 to 6
1	2,526	2 to 4	4	2,147	6 to 9
4	15,193	4 to 6	14	8,661	9 to 12
1	6,347	6 to 8	14	9,687	13 to 15
1	8,794	8 to10	20	22,837	15 to 18
1	8,146	10 to 12	13	14,722	18 to 21
3	16,523	12 to 18	10	6,347	21 to 24
			4	1,906	24 to 27
			2	1,290	27 to 30
			2	765	30 to 33
12	61,147		88	72,682	

Table 9
Range of impacts as a result of Harmonization of General Service customers of Acquired LDCs – Energy

Urban GS			GS		
# LDCs	# Cust	Impact Range	# LDCs	# Cust	Impact Range
3	1502	-5 to 0	0	0	0 to 3
0	0	0 to 2	0	0	3 to 6
1	294	2 to 4	1	99	6 to 9
3	1115	4 to 6	8	586	9 to 12
1	934	6 to 8	8	632	13 to 15
1	1107	8 to10	12	2543	15 to 18
1	578	10 to 12	16	2876	18 to 21
1	713	12 to 14	13	2025	21 to 24
			10	1056	24 to 27
			11	1395	27 to 30
			7	917	30 to 33
			4	503	33 to 37
11	6243		90	12632	

Table 10
Range of impacts as a result of Harmonization of General Service customers of Acquired LDCs – Demand

Urban GS				GS		
# LDCs	# Cust	Impact Range		# LDCs	# Cust	Impact Range
0	0	less than -5		3	16	Less than 0
0	0	-5 to 0		10	49	0 to 3
1	26	0 to 2		10	157	3 to 6
1	40	2 to 4		11	292	6 to 9
1	85	4 to 6		27	326	9 to 12
2	131	6 to 8		15	174	13 to 15
3	176	8 to10		10	153	15 to 18
3	197	10 to 12		0	0	18 to 21
0	0	12 to 14		0	0	21 to 24
11	655			86	1167	

RESULTS OF DENSITY REVIEW AND CUSTOMER CLASSIFICATION

This exhibit shows the results of the Density Review undertaken to identify customers that meet the Urban Density classification.

Table 1

Customers Grouped as Urban Residential

Current Customer Classification	Number of Residential customers
UR	82,519
R1	11,753
R2	293
F1	128
Arnprior	2,848 out of 3,134
Brockville	8,146 out of 8,338
Caledon OH-01	8,794
Carleton Place	3,618 out of 3,711
Dryden	2,526 out of 2,634
Lindsay	6,347 out of 6,514
Owen Sound (GBE)	7,638 out of 7,833
Perth	2,745 out of 2,845
Smith Falls	3,637 out of 3,736
Stoufville	3,228 out of 3,294
Thorold	5,963 out of 7,102
Trenton (Quinte West)	5,657 out of 6,662
Total Urban Residential	**155,840**

Table 2

Customers Grouped as General Service Urban Energy

Current Customer Classification	Number of Urban General Service Energy
UG	5,309
G1	425
G3	432
F1	18
Arnprior	294 out of 438
Brockville	934 out of 969
Carleton Place	284 out of 347
Dryden	427 out of 445
Lindsay	777 out of 837
Owen Sound (GBE)	1,107 out of 1,140
Perth	417 out of 447
Smith Falls	578 out of 635
Stoufville	271 out of 276
Thorold	441 out of 695
Trenton (Quinte West)	713 out of 825
Total Urban General Service energy	**12,427**

Table 3

Customers Grouped as General Service Urban Demand

Current Customer Classification	**Number of Urban General Service Demand**
UG	593
G1	8
G3	119
Arnprior	27 out of 48
Brockville	141 out of 159
Carleton Place	26 out of 34
Dryden	50
Lindsay	85 out of 110
Owen Sound (GBE)	104 out of 117
Perth	33 out of 46
Smith Falls	43 out of 50
Stoufville	23 out of 25
Thorold	40 out of 69
Trenton (Quinte West)	83 out of 106
Total Urban General Service energy	**1,375**

The following is a list of the communities analyzed:

Clarence Rockland
Dryden
Perth
Arnprior
Stouffville
Carleton Place
Smiths Falls
Trenton
Essex
Lindsay
Thorold
Owen Sound
Brockville
East Gwillimbury Twp

RETAIL TRANSMISSION SERVICE RATE DETAILS

This exhibit shows the details in support of the derivation of the Retail Transmission Service Rates (RTSR) for 2008.

1.0 INTRODUCTION

The process follows the steps as outlined in the 2000 Distribution Rates Handbook Chapter 11 Section 3.2 which provides a 3-Step process:

Step 1: Estimating retail transmission service costs
Step 2: Cost Allocation to customer classes
Step 3: Calculating Retail Transmission Service Rate

2.0 ESTIMATING RETAIL TRANSMISSION SERVICE COSTS

2.1 Transmission Delivery Point Forecasts

For each of Hydro One Networks Distribution's 230 Transmission Delivery Points, the weather normal hourly forecast was generated for 2008. At each Transmission Delivery point, the Network and Connection kWs were determined per month and totaled.

Network kWs (annual)	71,959,731
Line Connection kWs (annual)	62,053,860
Transformation Connection kWs (annual)	71,289,445

2.2 Rates Used

The latest monthly Uniform Transmission Rates being employed are:

Network Rate [$/kW]	2.31
Line Connection Rate [$/kW]	0.59
Transformation Connection Rate [$/kW]	1.61

2.3 Estimated Charge

Transmission Charge	**kWs**	**$/kW**	**$ Charges**
Network Charge	71,959,731	2.31	$166,226,978
Line Connection Charge	62,053,860	0.59	$ 36,611,777
Transformation Connection Charge	71,289,445	1.61	$114,776,007
Estimated 2008 Charge			$317,614,762

3.0 Cost Allocation To Customer Classes

3.1 New ST Class

With the new ST Class, customer connectivity is available to connect each customer to a Transmission Delivery Point. Using the time of each monthly peak per Transmission Delivery Point from Step 2 of above and the hourly profiles per customer delivery point the coincident peak for each ST customer delivery point is calculated.

The allocation of each Transmission Delivery Points charge to the ST connected customer is derived using the following formula:

$$\text{Allocated Charge} = \text{Estimated IESO Charge} \times \frac{\text{Coincident Peak kW}}{\text{Transmission peak kW}}$$

The summation of these allocated charges across all the ST connected Transmission Delivery points results in 46% of the $317.6 million being allocated to this class.

3.2 Retail Classes

The residual 54% is allocated to the remaining Retail customer classes. The process follows that outlined in Chapter 11 Section 11.3.2.3, each customer class was allocated its share based on class monthly demand coincident with the monthly transmission or distributor's peak, for the Network or Connection Cost Pools respectively.

Equation 11.3(a) re-stated:

$$\text{Class Alloc Network Cost} = \text{Network Cost Pool} \times \frac{\text{Class Monthly Demand}^2}{\text{Total Class Monthly Demand}^2}$$

^{2} = Class monthly demand coincident with the monthly transmission system peak

Equation 11.3(b) re-stated:

$$\text{Class Alloc Connection Cost} = \text{Connection Cost Pool} \times \frac{\text{Class Monthly Demand}^3}{\text{Total Class Monthly Demand}^3}$$

^{3} = Class monthly demand coincident with the distributor's monthly peak

3.3 Allocation of Retail Transmission Service Charges

The following table summarizes the estimated Retail Transmission Service Costs and the allocation to customer classes consistent with the methodology laid out in Chapter 11 of the Distribution Rate Handbook.

	Tx Network	**Tx Line**	**Tx Transformation**	**Total IESO Bill**	**Share**
IESO Bill	**$ 166,226,978**	**$ 36,611,777**	**$ 114,776,007**	**$ 317,614,762**	
ST	**$ 76,899,232**	**$ 16,207,183**	**$ 51,593,835**	**$ 144,700,250**	46%
Retail	**$ 89,327,746**	**$ 20,404,594**	**$ 63,182,172**	**$ 172,914,512**	54%
UR	$ 7,570,443	$ 1,769,046	$ 5,477,795	$ 14,817,285	
R1	$ 22,697,678	$ 5,351,517	$ 16,570,801	$ 44,619,996	
R2	$ 28,517,822	$ 6,467,960	$ 20,027,830	$ 55,013,611	
Seasonal	$ 3,374,629	$ 809,307	$ 2,505,993	$ 6,689,929	
Uge	$ 1,674,964	$ 370,818	$ 1,148,225	$ 3,194,007	
Ugd	$ 3,289,432	$ 727,263	$ 2,251,945	$ 6,268,640	
GSe	$ 8,807,534	$ 1,967,457	$ 6,092,168	$ 16,867,159	
GSd	$ 12,932,797	$ 2,841,350	$ 8,798,148	$ 24,572,294	
Lighting	$ 449,148	$ 96,938	$ 300,166	$ 846,252	
Dgen	$ 13,298	$ 2,939	$ 9,101	$ 25,338	

4.0 CALCULATING RETAIL TRANSMISSION SERVICE RATE

4.1 ST Customer Class

Based on the Charge Determinants laid out in Table 11.4 of the Distribution Rate Handbook, the following Charge Determinants Table and Rates are derived for these Interval Metered customers:

Network: Peak kW demand in month from 7 AM to 7 PM weekdays

Connection: Peak kW demand in month

	Tx Network	Tx Line	Tx Transformation
ST Allocated Cost	$ 76,899,232	$ 16,207,183	$ 51,593,835
Charge Determinant [kW]	38,272,898	32,136,412	37,417,280
$/kW	2.01	0.50	1.38

4.2 Retail Customer Class

Following Charge Determinant Table 11.4 of Distribution Rate Handbook, the Retail customer class charge determinants and rates derived and summarized in the following table. For Retail classes, there is no distinction between the Line Connection and Transformation Connection Charges and these Cost Pools are summed together. Energy billed customers are billed based on class energy while demand billed customers are billed based on peak demand per month.

	Allocation Cost Pools		Charge Determinants		Network	Connection	Network	Connection
	Network	Connection	kWh	kW	c/kWh	c/kWh	$/kW	$/kW
UR	$ 7,570,443	$ 7,246,842	1,610,732,413		0.47	0.45		
R1	$22,697,678	$21,922,317	4,782,076,285		0.47	0.46		
R2	$28,517,822	$26,495,789	6,141,936,529		0.46	0.43		
Seasonal	$ 3,374,629	$ 3,315,300	771,742,703		0.44	0.43		
Uge	$ 1,674,964	$ 1,519,043	463,185,604		0.36	0.33		
Ugd	$ 3,289,432	$ 2,979,208		2,337,698			1.41	1.27
GSe	$ 8,807,534	$ 8,059,625	2,510,853,555		0.35	0.32		
GSd	$12,932,797	$11,639,498		11,691,631			1.11	1.00
Lighting	$ 449,148	$ 397,104	156,172,049		0.29	0.25		
Dgen	$ 13,298	$ 12,040		52,409			0.25	0.23

HYDRO ONE NETWORKS INC.
TARIFF OF RATES AND CHARGES
FOR RETAIL DISTRIBUTION SERVICE
Effective Date: May 1, 2008

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

1.0 APPLICABILITY

These rates are applicable to Hydro One Networks' core retail customers, who are customers of Networks' retail distribution system, including some customers previously served by acquired distribution utilities.

The application of these rates and charges shall be in accordance with The Licence of The Distributor and any Codes, Guidelines or Orders of The Board, and amendments thereto as approved by The Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless

a) permitted by the Distributor's Licence or any Codes, Guidelines or Orders of the Board, and amendments thereto as approved by the Board, or as specified herein, or

b) as identified in Hydro One Network's Distribution Customers Conditions of Service document, or

c) related to work or service of a customized nature and required for distribution assets, for example customer-requested pole relocation, repair of damages, new connections, etc.

This schedule does not contain any rates and charges relating to the electricity commodity (e.g. the Regulated Price Plan).

1.1 EFFECTIVE DATES

DISTRIBUTION RATES - May 1, 2008 for all consumption or deemed consumption services used on or after that date.

MISCELLANEOUS CHARGES - May 1, 2008 for all charges billed to customers on or after that date.

RETAIL TRANSMISSION RATES - May 1, 2008 for all consumption or deemed consumption services used on or after that date.

LOSS FACTOR ADJUSTMENT – for all consumption or deemed consumption services billed following May 1, 2008 or later.

1.2 CUSTOMER CLASSIFICATIONS

Residential - Year-round customer classification applies to a customer's main place of abode and may include additional buildings served through the same meter, provided they are not rental income units. All of the following criteria must be met:

1. Occupant represents and warrants to Hydro One Networks Inc, that for so long as he/she have year-round residential rate status for the identified dwelling he/she will not designate another property that he/she owns as a year-round residence for purposes of Hydro One rate classification
2. Occupier must live in this residence for at least four (4) days of the week for eight (8) months of the year and the Occupier must not reside anywhere else for more than three (3) days a week during eight (8) months of the year.
3. The address of this residence must appear on documents such as the occupant's electric bill, driver's licence, credit card invoice, property tax bill, etc.
4. Occupants who are eligible to vote in Provincial or Federal elections must be enumerated for this purpose at the address of this residence.

Seasonal Residential customer classification is defined as any residential service not meeting the Residential Year-round criteria. It includes dwellings such as cottages, chalets and camps.

General Service classification applies to any service that does not fit the description of Residential or Farm classes. It includes combination type services where a variety of uses are made of the service by the owner of one property, and all multiple services except residential.

1.3 DENSITY ZONES

Urban Density Zone is defined as areas containing 3,000 or more customers with a line density of at least 60 customers per kilometre.

Medium Density Zone is defined as areas containing 100 or more customers with a line density of at least 15 customers per kilometre.

Low Density Zone is defined as areas other than Urban or Medium Density Zone.

1.4 RATE CLASSES

Residential

- UR — Year-round Residence in an Urban Density Zone
- R1 — Year-round Residence in a Medium Density Zone
- R2 — Year-round Residence in a Low Density Zone
- Seasonal — Seasonal Residential Occupancy

General Service

- UGe — General Service - Urban Density
  Applicable to Farm Three Phase customers, Farm Single Phase energy-billed customers, and Industrial Commercial customers located in an Urban Density Zone
- UGd — General Service - Urban Density
  Applicable to Farm Three Phase customers, Farm Single Phase demand-billed customers, and Industrial Commercial customers located in an Urban Density Zone
- GSe — General Service
  Single Phase and Three Phase
  Energy-billed customers not located in an Urban Density Zone
- GSd — General Service
  Single Phase and Three Phase
  Demand-billed customers not located in an Urban Density Zone
- DGen — Distributed Generation
- ST — General Service with average demand greater than 500kW and provides their own transformation

- Unmetered Scattered Load

This classification refers to certain instances where connections can be provided without metering. These loads are generally small in size and consistent in magnitude of load. Hydro One reserves the right to review all cases and may require that a meter be installed at its sole discretion. Services that can be unmetered include cable TV amplifiers, telephone switching devices, phone booths, bus shelters, rail way crossing signals, traffic signals, and other small fixed loads.

Further servicing details are available in the utility's Conditions of Service (including in the "Unmetered Connections" section).

Lighting

- **Street Lights**

This rate is applicable to all Hydro One Networks' core and acquired retail customers who have streetlights. Networks' core retail customers are customers of Networks' retail distribution system, excluding those customers previously served by acquired distribution utilities.

Distribution Volumetric Energy Charge is on metered or estimated usage (per kWh)

The energy consumption for street lights is estimated based on Networks' profile for street lighting load, which provides the amount of time each month that the street lights are operating.

- **Sentinel Lights**

This rate is applicable to all Hydro One Networks' core and acquired retail customers who have separate service to a sentinel light. Networks' core retail customers are customers of Networks' retail distribution system, excluding those customers previously served by acquired distribution utilities.

The energy consumption for sentinel lights is estimated based on Networks' profile for sentinel lighting load, which provides the amount of time each month that the sentinel lights are operating.

Distribution Volumetric Energy Charge is on metered or estimated usage (per kWh)

1.5 RURAL OR REMOTE ELECTRICITY RATE PROTECTION

Under the *Ontario Energy Board Act, 1998* and associated regulations, every qualifying year-round residence and farm with a principal residence is eligible to receive Rural or Remote Electricity Rate Protection (RRRP). The service charge shown for eligible R2 customers would be reduced by the applicable RRRP credit.

1.6 SPECIAL RATE CLASSES:

- Low Use Secondary Service
  - Applicable to separately metered services connected prior to January 1, 1996.
  - Applicable to supplementary service located on the same property as the primary service, supplied from the same transformer, with the same owner, separately metered, and which consumes less than specific yearly amounts:

Secondary Service	**Volumes [kWh per year]**
R1	1,500
R2	1,500
R3	500
R4	500
F1	2,500
F3	2,500
G1	2,500
G3	2,500

- Transformer Loss Allowance:
  - Applicable to customers requiring a billing adjustment for transformer losses as the result of being metered on the primary side of a transformer.

- Customer-Supplied Transformation Allowance:
  - Applicable to demand-billed customers providing their own transformers.

HYDRO ONE NETWORKS INC.

RATES FOR RETAIL DISTRIBUTION SERVICE

Effective Date: May 1, 2008

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Monthly Rates and Charges

Residential – Urban [UR]

Service Charge	$	14.00
Distribution Volumetric Rate	$ / kWh	0.0244
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0005
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0002)
Retail Transmission Rate - Network Service Rate (1)	$ / kWh	0.0047
Retail Transmission Rate - Line and Transformation Connection Service Rate (1)	$ / kWh	0.0045
Wholesale Market Service Rate (1)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (1)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

Residential – Medium Density [R1]

Service Charge	$	19.00
Distribution Volumetric Rate	$ / kWh	0.0281
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0007
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0004)
Retail Transmission Rate - Network Service Rate (1)	$ / kWh	0.0047
Retail Transmission Rate - Line and Transformation Connection Service Rate (1)	$ / kWh	0.0046
Wholesale Market Service Rate (1)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (1)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

HYDRO ONE NETWORKS INC.

RATES FOR RETAIL DISTRIBUTION SERVICE

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Monthly Rates and Charges

Residential – Low Density [R2]

Service Charge* - former R2 class	$	55.55
Service Charge* - former F1 class	$	54.70
Service Charge* - former F3 class	$	56.31
Distribution Volumetric Rate	$ / kWh	0.0268
Regulatory Asset Recovery - Rider #2 of former R2 class	$ / kWh	0.0013
Regulatory Asset Recovery - Rider #2 of former F1 class	$ / kWh	0.0010
Regulatory Asset Recovery - Rider #2 of former F3 class	$ / kWh	0.0004
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0005)
Retail Transmission Rate - Network Service Rate (1)	$ / kWh	0.0046
Retail Transmission Rate - Line and Transformation Connection Service Rate (1)	$ / kWh	0.0043
Wholesale Market Service Rate (1)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (1)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

* Under the Ontario Energy Board Act, 1998 and associated regulations, every qualifying year-round customer with a principal residence is eligible to receive Rural or Remote Rate Protection (RRRP). The service charge shown for eligible R2 customers will be reduced by the applicable RRRP credit.

Seasonal Residential – Seasonal

Service Charge – former R3	$	19.00
Service Charge – former R4	$	31.79
Distribution Volumetric Rate - former R3	$ / kWh	0.0469
Distribution Volumetric Rate - former R4	$ / kWh	0.0470
Regulatory Asset Recovery - Rider #2 – former R3	$ / kWh	0.0015
Regulatory Asset Recovery - Rider #2 – former R4	$ / kWh	0.0024
Regulatory Asset Recovery - Rider #3	$ / kWh	0.0002
Retail Transmission Rate - Network Service Rate (1)	$ / kWh	0.0044
Retail Transmission Rate - Line and Transformation Connection Service Rate (1)	$ / kWh	0.0043
Wholesale Market Service Rate (1)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (1)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

HYDRO ONE NETWORKS INC.

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General Service Energy Billed (less than 50 kW) [GSe - metered]

Service Charge – former F1	$	52.91
Service Charge – former F3	$	47.61
Service Charge – former G1	$	35.09
Service Charge – former G3	$	42.40
Service Charge – former T-Class	$	203.71
Distribution Volumetric Rate	$ / kWh	0.0338
Regulatory Asset Recovery - Rider #2 – former F1	$ / kWh	0.0010
Regulatory Asset Recovery - Rider #2 – former F3	$ / kWh	0.0004
Regulatory Asset Recovery - Rider #2 – former G1	$ / kWh	0.0009
Regulatory Asset Recovery - Rider #2 – former G3	$ / kWh	0.0005
Regulatory Asset Recovery - Rider #2 – former T-Class	$ / kWh	0.0003
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0006)
Retail Transmission Rate - Network Service Rate (1)	$ / kWh	0.0035
Retail Transmission Rate - Line and Transformation Connection Service Rate (1)	$ / kWh	0.0032
Wholesale Market Service Rate (1)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (1)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

Urban General Service Energy Billed (less than 50 kW) [UGe]

Service Charge	$	14.27
Distribution Volumetric Rate	$ / kWh	0.0200
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0003
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0006)
Retail Transmission Rate - Network Service Rate (1)	$ / kWh	0.0036
Retail Transmission Rate - Line and Transformation Connection Service Rate (1)	$ / kWh	0.0033
Wholesale Market Service Rate (1)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (1)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) – Administration Charge	$	0.25

DRO ONE NETWORKS INC.

RATES FOR RETAIL DISTRIBUTION SERVICE

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Monthly Rates and Charges

General Service Energy Billed (less than 50 kW) [GSe - unmetered]

Service Charge – former G1	$	22.84
Service Charge – former G3	$	10.81
Service Charge – former UG	$	6.18
Distribution Volumetric Rate – former G1	$ / kWh	0.0538
Distribution Volumetric Rate – former G3	$ / kWh	0.0360
Distribution Volumetric Rate – former UG	$ / kWh	0.0350
Regulatory Asset Recovery - Rider #2 – former G1	$ / kWh	0.0009
Regulatory Asset Recovery - Rider #2 – former G3	$ / kWh	0.0005
Regulatory Asset Recovery - Rider #2 – former UG	$ / kWh	0.0003
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0006)
Retail Transmission Rate - Network Service Rate (1)	$ / kWh	0.0035
Retail Transmission Rate - Line and Transformation Connection Service Rate (1)	$ / kWh	0.0032
Wholesale Market Service Rate (1)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (1)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

HYDRO ONE NETWORKS INC.

RATES FOR RETAIL DISTRIBUTION SERVICE

Effective Date: May 1, 2008

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Monthly Rates and Charges

General Service Demand Billed (greater than 50 kW) [GSd]

Service Charge – former F1	$	56.51
Service Charge – former F3	$	51.21
Service Charge – former G1	$	38.68
Service Charge – former G3	$	46.00
Service Charge – former T-Class	$	207.30
Distribution Volumetric Rate	$ / kW	9.51
Regulatory Asset Recovery - Rider #2 – former F1	$ / kW	0.31
Regulatory Asset Recovery - Rider #2 – former F3	$ / kW	0.16
Regulatory Asset Recovery - Rider #2 – former G1	$ / kW	0.29
Regulatory Asset Recovery - Rider #2 – former G3	$ / kW	0.15
Regulatory Asset Recovery - Rider #2 – former T-Class	$ / kW	0.09
Regulatory Asset Recovery - Rider #3	$ / kW	(0.22)
Retail Transmission Rate - Network Service Rate (1)	$ / kW	1.11
Retail Transmission Rate - Line and Transformation Connection Service Rate (1)	$ / kW	1.00
Wholesale Market Service Rate (1)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (1)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

Urban General Service Demand Billed (greater than 50 kW) [UGd]

Service Charge	$	18.49
Distribution Volumetric Rate	$ / kW	7.49
Regulatory Asset Recovery - Rider #2	$ / kW	0.11
Regulatory Asset Recovery - Rider #3	$ / kW	(0.27)
Retail Transmission Rate - Network Service Rate (1)	$ / kW	1.41
Retail Transmission Rate - Line and Transformation Connection Service Rate (1)	$ / kW	1.27
Wholesale Market Service Rate (1)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (1)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

HYDRO ONE NETWORKS INC.

RATES FOR RETAIL DISTRIBUTION SERVICE

Effective Date: May 1, 2008

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

Monthly Rates and Charges

Distributed Generation [DGen]

Service Charge	$	36.66
Distribution Volumetric Rate	$ / kW	7.14
Regulatory Asset Recovery - Rider #2 former G3	$ / kW	0.15
Regulatory Asset Recovery - Rider #2 former T-Class	$ / kW	0.09
Regulatory Asset Recovery - Rider #2 former Eganville GS	$ / kW	0.12
Regulatory Asset Recovery - Rider #3	$ / kW	(0.04)
Retail Transmission Rate - Network Service Rate (1)	$ / kW	0.25
Retail Transmission Rate - Line and Transformation Connection Service Rate (1)	$ / kW	0.23
Wholesale Market Service Rate (1)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (1)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

Street Lights

Service Charge	$	1.00
Distribution Volumetric Rate	$ / kWh	0.0457
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0006
Regulatory Asset Recovery - Rider #2 for Terrace Bay	$ / kWh	
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0008)
Retail Transmission Rate - Network Service Rate (1)	$ / kWh	0.0029
Retail Transmission Rate - Line and Transformation Connection Service Rate (1)	$ / kWh	0.0025
Wholesale Market Service Rate (1)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (1)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

Sentinel Lights

Service Charge	$	1.00
Distribution Volumetric Rate	$ / kWh	0.0530
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0006
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0008)
Retail Transmission Rate - Network Service Rate (1)	$ / kWh	0.0029
Retail Transmission Rate - Line and Transformation Connection Service Rate (1)	$ / kWh	0.0025
Wholesale Market Service Rate (1)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (1)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

HYDRO ONE NETWORKS INC.

RATES FOR RETAIL DISTRIBUTION SERVICE

Effective Date: May 1, 2008

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Monthly Rates and Charges

Low Use Secondary Service

Service Charge	$	6.19
Distribution Volumetric Rate	$ / kWh	0.0339
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0009
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0006)
Retail Transmission Rate - Network Service Rate (1)	$ / kWh	0.0035
Retail Transmission Rate - Line and Transformation Connection Service Rate (1)	$ / kWh	0.0032
Wholesale Market Service Rate (1)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (1)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

Customer-Supplied Transformation Allowance

Applicable to customers providing their own transformers:

Primary Voltage under 50 kV (per kW)

Demand Billed	$ / kW	0.60
Energy Billed	cent / kWh	0.14

Transformer Loss Allowance

- Applicable to customers requiring a billing adjustment for transformer losses as the result of being metered on the primary side of a transformer. The following uniform values shall be applied to measured demand and energy to calculate transformer losses for voltages up to and including 50 kV (as metered on the primary side):

(a) 1.5% for transformer installations up to an individual bank capacity of 400 kVA,

(b) 1.0% for bank capacities over 400 kVA.

- Alternatively, transformer losses may be determined from transformer test data, and measured demand and energy adjusted accordingly.

- For services which are not demand metered, an assumed demand of 50% of the transformer capacity will be used to calculate the loss allowance. Where several transformers are involved, the bank capacity is assumed to be the arithmetic sum of all transformer capacities.

HYDRO ONE NETWORKS INC.

RATES FOR RETAIL DISTRIBUTION SERVICE

Effective Date: May 1, 2008

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Loss Factors

Rate Class	Factor
Residential	
UR	1.078
R1	1.085
R2	1.092
Seasonal	1.092
General Service	
GSe	1.092
GSd	1.061
UGe	1.092
UGd	1.061
DGen	1.061
ST	1.034
Lights	
Street	1.092
Sentinel	1.092

Note 1:

For energy-only metered customers, the billing determinant is the customer's metered energy consumption adjusted by the total loss factor as approved by the Board.

For demand billed customers, appropriate loss factors must be applied to the applicable tariffs. Also, the billing determinant for the Line and Transformation Connection Services rate is the customer's peak demand in the billing period. The billing determinant for the Network Services rate is: for non-interval-metered customers, the peak demand in the billing period, and for interval-metered customers, the peak demand between 7 AM and 7 PM local time on IESO business days.

HYDRO ONE NETWORKS INC.

RATES FOR RETAIL DISTRIBUTION SERVICE

Effective Date: May 1, 2008

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MISCELLANEOUS CHARGES

Specific Service Charges: Standard Amounts

Rate Code	Specific Service Charge - Standard Name	Calculation Method			
		2006 Rate Handbook	**Standard Formula**	**Other Formula**	**Time and Materials**
1	Temporary Service	$500			
2	Dispute Meter Test	$30 plus Measurement Canada fees			
3	Collection of account – no disconnection/load limiter	$30			
4	Collection/Disconnect/load limiter/reconnect (at meter) trip – regular hours	$65			
5	Collection/Disconnect/load limiter/reconnect (at meter) trip – after regular hours	$185			
6	Collection/Disconnect/load limiter/reconnect (at pole) trip – regular hours	$185			
7	Collection/Disconnect/load limiter/reconnect (at pole) trip – after regular hours	$415			
8	Account Set-up Charge	$30			
9	Arrears Certificate	$15			
10	NSF Cheque Charge	$15 + bank charges			
11	Easement Charge for Unregistered Rights	$15			
12	Late Payment Charge	1.5%/month			
13a	Retailer Services – Establishing Service Agreements (refer to Handbook for all charges)	$100/agreement/Retailer +$20/month/Retailer +$0.50/month/customer + other			
13b	Retailer Services – Other (includes Bill Ready for Retailers and Service Transactions Requests) as per the Handbook, Chapter 12	$0.30/month/customer + $0.25/request for request fee + $0.50/request for process fee			
14	Special Meter Reads	$30			
15	Service Layout Fee – Basic		$495		
16	Service Layout Fee – Complex		$690		
17	Crossing Application – Pipeline		$2445		
18	Crossing Application – Water		$3045		

Rate Code	Specific Service Charge - Standard Name	Calculation Method			
		2006 Rate Handbook	**Standard Formula**	**Other Formula**	**Time and Materials**
19	Crossing Application – Railroad		$2945		
20	Line Staking – per meter		$3.70		
21	Central Metering – New service < 45 kW		$115		
22	Conversion to Central Metering < 45 kW		$915		
23	Conversion to Central Metering > 45 kW		$800		
24	Tingle Voltage Test – In Excess of 4 Hours (per hour – average 2 additional hours)		$125		
25	Standby Administration Charge per month		$440		
26	Sentinel Lights Rental Rate per month			$7.10	
27	Sentinel Pole Rental Rate per month			$4.15	
28	Joint Use for Cable and Telecom companies per pole			$22.35	
29	Joint Use for LDCs per pole			$28.61	

HYDRO ONE NETWORKS INC.
TARIFF OF RATES AND CHARGES
FOR RETAIL DISTRIBUTION SERVICE
Effective Date: May 1, 2007

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

1.0 APPLICABILITY

These rates are applicable to Hydro One Networks' core retail customers, who are customers of Networks' retail distribution system, excluding those customers previously served by acquired distribution utilities [except for the Street and Sentinel Light rates].

The application of these rates and charges shall be in accordance with The Licence of The Distributor and any Codes, Guidelines or Orders of The Board, and amendments thereto as approved by The Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code, Guideline or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

This schedule does not contain any rates and charges relating to the electricity commodity (e.g. the Regulated Price Plan).

1.1 EFFECTIVE DATES

DISTRIBUTION RATES - May 1, 2007 for all consumption or deemed consumption services used on or after that date.

MISCELLANEOUS CHARGES - May 1, 2007 for all charges billed to customers on or after that date.

RETAIL TRANSMISSION RATES - May 1, 2007 for all consumption or deemed consumption services used on or after that date.

LOSS FACTOR ADJUSTMENT – May 1, 2007.

1.2 CUSTOMER CLASSIFICATIONS

Residential - Year-round customer classification applies to a customer's main place of abode and may include additional buildings served through the same meter, provided they are not rental income units. All of the following criteria must be met:

1. Occupants must state that this is their principal residence for purposes of the Income Tax Act.
2. The occupant must live in this residence for at least 8 months of the calendar year.
3. The address of this residence must appear on documents such as the occupant's electric bill, driver's licence, credit card invoice, property tax bill, etc.
4. Occupants who are eligible to vote in Provincial or Federal elections must be enumerated for this purpose at the address of this residence.

Seasonal Residential customer classification is defined as any residential service not meeting the Residential Year-round criteria. It includes dwellings such as cottages, chalets and camps.

Farm classification is applicable to properties actively engaged in agricultural production as defined by Statistics Canada. It does not include tree, sod, or pet farms. Services to year-round pumping stations or other ancillary services remote from the main farm shall be classed as farm.

Industrial Commercial classification applies to any service that does not fit the description of Residential or Farm classes. It includes combination type services where a variety of uses are made of the service by the owner of one property, and all multiple services except residential.

Industrial Commercial General Service customer classification is applicable for Industrial Commercial customers not directly supplied by the sub-transmission system.

Industrial Commercial Sub-Transmission customer classification is applicable for Industrial Commercial customers supplied directly by the sub-transmission system.

1.3 DENSITY ZONES

Urban Density Zone is defined as areas containing 3,000 or more customers with a line density of at least 60 customers per kilometre.

High Density Zone is defined as areas containing 100 or more customers with a line density of at least 15 customers per kilometre.

Normal Density Zone is defined as areas other than Urban or High Density Zone.

1.4 RATE CLASSES

Residential

- UR2 [UR] Year-round residence in an Urban Density Zone, and Farm Single Phase customers which are energy-billed in an Urban Density Zone
- R1 Year-round Residence in a High Density Zone
- R2 Year-round Residence in a Normal Density Zone

Seasonal Residential

- R3 Seasonal Occupancy in a High Density
- R4 Seasonal Occupancy in a Normal Density Zone

Farms

- F1 Single Phase Farm Customers actively engaged in agricultural production, in areas other than Urban Density Zones
- F3 Three Phase Farm Customers actively engaged in agricultural production, in areas other than an Urban Density Zone

General Service

- UG2[UG] Industrial Commercial General Service, Urban Density
Applicable to Farm Three Phase customers, Farm Single Phase demand-billed customers, and Industrial Commercial customers located in an Urban Density Zone
- G1 Industrial Commercial General Service, Single Phase G1
Applicable to General Class Single Phase customers not located in an Urban Density Zone
- G3 Industrial Commercial General Service, Three Phase G3
Applicable to General Service Class Three Phase customers not located in an Urban Density Zone
- T Industrial Commercial Sub-Transmission T
Applicable to Industrial Commercial Sub-Transmission class customers not located in an Urban Density Zone

1.5 RURAL OR REMOTE RATE PROTECTION

Under the *Ontario Energy Board Act, 1998* and associated regulations, every qualifying year-round residence and farm with a principal residence is eligible to receive Rural or Remote Rate Protection (RRRP). The service charge shown for eligible R2, F1 and F3 customers would be reduced by the applicable RRRP credit.

1.6 SPECIAL RATE CLASSES:

- Low Use Secondary Service:
  - Applicable to separately metered services connected prior to January 1, 1996.
  - Applicable to supplementary service located on the same property as the primary service, supplied from the same transformer, with the same owner, separately metered, and which consumes less than specific yearly amounts:

Secondary Service	Volumes [kWh per year]
R1	1,500
R2	1,500
R3	500
R4	500
F1	2,500
F3	2,500
G1	2,500
G3	2,500

- Transformer Loss Allowance:
  - Applicable to customers requiring a billing adjustment for transformer losses as the result of being metered on the primary side of a transformer.

- Customer-Supplied Transformation Allowance:
  - Applicable to demand-billed customers providing their own transformers.

- Sentinel Lights

  This rate is applicable to all Hydro One Networks' core and acquired retail customers who have separate service to a sentinel light. Networks' core retail customers are customers of Networks' retail distribution system, excluding those customers previously served by acquired distribution utilities.

  The energy consumption for sentinel lights is estimated based on Networks' profile for sentinel lighting load, which provides the amount of time each month that the sentinel lights are operating.

  Distribution Volumetric Energy Charge is on metered or estimated usage (per kWh)

- Street Lights

  This rate is applicable to all Hydro One Networks' core and acquired retail customers who have streetlights. Networks' core retail customers are customers of Networks' retail distribution system, excluding those customers previously served by acquired distribution utilities.

  Distribution Volumetric Energy Charge is on metered or estimated usage (per kWh)

  The energy consumption for street lights is estimated based on Networks' profile for street lighting load, which provides the amount of time each month that the street lights are operating.

- Unmetered Scattered Load

  This classification refers to certain instances where connections can be provided without metering. These loads are generally small in size and consistent in magnitude of load. Hydro One reserves the right to review all cases and may require that a meter be installed at its sole discretion. Services that can be unmetered include cable TV amplifiers, telephone switching devices, phone booths, bus shelters, rail way crossing signals, traffic signals, and other small fixed loads.

  Further servicing details are available in the utility's Conditions of Service (including in the "Unmetered Connections" section).

- Interim Demand-Side Management Time-of-Use Rates

  Demand charges will be based on demand during the on-peak periods.

Eligibility Criteria

Customers' in the following rate classes having electricity consumption, (billing demand), in the off-peak period that is at least twice the electricity consumption during the on-peak period.

Definition of Time Periods

The on-peak hours will be between 0700 hours to 1900 hours Eastern Standard Time during the winter (standard time) on IESO business days and 0600 hours to 1800 hours Eastern Standard Time during the summer (daylight savings time) on IESO business days. The off-peak period constitutes all of the remaining hours.

Time-of-Use Rate Classes

Farm Single Phase *ToU* F1 – Applicable to Single Phase Farm Customers actively engaged in agricultural production, in areas other than Urban Density Zones

Farm Three Phase *ToU* F3 – Applicable to Three Phase Farm Customers actively engaged in agricultural production, in other areas than Urban Density zone

Industrial Commercial General Service, Urban Density *ToU* UG2 – Applicable to Farm Three Phase Customers, farm Single Phase demand-billed customers, and Industrial Commercial customers located in an Urban Density Zone

Industrial Commercial General Service, Single Phase *ToU* G1 – Applicable to General Service Class Single Phase customers not located in an Urban Density Zone

Industrial Commercial General Service, Three Phase *ToU* G3 – Applicable to General Service Class Three Phase customers not located in an Urban Density Zone

Industrial Commercial Sub-Transmission *ToU* T – Applicable to Industrial Commercial Sub-Transmission class customers not located in an Urban Density Zone

HYDRO ONE NETWORKS INC.
RATES FOR RETAIL DISTRIBUTION SERVICE
Effective Date: May 1, 2007

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

Monthly Rates and Charges

Residential – Urban [UR]

Service Charge	$	14.32
Distribution Volumetric Rate	$ / kWh	0.0183
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0020
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0005
Retail Transmission Rate - Network Service Rate (1)	$ / kWh	0.0052
Retail Transmission Rate - Line and Transformation Connection Service Rate (1)	$ / kWh	0.0042
Wholesale Market Service Rate (1)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (1)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

Residential – High Density [R1]

Service Charge	$	19.04
Distribution Volumetric Rate	$ / kWh	0.0238
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0015
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0007
Retail Transmission Rate - Network Service Rate (1)	$ / kWh	0.0052
Retail Transmission Rate - Line and Transformation Connection Service Rate (1)	$ / kWh	0.0042
Wholesale Market Service Rate (1)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (1)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

Residential – Normal Density [R2]

Service Charge[a]	$	57.72
Distribution Volumetric Rate	$ / kWh	0.0194
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0012
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0013
Retail Transmission Rate - Network Service Rate (1)	$ / kWh	0.0052
Retail Transmission Rate - Line and Transformation Connection Service Rate (1)	$ / kWh	0.0042
Wholesale Market Service Rate (1)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (1)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

[a] Under the Ontario Energy Board Act, 1998 and associated regulations, every qualifying year-round residence and farm with a principal residence is eligible to receive Rural or Remote Rate Protection (RRRP). The service charge shown for eligible R2 customers would be reduced by the applicable RRRP credit.

HYDRO ONE NETWORKS INC.
RATES FOR RETAIL DISTRIBUTION SERVICE
Effective Date: May 1, 2007

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Monthly Rates and Charges

Seasonal Residential – High Density [R3]

Service Charge	$	19.51
Distribution Volumetric Rate	$ / kWh	0.0274
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0035
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0015
Retail Transmission Rate - Network Service Rate (1)	$ / kWh	0.0041
Retail Transmission Rate - Line and Transformation Connection Service Rate (1)	$ / kWh	0.0040
Wholesale Market Service Rate (1)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (1)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

Seasonal Residential – Normal Density [R4]

Service Charge	$	36.36
Distribution Volumetric Rate	$ / kWh	0.0192
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0036
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0024
Retail Transmission Rate - Network Service Rate (1)	$ / kWh	0.0041
Retail Transmission Rate - Line and Transformation Connection Service Rate (1)	$ / kWh	0.0040
Wholesale Market Service Rate (1)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (1)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

Farms – Single Phase energy-billed [F1]

Service Charge[b]	$	60.71
Distribution Volumetric Rate	$ / kWh	0.0224
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0008
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0010
Retail Transmission Rate - Network Service Rate (1)	$ / kWh	0.0050
Retail Transmission Rate - Line and Transformation Connection Service Rate (1)	$ / kWh	0.0039
Wholesale Market Service Rate (1)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (1)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

[b] Under the Ontario Energy Board Act, 1998 and associated regulations, every qualifying year-round residence and farm with a principal residence is eligible to receive Rural or Remote Rate Protection (RRRP). The service charge shown for eligible F1 & F3 customers would be reduced by the applicable RRRP credit.

1.4 RATE CLASSES

Residential

- UR2 [UR] Year-round residence in an Urban Density Zone, and Farm Single Phase customers which are energy-billed in an Urban Density Zone
- R1 Year-round Residence in a High Density Zone
- R2 Year-round Residence in a Normal Density Zone

Seasonal Residential

- R3 Seasonal Occupancy in a High Density
- R4 Seasonal Occupancy in a Normal Density Zone

Farms

- F1 Single Phase Farm Customers actively engaged in agricultural production, in areas other than Urban Density Zones
- F3 Three Phase Farm Customers actively engaged in agricultural production, in areas other than an Urban Density Zone

General Service

- UG2[UG] Industrial Commercial General Service, Urban Density
  Applicable to Farm Three Phase customers, Farm Single Phase demand-billed customers, and Industrial Commercial customers located in an Urban Density Zone
- G1 Industrial Commercial General Service, Single Phase G1
  Applicable to General Class Single Phase customers not located in an Urban Density Zone
- G3 Industrial Commercial General Service, Three Phase G3
  Applicable to General Service Class Three Phase customers not located in an Urban Density Zone
- T Industrial Commercial Sub-Transmission T
  Applicable to Industrial Commercial Sub-Transmission class customers not located in an Urban Density Zone

1.5 RURAL OR REMOTE RATE PROTECTION

Under the *Ontario Energy Board Act, 1998* and associated regulations, every qualifying year-round residence and farm with a principal residence is eligible to receive Rural or Remote Rate Protection (RRRP). The service charge shown for eligible R2, F1 and F3 customers would be reduced by the applicable RRRP credit.

HYDRO ONE NETWORKS INC.
RATES FOR RETAIL DISTRIBUTION SERVICE
Effective Date: May 1, 2007

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

Monthly Rates and Charges

General Service Less Than 50 kW – Urban energy-billed [UG]

Service Charge if Metered	$	15.79
Service Charge if Unmetered	$	0.79
Distribution Volumetric Rate	$ / kWh	0.0274
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0003
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0003
Retail Transmission Rate - Network Service Rate (1)	$ / kWh	0.0052
Retail Transmission Rate - Line and Transformation Connection Service Rate (1)	$ / kWh	0.0033
Wholesale Market Service Rate (1)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (1)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service Less Than 50 kW – Single Phase energy-billed [G1]

Service Charge if Metered	$	36.93
Service Charge if Unmetered	$	22.16
Distribution Volumetric Rate	$ / kWh	0.0312
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0009
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0009
Retail Transmission Rate - Network Service Rate (1)	$ / kWh	0.0052
Retail Transmission Rate - Line and Transformation Connection Service Rate (1)	$ / kWh	0.0034
Wholesale Market Service Rate (1)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (1)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service Less Than 50 kW – Three Phase energy-billed [G3]

Service Charge if Metered	$	46.78
Service Charge if Unmetered	$	6.29
Distribution Volumetric Rate	$ / kWh	0.0307
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0002
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0005
Retail Transmission Rate - Network Service Rate (1)	$ / kWh	0.0052
Retail Transmission Rate - Line and Transformation Connection Service Rate (1)	$ / kWh	0.0033
Wholesale Market Service Rate (1)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (1)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

HYDRO ONE NETWORKS INC.
RATES FOR RETAIL DISTRIBUTION SERVICE
Effective Date: May 1, 2007

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

Monthly Rates and Charges

General Service Less Than 50 kW – Transmission Class energy-billed [T]

Service Charge	$	261.54
Distribution Volumetric Rate	$ / kWh	0.0243
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0001
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0003
Retail Transmission Rate - Network Service Rate (1)	$ / kWh	0.0051
Retail Transmission Rate - Line and Transformation Connection Service Rate (1)	$ / kWh	0.0033
Wholesale Market Service Rate (1)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (1)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service 50 to 4999 kW – Urban demand-billed [UG]

Service Charge	$	15.79
Distribution Volumetric Rate	$ / kW	8.44
Regulatory Asset Recovery - Rider #1	$ / kW	0.10
Regulatory Asset Recovery - Rider #2	$ / kW	0.11
Retail Transmission Rate - Network Service Rate (1)	$ / kW	1.584
Retail Transmission Rate - Line and Transformation Connection Service Rate (1)	$ / kW	0.998
Wholesale Market Service Rate (1)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (1)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service 50 to 4999 kW – Single Phase demand-billed [G1]

Service Charge	$	36.93
Distribution Volumetric Rate	$ / kW	9.59
Regulatory Asset Recovery - Rider #1	$ / kW	0.26
Regulatory Asset Recovery - Rider #2	$ / kW	0.29
Retail Transmission Rate - Network Service Rate (1)	$ / kW	1.603
Retail Transmission Rate - Line and Transformation Connection Service Rate (1)	$ / kW	1.016
Wholesale Market Service Rate (1)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (1)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

HYDRO ONE NETWORKS INC.
RATES FOR RETAIL DISTRIBUTION SERVICE
Effective Date: May 1, 2007

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

Monthly Rates and Charges

General Service 50 to 4999 kW – Three Phase demand-billed [G3]

Service Charge	$	46.78
Distribution Volumetric Rate	$ / kW	9.91
Regulatory Asset Recovery - Rider #1	$ / kW	0.08
Regulatory Asset Recovery - Rider #2	$ / kW	0.15
Retail Transmission Rate - Network Service Rate (1)	$ / kW	1.687
Retail Transmission Rate - Line and Transformation Connection Service Rate (1)	$ / kW	1.065
Wholesale Market Service Rate (1)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (1)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service 50 to 4999 kW – Transmission Class demand-billed [T]

Service Charge	$	261.54
Distribution Volumetric Rate	$ / kW	8.16
Regulatory Asset Recovery - Rider #1	$ / kW	0.04
Regulatory Asset Recovery - Rider #2	$ / kW	0.09
Retail Transmission Rate - Network Service Rate (1)	$ / kW	1.734
Retail Transmission Rate - Line and Transformation Connection Service Rate (1)	$ / kW	1.083
Wholesale Market Service Rate (1)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (1)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

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Interim Demand-Side Management Time-of-Use
General Service 50 to 4999 kW – Farm Single Phase [F1]

Service Charge	$	60.71
Distribution Volumetric Rate	$ / kW	7.06
Regulatory Asset Recovery - Rider #1	$ / kW	0.26
Regulatory Asset Recovery - Rider #2	$ / kW	0.31
Retail Transmission Rate - Network Service Rate (1)	$ / kW	1.593
Retail Transmission Rate - Line and Transformation Connection Service Rate (1)	$ / kW	1.236
Wholesale Market Service Rate (1)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (1)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

Interim Demand-Side Management Time-of-Use
General Service 50 to 4999 kW – Farm Three Phase [F3]

Service Charge	$	53.91
Distribution Volumetric Rate	$ / kW	10.87
Regulatory Asset Recovery - Rider #1	$ / kW	0.10
Regulatory Asset Recovery - Rider #2	$ / kW	0.16
Retail Transmission Rate - Network Service Rate (1)	$ / kW	1.800
Retail Transmission Rate - Line and Transformation Connection Service Rate (1)	$ / kW	1.329
Wholesale Market Service Rate (1)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (1)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

Interim Demand-Side Management Time-of-Use
General Service 50 to 4999 kW – Urban [UG]

Service Charge	$	15.79
Distribution Volumetric Rate	$ / kW	8.44
Regulatory Asset Recovery - Rider #1	$ / kW	0.10
Regulatory Asset Recovery - Rider #2	$ / kW	0.11
Retail Transmission Rate - Network Service Rate (1)	$ / kW	1.584
Retail Transmission Rate - Line and Transformation Connection Service Rate (1)	$ / kW	0.998
Wholesale Market Service Rate (1)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (1)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) – Administration Charge	$	0.25

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Monthly Rates and Charges

Interim Demand-Side Management Time-of-Use
General Service 50 to 4999 kW – Single Phase [G1]

Service Charge	$	36.93
Distribution Volumetric Rate	$ / kW	9.59
Regulatory Asset Recovery - Rider #1	$ / kW	0.26
Regulatory Asset Recovery - Rider #2	$ / kW	0.29
Retail Transmission Rate - Network Service Rate (1)	$ / kW	1.603
Retail Transmission Rate - Line and Transformation Connection Service Rate (1)	$ / kW	1.016
Wholesale Market Service Rate (1)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (1)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

Interim Demand-Side Management Time-of-Use
General Service 50 to 4999 kW – Three Phase [G3]

Service Charge	$	46.78
Distribution Volumetric Rate	$ / kW	9.91
Regulatory Asset Recovery - Rider #1	$ / kW	0.08
Regulatory Asset Recovery - Rider #2	$ / kW	0.15
Retail Transmission Rate - Network Service Rate (1)	$ / kW	1.687
Retail Transmission Rate - Line and Transformation Connection Service Rate (1)	$ / kW	1.065
Wholesale Market Service Rate (1)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (1)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

Interim Demand-Side Management Time-of-Use
General Service 50 to 4999 kW – Transmission Class [T]

Service Charge	$	261.54
Distribution Volumetric Rate	$ / kW	8.16
Regulatory Asset Recovery - Rider #1	$ / kW	0.04
Regulatory Asset Recovery - Rider #2	$ / kW	0.09
Retail Transmission Rate - Network Service Rate (1)	$ / kW	1.734
Retail Transmission Rate - Line and Transformation Connection Service Rate (1)	$ / kW	1.083
Wholesale Market Service Rate (1)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (1)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) – Administration Charge	$	0.25

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Monthly Rates and Charges

Low Use Secondary – Residential, Seasonal and Single Phase General Service R1,R2,R3,R4,G1

Service Charge	$	-
Distribution Volumetric Rate	$ / kWh	0.0325
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0009
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0009
Retail Transmission Rate - Network Service Rate (1)	$ / kWh	0.0052
Retail Transmission Rate - Line and Transformation Connection Service Rate (1)	$ / kWh	0.0034
Wholesale Market Service Rate (1)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (1)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

Low Use Secondary – Single Phase Farms F1

Service Charge	$	-
Distribution Volumetric Rate	$ / kWh	0.0237
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0008
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0010
Retail Transmission Rate - Network Service Rate (1)	$ / kWh	0.0050
Retail Transmission Rate - Line and Transformation Connection Service Rate (1)	$ / kWh	0.0039
Wholesale Market Service Rate (1)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (1)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

Low Use Secondary – Three Phase Farms and General Service F3,G3

Service Charge	$	-
Distribution Volumetric Rate	$ / kWh	0.0320
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0002
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0005
Retail Transmission Rate - Network Service Rate (1)	$ / kWh	0.0052
Retail Transmission Rate - Line and Transformation Connection Service Rate (1)	$ / kWh	0.0033
Wholesale Market Service Rate (1)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (1)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

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Monthly Rates and Charges

Street Lights

Service Charge	$	-
Distribution Volumetric Rate	$ / kWh	0.0396
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0001
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0006
Retail Transmission Rate - Network Service Rate (1)	$ / kWh	0.0030
Retail Transmission Rate - Line and Transformation Connection Service Rate (1)	$ / kWh	0.0023
Wholesale Market Service Rate (1)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (1)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

Sentinel Lights

Service Charge	$	-
Distribution Volumetric Rate	$ / kWh	0.0396
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0001
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0006
Retail Transmission Rate - Network Service Rate (1)	$ / kWh	0.0030
Retail Transmission Rate - Line and Transformation Connection Service Rate (1)	$ / kWh	0.0023
Wholesale Market Service Rate (1)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (1)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

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Monthly Rates and Charges

Customer-Supplied Transformation Allowance

Applicable to demand-billed customers providing their own transformers:

Primary Voltage under 50 kV (per kW)

Single Phase	$ / kW	0.20
Three Phase	$ / kW	0.60

Transformer Loss Allowance

- Applicable to customers requiring a billing adjustment for transformer losses as the result of being metered on the primary side of a transformer. The following uniform values shall be applied to measured demand and energy to calculate transformer losses for voltages up to and including 50 kV (as metered on the primary side):

  (a) 1.5% for transformer installations up to an individual bank capacity of 400 kVA,
  (b) 1.0% for bank capacities over 400 kVA.

- Alternatively, transformer losses may be determined from transformer test data, and measured demand and energy adjusted accordingly.

- For services which are not demand metered, an assumed demand of 50% of the transformer capacity will be used to calculate the loss allowance. Where several transformers are involved, the bank capacity is assumed to be the arithmetic sum of all transformer capacities.

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Loss Factors

Rate Class	Factor
Residential	
UR	1.092
R1	1.092
R2	1.092
Seasonal	
R3	1.092
R4	1.092
Farms	
F1	1.092
F3	1.061
General Service	
UG	1.092
G1	1.092
G3	1.061
T	1.061
Lights	
Street	1.092
Sentinel	1.092

Note 1:
For energy-only metered customers, the billing determinant is the customer’s metered energy consumption adjusted by the total loss factor as approved by the Board.

For demand billed customers, appropriate loss factors must be applied to the applicable tariffs. Also, the billing determinant for the Line and Transformation Connection Services rate is the customer’s peak demand in the billing period. The billing determinant for the Network Services rate is: for non-interval-metered customers, the peak demand in the billing period, and for interval-metered customers, the peak demand between 7 AM and 7 PM local time on IESO business days.

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MISCELLANEOUS CHARGES
Specific Service Charges: Standard Amounts

Rate Code	Specific Service Charge – Standard Name	Calculation Method			
		2006 Rate Handbook	Standard Formula	Other Formula	Time and Materials
1	Temporary Service	$500			
2	Dispute Meter Test	$30 plus Measurement Canada fees			
3	Collection of account – no disconnection/load limiter	$30			
4	Collection/Disconnect/load limiter/reconnect (at meter) trip – regular hours	$65			
5	Collection/Disconnect/load limiter/reconnect (at meter) trip – after regular hours	$185			
6	Collection/Disconnect/load limiter/reconnect (at pole) trip – regular hours	$185			
7	Collection/Disconnect/load limiter/reconnect (at pole) trip – after regular hours	$415			
8	Account Set-up Charge	$30			
9	Arrears Certificate	$15			
10	NSF Cheque Charge	$15 + bank charges			
11	Easement Charge for Unregistered Rights	$15			
12	Late Payment Charge	1.5%/month			
13a	Retailer Services – Establishing Service Agreements (refer to Handbook for all charges)	$100/agreement/Retailer +$20/month/Retailer +$0.50/month/customer + other			
13b	Retailer Services – Other (includes Bill Ready for Retailers and Service Transactions Requests) as per the Handbook, Chapter 12	$0.30/month/customer + $0.25/request for request fee + $0.50/request for process fee			
14	Special Meter Reads	$30			

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MISCELLANEOUS CHARGES

Specific Service Charges: Standard Amounts

Rate Code	Specific Service Charge – Standard Name	Calculation Method			
		2006 Rate Handbook	Standard Formula	Other Formula	Time and Materials
15	Billing Suspension and Terminations in Trailer Parks		$130		
16	Service Layout Fee – Basic		$405		
17	Service Layout Fee – Complex		$580		
18	Crossing Application – Pipeline		$2,065		
19	Crossing Application – Water		$2,525		
20	Crossing Application – Railroad		$2,565		
21	Line Staking – per meter		$3.10		
22	Central Metering – New service < 45 kW		$115		
23	Conversion to Central Metering < 45 kW		$795		
24	Conversion to Central Metering > 45 kW		$680		
25	Tingle Voltage Test – In Excess of 4 Hours (per hour – average 2 additional hours)		$105		
26	Standby Administration Charge per month (interim)		$375		
27	Sentinel Lights Rental Rate per month – Mercury Vapor			$7.00	
28	Guaranteed Units from Jan 01/91 to Aug 01/91			$26.50 / month	

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MISCELLANEOUS CHARGES

Specific Service Charges: Standard Amounts

29	Guaranteed Units from Jan 01/87 to Dec 31/90			$23.50 / month	
30	Joint Use for Cable and Telecom companies per pole			$22.35	
31	Joint Use for LDCs per pole			$28.61	

New Rate Class: UR

Bill Impacts of Proposed Distribution Rates exclude Riders

Classes		Scenario	Existing Dx Rates			Proposed Dx Rates			$ Incr	% Incr
			SrChg	base	Dx bill	SrChg	base	Dx bill		
New Class	Old Class	kWh	[$/month]	[c/kWh]	[$/month]	[$/month]	[c/kWh]	[$/month]		
UR	UR	100	14.32	1.83	16.15	14.00	2.44	16.44	0.29	1.8%
		250	14.32	1.83	18.90	14.00	2.44	20.10	1.21	6.4%
		500	14.32	1.83	23.47	14.00	2.44	26.20	2.73	11.6%
		750	14.32	1.83	28.05	14.00	2.44	32.30	4.26	15.2%
		1,000	14.32	1.83	32.62	14.00	2.44	38.41	5.79	17.7%
		1,500	14.32	1.83	41.77	14.00	2.44	50.61	8.84	21.2%
		2,000	14.32	1.83	50.92	14.00	2.44	62.81	11.89	23.4%
UR	R1	100	19.04	2.38	21.42	14.00	2.44	16.44	(4.98)	-23.2%
		250	19.04	2.38	24.99	14.00	2.44	20.10	(4.89)	-19.6%
		500	19.04	2.38	30.94	14.00	2.44	26.20	(4.74)	-15.3%
		750	19.04	2.38	36.89	14.00	2.44	32.30	(4.59)	-12.4%
		1,000	19.04	2.38	42.84	14.00	2.44	38.41	(4.43)	-10.3%
		1,500	19.04	2.38	54.74	14.00	2.44	50.61	(4.13)	-7.5%
		2,000	19.04	2.38	66.64	14.00	2.44	62.81	(3.83)	-5.7%
UR	R2	100	29.22	1.94	31.16	14.00	2.44	16.44	(14.72)	-47.2%
		250	29.22	1.94	34.07	14.00	2.44	20.10	(13.97)	-41.0%
		500	29.22	1.94	38.92	14.00	2.44	26.20	(12.72)	-32.7%
		750	29.22	1.94	43.77	14.00	2.44	32.30	(11.47)	-26.2%
		1,000	29.22	1.94	48.62	14.00	2.44	38.41	(10.21)	-21.0%
		1,500	29.22	1.94	58.32	14.00	2.44	50.61	(7.71)	-13.2%
		2,000	29.22	1.94	68.02	14.00	2.44	62.81	(5.21)	-7.7%
UR	F1	100	28.61	2.24	30.85	14.00	2.44	16.44	(14.41)	-46.7%
		250	28.61	2.24	34.21	14.00	2.44	20.10	(14.11)	-41.2%
		500	28.61	2.24	39.81	14.00	2.44	26.20	(13.61)	-34.2%
		750	28.61	2.24	45.41	14.00	2.44	32.30	(13.11)	-28.9%
		1,000	28.61	2.24	51.01	14.00	2.44	38.41	(12.60)	-24.7%
		1,500	28.61	2.24	62.21	14.00	2.44	50.61	(11.60)	-18.6%
		2,000	28.61	2.24	73.41	14.00	2.44	62.81	(10.60)	-14.4%

New Rate Class: UR

Bill Impacts of Proposed Distribution Rates exclude Riders

Classes		Scenario	Existing Dx Rates			Proposed Dx Rates			$ Incr	% Incr
			SrChg	base	Dx bill	SrChg	base	Dx bill		
New Class	Old Class	kWh	[$/month]	[c/kWh]	[$/month]	[$/month]	[c/kWh]	[$/month]		
UR	Arnprior	100	11.54	1.47	13.01	11.70	2.40	14.09	1.08	8.3%
		250	11.54	1.47	15.22	11.70	2.40	17.68	2.47	16.2%
		500	11.54	1.47	18.89	11.70	2.40	23.67	4.78	25.3%
		750	11.54	1.47	22.57	11.70	2.40	29.66	7.10	31.5%
		1,000	11.54	1.47	26.24	11.70	2.40	35.65	9.41	35.9%
		1,500	11.54	1.47	33.59	11.70	2.40	47.63	14.04	41.8%
		2,000	11.54	1.47	40.94	11.70	2.40	59.61	18.67	45.6%
UR	Brockville	100	12.33	0.93	13.26	12.50	2.40	14.89	1.63	12.3%
		250	12.33	0.93	14.66	12.50	2.40	18.49	3.83	26.1%
		500	12.33	0.93	16.98	12.50	2.40	24.48	7.50	44.1%
		750	12.33	0.93	19.31	12.50	2.40	30.47	11.16	57.8%
		1,000	12.33	0.93	21.63	12.50	2.40	36.46	14.83	68.5%
		1,500	12.33	0.93	26.28	12.50	2.40	48.43	22.15	84.3%
		2,000	12.33	0.93	30.93	12.50	2.40	60.41	29.48	95.3%
UR	Caledon OH 01	100	18.52	0.57	19.09	16.95	2.15	19.10	0.01	0.1%
		250	18.52	0.57	19.95	16.95	2.15	22.33	2.38	11.9%
		500	18.52	0.57	21.37	16.95	2.15	27.70	6.33	29.6%
		750	18.52	0.57	22.80	16.95	2.15	33.08	10.28	45.1%
		1,000	18.52	0.57	24.22	16.95	2.15	38.45	14.23	58.8%
		1,500	18.52	0.57	27.07	16.95	2.15	49.20	22.13	81.8%
		2,000	18.52	0.57	29.92	16.95	2.15	59.95	30.03	100.4%
UR	Carleton Place	100	14.17	1.79	15.96	14.04	2.40	16.43	0.47	3.0%
		250	14.17	1.79	18.65	14.04	2.40	20.03	1.38	7.4%
		500	14.17	1.79	23.12	14.04	2.40	26.02	2.90	12.5%
		750	14.17	1.79	27.60	14.04	2.40	32.01	4.41	16.0%
		1,000	14.17	1.79	32.07	14.04	2.40	38.00	5.93	18.5%
		1,500	14.17	1.79	41.02	14.04	2.40	49.97	8.95	21.8%
		2,000	14.17	1.79	49.97	14.04	2.40	61.95	11.98	24.0%

New Rate Class: UR

Bill Impacts of Proposed Distribution Rates exclude Riders

Classes		**Scenario**	Existing Dx Rates			Proposed Dx Rates			$ Incr	% Incr
			SrChg	base	Dx bill	SrChg	base	Dx bill		
New Class	**Old Class**	kWh	[$/month]	[c/kWh]	[$/month]	[$/month]	[c/kWh]	[$/month]		
UR	**Dryden**	100	14.28	1.65	15.93	14.01	2.40	16.41	0.48	3.0%
		250	14.28	1.65	18.41	14.01	2.40	20.00	1.59	8.7%
		500	14.28	1.65	22.53	14.01	2.40	25.99	3.46	15.4%
		750	14.28	1.65	26.66	14.01	2.40	31.98	5.32	20.0%
		1,000	14.28	1.65	30.78	14.01	2.40	37.97	7.19	23.4%
		1,500	14.28	1.65	39.03	14.01	2.40	49.95	10.92	28.0%
		2,000	14.28	1.65	47.28	14.01	2.40	61.93	14.65	31.0%
UR	**GBE**	100	9.68	0.95	10.63	10.16	2.35	12.51	1.88	17.7%
		250	9.68	0.95	12.06	10.16	2.35	16.04	3.98	33.0%
		500	9.68	0.95	14.43	10.16	2.35	21.91	7.48	51.8%
		750	9.68	0.95	16.81	10.16	2.35	27.79	10.98	65.3%
		1,000	9.68	0.95	19.18	10.16	2.35	33.66	14.48	75.5%
		1,500	9.68	0.95	23.93	10.16	2.35	45.41	21.48	89.8%
		2,000	9.68	0.95	28.68	10.16	2.35	57.16	28.48	99.3%
UR	**Lindsay**	100	15.81	1.01	16.82	14.63	2.40	17.02	0.20	1.2%
		250	15.81	1.01	18.34	14.63	2.40	20.62	2.28	12.4%
		500	15.81	1.01	20.86	14.63	2.40	26.61	5.75	27.5%
		750	15.81	1.01	23.39	14.63	2.40	32.60	9.21	39.4%
		1,000	15.81	1.01	25.91	14.63	2.40	38.59	12.68	48.9%
		1,500	15.81	1.01	30.96	14.63	2.40	50.56	19.60	63.3%
		2,000	15.81	1.01	36.01	14.63	2.40	62.54	26.53	73.7%
UR	**Perth**	100	14.47	1.22	15.69	13.96	2.40	16.36	0.67	4.3%
		250	14.47	1.22	17.52	13.96	2.40	19.95	2.43	13.9%
		500	14.47	1.22	20.57	13.96	2.40	25.94	5.37	26.1%
		750	14.47	1.22	23.62	13.96	2.40	31.93	8.31	35.2%
		1,000	14.47	1.22	26.67	13.96	2.40	37.92	11.25	42.2%
		1,500	14.47	1.22	32.77	13.96	2.40	49.90	17.13	52.3%
		2,000	14.47	1.22	38.87	13.96	2.40	61.88	23.01	59.2%

New Rate Class: UR

Bill Impacts of Proposed Distribution Rates exclude Riders

Classes		Scenario	Existing Dx Rates			Proposed Dx Rates			$ Incr	% Incr
			SrChg	base	Dx bill	SrChg	base	Dx bill		
New Class	Old Class	kWh	[$/month]	[c/kWh]	[$/month]	[$/month]	[c/kWh]	[$/month]		
UR	**Quinte West**	100	6.58	0.92	7.50	7.94	2.10	10.04	2.54	33.8%
		250	6.58	0.92	8.88	7.94	2.10	13.19	4.31	48.5%
		500	6.58	0.92	11.18	7.94	2.10	18.44	7.26	64.9%
		750	6.58	0.92	13.48	7.94	2.10	23.69	10.21	75.7%
		1,000	6.58	0.92	15.78	7.94	2.10	28.94	13.16	83.4%
		1,500	6.58	0.92	20.38	7.94	2.10	39.44	19.06	93.5%
		2,000	6.58	0.92	24.98	7.94	2.10	49.94	24.96	99.9%
UR	**Smiths Falls**	100	12.63	1.42	14.05	12.42	2.40	14.82	0.77	5.5%
		250	12.63	1.42	16.18	12.42	2.40	18.41	2.23	13.8%
		500	12.63	1.42	19.73	12.42	2.40	24.40	4.67	23.7%
		750	12.63	1.42	23.28	12.42	2.40	30.39	7.11	30.5%
		1,000	12.63	1.42	26.83	12.42	2.40	36.38	9.55	35.6%
		1,500	12.63	1.42	33.93	12.42	2.40	48.36	14.43	42.5%
		2,000	12.63	1.42	41.03	12.42	2.40	60.34	19.31	47.1%
UR	**Thorold**	100	13.68	1.47	15.15	13.16	2.40	15.56	0.41	2.7%
		250	13.68	1.47	17.36	13.16	2.40	19.15	1.79	10.3%
		500	13.68	1.47	21.03	13.16	2.40	25.14	4.11	19.5%
		750	13.68	1.47	24.71	13.16	2.40	31.13	6.42	26.0%
		1,000	13.68	1.47	28.38	13.16	2.40	37.12	8.74	30.8%
		1,500	13.68	1.47	35.73	13.16	2.40	49.10	13.37	37.4%
		2,000	13.68	1.47	43.08	13.16	2.40	61.08	18.00	41.8%
UR	**Whitchurch Stouffville**	100	10.54	1.02	11.56	10.95	2.30	13.25	1.69	14.6%
		250	10.54	1.02	13.09	10.95	2.30	16.70	3.61	27.5%
		500	10.54	1.02	15.64	10.95	2.30	22.45	6.81	43.5%
		750	10.54	1.02	18.19	10.95	2.30	28.20	10.01	55.0%
		1,000	10.54	1.02	20.74	10.95	2.30	33.95	13.21	63.7%
		1,500	10.54	1.02	25.84	10.95	2.30	45.45	19.61	75.9%
		2,000	10.54	1.02	30.94	10.95	2.30	56.95	26.01	84.0%

New Rate Class: R1

Bill Impacts of Proposed Distribution Rates excluding Riders

Classes		Scenario	Existing Dx Rates			Proposed Dx Rates			$ Incr	% Incr
			SrChg	base	Dx bill	SrChg	base	Dx bill		
New Class	Old Class	kWh	[$/month]	[c/kWh]	[$/month]	[$/month]	[c/kWh]	[$/month]		
R1	R1	100	19.04	2.38	21.42	19.00	2.81	21.81	0.39	1.8%
		250	19.04	2.38	24.99	19.00	2.81	26.01	1.02	4.1%
		500	19.04	2.38	30.94	19.00	2.81	33.03	2.09	6.7%
		750	19.04	2.38	36.89	19.00	2.81	40.04	3.15	8.5%
		1,000	19.04	2.38	42.84	19.00	2.81	47.06	4.22	9.8%
		1,500	19.04	2.38	54.74	19.00	2.81	61.08	6.34	11.6%
		2,000	19.04	2.38	66.64	19.00	2.81	75.11	8.47	12.7%
R1	Ailsa Craig	100	10.51	0.82	11.33	12.13	1.85	13.98	2.65	23.4%
		250	10.51	0.82	12.56	12.13	1.85	16.76	4.20	33.4%
		500	10.51	0.82	14.61	12.13	1.85	21.38	6.77	46.4%
		750	10.51	0.82	16.66	12.13	1.85	26.01	9.35	56.1%
		1,000	10.51	0.82	18.71	12.13	1.85	30.63	11.92	63.7%
		1,500	10.51	0.82	22.81	12.13	1.85	39.88	17.07	74.8%
		2,000	10.51	0.82	26.91	12.13	1.85	49.13	22.22	82.6%
R1	Arkona	100	5.84	0.26	6.10	8.30	1.50	9.80	3.70	60.7%
		250	5.84	0.26	6.49	8.30	1.50	12.05	5.56	85.7%
		500	5.84	0.26	7.14	8.30	1.50	15.80	8.66	121.3%
		750	5.84	0.26	7.79	8.30	1.50	19.55	11.76	151.0%
		1,000	5.84	0.26	8.44	8.30	1.50	23.30	14.86	176.1%
		1,500	5.84	0.26	9.74	8.30	1.50	30.80	21.06	216.2%
		2,000	5.84	0.26	11.04	8.30	1.50	38.30	27.26	246.9%
UR	Arnprior	100	11.54	1.47	13.01	11.70	2.40	14.09	1.08	8.3%
		250	11.54	1.47	15.22	11.70	2.40	17.68	2.47	16.2%
		500	11.54	1.47	18.89	11.70	2.40	23.67	4.78	25.3%
		750	11.54	1.47	22.57	11.70	2.40	29.66	7.10	31.5%
		1,000	11.54	1.47	26.24	11.70	2.40	35.65	9.41	35.9%
		1,500	11.54	1.47	33.59	11.70	2.40	47.63	14.04	41.8%
		2,000	11.54	1.47	40.94	11.70	2.40	59.61	18.67	45.6%

New Rate Class: R1

Bill Impacts of Proposed Distribution Rates excluding Riders

Classes		Scenario	Existing Dx Rates			Proposed Dx Rates			$ Incr	% Incr
			SrChg	base	Dx bill	SrChg	base	Dx bill		
New Class	**Old Class**	kWh	[$/month]	[c/kWh]	[$/month]	[$/month]	[c/kWh]	[$/month]		
R1	**Arran-Elderslie**	100	9.02	0.95	9.97	11.51	1.90	13.41	3.44	34.5%
		250	9.02	0.95	11.40	11.51	1.90	16.26	4.86	42.7%
		500	9.02	0.95	13.77	11.51	1.90	21.01	7.24	52.5%
		750	9.02	0.95	16.15	11.51	1.90	25.76	9.61	59.5%
		1,000	9.02	0.95	18.52	11.51	1.90	30.51	11.99	64.7%
		1,500	9.02	0.95	23.27	11.51	1.90	40.01	16.74	71.9%
		2,000	9.02	0.95	28.02	11.51	1.90	49.51	21.49	76.7%
R1	**Artemesia**	100	12.73	0.93	13.66	13.58	2.35	15.93	2.27	16.6%
		250	12.73	0.93	15.06	13.58	2.35	19.45	4.40	29.2%
		500	12.73	0.93	17.38	13.58	2.35	25.33	7.95	45.7%
		750	12.73	0.93	19.71	13.58	2.35	31.20	11.50	58.3%
		1,000	12.73	0.93	22.03	13.58	2.35	37.08	15.05	68.3%
		1,500	12.73	0.93	26.68	13.58	2.35	48.83	22.15	83.0%
		2,000	12.73	0.93	31.33	13.58	2.35	60.58	29.25	93.4%
R1	**Bancroft**	100	13.48	0.95	14.43	14.39	2.10	16.49	2.06	14.3%
		250	13.48	0.95	15.86	14.39	2.10	19.64	3.79	23.9%
		500	13.48	0.95	18.23	14.39	2.10	24.89	6.66	36.5%
		750	13.48	0.95	20.61	14.39	2.10	30.14	9.54	46.3%
		1,000	13.48	0.95	22.98	14.39	2.10	35.39	12.41	54.0%
		1,500	13.48	0.95	27.73	14.39	2.10	45.89	18.16	65.5%
		2,000	13.48	0.95	32.48	14.39	2.10	56.39	23.91	73.6%
R1	**Bath**	100	13.38	0.86	14.24	14.42	2.35	16.77	2.53	17.7%
		250	13.38	0.86	15.53	14.42	2.35	20.29	4.76	30.7%
		500	13.38	0.86	17.68	14.42	2.35	26.17	8.49	48.0%
		750	13.38	0.86	19.83	14.42	2.35	32.04	12.21	61.6%
		1,000	13.38	0.86	21.98	14.42	2.35	37.92	15.94	72.5%
		1,500	13.38	0.86	26.28	14.42	2.35	49.67	23.39	89.0%
		2,000	13.38	0.86	30.58	14.42	2.35	61.42	30.84	100.8%

New Rate Class: R1

Bill Impacts of Proposed Distribution Rates excluding Riders

Classes		Scenario	Existing Dx Rates			Proposed Dx Rates			$ Incr	% Incr
			SrChg	base	Dx bill	SrChg	base	Dx bill		
New Class	**Old Class**	kWh	[$/month]	[c/kWh]	[$/month]	[$/month]	[c/kWh]	[$/month]		
R1	**Blandford-Blenheim**	100	11.63	0.90	12.53	12.85	2.30	15.15	2.62	20.9%
		250	11.63	0.90	13.88	12.85	2.30	18.60	4.72	34.0%
		500	11.63	0.90	16.13	12.85	2.30	24.35	8.22	51.0%
		750	11.63	0.90	18.38	12.85	2.30	30.10	11.72	63.8%
		1,000	11.63	0.90	20.63	12.85	2.30	35.85	15.22	73.8%
		1,500	11.63	0.90	25.13	12.85	2.30	47.35	22.22	88.4%
		2,000	11.63	0.90	29.63	12.85	2.30	58.85	29.22	98.6%
R1	**Blyth**	100	7.19	0.91	8.10	9.96	2.00	11.96	3.86	47.7%
		250	7.19	0.91	9.47	9.96	2.00	14.96	5.50	58.1%
		500	7.19	0.91	11.74	9.96	2.00	19.96	8.22	70.0%
		750	7.19	0.91	14.02	9.96	2.00	24.96	10.95	78.1%
		1,000	7.19	0.91	16.29	9.96	2.00	29.96	13.67	83.9%
		1,500	7.19	0.91	20.84	9.96	2.00	39.96	19.12	91.8%
		2,000	7.19	0.91	25.39	9.96	2.00	49.96	24.57	96.8%
R1	**Bobcaygeon**	100	14.47	0.97	15.44	15.14	2.05	17.19	1.75	11.4%
		250	14.47	0.97	16.90	15.14	2.05	20.27	3.37	20.0%
		500	14.47	0.97	19.32	15.14	2.05	25.39	6.07	31.4%
		750	14.47	0.97	21.75	15.14	2.05	30.52	8.77	40.3%
		1,000	14.47	0.97	24.17	15.14	2.05	35.64	11.47	47.5%
		1,500	14.47	0.97	29.02	15.14	2.05	45.89	16.87	58.1%
		2,000	14.47	0.97	33.87	15.14	2.05	56.14	22.27	65.8%
R1	**Brighton**	100	11.61	1.07	12.68	12.86	2.20	15.06	2.38	18.8%
		250	11.61	1.07	14.29	12.86	2.20	18.36	4.07	28.5%
		500	11.61	1.07	16.96	12.86	2.20	23.86	6.90	40.7%
		750	11.61	1.07	19.64	12.86	2.20	29.36	9.72	49.5%
		1,000	11.61	1.07	22.31	12.86	2.20	34.86	12.55	56.2%
		1,500	11.61	1.07	27.66	12.86	2.20	45.86	18.20	65.8%
		2,000	11.61	1.07	33.01	12.86	2.20	56.86	23.85	72.2%

New Rate Class: R1

Bill Impacts of Proposed Distribution Rates excluding Riders

Classes		Scenario	Existing Dx Rates			Proposed Dx Rates			$ Incr	% Incr
			SrChg	base	Dx bill	SrChg	base	Dx bill		
New Class	Old Class	kWh	[$/month]	[c/kWh]	[$/month]	[$/month]	[c/kWh]	[$/month]		
UR	Brockville	100	12.33	0.93	13.26	12.50	2.40	14.89	1.63	12.3%
		250	12.33	0.93	14.66	12.50	2.40	18.49	3.83	26.1%
		500	12.33	0.93	16.98	12.50	2.40	24.48	7.50	44.1%
		750	12.33	0.93	19.31	12.50	2.40	30.47	11.16	57.8%
		1,000	12.33	0.93	21.63	12.50	2.40	36.46	14.83	68.5%
		1,500	12.33	0.93	26.28	12.50	2.40	48.43	22.15	84.3%
		2,000	12.33	0.93	30.93	12.50	2.40	60.41	29.48	95.3%
R1	Caledon CH 02	100	15.19	1.02	16.21	15.96	2.10	18.06	1.85	11.4%
		250	15.19	1.02	17.74	15.96	2.10	21.21	3.47	19.6%
		500	15.19	1.02	20.29	15.96	2.10	26.46	6.17	30.4%
		750	15.19	1.02	22.84	15.96	2.10	31.71	8.87	38.8%
		1,000	15.19	1.02	25.39	15.96	2.10	36.96	11.57	45.6%
		1,500	15.19	1.02	30.49	15.96	2.10	47.46	16.97	55.7%
		2,000	15.19	1.02	35.59	15.96	2.10	57.96	22.37	62.9%
R1	Campbellford-Seymour	100	12.30	1.07	13.37	13.69	2.25	15.94	2.57	19.2%
		250	12.30	1.07	14.98	13.69	2.25	19.31	4.34	28.9%
		500	12.30	1.07	17.65	13.69	2.25	24.94	7.29	41.3%
		750	12.30	1.07	20.33	13.69	2.25	30.56	10.24	50.4%
		1,000	12.30	1.07	23.00	13.69	2.25	36.19	13.19	57.3%
		1,500	12.30	1.07	28.35	13.69	2.25	47.44	19.09	67.3%
		2,000	12.30	1.07	33.70	13.69	2.25	58.69	24.99	74.1%
UR	Carleton Place	100	14.17	1.79	15.96	14.04	2.40	16.43	0.47	3.0%
		250	14.17	1.79	18.65	14.04	2.40	20.03	1.38	7.4%
		500	14.17	1.79	23.12	14.04	2.40	26.02	2.90	12.5%
		750	14.17	1.79	27.60	14.04	2.40	32.01	4.41	16.0%
		1,000	14.17	1.79	32.07	14.04	2.40	38.00	5.93	18.5%
		1,500	14.17	1.79	41.02	14.04	2.40	49.97	8.95	21.8%
		2,000	14.17	1.79	49.97	14.04	2.40	61.95	11.98	24.0%

New Rate Class: R1

Bill Impacts of Proposed Distribution Rates excluding Riders

Classes		Scenario	Existing Dx Rates			Proposed Dx Rates			$ Incr	% Incr
			SrChg	base	Dx bill	SrChg	base	Dx bill		
New Class	**Old Class**	kWh	[$/month]	[c/kWh]	[$/month]	[$/month]	[c/kWh]	[$/month]		
R1	**Cavan-Millbrook-North Monaghan**	100	15.01	1.34	16.35	16.01	2.71	18.72	2.37	14.5%
		250	15.01	1.34	18.36	16.01	2.71	22.79	4.43	24.1%
		500	15.01	1.34	21.71	16.01	2.71	29.57	7.86	36.2%
		750	15.01	1.34	25.06	16.01	2.71	36.36	11.30	45.1%
		1000	15.01	1.34	28.41	16.01	2.71	43.14	14.73	51.9%
		1500	15.01	1.34	35.11	16.01	2.71	56.71	21.60	61.5%
		2000	15.01	1.34	41.81	16.01	2.71	70.28	28.47	68.1%
R1	**Centre Hastings**	100	11.67	0.96	12.63	12.84	2.00	14.84	2.21	17.5%
		250	11.67	0.96	14.07	12.84	2.00	17.84	3.77	26.8%
		500	11.67	0.96	16.47	12.84	2.00	22.84	6.37	38.7%
		750	11.67	0.96	18.87	12.84	2.00	27.84	8.97	47.5%
		1000	11.67	0.96	21.27	12.84	2.00	32.84	11.57	54.4%
		1500	11.67	0.96	26.07	12.84	2.00	42.84	16.77	64.3%
		2000	11.67	0.96	30.87	12.84	2.00	52.84	21.97	71.2%
R1	**Chalk River**	100	14.03	1.37	15.40	15.25	2.71	17.97	2.57	16.7%
		250	14.03	1.37	17.46	15.25	2.71	22.04	4.58	26.2%
		500	14.03	1.37	20.88	15.25	2.71	28.82	7.94	38.0%
		750	14.03	1.37	24.31	15.25	2.71	35.60	11.30	46.5%
		1000	14.03	1.37	27.73	15.25	2.71	42.39	14.66	52.9%
		1500	14.03	1.37	34.58	15.25	2.71	55.95	21.37	61.8%
		2000	14.03	1.37	41.43	15.25	2.71	69.52	28.09	67.8%
R1	**Champlain**	100	10.36	0.88	11.24	12.17	2.00	14.17	2.93	26.1%
		250	10.36	0.88	12.56	12.17	2.00	17.17	4.61	36.7%
		500	10.36	0.88	14.76	12.17	2.00	22.17	7.41	50.2%
		750	10.36	0.88	16.96	12.17	2.00	27.17	10.21	60.2%
		1000	10.36	0.88	19.16	12.17	2.00	32.17	13.01	67.9%
		1500	10.36	0.88	23.56	12.17	2.00	42.17	18.61	79.0%
		2000	10.36	0.88	27.96	12.17	2.00	52.17	24.21	86.6%

New Rate Class: R1

Bill Impacts of Proposed Distribution Rates excluding Riders

Classes		Scenario	Existing Dx Rates			Proposed Dx Rates			$ Incr	% Incr
			SrChg	base	Dx bill	SrChg	base	Dx bill		
New Class	**Old Class**	kWh	[$/month]	[c/kWh]	[$/month]	[$/month]	[c/kWh]	[$/month]		
R1	**Cobden**	100	13.07	1.76	14.83	14.49	2.71	17.21	2.38	16.0%
		250	13.07	1.76	17.47	14.49	2.71	21.28	3.81	21.8%
		500	13.07	1.76	21.87	14.49	2.71	28.06	6.19	28.3%
		750	13.07	1.76	26.27	14.49	2.71	34.84	8.57	32.6%
		1000	13.07	1.76	30.67	14.49	2.71	41.63	10.96	35.7%
		1500	13.07	1.76	39.47	14.49	2.71	55.19	15.72	39.8%
		2000	13.07	1.76	48.27	14.49	2.71	68.76	20.49	42.5%
R1	**Deep River**	100	16.62	2.29	18.91	16.61	2.71	19.32	0.41	2.2%
		250	16.62	2.29	22.35	16.61	2.71	23.39	1.04	4.7%
		500	16.62	2.29	28.07	16.61	2.71	30.17	2.10	7.5%
		750	16.62	2.29	33.80	16.61	2.71	36.96	3.16	9.4%
		1000	16.62	2.29	39.52	16.61	2.71	43.74	4.22	10.7%
		1500	16.62	2.29	50.97	16.61	2.71	57.31	6.34	12.4%
		2000	16.62	2.29	62.42	16.61	2.71	70.87	8.45	13.5%
R1	**Deseronto**	100	12.89	1.12	14.01	13.54	2.30	15.84	1.83	13.0%
		250	12.89	1.12	15.69	13.54	2.30	19.29	3.60	22.9%
		500	12.89	1.12	18.49	13.54	2.30	25.04	6.55	35.4%
		750	12.89	1.12	21.29	13.54	2.30	30.79	9.50	44.6%
		1000	12.89	1.12	24.09	13.54	2.30	36.54	12.45	51.7%
		1500	12.89	1.12	29.69	13.54	2.30	48.04	18.35	61.8%
		2000	12.89	1.12	35.29	13.54	2.30	59.54	24.25	68.7%
UR	**Dryden**	100	14.28	1.65	15.93	14.01	2.40	16.41	0.48	3.0%
		250	14.28	1.65	18.41	14.01	2.40	20.00	1.59	8.7%
		500	14.28	1.65	22.53	14.01	2.40	25.99	3.46	15.4%
		750	14.28	1.65	26.66	14.01	2.40	31.98	5.32	20.0%
		1000	14.28	1.65	30.78	14.01	2.40	37.97	7.19	23.4%
		1500	14.28	1.65	39.03	14.01	2.40	49.95	10.92	28.0%
		2000	14.28	1.65	47.28	14.01	2.40	61.93	14.65	31.0%

New Rate Class: R1

Bill Impacts of Proposed Distribution Rates excluding Riders

Classes		Scenario	Existing Dx Rates			Proposed Dx Rates			$ Incr	% Incr
			SrChg	base	Dx bill	SrChg	base	Dx bill		
New Class	**Old Class**	kWh	[$/month]	[c/kWh]	[$/month]	[$/month]	[c/kWh]	[$/month]		
R1	**Dundalk**	100	14.47	1.08	15.55	15.14	2.30	17.44	1.89	12.2%
		250	14.47	1.08	17.17	15.14	2.30	20.89	3.72	21.7%
		500	14.47	1.08	19.87	15.14	2.30	26.64	6.77	34.1%
		750	14.47	1.08	22.57	15.14	2.30	32.39	9.82	43.5%
		1000	14.47	1.08	25.27	15.14	2.30	38.14	12.87	50.9%
		1500	14.47	1.08	30.67	15.14	2.30	49.64	18.97	61.9%
		2000	14.47	1.08	36.07	15.14	2.30	61.14	25.07	69.5%
R1	**Durham**	100	16.35	1.24	17.59	16.67	2.60	19.27	1.68	9.6%
		250	16.35	1.24	19.45	16.67	2.60	23.17	3.72	19.1%
		500	16.35	1.24	22.55	16.67	2.60	29.67	7.12	31.6%
		750	16.35	1.24	25.65	16.67	2.60	36.17	10.52	41.0%
		1000	16.35	1.24	28.75	16.67	2.60	42.67	13.92	48.4%
		1500	16.35	1.24	34.95	16.67	2.60	55.67	20.72	59.3%
		2000	16.35	1.24	41.15	16.67	2.60	68.67	27.52	66.9%
R1	**Eganville**	100	13.86	1.53	15.39	14.30	2.71	17.01	1.62	10.5%
		250	13.86	1.53	17.69	14.30	2.71	21.08	3.39	19.2%
		500	13.86	1.53	21.51	14.30	2.71	27.86	6.35	29.5%
		750	13.86	1.53	25.34	14.30	2.71	34.65	9.31	36.8%
		1000	13.86	1.53	29.16	14.30	2.71	41.43	12.27	42.1%
		1500	13.86	1.53	36.81	14.30	2.71	55.00	18.19	49.4%
		2000	13.86	1.53	44.46	14.30	2.71	68.56	24.10	54.2%
R1	**Erin**	100	13.13	1.90	15.03	14.48	2.71	17.19	2.16	14.4%
		250	13.13	1.90	17.88	14.48	2.71	21.26	3.38	18.9%
		500	13.13	1.90	22.63	14.48	2.71	28.04	5.41	23.9%
		750	13.13	1.90	27.38	14.48	2.71	34.83	7.45	27.2%
		1000	13.13	1.90	32.13	14.48	2.71	41.61	9.48	29.5%
		1500	13.13	1.90	41.63	14.48	2.71	55.18	13.55	32.5%
		2000	13.13	1.90	51.13	14.48	2.71	68.75	17.62	34.5%

New Rate Class: R1

Bill Impacts of Proposed Distribution Rates excluding Riders

Classes		Scenario	Existing Dx Rates			Proposed Dx Rates			$ Incr	% Incr
			SrChg	base	Dx bill	SrChg	base	Dx bill		
New Class	**Old Class**	kWh	[$/month]	[c/kWh]	[$/month]	[$/month]	[c/kWh]	[$/month]		
R1	**Exeter**	100	15.10	0.96	16.06	15.99	2.25	18.24	2.18	13.5%
		250	15.10	0.96	17.50	15.99	2.25	21.61	4.11	23.5%
		500	15.10	0.96	19.90	15.99	2.25	27.24	7.34	36.9%
		750	15.10	0.96	22.30	15.99	2.25	32.86	10.56	47.4%
		1000	15.10	0.96	24.70	15.99	2.25	38.49	13.79	55.8%
		1500	15.10	0.96	29.50	15.99	2.25	49.74	20.24	68.6%
		2000	15.10	0.96	34.30	15.99	2.25	60.99	26.69	77.8%
R1	**Fenelon Falls**	100	6.09	0.96	7.05	9.24	1.70	10.94	3.89	55.1%
		250	6.09	0.96	8.49	9.24	1.70	13.49	5.00	58.9%
		500	6.09	0.96	10.89	9.24	1.70	17.74	6.85	62.9%
		750	6.09	0.96	13.29	9.24	1.70	21.99	8.70	65.4%
		1000	6.09	0.96	15.69	9.24	1.70	26.24	10.55	67.2%
		1500	6.09	0.96	20.49	9.24	1.70	34.74	14.25	69.5%
		2000	6.09	0.96	25.29	9.24	1.70	43.24	17.95	71.0%
R1	**Forest**	100	15.26	0.95	16.21	15.95	2.20	18.15	1.94	11.9%
		250	15.26	0.95	17.64	15.95	2.20	21.45	3.81	21.6%
		500	15.26	0.95	20.01	15.95	2.20	26.95	6.94	34.7%
		750	15.26	0.95	22.39	15.95	2.20	32.45	10.06	44.9%
		1000	15.26	0.95	24.76	15.95	2.20	37.95	13.19	53.3%
		1500	15.26	0.95	29.51	15.95	2.20	48.95	19.44	65.9%
		2000	15.26	0.95	34.26	15.95	2.20	59.95	25.69	75.0%
UR	**GBE**	100	9.68	0.95	10.63	10.16	2.35	12.51	1.88	17.7%
		250	9.68	0.95	12.06	10.16	2.35	16.04	3.98	33.0%
		500	9.68	0.95	14.43	10.16	2.35	21.91	7.48	51.8%
		750	9.68	0.95	16.81	10.16	2.35	27.79	10.98	65.3%
		1000	9.68	0.95	19.18	10.16	2.35	33.66	14.48	75.5%
		1500	9.68	0.95	23.93	10.16	2.35	45.41	21.48	89.8%
		2000	9.68	0.95	28.68	10.16	2.35	57.16	28.48	99.3%

New Rate Class: R1

Bill Impacts of Proposed Distribution Rates excluding Riders

Classes		Scenario	Existing Dx Rates			Proposed Dx Rates			$ Incr	% Incr
New Class	Old Class	kWh	SrChg [$/month]	base [c/kWh]	Dx bill [$/month]	SrChg [$/month]	base [c/kWh]	Dx bill [$/month]		
R1	Georgina	100	11.72	0.98	12.70	12.83	2.05	14.88	2.18	17.2%
		250	11.72	0.98	14.17	12.83	2.05	17.96	3.79	26.7%
		500	11.72	0.98	16.62	12.83	2.05	23.08	6.46	38.9%
		750	11.72	0.98	19.07	12.83	2.05	28.21	9.14	47.9%
		1000	11.72	0.98	21.52	12.83	2.05	33.33	11.81	54.9%
		1500	11.72	0.98	26.42	12.83	2.05	43.58	17.16	65.0%
		2000	11.72	0.98	31.32	12.83	2.05	53.83	22.51	71.9%
R1	Glencoe	100	12.90	0.77	13.67	13.54	2.55	16.09	2.42	17.7%
		250	12.90	0.77	14.83	13.54	2.55	19.91	5.09	34.3%
		500	12.90	0.77	16.75	13.54	2.55	26.29	9.54	56.9%
		750	12.90	0.77	18.68	13.54	2.55	32.66	13.99	74.9%
		1000	12.90	0.77	20.60	13.54	2.55	39.04	18.44	89.5%
		1500	12.90	0.77	24.45	13.54	2.55	51.79	27.34	111.8%
		2000	12.90	0.77	28.30	13.54	2.55	64.54	36.24	128.0%
R1	Grand Bend	100	13.58	0.87	14.45	14.37	2.10	16.47	2.02	13.9%
		250	13.58	0.87	15.76	14.37	2.10	19.62	3.86	24.5%
		500	13.58	0.87	17.93	14.37	2.10	24.87	6.94	38.7%
		750	13.58	0.87	20.11	14.37	2.10	30.12	10.01	49.8%
		1000	13.58	0.87	22.28	14.37	2.10	35.37	13.09	58.7%
		1500	13.58	0.87	26.63	14.37	2.10	45.87	19.24	72.2%
		2000	13.58	0.87	30.98	14.37	2.10	56.37	25.39	81.9%
R1	Hastings	100	16.44	1.35	17.79	16.65	2.65	19.30	1.51	8.5%
		250	16.44	1.35	19.82	16.65	2.65	23.28	3.46	17.5%
		500	16.44	1.35	23.19	16.65	2.65	29.90	6.71	28.9%
		750	16.44	1.35	26.57	16.65	2.65	36.53	9.96	37.5%
		1000	16.44	1.35	29.94	16.65	2.65	43.15	13.21	44.1%
		1500	16.44	1.35	36.69	16.65	2.65	56.40	19.71	53.7%
		2000	16.44	1.35	43.44	16.65	2.65	69.65	26.21	60.3%

New Rate Class: R1

Bill Impacts of Proposed Distribution Rates excluding Riders

Classes		Scenario	Existing Dx Rates			Proposed Dx Rates			$ Incr	% Incr
New Class	Old Class	kWh	SrChg [$/month]	base [c/kWh]	Dx bill [$/month]	SrChg [$/month]	base [c/kWh]	Dx bill [$/month]		
R1	**Havelock**	100	15.17	1.14	16.31	15.97	2.30	18.27	1.96	12.0%
		250	15.17	1.14	18.02	15.97	2.30	21.72	3.70	20.5%
		500	15.17	1.14	20.87	15.97	2.30	27.47	6.60	31.6%
		750	15.17	1.14	23.72	15.97	2.30	33.22	9.50	40.0%
		1000	15.17	1.14	26.57	15.97	2.30	38.97	12.40	46.7%
		1500	15.17	1.14	32.27	15.97	2.30	50.47	18.20	56.4%
		2000	15.17	1.14	37.97	15.97	2.30	61.97	24.00	63.2%
R1	**Kirkfield**	100	5.34	1.00	6.34	8.43	2.00	10.43	4.09	64.4%
		250	5.34	1.00	7.84	8.43	2.00	13.43	5.59	71.2%
		500	5.34	1.00	10.34	8.43	2.00	18.43	8.09	78.2%
		750	5.34	1.00	12.84	8.43	2.00	23.43	10.59	82.4%
		1000	5.34	1.00	15.34	8.43	2.00	28.43	13.09	85.3%
		1500	5.34	1.00	20.34	8.43	2.00	38.43	18.09	88.9%
		2000	5.34	1.00	25.34	8.43	2.00	48.43	23.09	91.1%
R1	**Lanark Highlands**	100	11.31	1.02	12.33	12.93	2.35	15.28	2.95	23.9%
		250	11.31	1.02	13.86	12.93	2.35	18.81	4.95	35.7%
		500	11.31	1.02	16.41	12.93	2.35	24.68	8.27	50.4%
		750	11.31	1.02	18.96	12.93	2.35	30.56	11.60	61.2%
		1000	11.31	1.02	21.51	12.93	2.35	36.43	14.92	69.4%
		1500	11.31	1.02	26.61	12.93	2.35	48.18	21.57	81.1%
		2000	11.31	1.02	31.71	12.93	2.35	59.93	28.22	89.0%
R1	**Larder Lake**	100	15.84	1.01	16.85	15.80	2.70	18.50	1.65	9.8%
		250	15.84	1.01	18.37	15.80	2.70	22.55	4.19	22.8%
		500	15.84	1.01	20.89	15.80	2.70	29.30	8.41	40.3%
		750	15.84	1.01	23.42	15.80	2.70	36.05	12.64	54.0%
		1000	15.84	1.01	25.94	15.80	2.70	42.80	16.86	65.0%
		1500	15.84	1.01	30.99	15.80	2.70	56.30	25.31	81.7%
		2000	15.84	1.01	36.04	15.80	2.70	69.80	33.76	93.7%

New Rate Class: R1

Bill Impacts of Proposed Distribution Rates excluding Riders

Classes		**Scenario**	Existing Dx Rates			Proposed Dx Rates			$ Incr	% Incr
			SrChg	base	Dx bill	SrChg	base	Dx bill		
New Class	**Old Class**	kWh	[$/month]	[c/kWh]	[$/month]	[$/month]	[c/kWh]	[$/month]		
R1	**Latchford**	100	13.31	0.88	14.19	14.43	2.71	17.15	2.96	20.8%
		250	13.31	0.88	15.51	14.43	2.71	21.22	5.71	36.8%
		500	13.31	0.88	17.71	14.43	2.71	28.00	10.29	58.1%
		750	13.31	0.88	19.91	14.43	2.71	34.78	14.87	74.7%
		1000	13.31	0.88	22.11	14.43	2.71	41.57	19.46	88.0%
		1500	13.31	0.88	26.51	14.43	2.71	55.13	28.62	108.0%
		2000	13.31	0.88	30.91	14.43	2.71	68.70	37.79	122.3%
UR	**Lindsay**	100	15.81	1.01	16.82	14.63	2.40	17.02	0.20	1.2%
		250	15.81	1.01	18.34	14.63	2.40	20.62	2.28	12.4%
		500	15.81	1.01	20.86	14.63	2.40	26.61	5.75	27.5%
		750	15.81	1.01	23.39	14.63	2.40	32.60	9.21	39.4%
		1000	15.81	1.01	25.91	14.63	2.40	38.59	12.68	48.9%
		1500	15.81	1.01	30.96	14.63	2.40	50.56	19.60	63.3%
		2000	15.81	1.01	36.01	14.63	2.40	62.54	26.53	73.7%
R1	**Lucan Granton**	100	11.72	1.42	13.14	12.83	2.60	15.43	2.29	17.4%
		250	11.72	1.42	15.27	12.83	2.60	19.33	4.06	26.6%
		500	11.72	1.42	18.82	12.83	2.60	25.83	7.01	37.2%
		750	11.72	1.42	22.37	12.83	2.60	32.33	9.96	44.5%
		1000	11.72	1.42	25.92	12.83	2.60	38.83	12.91	49.8%
		1500	11.72	1.42	33.02	12.83	2.60	51.83	18.81	57.0%
		2000	11.72	1.42	40.12	12.83	2.60	64.83	24.71	61.6%
R1	**Malahide**	100	11.17	0.87	12.04	12.97	2.40	15.37	3.33	27.6%
		250	11.17	0.87	13.35	12.97	2.40	18.97	5.62	42.1%
		500	11.17	0.87	15.52	12.97	2.40	24.97	9.45	60.9%
		750	11.17	0.87	17.70	12.97	2.40	30.97	13.27	75.0%
		1000	11.17	0.87	19.87	12.97	2.40	36.97	17.10	86.0%
		1500	11.17	0.87	24.22	12.97	2.40	48.97	24.75	102.2%
		2000	11.17	0.87	28.57	12.97	2.40	60.97	32.40	113.4%

New Rate Class: R1

Bill Impacts of Proposed Distribution Rates excluding Riders

Classes		Scenario	Existing Dx Rates			Proposed Dx Rates			$ Incr	% Incr
			SrChg	base	Dx bill	SrChg	base	Dx bill		
New Class	Old Class	kWh	[$/month]	[c/kWh]	[$/month]	[$/month]	[c/kWh]	[$/month]		
R1	Mapleton	100	13.47	0.92	14.39	14.39	2.40	16.79	2.40	16.7%
		250	13.47	0.92	15.77	14.39	2.40	20.39	4.62	29.3%
		500	13.47	0.92	18.07	14.39	2.40	26.39	8.32	46.1%
		750	13.47	0.92	20.37	14.39	2.40	32.39	12.02	59.0%
		1000	13.47	0.92	22.67	14.39	2.40	38.39	15.72	69.4%
		1500	13.47	0.92	27.27	14.39	2.40	50.39	23.12	84.8%
		2000	13.47	0.92	31.87	14.39	2.40	62.39	30.52	95.8%
R1	Markdale	100	14.30	0.86	15.16	15.19	2.10	17.29	2.13	14.0%
		250	14.30	0.86	16.45	15.19	2.10	20.44	3.99	24.2%
		500	14.30	0.86	18.60	15.19	2.10	25.69	7.09	38.1%
		750	14.30	0.86	20.75	15.19	2.10	30.94	10.19	49.1%
		1000	14.30	0.86	22.90	15.19	2.10	36.19	13.29	58.0%
		1500	14.30	0.86	27.20	15.19	2.10	46.69	19.49	71.6%
		2000	14.30	0.86	31.50	15.19	2.10	57.19	25.69	81.5%
R1	Marmora	100	11.59	0.92	12.51	12.86	2.00	14.86	2.35	18.8%
		250	11.59	0.92	13.89	12.86	2.00	17.86	3.97	28.6%
		500	11.59	0.92	16.19	12.86	2.00	22.86	6.67	41.2%
		750	11.59	0.92	18.49	12.86	2.00	27.86	9.37	50.7%
		1000	11.59	0.92	20.79	12.86	2.00	32.86	12.07	58.1%
		1500	11.59	0.92	25.39	12.86	2.00	42.86	17.47	68.8%
		2000	11.59	0.92	29.99	12.86	2.00	52.86	22.87	76.3%
R1	McGarry	100	12.85	0.93	13.78	13.55	2.50	16.05	2.27	16.5%
		250	12.85	0.93	15.18	13.55	2.50	19.80	4.62	30.5%
		500	12.85	0.93	17.50	13.55	2.50	26.05	8.55	48.8%
		750	12.85	0.93	19.83	13.55	2.50	32.30	12.47	62.9%
		1000	12.85	0.93	22.15	13.55	2.50	38.55	16.40	74.0%
		1500	12.85	0.93	26.80	13.55	2.50	51.05	24.25	90.5%
		2000	12.85	0.93	31.45	13.55	2.50	63.55	32.10	102.1%

New Rate Class: R1

Bill Impacts of Proposed Distribution Rates excluding Riders

Classes		Scenario	Existing Dx Rates			Proposed Dx Rates			$ Incr	% Incr
			SrChg	base	Dx bill	SrChg	base	Dx bill		
New Class	Old Class	kWh	[$/month]	[c/kWh]	[$/month]	[$/month]	[c/kWh]	[$/month]		
R1	Meaford	100	12.75	0.97	13.72	13.57	2.20	15.77	2.05	15.0%
		250	12.75	0.97	15.18	13.57	2.20	19.07	3.90	25.7%
		500	12.75	0.97	17.60	13.57	2.20	24.57	6.97	39.6%
		750	12.75	0.97	20.03	13.57	2.20	30.07	10.05	50.2%
		1000	12.75	0.97	22.45	13.57	2.20	35.57	13.12	58.5%
		1500	12.75	0.97	27.30	13.57	2.20	46.57	19.27	70.6%
		2000	12.75	0.97	32.15	13.57	2.20	57.57	25.42	79.1%
R1	Middlesex Centre	100	14.19	0.78	14.97	15.21	2.25	17.46	2.49	16.6%
		250	14.19	0.78	16.14	15.21	2.25	20.84	4.70	29.1%
		500	14.19	0.78	18.09	15.21	2.25	26.46	8.37	46.3%
		750	14.19	0.78	20.04	15.21	2.25	32.09	12.05	60.1%
		1000	14.19	0.78	21.99	15.21	2.25	37.71	15.72	71.5%
		1500	14.19	0.78	25.89	15.21	2.25	48.96	23.07	89.1%
		2000	14.19	0.78	29.79	15.21	2.25	60.21	30.42	102.1%
R1	Napanee	100	14.70	1.02	15.72	15.09	2.35	17.44	1.72	10.9%
		250	14.70	1.02	17.25	15.09	2.35	20.96	3.71	21.5%
		500	14.70	1.02	19.80	15.09	2.35	26.84	7.04	35.5%
		750	14.70	1.02	22.35	15.09	2.35	32.71	10.36	46.4%
		1000	14.70	1.02	24.90	15.09	2.35	38.59	13.69	55.0%
		1500	14.70	1.02	30.00	15.09	2.35	50.34	20.34	67.8%
		2000	14.70	1.02	35.10	15.09	2.35	62.09	26.99	76.9%
R1	Nipigon	100	14.23	1.42	15.65	15.20	2.71	17.92	2.27	14.5%
		250	14.23	1.42	17.78	15.20	2.71	21.99	4.21	23.7%
		500	14.23	1.42	21.33	15.20	2.71	28.77	7.44	34.9%
		750	14.23	1.42	24.88	15.20	2.71	35.55	10.67	42.9%
		1000	14.23	1.42	28.43	15.20	2.71	42.34	13.91	48.9%
		1500	14.23	1.42	35.53	15.20	2.71	55.90	20.37	57.3%
		2000	14.23	1.42	42.63	15.20	2.71	69.47	26.84	63.0%

New Rate Class: R1

Bill Impacts of Proposed Distribution Rates excluding Riders

Classes		Scenario	Existing Dx Rates			Proposed Dx Rates			$ Incr	% Incr
			SrChg	base	Dx bill	SrChg	base	Dx bill		
New Class	**Old Class**	kWh	[$/month]	[c/kWh]	[$/month]	[$/month]	[c/kWh]	[$/month]		
R1	**North Dorchester**	100	8.97	0.86	9.83	10.52	2.25	12.77	2.94	29.9%
		250	8.97	0.86	11.12	10.52	2.25	16.14	5.02	45.2%
		500	8.97	0.86	13.27	10.52	2.25	21.77	8.50	64.0%
		750	8.97	0.86	15.42	10.52	2.25	27.39	11.97	77.6%
		1000	8.97	0.86	17.57	10.52	2.25	33.02	15.45	87.9%
		1500	8.97	0.86	21.87	10.52	2.25	44.27	22.40	102.4%
		2000	8.97	0.86	26.17	10.52	2.25	55.52	29.35	112.1%
R1	**North Dundas**	100	11.17	0.97	12.14	12.97	2.25	15.22	3.08	25.4%
		250	11.17	0.97	13.60	12.97	2.25	18.59	5.00	36.8%
		500	11.17	0.97	16.02	12.97	2.25	24.22	8.20	51.2%
		750	11.17	0.97	18.45	12.97	2.25	29.84	11.40	61.8%
		1000	11.17	0.97	20.87	12.97	2.25	35.47	14.60	69.9%
		1500	11.17	0.97	25.72	12.97	2.25	46.72	21.00	81.6%
		2000	11.17	0.97	30.57	12.97	2.25	57.97	27.40	89.6%
R1	**North Glengarry**	100	7.74	1.02	8.76	9.83	2.20	12.03	3.27	37.3%
		250	7.74	1.02	10.29	9.83	2.20	15.33	5.04	48.9%
		500	7.74	1.02	12.84	9.83	2.20	20.83	7.99	62.2%
		750	7.74	1.02	15.39	9.83	2.20	26.33	10.94	71.1%
		1000	7.74	1.02	17.94	9.83	2.20	31.83	13.89	77.4%
		1500	7.74	1.02	23.04	9.83	2.20	42.83	19.79	85.9%
		2000	7.74	1.02	28.14	9.83	2.20	53.83	25.69	91.3%
R1	**North Grenville**	100	14.40	1.65	16.05	15.16	2.71	17.87	1.82	11.4%
		250	14.40	1.65	18.53	15.16	2.71	21.94	3.42	18.5%
		500	14.40	1.65	22.65	15.16	2.71	28.73	6.08	26.8%
		750	14.40	1.65	26.78	15.16	2.71	35.51	8.74	32.6%
		1000	14.40	1.65	30.90	15.16	2.71	42.29	11.39	36.9%
		1500	14.40	1.65	39.15	15.16	2.71	55.86	16.71	42.7%
		2000	14.40	1.65	47.40	15.16	2.71	69.43	22.03	46.5%

New Rate Class: R1

Bill Impacts of Proposed Distribution Rates excluding Riders

Classes		Scenario	Existing Dx Rates			Proposed Dx Rates			$ Incr	% Incr
			SrChg	base	Dx bill	SrChg	base	Dx bill		
New Class	**Old Class**	kWh	[$/month]	[c/kWh]	[$/month]	[$/month]	[c/kWh]	[$/month]		
R1	**North Perth**	100	14.73	1.05	15.78	15.08	2.40	17.48	1.70	10.8%
		250	14.73	1.05	17.36	15.08	2.40	21.08	3.72	21.4%
		500	14.73	1.05	19.98	15.08	2.40	27.08	7.10	35.5%
		750	14.73	1.05	22.61	15.08	2.40	33.08	10.47	46.3%
		1000	14.73	1.05	25.23	15.08	2.40	39.08	13.85	54.9%
		1500	14.73	1.05	30.48	15.08	2.40	51.08	20.60	67.6%
		2000	14.73	1.05	35.73	15.08	2.40	63.08	27.35	76.5%
R1	**North Stormont**	100	5.42	0.92	6.34	8.41	2.10	10.51	4.17	65.7%
		250	5.42	0.92	7.72	8.41	2.10	13.66	5.94	76.9%
		500	5.42	0.92	10.02	8.41	2.10	18.91	8.89	88.7%
		750	5.42	0.92	12.32	8.41	2.10	24.16	11.84	96.1%
		1000	5.42	0.92	14.62	8.41	2.10	29.41	14.79	101.1%
		1500	5.42	0.92	19.22	8.41	2.10	39.91	20.69	107.6%
		2000	5.42	0.92	23.82	8.41	2.10	50.41	26.59	111.6%
R1	**Omemee**	100	14.99	1.50	16.49	15.01	2.71	17.73	1.24	7.5%
		250	14.99	1.50	18.74	15.01	2.71	21.80	3.06	16.3%
		500	14.99	1.50	22.49	15.01	2.71	28.58	6.09	27.1%
		750	14.99	1.50	26.24	15.01	2.71	35.36	9.12	34.8%
		1000	14.99	1.50	29.99	15.01	2.71	42.15	12.16	40.5%
		1500	14.99	1.50	37.49	15.01	2.71	55.71	18.22	48.6%
		2000	14.99	1.50	44.99	15.01	2.71	69.28	24.29	54.0%
UR	**Perth**	100	14.47	1.22	15.69	13.96	2.40	16.36	0.67	4.3%
		250	14.47	1.22	17.52	13.96	2.40	19.95	2.43	13.9%
		500	14.47	1.22	20.57	13.96	2.40	25.94	5.37	26.1%
		750	14.47	1.22	23.62	13.96	2.40	31.93	8.31	35.2%
		1000	14.47	1.22	26.67	13.96	2.40	37.92	11.25	42.2%
		1500	14.47	1.22	32.77	13.96	2.40	49.90	17.13	52.3%
		2000	14.47	1.22	38.87	13.96	2.40	61.88	23.01	59.2%

New Rate Class: R1

Bill Impacts of Proposed Distribution Rates excluding Riders

Classes		Scenario	Existing Dx Rates			Proposed Dx Rates			$ Incr	% Incr
			SrChg	base	Dx bill	SrChg	base	Dx bill		
New Class	**Old Class**	kWh	[$/month]	[c/kWh]	[$/month]	[$/month]	[c/kWh]	[$/month]		
R1	**Perth East**	100	5.95	0.78	6.73	8.27	1.60	9.87	3.14	46.7%
		250	5.95	0.78	7.90	8.27	1.60	12.27	4.37	55.3%
		500	5.95	0.78	9.85	8.27	1.60	16.27	6.42	65.2%
		750	5.95	0.78	11.80	8.27	1.60	20.27	8.47	71.8%
		1000	5.95	0.78	13.75	8.27	1.60	24.27	10.52	76.5%
		1500	5.95	0.78	17.65	8.27	1.60	32.27	14.62	82.8%
		2000	5.95	0.78	21.55	8.27	1.60	40.27	18.72	86.9%
R1	**Prince Edward**	100	14.25	1.05	15.30	15.20	2.25	17.45	2.15	14.0%
		250	14.25	1.05	16.88	15.20	2.25	20.82	3.95	23.4%
		500	14.25	1.05	19.50	15.20	2.25	26.45	6.95	35.6%
		750	14.25	1.05	22.13	15.20	2.25	32.07	9.95	45.0%
		1000	14.25	1.05	24.75	15.20	2.25	37.70	12.95	52.3%
		1500	14.25	1.05	30.00	15.20	2.25	48.95	18.95	63.2%
		2000	14.25	1.05	35.25	15.20	2.25	60.20	24.95	70.8%
UR	**Quinte West**	100	6.58	0.92	7.50	7.94	2.10	10.04	2.54	33.8%
		250	6.58	0.92	8.88	7.94	2.10	13.19	4.31	48.5%
		500	6.58	0.92	11.18	7.94	2.10	18.44	7.26	64.9%
		750	6.58	0.92	13.48	7.94	2.10	23.69	10.21	75.7%
		1000	6.58	0.92	15.78	7.94	2.10	28.94	13.16	83.4%
		1500	6.58	0.92	20.38	7.94	2.10	39.44	19.06	93.5%
		2000	6.58	0.92	24.98	7.94	2.10	49.94	24.96	99.9%
R1	**Rainy River**	100	15.04	1.02	16.06	16.00	2.65	18.65	2.59	16.1%
		250	15.04	1.02	17.59	16.00	2.65	22.63	5.04	28.6%
		500	15.04	1.02	20.14	16.00	2.65	29.25	9.11	45.2%
		750	15.04	1.02	22.69	16.00	2.65	35.88	13.19	58.1%
		1000	15.04	1.02	25.24	16.00	2.65	42.50	17.26	68.4%
		1500	15.04	1.02	30.34	16.00	2.65	55.75	25.41	83.8%
		2000	15.04	1.02	35.44	16.00	2.65	69.00	33.56	94.7%

New Rate Class: R1

Bill Impacts of Proposed Distribution Rates excluding Riders

Classes		**Scenario**	Existing Dx Rates			Proposed Dx Rates			$ Incr	% Incr
			SrChg	base	Dx bill	SrChg	base	Dx bill		
New Class	**Old Class**	kWh	[$/month]	[c/kWh]	[$/month]	[$/month]	[c/kWh]	[$/month]		
R1	**Ramara**	100	6.52	0.95	7.47	9.13	2.10	11.23	3.76	50.3%
		250	6.52	0.95	8.90	9.13	2.10	14.38	5.49	61.7%
		500	6.52	0.95	11.27	9.13	2.10	19.63	8.36	74.2%
		750	6.52	0.95	13.65	9.13	2.10	24.88	11.24	82.3%
		1000	6.52	0.95	16.02	9.13	2.10	30.13	14.11	88.1%
		1500	6.52	0.95	20.77	9.13	2.10	40.63	19.86	95.6%
		2000	6.52	0.95	25.52	9.13	2.10	51.13	25.61	100.4%
R1	**Red Rock**	100	15.21	2.07	17.28	15.96	2.71	18.67	1.39	8.0%
		250	15.21	2.07	20.39	15.96	2.71	22.74	2.36	11.6%
		500	15.21	2.07	25.56	15.96	2.71	29.52	3.96	15.5%
		750	15.21	2.07	30.74	15.96	2.71	36.31	5.57	18.1%
		1000	15.21	2.07	35.91	15.96	2.71	43.09	7.18	20.0%
		1500	15.21	2.07	46.26	15.96	2.71	56.66	10.40	22.5%
		2000	15.21	2.07	56.61	15.96	2.71	70.23	13.62	24.1%
R1	**Rockland**	100	9.41	0.92	10.33	11.41	2.30	13.71	3.38	32.7%
		250	9.41	0.92	11.71	11.41	2.30	17.16	5.45	46.5%
		500	9.41	0.92	14.01	11.41	2.30	22.91	8.90	63.5%
		750	9.41	0.92	16.31	11.41	2.30	28.66	12.35	75.7%
		1000	9.41	0.92	18.61	11.41	2.30	34.41	15.80	84.9%
		1500	9.41	0.92	23.21	11.41	2.30	45.91	22.70	97.8%
		2000	9.41	0.92	27.81	11.41	2.30	57.41	29.60	106.4%
R1	**Russell**	100	13.11	1.44	14.55	14.48	2.50	16.98	2.43	16.7%
		250	13.11	1.44	16.71	14.48	2.50	20.73	4.02	24.1%
		500	13.11	1.44	20.31	14.48	2.50	26.98	6.67	32.9%
		750	13.11	1.44	23.91	14.48	2.50	33.23	9.32	39.0%
		1000	13.11	1.44	27.51	14.48	2.50	39.48	11.97	43.5%
		1500	13.11	1.44	34.71	14.48	2.50	51.98	17.27	49.8%
		2000	13.11	1.44	41.91	14.48	2.50	64.48	22.57	53.9%

New Rate Class: R1

Bill Impacts of Proposed Distribution Rates excluding Riders

Classes		**Scenario**	Existing Dx Rates			Proposed Dx Rates			$ Incr	% Incr
			SrChg	base	Dx bill	SrChg	base	Dx bill		
New Class	**Old Class**	kWh	[$/month]	[c/kWh]	[$/month]	[$/month]	[c/kWh]	[$/month]		
R1	**Schreiber**	100	16.32	1.84	18.16	16.68	2.71	19.39	1.23	6.8%
		250	16.32	1.84	20.92	16.68	2.71	23.46	2.54	12.2%
		500	16.32	1.84	25.52	16.68	2.71	30.25	4.73	18.5%
		750	16.32	1.84	30.12	16.68	2.71	37.03	6.91	22.9%
		1000	16.32	1.84	34.72	16.68	2.71	43.81	9.09	26.2%
		1500	16.32	1.84	43.92	16.68	2.71	57.38	13.46	30.7%
		2000	16.32	1.84	53.12	16.68	2.71	70.95	17.83	33.6%
R1	**Severn**	100	10.60	0.90	11.50	12.11	2.25	14.36	2.86	24.9%
		250	10.60	0.90	12.85	12.11	2.25	17.74	4.89	38.0%
		500	10.60	0.90	15.10	12.11	2.25	23.36	8.26	54.7%
		750	10.60	0.90	17.35	12.11	2.25	28.99	11.64	67.1%
		1000	10.60	0.90	19.60	12.11	2.25	34.61	15.01	76.6%
		1500	10.60	0.90	24.10	12.11	2.25	45.86	21.76	90.3%
		2000	10.60	0.90	28.60	12.11	2.25	57.11	28.51	99.7%
R1	**Shelburne**	100	14.14	1.33	15.47	15.23	2.55	17.78	2.31	14.9%
		250	14.14	1.33	17.47	15.23	2.55	21.60	4.14	23.7%
		500	14.14	1.33	20.79	15.23	2.55	27.98	7.19	34.6%
		750	14.14	1.33	24.12	15.23	2.55	34.35	10.24	42.4%
		1000	14.14	1.33	27.44	15.23	2.55	40.73	13.29	48.4%
		1500	14.14	1.33	34.09	15.23	2.55	53.48	19.39	56.9%
		2000	14.14	1.33	40.74	15.23	2.55	66.23	25.49	62.6%
UR	**Smiths Falls**	100	12.63	1.42	14.05	12.42	2.40	14.82	0.77	5.5%
		250	12.63	1.42	16.18	12.42	2.40	18.41	2.23	13.8%
		500	12.63	1.42	19.73	12.42	2.40	24.40	4.67	23.7%
		750	12.63	1.42	23.28	12.42	2.40	30.39	7.11	30.5%
		1000	12.63	1.42	26.83	12.42	2.40	36.38	9.55	35.6%
		1500	12.63	1.42	33.93	12.42	2.40	48.36	14.43	42.5%
		2000	12.63	1.42	41.03	12.42	2.40	60.34	19.31	47.1%

New Rate Class: R1

Bill Impacts of Proposed Distribution Rates excluding Riders

Classes		Scenario	Existing Dx Rates			Proposed Dx Rates			$ Incr	% Incr
			SrChg	base	Dx bill	SrChg	base	Dx bill		
New Class	**Old Class**	kWh	[$/month]	[c/kWh]	[$/month]	[$/month]	[c/kWh]	[$/month]		
R1	**South Glengarry**	100	9.46	0.75	10.21	11.40	1.95	13.35	3.14	30.7%
		250	9.46	0.75	11.34	11.40	1.95	16.27	4.94	43.5%
		500	9.46	0.75	13.21	11.40	1.95	21.15	7.94	60.1%
		750	9.46	0.75	15.09	11.40	1.95	26.02	10.94	72.5%
		1000	9.46	0.75	16.96	11.40	1.95	30.90	13.94	82.2%
		1500	9.46	0.75	20.71	11.40	1.95	40.65	19.94	96.3%
		2000	9.46	0.75	24.46	11.40	1.95	50.40	25.94	106.0%
R1	**South River**	100	14.22	1.25	15.47	15.21	2.71	17.92	2.45	15.8%
		250	14.22	1.25	17.35	15.21	2.71	21.99	4.64	26.8%
		500	14.22	1.25	20.47	15.21	2.71	28.77	8.30	40.6%
		750	14.22	1.25	23.60	15.21	2.71	35.56	11.96	50.7%
		1000	14.22	1.25	26.72	15.21	2.71	42.34	15.62	58.5%
		1500	14.22	1.25	32.97	15.21	2.71	55.91	22.94	69.6%
		2000	14.22	1.25	39.22	15.21	2.71	69.47	30.25	77.1%
R1	**Springwater**	100	11.79	0.82	12.61	12.81	2.25	15.06	2.45	19.4%
		250	11.79	0.82	13.84	12.81	2.25	18.44	4.60	33.2%
		500	11.79	0.82	15.89	12.81	2.25	24.06	8.17	51.4%
		750	11.79	0.82	17.94	12.81	2.25	29.69	11.75	65.5%
		1000	11.79	0.82	19.99	12.81	2.25	35.31	15.32	76.7%
		1500	11.79	0.82	24.09	12.81	2.25	46.56	22.47	93.3%
		2000	11.79	0.82	28.19	12.81	2.25	57.81	29.62	105.1%
R1	**Stirling-Rawdon**	100	12.55	1.03	13.58	13.62	2.20	15.82	2.24	16.5%
		250	12.55	1.03	15.13	13.62	2.20	19.12	4.00	26.4%
		500	12.55	1.03	17.70	13.62	2.20	24.62	6.92	39.1%
		750	12.55	1.03	20.28	13.62	2.20	30.12	9.85	48.6%
		1000	12.55	1.03	22.85	13.62	2.20	35.62	12.77	55.9%
		1500	12.55	1.03	28.00	13.62	2.20	46.62	18.62	66.5%
		2000	12.55	1.03	33.15	13.62	2.20	57.62	24.47	73.8%

New Rate Class: R1

Bill Impacts of Proposed Distribution Rates excluding Riders

Classes		Scenario	Existing Dx Rates			Proposed Dx Rates			$ Incr	% Incr
			SrChg	base	Dx bill	SrChg	base	Dx bill		
New Class	**Old Class**	kWh	[$/month]	[c/kWh]	[$/month]	[$/month]	[c/kWh]	[$/month]		
R1	**Thedford**	100	12.75	0.81	13.56	13.57	2.50	16.07	2.51	18.5%
		250	12.75	0.81	14.78	13.57	2.50	19.82	5.05	34.2%
		500	12.75	0.81	16.80	13.57	2.50	26.07	9.27	55.2%
		750	12.75	0.81	18.83	13.57	2.50	32.32	13.50	71.7%
		1000	12.75	0.81	20.85	13.57	2.50	38.57	17.72	85.0%
		1500	12.75	0.81	24.90	13.57	2.50	51.07	26.17	105.1%
		2000	12.75	0.81	28.95	13.57	2.50	63.57	34.62	119.6%
R1	**Thessalon**	100	15.56	1.05	16.61	15.87	2.20	18.07	1.46	8.8%
		250	15.56	1.05	18.19	15.87	2.20	21.37	3.19	17.5%
		500	15.56	1.05	20.81	15.87	2.20	26.87	6.06	29.1%
		750	15.56	1.05	23.44	15.87	2.20	32.37	8.94	38.1%
		1000	15.56	1.05	26.06	15.87	2.20	37.87	11.81	45.3%
		1500	15.56	1.05	31.31	15.87	2.20	48.87	17.56	56.1%
		2000	15.56	1.05	36.56	15.87	2.20	59.87	23.31	63.8%
R1	**Thorndale**	100	4.32	0.88	5.20	7.68	2.00	9.68	4.48	86.2%
		250	4.32	0.88	6.52	7.68	2.00	12.68	6.16	94.5%
		500	4.32	0.88	8.72	7.68	2.00	17.68	8.96	102.8%
		750	4.32	0.88	10.92	7.68	2.00	22.68	11.76	107.7%
		1000	4.32	0.88	13.12	7.68	2.00	27.68	14.56	111.0%
		1500	4.32	0.88	17.52	7.68	2.00	37.68	20.16	115.1%
		2000	4.32	0.88	21.92	7.68	2.00	47.68	25.76	117.5%
UR	**Thorold**	100	13.68	1.47	15.15	13.16	2.40	15.56	0.41	2.7%
		250	13.68	1.47	17.36	13.16	2.40	19.15	1.79	10.3%
		500	13.68	1.47	21.03	13.16	2.40	25.14	4.11	19.5%
		750	13.68	1.47	24.71	13.16	2.40	31.13	6.42	26.0%
		1000	13.68	1.47	28.38	13.16	2.40	37.12	8.74	30.8%
		1500	13.68	1.47	35.73	13.16	2.40	49.10	13.37	37.4%
		2000	13.68	1.47	43.08	13.16	2.40	61.08	18.00	41.8%

New Rate Class: R1

Bill Impacts of Proposed Distribution Rates excluding Riders

Classes		Scenario	Existing Dx Rates			Proposed Dx Rates			$ Incr	% Incr
			SrChg	base	Dx bill	SrChg	base	Dx bill		
New Class	Old Class	kWh	[$/month]	[c/kWh]	[$/month]	[$/month]	[c/kWh]	[$/month]		
R1	Tweed	100	4.48	0.95	5.43	7.64	2.10	9.74	4.31	79.4%
		250	4.48	0.95	6.86	7.64	2.10	12.89	6.04	88.0%
		500	4.48	0.95	9.23	7.64	2.10	18.14	8.91	96.5%
		750	4.48	0.95	11.61	7.64	2.10	23.39	11.79	101.6%
		1000	4.48	0.95	13.98	7.64	2.10	28.64	14.66	104.9%
		1500	4.48	0.95	18.73	7.64	2.10	39.14	20.41	109.0%
		2000	4.48	0.95	23.48	7.64	2.10	49.64	26.16	111.4%
R1	Wardsville	100	9.64	0.97	10.61	11.35	2.00	13.35	2.74	25.8%
		250	9.64	0.97	12.07	11.35	2.00	16.35	4.29	35.5%
		500	9.64	0.97	14.49	11.35	2.00	21.35	6.86	47.3%
		750	9.64	0.97	16.92	11.35	2.00	26.35	9.44	55.8%
		1000	9.64	0.97	19.34	11.35	2.00	31.35	12.01	62.1%
		1500	9.64	0.97	24.19	11.35	2.00	41.35	17.16	70.9%
		2000	9.64	0.97	29.04	11.35	2.00	51.35	22.31	76.8%
R1	Warkworth	100	15.25	1.18	16.43	15.95	2.71	18.66	2.23	13.6%
		250	15.25	1.18	18.20	15.95	2.71	22.73	4.53	24.9%
		500	15.25	1.18	21.15	15.95	2.71	29.51	8.36	39.6%
		750	15.25	1.18	24.10	15.95	2.71	36.30	12.20	50.6%
		1000	15.25	1.18	27.05	15.95	2.71	43.08	16.03	59.3%
		1500	15.25	1.18	32.95	15.95	2.71	56.65	23.70	71.9%
		2000	15.25	1.18	38.85	15.95	2.71	70.22	31.37	80.7%
R1	West Elgin	100	13.30	1.42	14.72	14.44	2.71	17.15	2.43	16.5%
		250	13.30	1.42	16.85	14.44	2.71	21.22	4.37	25.9%
		500	13.30	1.42	20.40	14.44	2.71	28.00	7.60	37.3%
		750	13.30	1.42	23.95	14.44	2.71	34.79	10.84	45.2%
		1000	13.30	1.42	27.50	14.44	2.71	41.57	14.07	51.2%
		1500	13.30	1.42	34.60	14.44	2.71	55.14	20.54	59.4%
		2000	13.30	1.42	41.70	14.44	2.71	68.70	27.00	64.8%

New Rate Class: R1

Bill Impacts of Proposed Distribution Rates excluding Riders

Classes		Scenario	Existing Dx Rates			Proposed Dx Rates			$ Incr	% Incr
			SrChg	base	Dx bill	SrChg	base	Dx bill		
New Class	**Old Class**	kWh	[$/month]	[c/kWh]	[$/month]	[$/month]	[c/kWh]	[$/month]		
UR	**Whitchurch Stouffville**	100	10.54	1.02	11.56	10.95	2.30	13.25	1.69	14.6%
		250	10.54	1.02	13.09	10.95	2.30	16.70	3.61	27.5%
		500	10.54	1.02	15.64	10.95	2.30	22.45	6.81	43.5%
		750	10.54	1.02	18.19	10.95	2.30	28.20	10.01	55.0%
		1000	10.54	1.02	20.74	10.95	2.30	33.95	13.21	63.7%
		1500	10.54	1.02	25.84	10.95	2.30	45.45	19.61	75.9%
		2000	10.54	1.02	30.94	10.95	2.30	56.95	26.01	84.0%
R1	**Wiarton**	100	15.83	1.55	17.38	15.80	2.71	18.52	1.14	6.5%
		250	15.83	1.55	19.71	15.80	2.71	22.59	2.88	14.6%
		500	15.83	1.55	23.58	15.80	2.71	29.37	5.79	24.6%
		750	15.83	1.55	27.46	15.80	2.71	36.15	8.70	31.7%
		1000	15.83	1.55	31.33	15.80	2.71	42.94	11.61	37.0%
		1500	15.83	1.55	39.08	15.80	2.71	56.50	17.42	44.6%
		2000	15.83	1.55	46.83	15.80	2.71	70.07	23.24	49.6%
R1	**Woodville**	100	3.78	0.95	4.73	6.82	2.00	8.82	4.09	86.4%
		250	3.78	0.95	6.16	6.82	2.00	11.82	5.66	92.0%
		500	3.78	0.95	8.53	6.82	2.00	16.82	8.29	97.1%
		750	3.78	0.95	10.91	6.82	2.00	21.82	10.91	100.0%
		1000	3.78	0.95	13.28	6.82	2.00	26.82	13.54	101.9%
		1500	3.78	0.95	18.03	6.82	2.00	36.82	18.79	104.2%
		2000	3.78	0.95	22.78	6.82	2.00	46.82	24.04	105.5%
R1	**Wyoming**	100	11.52	0.81	12.33	12.88	1.90	14.78	2.45	19.9%
		250	11.52	0.81	13.55	12.88	1.90	17.63	4.09	30.2%
		500	11.52	0.81	15.57	12.88	1.90	22.38	6.81	43.7%
		750	11.52	0.81	17.60	12.88	1.90	27.13	9.54	54.2%
		1000	11.52	0.81	19.62	12.88	1.90	31.88	12.26	62.5%
		1500	11.52	0.81	23.67	12.88	1.90	41.38	17.71	74.8%
		2000	11.52	0.81	27.72	12.88	1.90	50.88	23.16	83.5%

New Rate Class: R1

Bill Impacts of Proposed Distribution Rates excluding Riders

Classes		Scenario	Existing Dx Rates			Proposed Dx Rates			$ Incr	% Incr
			SrChg	base	Dx bill	SrChg	base	Dx bill		
New Class	**Old Class**	kWh	[$/month]	[c/kWh]	[$/month]	[$/month]	[c/kWh]	[$/month]		
R1	**Terrace Bay**	100	20.81	1.45	22.26	19.56	2.71	22.27	0.01	0.0%
		250	20.81	1.45	24.44	19.56	2.71	26.34	1.91	7.8%
		500	20.81	1.45	28.06	19.56	2.71	33.12	5.06	18.1%
		750	20.81	1.45	31.69	19.56	2.71	39.91	8.22	26.0%
		1000	20.81	1.45	35.31	19.56	2.71	46.69	11.38	32.2%
		1500	20.81	1.45	42.56	19.56	2.71	60.26	17.70	41.6%
		2000	20.81	1.45	49.81	19.56	2.71	73.83	24.02	48.2%

New Rate Class: R2

Bill Impacts of Proposed Distribution Rates excluding Riders

Classes		Scenario	Existing Dx Rates			Proposed Dx Rates			$ Incr	% Incr
			SrChg	base	Dx bill	SrChg	base	Dx bill		
New Class	**Old Class**	kWh	[$/month]	[c/kWh]	[$/month]	[$/month]	[c/kWh]	[$/month]		
R2	**R2**	100	29.22	1.94	31.16	27.05	2.68	29.72	(1.44)	-4.6%
		250	29.22	1.94	34.07	27.05	2.68	33.74	(0.33)	-1.0%
		500	29.22	1.94	38.92	27.05	2.68	40.43	1.51	3.9%
		750	29.22	1.94	43.77	27.05	2.68	47.12	3.35	7.7%
		1,000	29.22	1.94	48.62	27.05	2.68	53.81	5.19	10.7%
		1,500	29.22	1.94	58.32	27.05	2.68	67.20	8.88	15.2%
		2,000	29.22	1.94	68.02	27.05	2.68	80.58	12.56	18.5%
R2	**F1**	100	28.61	2.24	30.85	26.20	2.68	28.88	(1.97)	-6.4%
		250	28.61	2.24	34.21	26.20	2.68	32.89	(1.32)	-3.9%
		500	28.61	2.24	39.81	26.20	2.68	39.58	(0.23)	-0.6%
		750	28.61	2.24	45.41	26.20	2.68	46.27	0.86	1.9%
		1,000	28.61	2.24	51.01	26.20	2.68	52.97	1.96	3.8%
		1,500	28.61	2.24	62.21	26.20	2.68	66.35	4.14	6.7%
		2,000	28.61	2.24	73.41	26.20	2.68	79.73	6.32	8.6%
R2	**F3**	100	30.16	2.89	33.05	27.81	2.68	30.49	(2.56)	-7.8%
		250	30.16	2.89	37.39	27.81	2.68	34.50	(2.88)	-7.7%
		500	30.16	2.89	44.61	27.81	2.68	41.19	(3.42)	-7.7%
		750	30.16	2.89	51.84	27.81	2.68	47.89	(3.95)	-7.6%
		1,000	30.16	2.89	59.06	27.81	2.68	54.58	(4.48)	-7.6%
		1,500	30.16	2.89	73.51	27.81	2.68	67.96	(5.55)	-7.5%
		2,000	30.16	2.89	87.96	27.81	2.68	81.34	(6.62)	-7.5%
R2	**Caledon OH 06**	100	34.85	0.50	35.35	30.64	2.20	32.84	(2.51)	-7.1%
		250	34.85	0.50	36.10	30.64	2.20	36.14	0.04	0.1%
		500	34.85	0.50	37.35	30.64	2.20	41.64	4.29	11.5%
		750	34.85	0.50	38.60	30.64	2.20	47.14	8.54	22.1%
		1,000	34.85	0.50	39.85	30.64	2.20	52.64	12.79	32.1%
		1,500	34.85	0.50	42.35	30.64	2.20	63.64	21.29	50.3%
		2,000	34.85	0.50	44.85	30.64	2.20	74.64	29.79	66.4%

New Rate Class: Seasonal

Bill Impacts of Proposed Distribution Rates excluding Riders

Classes		Scenario	Existing Dx Rates			Proposed Dx Rates			$ Incr	% Incr
			SrChg	base	Dx bill	SrChg	base	Dx bill		
New Class	**Old Class**	kWh	[$/month]	[c/kWh]	[$/month]	[$/month]	[c/kWh]	[$/month]		
Seasonal	**R3**	100	19.51	2.74	22.25	19.00	4.69	23.69	1.44	6.5%
		250	19.51	2.74	26.36	19.00	4.69	30.72	4.36	16.6%
		500	19.51	2.74	33.21	19.00	4.69	42.45	9.24	27.8%
		750	19.51	2.74	40.06	19.00	4.69	54.17	14.11	35.2%
		1,000	19.51	2.74	46.91	19.00	4.69	65.89	18.98	40.5%
		1,500	19.51	2.74	60.61	19.00	4.69	89.34	28.73	47.4%
		2,000	19.51	2.74	74.31	19.00	4.69	112.78	38.47	51.8%
Seasonal	**R4**	100	36.36	1.92	38.28	31.79	4.70	36.48	(1.80)	-4.7%
		250	36.36	1.92	41.16	31.79	4.70	43.53	2.37	5.8%
		500	36.36	1.92	45.96	31.79	4.70	55.27	9.31	20.3%
		750	36.36	1.92	50.76	31.79	4.70	67.02	16.26	32.0%
		1,000	36.36	1.92	55.56	31.79	4.70	78.76	23.20	41.8%
		1,500	36.36	1.92	65.16	31.79	4.70	102.25	37.09	56.9%
		2,000	36.36	1.92	74.76	31.79	4.70	125.73	50.97	68.2%
Seasonal	**Caledon OH 07**	100	38.78	1.04	39.82	33.18	3.20	36.38	(3.44)	-8.6%
		250	38.78	1.04	41.38	33.18	3.20	41.18	(0.20)	-0.5%
		500	38.78	1.04	43.98	33.18	3.20	49.18	5.20	11.8%
		750	38.78	1.04	46.58	33.18	3.20	57.18	10.60	22.8%
		1,000	38.78	1.04	49.18	33.18	3.20	65.18	16.00	32.5%
		1,500	38.78	1.04	54.38	33.18	3.20	81.18	26.80	49.3%
		2,000	38.78	1.04	59.58	33.18	3.20	97.18	37.60	63.1%

New Rate Class: UGe

Bill Impacts of Proposed Distribution Rates exclude Riders

Classes		Scenario	Existing Dx Rates			Proposed Dx Rates			$ Incr	% Incr
			SrChg	base	Dx bill	SrChg	base	Dx bill		
New Class	Old Class	kWh	[$/month]	[c/kWh]	[$/month]	[$/month]	[c/kWh]	[$/month]		
UGe	UG	1,000	15.79	2.74	43.19	14.27	2.00	34.32	(8.87)	-20.5%
		2,000	15.79	2.74	70.59	14.27	2.00	54.36	(16.23)	-23.0%
		5,000	15.79	2.74	152.79	14.27	2.00	114.48	(38.31)	-25.1%
		10,000	15.79	2.74	289.79	14.27	2.00	214.69	(75.10)	-25.9%
		15,000	15.79	2.74	426.79	14.27	2.00	314.90	(111.89)	-26.2%
UGe	F1	1,000	60.71	2.24	83.11	14.27	2.00	34.32	(48.79)	-58.7%
		2,000	60.71	2.24	105.51	14.27	2.00	54.36	(51.15)	-48.5%
		5,000	60.71	2.24	172.71	14.27	2.00	114.48	(58.23)	-33.7%
		10,000	60.71	2.24	284.71	14.27	2.00	214.69	(70.02)	-24.6%
		15,000	60.71	2.24	396.71	14.27	2.00	314.90	(81.81)	-20.6%
UGe	G1	1,000	36.93	3.12	68.13	14.27	2.00	34.32	(33.81)	-49.6%
		2,000	36.93	3.12	99.33	14.27	2.00	54.36	(44.97)	-45.3%
		5,000	36.93	3.12	192.93	14.27	2.00	114.48	(78.45)	-40.7%
		10,000	36.93	3.12	348.93	14.27	2.00	214.69	(134.24)	-38.5%
		15,000	36.93	3.12	504.93	14.27	2.00	314.90	(190.03)	-37.6%
UGe	G3	1,000	46.78	3.07	77.48	14.27	2.00	34.32	(43.16)	-55.7%
		2,000	46.78	3.07	108.18	14.27	2.00	54.36	(53.82)	-49.8%
		5,000	46.78	3.07	200.28	14.27	2.00	114.48	(85.80)	-42.8%
		10,000	46.78	3.07	353.78	14.27	2.00	214.69	(139.09)	-39.3%
		15,000	46.78	3.07	507.28	14.27	2.00	314.90	(192.38)	-37.9%

New Rate Class: UGe

Bill Impacts of Proposed Distribution Rates exclude Riders

Classes		Scenario	Existing Dx Rates			Proposed Dx Rates			$ Incr	% Incr
			SrChg	base	Dx bill	SrChg	base	Dx bill		
New Class	**Old Class**	kWh	[$/month]	[c/kWh]	[$/month]	[$/month]	[c/kWh]	[$/month]		
UGe	**Arnprior**	1,000	21.38	1.17	33.08	18.74	2.00	38.78	5.70	17.2%
		2,000	21.38	1.17	44.78	18.74	2.00	58.82	14.04	31.4%
		5,000	21.38	1.17	79.88	18.74	2.00	118.95	39.07	48.9%
		10,000	21.38	1.17	138.38	18.74	2.00	219.16	80.78	58.4%
		15,000	21.38	1.17	196.88	18.74	2.00	319.37	122.49	62.2%
UGe	**Brockville**	1,000	21.65	0.78	29.45	18.67	2.00	38.71	9.26	31.5%
		2,000	21.65	0.78	37.25	18.67	2.00	58.75	21.50	57.7%
		5,000	21.65	0.78	60.65	18.67	2.00	118.88	58.23	96.0%
		10,000	21.65	0.78	99.65	18.67	2.00	219.09	119.44	119.9%
		15,000	21.65	0.78	138.65	18.67	2.00	319.30	180.65	130.3%
UGe	**Carleton Place**	1,000	23.65	1.68	40.45	20.17	2.00	40.21	(0.24)	-0.6%
		2,000	23.65	1.68	57.25	20.17	2.00	60.25	3.00	5.2%
		5,000	23.65	1.68	107.65	20.17	2.00	120.38	12.73	11.8%
		10,000	23.65	1.68	191.65	20.17	2.00	220.59	28.94	15.1%
		15,000	23.65	1.68	275.65	20.17	2.00	320.80	45.15	16.4%
UGe	**Dryden**	1,000	19.11	1.03	29.41	17.31	2.00	37.35	7.94	27.0%
		2,000	19.11	1.03	39.71	17.31	2.00	57.39	17.68	44.5%
		5,000	19.11	1.03	70.61	17.31	2.00	117.52	46.91	66.4%
		10,000	19.11	1.03	122.11	17.31	2.00	217.73	95.62	78.3%
		15,000	19.11	1.03	173.61	17.31	2.00	317.94	144.33	83.1%

New Rate Class: UGe

Bill Impacts of Proposed Distribution Rates exclude Riders

Classes		Scenario	Existing Dx Rates			Proposed Dx Rates			$ Incr	% Incr
			SrChg	base	Dx bill	SrChg	base	Dx bill		
New Class	**Old Class**	kWh	[$/month]	[c/kWh]	[$/month]	[$/month]	[c/kWh]	[$/month]		
UGe	**GBE**	1,000	10.77	1.14	22.17	10.39	2.00	30.43	8.26	37.3%
		2,000	10.77	1.14	33.57	10.39	2.00	50.47	16.90	50.4%
		5,000	10.77	1.14	67.77	10.39	2.00	110.60	42.83	63.2%
		10,000	10.77	1.14	124.77	10.39	2.00	210.81	86.04	69.0%
		15,000	10.77	1.14	181.77	10.39	2.00	311.02	129.25	71.1%
UGe	**Lindsay**	1,000	23.94	1.38	37.74	20.10	2.00	40.14	2.40	6.4%
		2,000	23.94	1.38	51.54	20.10	2.00	60.18	8.64	16.8%
		5,000	23.94	1.38	92.94	20.10	2.00	120.31	27.37	29.4%
		10,000	23.94	1.38	161.94	20.10	2.00	220.52	58.58	36.2%
		15,000	23.94	1.38	230.94	20.10	2.00	320.73	89.79	38.9%
UGe	**Perth**	1,000	19.92	0.92	29.12	17.10	2.00	37.15	8.03	27.6%
		2,000	19.92	0.92	38.32	17.10	2.00	57.19	18.87	49.2%
		5,000	19.92	0.92	65.92	17.10	2.00	117.31	51.39	78.0%
		10,000	19.92	0.92	111.92	17.10	2.00	217.52	105.60	94.4%
		15,000	19.92	0.92	157.92	17.10	2.00	317.73	159.81	101.2%
UGe	**Quinte West**	1,000	3.74	1.05	14.24	5.15	2.00	25.19	10.95	76.9%
		2,000	3.74	1.05	24.74	5.15	2.00	45.23	20.49	82.8%
		5,000	3.74	1.05	56.24	5.15	2.00	105.36	49.12	87.3%
		10,000	3.74	1.05	108.74	5.15	2.00	205.57	96.83	89.0%
		15,000	3.74	1.05	161.24	5.15	2.00	305.78	144.54	89.6%

New Rate Class: UGe

Bill Impacts of Proposed Distribution Rates exclude Riders

Classes		Scenario	Existing Dx Rates			Proposed Dx Rates			$ Incr	% Incr
New Class	Old Class	kWh	SrChg [$/month]	base [c/kWh]	Dx bill [$/month]	SrChg [$/month]	base [c/kWh]	Dx bill [$/month]		
UGe	**Smiths Falls**	1,000	9.84	1.05	20.34	9.62	2.00	29.67	9.33	45.8%
		2,000	9.84	1.05	30.84	9.62	2.00	49.71	18.87	61.2%
		5,000	9.84	1.05	62.34	9.62	2.00	109.83	47.49	76.2%
		10,000	9.84	1.05	114.84	9.62	2.00	210.04	95.20	82.9%
		15,000	9.84	1.05	167.34	9.62	2.00	310.25	142.91	85.4%
UGe	**Thorold**	1,000	22.63	1.50	37.63	19.43	2.00	39.47	1.84	4.9%
		2,000	22.63	1.50	52.63	19.43	2.00	59.51	6.88	13.1%
		5,000	22.63	1.50	97.63	19.43	2.00	119.64	22.01	22.5%
		10,000	22.63	1.50	172.63	19.43	2.00	219.85	47.22	27.4%
		15,000	22.63	1.50	247.63	19.43	2.00	320.06	72.43	29.2%
UGe	**Whitchurch Stouffville**	1,000	21.85	0.93	31.15	18.62	2.00	38.66	7.51	24.1%
		2,000	21.85	0.93	40.45	18.62	2.00	58.70	18.25	45.1%
		5,000	21.85	0.93	68.35	18.62	2.00	118.83	50.48	73.9%
		10,000	21.85	0.93	114.85	18.62	2.00	219.04	104.19	90.7%
		15,000	21.85	0.93	161.35	18.62	2.00	319.25	157.90	97.9%

New Rate Class: UGd

Bill Impacts of Proposed Distribution Rates exclude Riders

Classes		**Scenario**			Existing Dx Rates			Proposed Dx Rates			$ Incr	% Incr
					SrChg [$/month]	base [$/kW]	Dx bill [$/month]	SrChg [$/month]	base [$/kW]	Dx bill [$/month]		
New Class	**Old Class**	kWh	kW	LF								
UGd	**UG**	15,000	60	35%	15.79	8.44	522	18.49	7.42	464	(58)	-11.2%
		43,164	133	45%	15.79	8.44	1,138	18.49	7.42	1,006	(132)	-11.6%
		100,000	500	28%	15.79	8.44	4,236	18.49	7.42	3,731	(505)	-11.9%
		400,000	1000	56%	15.79	8.44	8,456	18.49	7.42	7,443	(1,013)	-12.0%
		1,000,000	3000	46%	15.79	8.44	25,336	18.49	7.42	22,292	(3,044)	-12.0%
		1,500,000	4000	52%	15.79	8.44	33,776	18.49	7.42	29,717	(4,059)	-12.0%
UGd	**G1**	15,000	60	35%	36.93	9.59	612	18.49	7.42	464	(148)	-24.2%
		43,164	133	45%	36.93	9.59	1,312	18.49	7.42	1,006	(306)	-23.3%
		100,000	500	28%	36.93	9.59	4,832	18.49	7.42	3,731	(1,101)	-22.8%
		400,000	1000	56%	36.93	9.59	9,627	18.49	7.42	7,443	(2,184)	-22.7%
		1,000,000	3000	46%	36.93	9.59	28,807	18.49	7.42	22,292	(6,515)	-22.6%
		1,500,000	4000	52%	36.93	9.59	38,397	18.49	7.42	29,717	(8,680)	-22.6%
UGd	**G3**	15,000	60	35%	46.78	9.91	641	18.49	7.42	464	(177)	-27.7%
		43,164	133	45%	46.78	9.91	1,365	18.49	7.42	1,006	(359)	-26.3%
		100,000	500	28%	46.78	9.91	5,002	18.49	7.42	3,731	(1,271)	-25.4%
		400,000	1000	56%	46.78	9.91	9,957	18.49	7.42	7,443	(2,514)	-25.2%
		1,000,000	3000	46%	46.78	9.91	29,777	18.49	7.42	22,292	(7,485)	-25.1%
		1,500,000	4000	52%	46.78	9.91	39,687	18.49	7.42	29,717	(9,970)	-25.1%
UGd	**Arnprior**	15,000	60	35%	21.38	3.70	243	22.95	7.33	463	220	90.2%
		43,164	133	45%	21.38	3.70	513	22.95	7.33	998	485	94.4%
		100,000	500	28%	21.38	3.70	1,871	22.95	7.33	3,689	1,818	97.2%
		400,000	1000	56%	21.38	3.70	3,721	22.95	7.33	7,356	3,635	97.7%
		1,000,000	3000	46%	21.38	3.70	11,121	22.95	7.33	22,022	10,901	98.0%
		1,500,000	4000	52%	21.38	3.70	14,821	22.95	7.33	29,355	14,534	98.1%

New Rate Class: UGd

Bill Impacts of Proposed Distribution Rates exclude Riders

Classes		Scenario			Existing Dx Rates			Proposed Dx Rates			$ Incr	% Incr
					SrChg [$/month]	base [$/kW]	Dx bill [$/month]	SrChg [$/month]	base [$/kW]	Dx bill [$/month]		
New Class	**Old Class**	kWh	kW	LF								
UGd	**Brockville**	15,000	60	35%	21.65	2.49	171	22.89	6.70	425	254	148.4%
		43,164	133	45%	21.65	2.49	353	22.89	6.70	914	561	159.1%
		100,000	500	28%	21.65	2.49	1,267	22.89	6.70	3,373	2,106	166.3%
		400,000	1000	56%	21.65	2.49	2,512	22.89	6.70	6,723	4,211	167.7%
		1,000,000	3000	46%	21.65	2.49	7,492	22.89	6.70	20,123	12,631	168.6%
		1,500,000	4000	52%	21.65	2.49	9,982	22.89	6.70	26,823	16,841	168.7%
UGd	**Carleton Place**	15,000	60	35%	23.65	5.31	342	24.39	7.33	464	122	35.7%
		43,164	133	45%	23.65	5.31	730	24.39	7.33	1,000	270	37.0%
		100,000	500	28%	23.65	5.31	2,679	24.39	7.33	3,691	1,012	37.8%
		400,000	1000	56%	23.65	5.31	5,334	24.39	7.33	7,357	2,024	37.9%
		1,000,000	3000	46%	23.65	5.31	15,954	24.39	7.33	22,024	6,070	38.0%
		1,500,000	4000	52%	23.65	5.31	21,264	24.39	7.33	29,357	8,093	38.1%
UGd	**Dryden**	15,000	60	35%	19.11	3.29	217	21.52	7.33	462	245	113.2%
		43,164	133	45%	19.11	3.29	457	21.52	7.33	997	540	118.3%
		100,000	500	28%	19.11	3.29	1,664	21.52	7.33	3,688	2,024	121.6%
		400,000	1000	56%	19.11	3.29	3,309	21.52	7.33	7,355	4,045	122.3%
		1,000,000	3000	46%	19.11	3.29	9,889	21.52	7.33	22,021	12,132	122.7%
		1,500,000	4000	52%	19.11	3.29	13,179	21.52	7.33	29,354	16,175	122.7%
UGd	**GBE**	15,000	60	35%	10.77	3.64	229	14.61	7.33	455	225	98.4%
		43,164	133	45%	10.77	3.64	495	14.61	7.33	990	495	100.0%
		100,000	500	28%	10.77	3.64	1,831	14.61	7.33	3,681	1,850	101.1%
		400,000	1000	56%	10.77	3.64	3,651	14.61	7.33	7,348	3,697	101.3%
		1,000,000	3000	46%	10.77	3.64	10,931	14.61	7.33	22,014	11,083	101.4%
		1,500,000	4000	52%	10.77	3.64	14,571	14.61	7.33	29,347	14,776	101.4%

New Rate Class: UGd

Bill Impacts of Proposed Distribution Rates exclude Riders

Classes		Scenario			Existing Dx Rates			Proposed Dx Rates			$ Incr	% Incr
					SrChg [$/month]	base [$/kW]	Dx bill [$/month]	SrChg [$/month]	base [$/kW]	Dx bill [$/month]		
New Class	**Old Class**	kWh	kW	LF								
UGd	**Lindsay**	15,000	60	35%	23.94	4.36	286	24.31	7.33	464	179	62.6%
		43,164	133	45%	23.94	4.36	604	24.31	7.33	1,000	396	65.5%
		100,000	500	28%	23.94	4.36	2,204	24.31	7.33	3,691	1,487	67.5%
		400,000	1000	56%	23.94	4.36	4,384	24.31	7.33	7,357	2,973	67.8%
		1,000,000	3000	46%	23.94	4.36	13,104	24.31	7.33	22,024	8,920	68.1%
		1,500,000	4000	52%	23.94	4.36	17,464	24.31	7.33	29,357	11,893	68.1%
UGd	**Perth**	15,000	60	35%	19.92	2.87	192	21.32	7.15	450	258	134.4%
		43,164	133	45%	19.92	2.87	402	21.32	7.15	972	571	142.1%
		100,000	500	28%	19.92	2.87	1,455	21.32	7.15	3,596	2,141	147.2%
		400,000	1000	56%	19.92	2.87	2,890	21.32	7.15	7,171	4,281	148.1%
		1,000,000	3000	46%	19.92	2.87	8,630	21.32	7.15	21,471	12,841	148.8%
		1,500,000	4000	52%	19.92	2.87	11,500	21.32	7.15	28,621	17,121	148.9%
UGd	**Quinte West**	15,000	60	35%	3.74	3.32	203	9.36	7.33	449	246	121.4%
		43,164	133	45%	3.74	3.32	445	9.36	7.33	985	539	121.1%
		100,000	500	28%	3.74	3.32	1,664	9.36	7.33	3,676	2,012	120.9%
		400,000	1000	56%	3.74	3.32	3,324	9.36	7.33	7,342	4,019	120.9%
		1,000,000	3000	46%	3.74	3.32	9,964	9.36	7.33	22,009	12,045	120.9%
		1,500,000	4000	52%	3.74	3.32	13,284	9.36	7.33	29,342	16,058	120.9%
UGd	**Smiths Falls**	15,000	60	35%	9.84	3.33	210	13.84	7.33	454	244	116.5%
		43,164	133	45%	9.84	3.33	453	13.84	7.33	989	536	118.5%
		100,000	500	28%	9.84	3.33	1,675	13.84	7.33	3,680	2,006	119.7%
		400,000	1000	56%	9.84	3.33	3,340	13.84	7.33	7,347	4,007	120.0%
		1,000,000	3000	46%	9.84	3.33	10,000	13.84	7.33	22,013	12,013	120.1%
		1,500,000	4000	52%	9.84	3.33	13,330	13.84	7.33	29,346	16,016	120.2%

New Rate Class: UGd

Bill Impacts of Proposed Distribution Rates exclude Riders

Classes		Scenario			Existing Dx Rates			Proposed Dx Rates			$ Incr	% Incr
					SrChg	base	Dx bill	SrChg	base	Dx bill		
New Class	Old Class	kWh	kW	LF	[$/month]	[$/kW]	[$/month]	[$/month]	[$/kW]	[$/month]		
UGd	Thorold	15,000	60	35%	22.63	4.76	308	23.64	7.33	464	155	50.4%
		43,164	133	45%	22.63	4.76	656	23.64	7.33	999	343	52.3%
		100,000	500	28%	22.63	4.76	2,403	23.64	7.33	3,690	1,288	53.6%
		400,000	1000	56%	22.63	4.76	4,783	23.64	7.33	7,357	2,574	53.8%
		1,000,000	3000	46%	22.63	4.76	14,303	23.64	7.33	22,023	7,720	54.0%
		1,500,000	4000	52%	22.63	4.76	19,063	23.64	7.33	29,356	10,293	54.0%
UGd	Whitchurch Stouffville	15,000	60	35%	21.85	2.93	198	22.84	7.15	452	254	128.6%
		43,164	133	45%	21.85	2.93	412	22.84	7.15	974	562	136.6%
		100,000	500	28%	21.85	2.93	1,487	22.84	7.15	3,598	2,111	142.0%
		400,000	1000	56%	21.85	2.93	2,952	22.84	7.15	7,173	4,221	143.0%
		1,000,000	3000	46%	21.85	2.93	8,812	22.84	7.15	21,473	12,661	143.7%
		1,500,000	4000	52%	21.85	2.93	11,742	22.84	7.15	28,623	16,881	143.8%

New Rate Class: GSe

Bill Impacts of Proposed Distribution Rates exclude Riders

Classes		Scenario	Existing Dx Rates			Proposed Dx Rates			$ Incr	% Incr
			SrChg	base	Dx bill	SrChg	base	Dx bill		
New Class	**Old Class**	kWh	[$/month]	[c/kWh]	[$/month]	[$/month]	[c/kWh]	[$/month]		
GSe	**F1**	1,000	60.71	2.24	83.11	52.91	3.38	86.68	3.57	4.3%
		2,000	60.71	2.24	105.51	52.91	3.38	120.45	14.94	14.2%
		5,000	60.71	2.24	172.71	52.91	3.38	221.76	49.05	28.4%
		10,000	60.71	2.24	284.71	52.91	3.38	390.61	105.90	37.2%
		15,000	60.71	2.24	396.71	52.91	3.38	559.45	162.74	41.0%
GSe	**F3**	1,000	53.91	2.89	82.81	47.61	3.38	81.38	(1.43)	-1.7%
		2,000	53.91	2.89	111.71	47.61	3.38	115.15	3.44	3.1%
		5,000	53.91	2.89	198.41	47.61	3.38	216.46	18.05	9.1%
		10,000	53.91	2.89	342.91	47.61	3.38	385.31	42.40	12.4%
		15,000	53.91	2.89	487.41	47.61	3.38	554.15	66.74	13.7%
GSe	**G1**	1,000	36.93	3.12	68.13	35.09	3.38	68.86	0.73	1.1%
		2,000	36.93	3.12	99.33	35.09	3.38	102.63	3.30	3.3%
		5,000	36.93	3.12	192.93	35.09	3.38	203.93	11.00	5.7%
		10,000	36.93	3.12	348.93	35.09	3.38	372.78	23.85	6.8%
		15,000	36.93	3.12	504.93	35.09	3.38	541.62	36.69	7.3%
GSe	**G3**	1,000	46.78	3.07	77.48	42.40	3.38	76.17	(1.31)	-1.7%
		2,000	46.78	3.07	108.18	42.40	3.38	109.94	1.76	1.6%
		5,000	46.78	3.07	200.28	42.40	3.38	211.25	10.97	5.5%
		10,000	46.78	3.07	353.78	42.40	3.38	380.10	26.32	7.4%
		15,000	46.78	3.07	507.28	42.40	3.38	548.94	41.66	8.2%
GSe	**T**	1,000	261.54	2.43	285.84	203.71	3.38	237.48	(48.36)	-16.9%
		2,000	261.54	2.43	310.14	203.71	3.38	271.25	(38.89)	-12.5%
		5,000	261.54	2.43	383.04	203.71	3.38	372.55	(10.49)	-2.7%
		10,000	261.54	2.43	504.54	203.71	3.38	541.40	36.86	7.3%
		15,000	261.54	2.43	626.04	203.71	3.38	710.24	84.20	13.5%

New Rate Class: GSe

Bill Impacts of Proposed Distribution Rates exclude Riders

Classes		Scenario	Existing Dx Rates			Proposed Dx Rates			$ Incr	% Incr
New Class	Old Class	kWh	SrChg [$/month]	base [c/kWh]	Dx bill [$/month]	SrChg [$/month]	base [c/kWh]	Dx bill [$/month]		
GSe	Ailsa Craig	1,000	17.31	1.32	30.51	20.76	2.34	44.16	13.65	44.8%
		2,000	17.31	1.32	43.71	20.76	2.34	67.56	23.85	54.6%
		5,000	17.31	1.32	83.31	20.76	2.34	137.76	54.45	65.4%
		10,000	17.31	1.32	149.31	20.76	2.34	254.76	105.45	70.6%
		15,000	17.31	1.32	215.31	20.76	2.34	371.76	156.45	72.7%
GSe	Arkona	1,000	3.20	0.86	11.80	10.29	1.98	30.09	18.29	155.0%
		2,000	3.20	0.86	20.40	10.29	1.98	49.89	29.49	144.6%
		5,000	3.20	0.86	46.20	10.29	1.98	109.29	63.09	136.6%
		10,000	3.20	0.86	89.20	10.29	1.98	208.29	119.09	133.5%
		15,000	3.20	0.86	132.20	10.29	1.98	307.29	175.09	132.4%
UGe	Arnprior	1,000	21.38	1.17	33.08	18.74	2.00	38.78	5.70	17.2%
		2,000	21.38	1.17	44.78	18.74	2.00	58.82	14.04	31.4%
		5,000	21.38	1.17	79.88	18.74	2.00	118.95	39.07	48.9%
		10,000	21.38	1.17	138.38	18.74	2.00	219.16	80.78	58.4%
		15,000	21.38	1.17	196.88	18.74	2.00	319.37	122.49	62.2%
GSe	Arran-Elderslie	1,000	8.83	1.03	19.13	13.88	1.90	32.88	13.75	71.9%
		2,000	8.83	1.03	29.43	13.88	1.90	51.88	22.45	76.3%
		5,000	8.83	1.03	60.33	13.88	1.90	108.88	48.55	80.5%
		10,000	8.83	1.03	111.83	13.88	1.90	203.88	92.05	82.3%
		15,000	8.83	1.03	163.33	13.88	1.90	298.88	135.55	83.0%
GSe	Artemesia	1,000	19.62	1.74	37.02	22.19	3.21	54.29	17.27	46.7%
		2,000	19.62	1.74	54.42	22.19	3.21	86.40	31.98	58.8%
		5,000	19.62	1.74	106.62	22.19	3.21	182.71	76.09	71.4%
		10,000	19.62	1.74	193.62	22.19	3.21	343.24	149.62	77.3%
		15,000	19.62	1.74	280.62	22.19	3.21	503.76	223.14	79.5%

New Rate Class: GSe

Bill Impacts of Proposed Distribution Rates exclude Riders

Classes		Scenario	Existing Dx Rates			Proposed Dx Rates			$ Incr	% Incr
New Class	Old Class	kWh	SrChg [$/month]	base [c/kWh]	Dx bill [$/month]	SrChg [$/month]	base [c/kWh]	Dx bill [$/month]		
GSe	**Bancroft**	1,000	24.41	1.18	36.21	25.99	2.30	48.99	12.78	35.3%
		2,000	24.41	1.18	48.01	25.99	2.30	71.99	23.98	49.9%
		5,000	24.41	1.18	83.41	25.99	2.30	140.99	57.58	69.0%
		10,000	24.41	1.18	142.41	25.99	2.30	255.99	113.58	79.8%
		15,000	24.41	1.18	201.41	25.99	2.30	370.99	169.58	84.2%
GSe	**Bath**	1,000	10.65	1.47	25.35	15.43	2.55	40.93	15.58	61.5%
		2,000	10.65	1.47	40.05	15.43	2.55	66.43	26.38	65.9%
		5,000	10.65	1.47	84.15	15.43	2.55	142.93	58.78	69.9%
		10,000	10.65	1.47	157.65	15.43	2.55	270.43	112.78	71.5%
		15,000	10.65	1.47	231.15	15.43	2.55	397.93	166.78	72.2%
GSe	**Blandford-Blenheim**	1,000	23.85	1.14	35.25	25.13	2.40	49.13	13.88	39.4%
		2,000	23.85	1.14	46.65	25.13	2.40	73.13	26.48	56.8%
		5,000	23.85	1.14	80.85	25.13	2.40	145.13	64.28	79.5%
		10,000	23.85	1.14	137.85	25.13	2.40	265.13	127.28	92.3%
		15,000	23.85	1.14	194.85	25.13	2.40	385.13	190.28	97.7%
GSe	**Blyth**	1,000	21.63	1.05	32.13	23.68	2.20	45.68	13.55	42.2%
		2,000	21.63	1.05	42.63	23.68	2.20	67.68	25.05	58.8%
		5,000	21.63	1.05	74.13	23.68	2.20	133.68	59.55	80.3%
		10,000	21.63	1.05	126.63	23.68	2.20	243.68	117.05	92.4%
		15,000	21.63	1.05	179.13	23.68	2.20	353.68	174.55	97.4%
GSe	**Bobcaygeon**	1,000	23.20	1.38	37.00	25.29	2.50	50.29	13.29	35.9%
		2,000	23.20	1.38	50.80	25.29	2.50	75.29	24.49	48.2%
		5,000	23.20	1.38	92.20	25.29	2.50	150.29	58.09	63.0%
		10,000	23.20	1.38	161.20	25.29	2.50	275.29	114.09	70.8%
		15,000	23.20	1.38	230.20	25.29	2.50	400.29	170.09	73.9%

New Rate Class: GSe

Bill Impacts of Proposed Distribution Rates exclude Riders

Classes		Scenario	Existing Dx Rates			Proposed Dx Rates			$ Incr	% Incr
			SrChg	base	Dx bill	SrChg	base	Dx bill		
New Class	**Old Class**	kWh	[$/month]	[c/kWh]	[$/month]	[$/month]	[c/kWh]	[$/month]		
GSe	**Brighton**	1,000	22.90	1.35	36.40	24.37	2.50	49.37	12.97	35.6%
		2,000	22.90	1.35	49.90	24.37	2.50	74.37	24.47	49.0%
		5,000	22.90	1.35	90.40	24.37	2.50	149.37	58.97	65.2%
		10,000	22.90	1.35	157.90	24.37	2.50	274.37	116.47	73.8%
		15,000	22.90	1.35	225.40	24.37	2.50	399.37	173.97	77.2%
UGe	**Brockville**	1,000	21.65	0.78	29.45	18.67	2.00	38.71	9.26	31.5%
		2,000	21.65	0.78	37.25	18.67	2.00	58.75	21.50	57.7%
		5,000	21.65	0.78	60.65	18.67	2.00	118.88	58.23	96.0%
		10,000	21.65	0.78	99.65	18.67	2.00	219.09	119.44	119.9%
		15,000	21.65	0.78	138.65	18.67	2.00	319.30	180.65	130.3%
GSe	**Caledon CH**	1,000	24.21	1.80	42.21	26.04	2.90	55.04	12.83	30.4%
		2,000	24.21	1.80	60.21	26.04	2.90	84.04	23.83	39.6%
		5,000	24.21	1.80	114.21	26.04	2.90	171.04	56.83	49.8%
		10,000	24.21	1.80	204.21	26.04	2.90	316.04	111.83	54.8%
		15,000	24.21	1.80	294.21	26.04	2.90	461.04	166.83	56.7%
GSe	**Caledon OH**	1,000	25.56	1.70	42.56	26.70	2.90	55.70	13.14	30.9%
		2,000	25.56	1.70	59.56	26.70	2.90	84.70	25.14	42.2%
		5,000	25.56	1.70	110.56	26.70	2.90	171.70	61.14	55.3%
		10,000	25.56	1.70	195.56	26.70	2.90	316.70	121.14	61.9%
		15,000	25.56	1.70	280.56	26.70	2.90	461.70	181.14	64.6%
GSe	**Campbellford-Seymour**	1,000	16.19	1.19	28.09	20.04	2.15	41.54	13.45	47.9%
		2,000	16.19	1.19	39.99	20.04	2.15	63.04	23.05	57.7%
		5,000	16.19	1.19	75.69	20.04	2.15	127.54	51.85	68.5%
		10,000	16.19	1.19	135.19	20.04	2.15	235.04	99.85	73.9%
		15,000	16.19	1.19	194.69	20.04	2.15	342.54	147.85	75.9%

New Rate Class: GSe

Bill Impacts of Proposed Distribution Rates exclude Riders

Classes		Scenario	Existing Dx Rates			Proposed Dx Rates			$ Incr	% Incr
			SrChg	base	Dx bill	SrChg	base	Dx bill		
New Class	Old Class	kWh	[$/month]	[c/kWh]	[$/month]	[$/month]	[c/kWh]	[$/month]		
UGe	Carleton Place	1,000	23.65	1.68	40.45	20.17	2.00	40.21	(0.24)	-0.6%
		2,000	23.65	1.68	57.25	20.17	2.00	60.25	3.00	5.2%
		5,000	23.65	1.68	107.65	20.17	2.00	120.38	12.73	11.8%
		10,000	23.65	1.68	191.65	20.17	2.00	220.59	28.94	15.1%
		15,000	23.65	1.68	275.65	20.17	2.00	320.80	45.15	16.4%
GSe	Cavan-Millbrook-North Mor	1,000	22.28	1.50	37.28	24.52	2.80	52.52	15.24	40.9%
		2,000	22.28	1.50	52.28	24.52	2.80	80.52	28.24	54.0%
		5,000	22.28	1.50	97.28	24.52	2.80	164.52	67.24	69.1%
		10,000	22.28	1.50	172.28	24.52	2.80	304.52	132.24	76.8%
		15,000	22.28	1.50	247.28	24.52	2.80	444.52	197.24	79.8%
GSe	Centre Hastings	1,000	18.38	0.97	28.08	21.50	1.94	40.90	12.82	45.6%
		2,000	18.38	0.97	37.78	21.50	1.94	60.30	22.52	59.6%
		5,000	18.38	0.97	66.88	21.50	1.94	118.50	51.62	77.2%
		10,000	18.38	0.97	115.38	21.50	1.94	215.50	100.12	86.8%
		15,000	18.38	0.97	163.88	21.50	1.94	312.50	148.62	90.7%
GSe	Chalk River	1,000	21.33	1.79	39.23	23.76	3.18	55.56	16.33	41.6%
		2,000	21.33	1.79	57.13	23.76	3.18	87.36	30.23	52.9%
		5,000	21.33	1.79	110.83	23.76	3.18	182.76	71.93	64.9%
		10,000	21.33	1.79	200.33	23.76	3.18	341.76	141.43	70.6%
		15,000	21.33	1.79	289.83	23.76	3.18	500.76	210.93	72.8%
GSe	Champlain	1,000	20.59	0.91	29.69	22.94	2.05	43.44	13.75	46.3%
		2,000	20.59	0.91	38.79	22.94	2.05	63.94	25.15	64.8%
		5,000	20.59	0.91	66.09	22.94	2.05	125.44	59.35	89.8%
		10,000	20.59	0.91	111.59	22.94	2.05	227.94	116.35	104.3%
		15,000	20.59	0.91	157.09	22.94	2.05	330.44	173.35	110.4%

New Rate Class: GSe

Bill Impacts of Proposed Distribution Rates exclude Riders

Classes		Scenario	Existing Dx Rates			Proposed Dx Rates			$ Incr	% Incr
New Class	Old Class	kWh	SrChg [$/month]	base [c/kWh]	Dx bill [$/month]	SrChg [$/month]	base [c/kWh]	Dx bill [$/month]		
GSe	Cobden	1,000	21.93	2.13	43.23	23.61	3.21	55.71	12.48	28.9%
		2,000	21.93	2.13	64.53	23.61	3.21	87.82	23.29	36.1%
		5,000	21.93	2.13	128.43	23.61	3.21	184.13	55.70	43.4%
		10,000	21.93	2.13	234.93	23.61	3.21	344.66	109.73	46.7%
		15,000	21.93	2.13	341.43	23.61	3.21	505.18	163.75	48.0%
GSe	Deep River	1,000	23.94	2.26	46.54	25.11	3.21	57.21	10.67	22.9%
		2,000	23.94	2.26	69.14	25.11	3.21	89.32	20.18	29.2%
		5,000	23.94	2.26	136.94	25.11	3.21	185.63	48.69	35.6%
		10,000	23.94	2.26	249.94	25.11	3.21	346.16	96.22	38.5%
		15,000	23.94	2.26	362.94	25.11	3.21	506.68	143.74	39.6%
GSe	Deseronto	1,000	10.14	1.35	23.64	15.56	2.18	37.36	13.72	58.0%
		2,000	10.14	1.35	37.14	15.56	2.18	59.16	22.02	59.3%
		5,000	10.14	1.35	77.64	15.56	2.18	124.56	46.92	60.4%
		10,000	10.14	1.35	145.14	15.56	2.18	233.56	88.42	60.9%
		15,000	10.14	1.35	212.64	15.56	2.18	342.56	129.92	61.1%
UGe	Dryden	1,000	19.11	1.03	29.41	17.31	2.00	37.35	7.94	27.0%
		2,000	19.11	1.03	39.71	17.31	2.00	57.39	17.68	44.5%
		5,000	19.11	1.03	70.61	17.31	2.00	117.52	46.91	66.4%
		10,000	19.11	1.03	122.11	17.31	2.00	217.73	95.62	78.3%
		15,000	19.11	1.03	173.61	17.31	2.00	317.94	144.33	83.1%
GSe	Dundalk	1,000	23.56	1.64	39.96	25.20	2.85	53.70	13.74	34.4%
		2,000	23.56	1.64	56.36	25.20	2.85	82.20	25.84	45.9%
		5,000	23.56	1.64	105.56	25.20	2.85	167.70	62.14	58.9%
		10,000	23.56	1.64	187.56	25.20	2.85	310.20	122.64	65.4%
		15,000	23.56	1.64	269.56	25.20	2.85	452.70	183.14	67.9%

New Rate Class: GSe

Bill Impacts of Proposed Distribution Rates exclude Riders

Classes		Scenario	Existing Dx Rates			Proposed Dx Rates			$ Incr	% Incr
			SrChg	base	Dx bill	SrChg	base	Dx bill		
New Class	**Old Class**	kWh	[$/month]	[c/kWh]	[$/month]	[$/month]	[c/kWh]	[$/month]		
GSe	**Durham**	1,000	24.12	1.37	37.82	26.06	2.48	50.86	13.04	34.5%
		2,000	24.12	1.37	51.52	26.06	2.48	75.66	24.14	46.9%
		5,000	24.12	1.37	92.62	26.06	2.48	150.06	57.44	62.0%
		10,000	24.12	1.37	161.12	26.06	2.48	274.06	112.94	70.1%
		15,000	24.12	1.37	229.62	26.06	2.48	398.06	168.44	73.4%
GSe	**Eganville**	1,000	21.35	2.32	44.55	23.75	3.21	55.86	11.31	25.4%
		2,000	21.35	2.32	67.75	23.75	3.21	87.96	20.21	29.8%
		5,000	21.35	2.32	137.35	23.75	3.21	184.28	46.93	34.2%
		10,000	21.35	2.32	253.35	23.75	3.21	344.80	91.45	36.1%
		15,000	21.35	2.32	369.35	23.75	3.21	505.33	135.98	36.8%
GSe	**Erin**	1,000	40.38	0.73	47.68	38.00	2.10	59.00	11.32	23.7%
		2,000	40.38	0.73	54.98	38.00	2.10	80.00	25.02	45.5%
		5,000	40.38	0.73	76.88	38.00	2.10	143.00	66.12	86.0%
		10,000	40.38	0.73	113.38	38.00	2.10	248.00	134.62	118.7%
		15,000	40.38	0.73	149.88	38.00	2.10	353.00	203.12	135.5%
GSe	**Exeter**	1,000	11.36	1.30	24.36	16.25	2.18	38.05	13.69	56.2%
		2,000	11.36	1.30	37.36	16.25	2.18	59.85	22.49	60.2%
		5,000	11.36	1.30	76.36	16.25	2.18	125.25	48.89	64.0%
		10,000	11.36	1.30	141.36	16.25	2.18	234.25	92.89	65.7%
		15,000	11.36	1.30	206.36	16.25	2.18	343.25	136.89	66.3%
GSe	**Fenelon Falls**	1,000	19.81	0.95	29.31	22.14	1.98	41.94	12.63	43.1%
		2,000	19.81	0.95	38.81	22.14	1.98	61.74	22.93	59.1%
		5,000	19.81	0.95	67.31	22.14	1.98	121.14	53.83	80.0%
		10,000	19.81	0.95	114.81	22.14	1.98	220.14	105.33	91.7%
		15,000	19.81	0.95	162.31	22.14	1.98	319.14	156.83	96.6%

New Rate Class: GSe

Bill Impacts of Proposed Distribution Rates exclude Riders

Classes		Scenario	Existing Dx Rates			Proposed Dx Rates			$ Incr	% Incr
			SrChg	base	Dx bill	SrChg	base	Dx bill		
New Class	Old Class	kWh	[$/month]	[c/kWh]	[$/month]	[$/month]	[c/kWh]	[$/month]		
GSe	Forest	1,000	24.91	1.18	36.71	25.86	2.32	49.06	12.35	33.7%
		2,000	24.91	1.18	48.51	25.86	2.32	72.26	23.75	49.0%
		5,000	24.91	1.18	83.91	25.86	2.32	141.86	57.95	69.1%
		10,000	24.91	1.18	142.91	25.86	2.32	257.86	114.95	80.4%
		15,000	24.91	1.18	201.91	25.86	2.32	373.86	171.95	85.2%
UGe	GBE	1,000	10.77	1.14	22.17	10.39	2.00	30.43	8.26	37.3%
		2,000	10.77	1.14	33.57	10.39	2.00	50.47	16.90	50.4%
		5,000	10.77	1.14	67.77	10.39	2.00	110.60	42.83	63.2%
		10,000	10.77	1.14	124.77	10.39	2.00	210.81	86.04	69.0%
		15,000	10.77	1.14	181.77	10.39	2.00	311.02	129.25	71.1%
GSe	Georgina	1,000	17.40	1.62	33.60	20.74	2.65	47.24	13.64	40.6%
		2,000	17.40	1.62	49.80	20.74	2.65	73.74	23.94	48.1%
		5,000	17.40	1.62	98.40	20.74	2.65	153.24	54.84	55.7%
		10,000	17.40	1.62	179.40	20.74	2.65	285.74	106.34	59.3%
		15,000	17.40	1.62	260.40	20.74	2.65	418.24	157.84	60.6%
GSe	Glencoe	1,000	11.37	0.81	19.47	16.25	1.74	33.65	14.18	72.8%
		2,000	11.37	0.81	27.57	16.25	1.74	51.05	23.48	85.2%
		5,000	11.37	0.81	51.87	16.25	1.74	103.25	51.38	99.1%
		10,000	11.37	0.81	92.37	16.25	1.74	190.25	97.88	106.0%
		15,000	11.37	0.81	132.87	16.25	1.74	277.25	144.38	108.7%
GSe	Grand Bend	1,000	22.20	1.23	34.50	24.54	2.34	47.94	13.44	39.0%
		2,000	22.20	1.23	46.80	24.54	2.34	71.34	24.54	52.4%
		5,000	22.20	1.23	83.70	24.54	2.34	141.54	57.84	69.1%
		10,000	22.20	1.23	145.20	24.54	2.34	258.54	113.34	78.1%
		15,000	22.20	1.23	206.70	24.54	2.34	375.54	168.84	81.7%

New Rate Class: GSe

Bill Impacts of Proposed Distribution Rates exclude Riders

Classes		Scenario	Existing Dx Rates			Proposed Dx Rates			$ Incr	% Incr
			SrChg	base	Dx bill	SrChg	base	Dx bill		
New Class	Old Class	kWh	[$/month]	[c/kWh]	[$/month]	[$/month]	[c/kWh]	[$/month]		
GSe	**Hastings**	1,000	22.89	1.69	39.79	24.37	2.93	53.67	13.88	34.9%
		2,000	22.89	1.69	56.69	24.37	2.93	82.97	26.28	46.4%
		5,000	22.89	1.69	107.39	24.37	2.93	170.87	63.48	59.1%
		10,000	22.89	1.69	191.89	24.37	2.93	317.37	125.48	65.4%
		15,000	22.89	1.69	276.39	24.37	2.93	463.87	187.48	67.8%
GSe	**Havelock**	1,000	22.18	1.52	37.38	24.55	2.60	50.55	13.17	35.2%
		2,000	22.18	1.52	52.58	24.55	2.60	76.55	23.97	45.6%
		5,000	22.18	1.52	98.18	24.55	2.60	154.55	56.37	57.4%
		10,000	22.18	1.52	174.18	24.55	2.60	284.55	110.37	63.4%
		15,000	22.18	1.52	250.18	24.55	2.60	414.55	164.37	65.7%
GSe	**Kirkfield**	1,000	14.69	1.95	34.19	18.42	3.21	50.52	16.33	47.8%
		2,000	14.69	1.95	53.69	18.42	3.21	82.63	28.94	53.9%
		5,000	14.69	1.95	112.19	18.42	3.21	178.94	66.75	59.5%
		10,000	14.69	1.95	209.69	18.42	3.21	339.47	129.78	61.9%
		15,000	14.69	1.95	307.19	18.42	3.21	499.99	192.80	62.8%
GSe	**Lanark Highlands**	1,000	18.43	1.99	38.33	21.48	3.21	53.59	15.26	39.8%
		2,000	18.43	1.99	58.23	21.48	3.21	85.69	27.46	47.2%
		5,000	18.43	1.99	117.93	21.48	3.21	182.01	64.08	54.3%
		10,000	18.43	1.99	217.43	21.48	3.21	342.53	125.10	57.5%
		15,000	18.43	1.99	316.93	21.48	3.21	503.06	186.13	58.7%
GSe	**Larder Lake**	1,000	20.18	1.58	35.98	23.05	3.05	53.55	17.57	48.8%
		2,000	20.18	1.58	51.78	23.05	3.05	84.05	32.27	62.3%
		5,000	20.18	1.58	99.18	23.05	3.05	175.55	76.37	77.0%
		10,000	20.18	1.58	178.18	23.05	3.05	328.05	149.87	84.1%
		15,000	20.18	1.58	257.18	23.05	3.05	480.55	223.37	86.9%

New Rate Class: GSe

Bill Impacts of Proposed Distribution Rates exclude Riders

Classes		Scenario	Existing Dx Rates			Proposed Dx Rates			$ Incr	% Incr
			SrChg	base	Dx bill	SrChg	base	Dx bill		
New Class	Old Class	kWh	[$/month]	[c/kWh]	[$/month]	[$/month]	[c/kWh]	[$/month]		
GSe	Latchford	1,000	2.88	1.02	13.08	9.37	2.32	32.57	19.49	149.0%
		2,000	2.88	1.02	23.28	9.37	2.32	55.77	32.49	139.6%
		5,000	2.88	1.02	53.88	9.37	2.32	125.37	71.49	132.7%
		10,000	2.88	1.02	104.88	9.37	2.32	241.37	136.49	130.1%
		15,000	2.88	1.02	155.88	9.37	2.32	357.37	201.49	129.3%
UGe	Lindsay	1,000	23.94	1.38	37.74	20.10	2.00	40.14	2.40	6.4%
		2,000	23.94	1.38	51.54	20.10	2.00	60.18	8.64	16.8%
		5,000	23.94	1.38	92.94	20.10	2.00	120.31	27.37	29.4%
		10,000	23.94	1.38	161.94	20.10	2.00	220.52	58.58	36.2%
		15,000	23.94	1.38	230.94	20.10	2.00	320.73	89.79	38.9%
GSe	Lucan Granton	1,000	16.99	1.47	31.69	19.84	2.53	45.14	13.45	42.5%
		2,000	16.99	1.47	46.39	19.84	2.53	70.44	24.05	51.9%
		5,000	16.99	1.47	90.49	19.84	2.53	146.34	55.85	61.7%
		10,000	16.99	1.47	163.99	19.84	2.53	272.84	108.85	66.4%
		15,000	16.99	1.47	237.49	19.84	2.53	399.34	161.85	68.2%
GSe	Malahide	1,000	15.84	1.98	35.64	19.13	3.21	51.24	15.60	43.8%
		2,000	15.84	1.98	55.44	19.13	3.21	83.34	27.90	50.3%
		5,000	15.84	1.98	114.84	19.13	3.21	179.66	64.82	56.4%
		10,000	15.84	1.98	213.84	19.13	3.21	340.18	126.34	59.1%
		15,000	15.84	1.98	312.84	19.13	3.21	500.70	187.86	60.1%
GSe	Mapleton	1,000	21.55	1.71	38.65	23.70	3.11	54.80	16.15	41.8%
		2,000	21.55	1.71	55.75	23.70	3.11	85.90	30.15	54.1%
		5,000	21.55	1.71	107.05	23.70	3.11	179.20	72.15	67.4%
		10,000	21.55	1.71	192.55	23.70	3.11	334.70	142.15	73.8%
		15,000	21.55	1.71	278.05	23.70	3.11	490.20	212.15	76.3%

New Rate Class: GSe

Bill Impacts of Proposed Distribution Rates exclude Riders

Classes		Scenario	Existing Dx Rates			Proposed Dx Rates			$ Incr	% Incr
			SrChg	base	Dx bill	SrChg	base	Dx bill		
New Class	Old Class	kWh	[$/month]	[c/kWh]	[$/month]	[$/month]	[c/kWh]	[$/month]		
GSe	**Markdale**	1,000	23.00	0.80	31.00	25.34	1.82	43.54	12.54	40.5%
		2,000	23.00	0.80	39.00	25.34	1.82	61.74	22.74	58.3%
		5,000	23.00	0.80	63.00	25.34	1.82	116.34	53.34	84.7%
		10,000	23.00	0.80	103.00	25.34	1.82	207.34	104.34	101.3%
		15,000	23.00	0.80	143.00	25.34	1.82	298.34	155.34	108.6%
GSe	**Marmora**	1,000	10.02	1.05	20.52	15.59	1.88	34.39	13.87	67.6%
		2,000	10.02	1.05	31.02	15.59	1.88	53.19	22.17	71.5%
		5,000	10.02	1.05	62.52	15.59	1.88	109.59	47.07	75.3%
		10,000	10.02	1.05	115.02	15.59	1.88	203.59	88.57	77.0%
		15,000	10.02	1.05	167.52	15.59	1.88	297.59	130.07	77.6%
GSe	**McGarry**	1,000	19.99	2.00	39.99	22.09	3.21	54.20	14.21	35.5%
		2,000	19.99	2.00	59.99	22.09	3.21	86.30	26.31	43.9%
		5,000	19.99	2.00	119.99	22.09	3.21	182.62	62.63	52.2%
		10,000	19.99	2.00	219.99	22.09	3.21	343.14	123.15	56.0%
		15,000	19.99	2.00	319.99	22.09	3.21	503.67	183.68	57.4%
GSe	**Meaford**	1,000	24.05	1.23	36.35	26.08	2.32	49.28	12.93	35.6%
		2,000	24.05	1.23	48.65	26.08	2.32	72.48	23.83	49.0%
		5,000	24.05	1.23	85.55	26.08	2.32	142.08	56.53	66.1%
		10,000	24.05	1.23	147.05	26.08	2.32	258.08	111.03	75.5%
		15,000	24.05	1.23	208.55	26.08	2.32	374.08	165.53	79.4%
GSe	**Middlesex Centre**	1,000	17.35	1.37	31.05	20.75	2.70	47.75	16.70	53.8%
		2,000	17.35	1.37	44.75	20.75	2.70	74.75	30.00	67.0%
		5,000	17.35	1.37	85.85	20.75	2.70	155.75	69.90	81.4%
		10,000	17.35	1.37	154.35	20.75	2.70	290.75	136.40	88.4%
		15,000	17.35	1.37	222.85	20.75	2.70	425.75	202.90	91.0%

New Rate Class: GSe

Bill Impacts of Proposed Distribution Rates exclude Riders

Classes		Scenario	Existing Dx Rates			Proposed Dx Rates			$ Incr	% Incr
New Class	Old Class	kWh	SrChg [$/month]	base [c/kWh]	Dx bill [$/month]	SrChg [$/month]	base [c/kWh]	Dx bill [$/month]		
GSe	**Napanee**	1,000	22.17	1.28	34.97	24.55	2.35	48.05	13.08	37.4%
		2,000	22.17	1.28	47.77	24.55	2.35	71.55	23.78	49.8%
		5,000	22.17	1.28	86.17	24.55	2.35	142.05	55.88	64.8%
		10,000	22.17	1.28	150.17	24.55	2.35	259.55	109.38	72.8%
		15,000	22.17	1.28	214.17	24.55	2.35	377.05	162.88	76.1%
GSe	**Nipigon**	1,000	23.32	1.05	33.82	25.26	2.34	48.66	14.84	43.9%
		2,000	23.32	1.05	44.32	25.26	2.34	72.06	27.74	62.6%
		5,000	23.32	1.05	75.82	25.26	2.34	142.26	66.44	87.6%
		10,000	23.32	1.05	128.32	25.26	2.34	259.26	130.94	102.0%
		15,000	23.32	1.05	180.82	25.26	2.34	376.26	195.44	108.1%
GSe	**North Dorchester**	1,000	15.88	0.90	24.88	19.12	2.08	39.92	15.04	60.5%
		2,000	15.88	0.90	33.88	19.12	2.08	60.72	26.84	79.2%
		5,000	15.88	0.90	60.88	19.12	2.08	123.12	62.24	102.2%
		10,000	15.88	0.90	105.88	19.12	2.08	227.12	121.24	114.5%
		15,000	15.88	0.90	150.88	19.12	2.08	331.12	180.24	119.5%
GSe	**North Dundas**	1,000	13.52	0.83	21.82	17.71	1.72	34.91	13.09	60.0%
		2,000	13.52	0.83	30.12	17.71	1.72	52.11	21.99	73.0%
		5,000	13.52	0.83	55.02	17.71	1.72	103.71	48.69	88.5%
		10,000	13.52	0.83	96.52	17.71	1.72	189.71	93.19	96.6%
		15,000	13.52	0.83	138.02	17.71	1.72	275.71	137.69	99.8%
GSe	**North Glengarry**	1,000	17.72	0.90	26.72	20.66	1.95	40.16	13.44	50.3%
		2,000	17.72	0.90	35.72	20.66	1.95	59.66	23.94	67.0%
		5,000	17.72	0.90	62.72	20.66	1.95	118.16	55.44	88.4%
		10,000	17.72	0.90	107.72	20.66	1.95	215.66	107.94	100.2%
		15,000	17.72	0.90	152.72	20.66	1.95	313.16	160.44	105.1%

New Rate Class: GSe

Bill Impacts of Proposed Distribution Rates exclude Riders

Classes		Scenario	Existing Dx Rates			Proposed Dx Rates			$ Incr	% Incr
New Class	Old Class	kWh	SrChg [$/month]	base [c/kWh]	Dx bill [$/month]	SrChg [$/month]	base [c/kWh]	Dx bill [$/month]		
GSe	**North Grenville**	1,000	20.42	1.71	37.52	22.99	2.79	50.89	13.37	35.6%
		2,000	20.42	1.71	54.62	22.99	2.79	78.79	24.17	44.2%
		5,000	20.42	1.71	105.92	22.99	2.79	162.49	56.57	53.4%
		10,000	20.42	1.71	191.42	22.99	2.79	301.99	110.57	57.8%
		15,000	20.42	1.71	276.92	22.99	2.79	441.49	164.57	59.4%
GSe	**North Perth**	1,000	29.52	1.00	39.52	29.71	2.15	51.21	11.69	29.6%
		2,000	29.52	1.00	49.52	29.71	2.15	72.71	23.19	46.8%
		5,000	29.52	1.00	79.52	29.71	2.15	137.21	57.69	72.6%
		10,000	29.52	1.00	129.52	29.71	2.15	244.71	115.19	88.9%
		15,000	29.52	1.00	179.52	29.71	2.15	352.21	172.69	96.2%
GSe	**North Stormont**	1,000	5.37	0.78	13.17	11.75	1.78	29.55	16.38	124.4%
		2,000	5.37	0.78	20.97	11.75	1.78	47.35	26.38	125.8%
		5,000	5.37	0.78	44.37	11.75	1.78	100.75	56.38	127.1%
		10,000	5.37	0.78	83.37	11.75	1.78	189.75	106.38	127.6%
		15,000	5.37	0.78	122.37	11.75	1.78	278.75	156.38	127.8%
GSe	**Omemee**	1,000	21.28	1.47	35.98	23.77	2.55	49.27	13.29	36.9%
		2,000	21.28	1.47	50.68	23.77	2.55	74.77	24.09	47.5%
		5,000	21.28	1.47	94.78	23.77	2.55	151.27	56.49	59.6%
		10,000	21.28	1.47	168.28	23.77	2.55	278.77	110.49	65.7%
		15,000	21.28	1.47	241.78	23.77	2.55	406.27	164.49	68.0%
UGe	**Perth**	1,000	19.92	0.92	29.12	17.10	2.00	37.15	8.03	27.6%
		2,000	19.92	0.92	38.32	17.10	2.00	57.19	18.87	49.2%
		5,000	19.92	0.92	65.92	17.10	2.00	117.31	51.39	78.0%
		10,000	19.92	0.92	111.92	17.10	2.00	217.52	105.60	94.4%
		15,000	19.92	0.92	157.92	17.10	2.00	317.73	159.81	101.2%

New Rate Class: GSe

Bill Impacts of Proposed Distribution Rates exclude Riders

Classes		Scenario	Existing Dx Rates			Proposed Dx Rates			$ Incr	% Incr
			SrChg	base	Dx bill	SrChg	base	Dx bill		
New Class	**Old Class**	kWh	[$/month]	[c/kWh]	[$/month]	[$/month]	[c/kWh]	[$/month]		
GSe	**Perth East**	1,000	14.65	1.29	27.55	18.43	2.25	40.93	13.38	48.6%
		2,000	14.65	1.29	40.45	18.43	2.25	63.43	22.98	56.8%
		5,000	14.65	1.29	79.15	18.43	2.25	130.93	51.78	65.4%
		10,000	14.65	1.29	143.65	18.43	2.25	243.43	99.78	69.5%
		15,000	14.65	1.29	208.15	18.43	2.25	355.93	147.78	71.0%
GSe	**Prince Edward**	1,000	22.85	1.42	37.05	24.38	2.57	50.08	13.03	35.2%
		2,000	22.85	1.42	51.25	24.38	2.57	75.78	24.53	47.9%
		5,000	22.85	1.42	93.85	24.38	2.57	152.88	59.03	62.9%
		10,000	22.85	1.42	164.85	24.38	2.57	281.38	116.53	70.7%
		15,000	22.85	1.42	235.85	24.38	2.57	409.88	174.03	73.8%
UGe	**Quinte West**	1,000	3.74	1.05	14.24	5.15	2.00	25.19	10.95	76.9%
		2,000	3.74	1.05	24.74	5.15	2.00	45.23	20.49	82.8%
		5,000	3.74	1.05	56.24	5.15	2.00	105.36	49.12	87.3%
		10,000	3.74	1.05	108.74	5.15	2.00	205.57	96.83	89.0%
		15,000	3.74	1.05	161.24	5.15	2.00	305.78	144.54	89.6%
GSe	**Rainy River**	1,000	19.29	1.76	36.89	22.27	3.18	54.07	17.18	46.6%
		2,000	19.29	1.76	54.49	22.27	3.18	85.87	31.38	57.6%
		5,000	19.29	1.76	107.29	22.27	3.18	181.27	73.98	69.0%
		10,000	19.29	1.76	195.29	22.27	3.18	340.27	144.98	74.2%
		15,000	19.29	1.76	283.29	22.27	3.18	499.27	215.98	76.2%
GSe	**Ramara**	1,000	20.97	1.06	31.57	22.85	2.48	47.65	16.08	50.9%
		2,000	20.97	1.06	42.17	22.85	2.48	72.45	30.28	71.8%
		5,000	20.97	1.06	73.97	22.85	2.48	146.85	72.88	98.5%
		10,000	20.97	1.06	126.97	22.85	2.48	270.85	143.88	113.3%
		15,000	20.97	1.06	179.97	22.85	2.48	394.85	214.88	119.4%

New Rate Class: GSe

Bill Impacts of Proposed Distribution Rates exclude Riders

Classes		Scenario	Existing Dx Rates			Proposed Dx Rates			$ Incr	% Incr
			SrChg	base	Dx bill	SrChg	base	Dx bill		
New Class	**Old Class**	kWh	[$/month]	[c/kWh]	[$/month]	[$/month]	[c/kWh]	[$/month]		
GSe	**Red Rock**	1,000	21.64	1.94	41.04	23.68	3.21	55.79	14.75	35.9%
		2,000	21.64	1.94	60.44	23.68	3.21	87.89	27.45	45.4%
		5,000	21.64	1.94	118.64	23.68	3.21	184.21	65.57	55.3%
		10,000	21.64	1.94	215.64	23.68	3.21	344.73	129.09	59.9%
		15,000	21.64	1.94	312.64	23.68	3.21	505.25	192.61	61.6%
GSe	**Rockland**	1,000	7.27	1.00	17.27	13.27	1.80	31.27	14.00	81.1%
		2,000	7.27	1.00	27.27	13.27	1.80	49.27	22.00	80.7%
		5,000	7.27	1.00	57.27	13.27	1.80	103.27	46.00	80.3%
		10,000	7.27	1.00	107.27	13.27	1.80	193.27	86.00	80.2%
		15,000	7.27	1.00	157.27	13.27	1.80	283.27	126.00	80.1%
GSe	**Russell**	1,000	19.26	2.24	41.66	22.28	3.21	54.38	12.72	30.5%
		2,000	19.26	2.24	64.06	22.28	3.21	86.49	22.43	35.0%
		5,000	19.26	2.24	131.26	22.28	3.21	182.80	51.54	39.3%
		10,000	19.26	2.24	243.26	22.28	3.21	343.33	100.07	41.1%
		15,000	19.26	2.24	355.26	22.28	3.21	503.85	148.59	41.8%
GSe	**Schreiber**	1,000	20.70	2.51	45.80	22.92	3.21	55.02	9.22	20.1%
		2,000	20.70	2.51	70.90	22.92	3.21	87.13	16.23	22.9%
		5,000	20.70	2.51	146.20	22.92	3.21	183.44	37.24	25.5%
		10,000	20.70	2.51	271.70	22.92	3.21	343.97	72.27	26.6%
		15,000	20.70	2.51	397.20	22.92	3.21	504.49	107.29	27.0%
GSe	**Severn**	1,000	22.17	1.06	32.77	24.55	2.30	47.55	14.78	45.1%
		2,000	22.17	1.06	43.37	24.55	2.30	70.55	27.18	62.7%
		5,000	22.17	1.06	75.17	24.55	2.30	139.55	64.38	85.6%
		10,000	22.17	1.06	128.17	24.55	2.30	254.55	126.38	98.6%
		15,000	22.17	1.06	181.17	24.55	2.30	369.55	188.38	104.0%

New Rate Class: GSe

Bill Impacts of Proposed Distribution Rates exclude Riders

Classes		Scenario	Existing Dx Rates			Proposed Dx Rates			$ Incr	% Incr
			SrChg	base	Dx bill	SrChg	base	Dx bill		
New Class	Old Class	kWh	[$/month]	[c/kWh]	[$/month]	[$/month]	[c/kWh]	[$/month]		
GSe	Shelburne	1,000	20.01	0.87	28.71	23.09	1.79	40.99	12.28	42.8%
		2,000	20.01	0.87	37.41	23.09	1.79	58.89	21.48	57.4%
		5,000	20.01	0.87	63.51	23.09	1.79	112.59	49.08	77.3%
		10,000	20.01	0.87	107.01	23.09	1.79	202.09	95.08	88.9%
		15,000	20.01	0.87	150.51	23.09	1.79	291.59	141.08	93.7%
UGe	Smiths Falls	1,000	9.84	1.05	20.34	9.62	2.00	29.67	9.33	45.8%
		2,000	9.84	1.05	30.84	9.62	2.00	49.71	18.87	61.2%
		5,000	9.84	1.05	62.34	9.62	2.00	109.83	47.49	76.2%
		10,000	9.84	1.05	114.84	9.62	2.00	210.04	95.20	82.9%
		15,000	9.84	1.05	167.34	9.62	2.00	310.25	142.91	85.4%
GSe	South Glengarry	1,000	17.41	0.75	24.91	20.74	1.96	40.34	15.43	61.9%
		2,000	17.41	0.75	32.41	20.74	1.96	59.94	27.53	84.9%
		5,000	17.41	0.75	54.91	20.74	1.96	118.74	63.83	116.2%
		10,000	17.41	0.75	92.41	20.74	1.96	216.74	124.33	134.5%
		15,000	17.41	0.75	129.91	20.74	1.96	314.74	184.83	142.3%
GSe	South River	1,000	22.11	1.58	37.91	24.56	2.95	54.06	16.15	42.6%
		2,000	22.11	1.58	53.71	24.56	2.95	83.56	29.85	55.6%
		5,000	22.11	1.58	101.11	24.56	2.95	172.06	70.95	70.2%
		10,000	22.11	1.58	180.11	24.56	2.95	319.56	139.45	77.4%
		15,000	22.11	1.58	259.11	24.56	2.95	467.06	207.95	80.3%
GSe	Springwater	1,000	20.53	1.07	31.23	22.96	2.25	45.46	14.23	45.6%
		2,000	20.53	1.07	41.93	22.96	2.25	67.96	26.03	62.1%
		5,000	20.53	1.07	74.03	22.96	2.25	135.46	61.43	83.0%
		10,000	20.53	1.07	127.53	22.96	2.25	247.96	120.43	94.4%
		15,000	20.53	1.07	181.03	22.96	2.25	360.46	179.43	99.1%

New Rate Class: GSe

Bill Impacts of Proposed Distribution Rates exclude Riders

Classes		Scenario	Existing Dx Rates			Proposed Dx Rates			$ Incr	% Incr
New Class	Old Class	kWh	SrChg [$/month]	base [c/kWh]	Dx bill [$/month]	SrChg [$/month]	base [c/kWh]	Dx bill [$/month]		
GSe	**Stirling-Rawdon**	1,000	24.12	1.30	37.12	26.06	2.47	50.76	13.64	36.8%
		2,000	24.12	1.30	50.12	26.06	2.47	75.46	25.34	50.6%
		5,000	24.12	1.30	89.12	26.06	2.47	149.56	60.44	67.8%
		10,000	24.12	1.30	154.12	26.06	2.47	273.06	118.94	77.2%
		15,000	24.12	1.30	219.12	26.06	2.47	396.56	177.44	81.0%
GSe	**Thedford**	1,000	17.83	1.06	28.43	20.63	2.30	43.63	15.20	53.5%
		2,000	17.83	1.06	39.03	20.63	2.30	66.63	27.60	70.7%
		5,000	17.83	1.06	70.83	20.63	2.30	135.63	64.80	91.5%
		10,000	17.83	1.06	123.83	20.63	2.30	250.63	126.80	102.4%
		15,000	17.83	1.06	176.83	20.63	2.30	365.63	188.80	106.8%
GSe	**Thessalon**	1,000	18.90	1.55	34.40	21.37	2.56	46.97	12.57	36.5%
		2,000	18.90	1.55	49.90	21.37	2.56	72.57	22.67	45.4%
		5,000	18.90	1.55	96.40	21.37	2.56	149.37	52.97	54.9%
		10,000	18.90	1.55	173.90	21.37	2.56	277.37	103.47	59.5%
		15,000	18.90	1.55	251.40	21.37	2.56	405.37	153.97	61.2%
GSe	**Thorndale**	1,000	14.52	1.02	24.72	18.46	2.38	42.26	17.54	71.0%
		2,000	14.52	1.02	34.92	18.46	2.38	66.06	31.14	89.2%
		5,000	14.52	1.02	65.52	18.46	2.38	137.46	71.94	109.8%
		10,000	14.52	1.02	116.52	18.46	2.38	256.46	139.94	120.1%
		15,000	14.52	1.02	167.52	18.46	2.38	375.46	207.94	124.1%
UGe	**Thorold**	1,000	22.63	1.50	37.63	19.43	2.00	39.47	1.84	4.9%
		2,000	22.63	1.50	52.63	19.43	2.00	59.51	6.88	13.1%
		5,000	22.63	1.50	97.63	19.43	2.00	119.64	22.01	22.5%
		10,000	22.63	1.50	172.63	19.43	2.00	219.85	47.22	27.4%
		15,000	22.63	1.50	247.63	19.43	2.00	320.06	72.43	29.2%

New Rate Class: GSe

Bill Impacts of Proposed Distribution Rates exclude Riders

Classes		Scenario	Existing Dx Rates			Proposed Dx Rates			$ Incr	% Incr
			SrChg	base	Dx bill	SrChg	base	Dx bill		
New Class	**Old Class**	kWh	[$/month]	[c/kWh]	[$/month]	[$/month]	[c/kWh]	[$/month]		
GSe	**Tweed**	1,000	8.26	0.97	17.96	14.03	2.10	35.03	17.07	95.0%
		2,000	8.26	0.97	27.66	14.03	2.10	56.03	28.37	102.6%
		5,000	8.26	0.97	56.76	14.03	2.10	119.03	62.27	109.7%
		10,000	8.26	0.97	105.26	14.03	2.10	224.03	118.77	112.8%
		15,000	8.26	0.97	153.76	14.03	2.10	329.03	175.27	114.0%
GSe	**Wardsville**	1,000	12.32	1.00	22.32	17.01	1.99	36.91	14.59	65.4%
		2,000	12.32	1.00	32.32	17.01	1.99	56.81	24.49	75.8%
		5,000	12.32	1.00	62.32	17.01	1.99	116.51	54.19	87.0%
		10,000	12.32	1.00	112.32	17.01	1.99	216.01	103.69	92.3%
		15,000	12.32	1.00	162.32	17.01	1.99	315.51	153.19	94.4%
GSe	**Warkworth**	1,000	21.31	1.52	36.51	23.76	2.95	53.26	16.75	45.9%
		2,000	21.31	1.52	51.71	23.76	2.95	82.76	31.05	60.1%
		5,000	21.31	1.52	97.31	23.76	2.95	171.26	73.95	76.0%
		10,000	21.31	1.52	173.31	23.76	2.95	318.76	145.45	83.9%
		15,000	21.31	1.52	249.31	23.76	2.95	466.26	216.95	87.0%
GSe	**West Elgin**	1,000	15.40	0.70	22.40	19.24	1.62	35.44	13.04	58.2%
		2,000	15.40	0.70	29.40	19.24	1.62	51.64	22.24	75.7%
		5,000	15.40	0.70	50.40	19.24	1.62	100.24	49.84	98.9%
		10,000	15.40	0.70	85.40	19.24	1.62	181.24	95.84	112.2%
		15,000	15.40	0.70	120.40	19.24	1.62	262.24	141.84	117.8%
UGe	**Whitchurch Stouffville**	1,000	21.85	0.93	31.15	18.62	2.00	38.66	7.51	24.1%
		2,000	21.85	0.93	40.45	18.62	2.00	58.70	18.25	45.1%
		5,000	21.85	0.93	68.35	18.62	2.00	118.83	50.48	73.9%
		10,000	21.85	0.93	114.85	18.62	2.00	219.04	104.19	90.7%
		15,000	21.85	0.93	161.35	18.62	2.00	319.25	157.90	97.9%

New Rate Class: GSe

Bill Impacts of Proposed Distribution Rates exclude Riders

Classes		Scenario	Existing Dx Rates			Proposed Dx Rates			$ Incr	% Incr
New Class	Old Class	kWh	SrChg [$/month]	base [c/kWh]	Dx bill [$/month]	SrChg [$/month]	base [c/kWh]	Dx bill [$/month]		
GSe	**Wiarton**	1,000	23.78	1.89	42.68	25.15	3.10	56.15	13.47	31.6%
		2,000	23.78	1.89	61.58	25.15	3.10	87.15	25.57	41.5%
		5,000	23.78	1.89	118.28	25.15	3.10	180.15	61.87	52.3%
		10,000	23.78	1.89	212.78	25.15	3.10	335.15	122.37	57.5%
		15,000	23.78	1.89	307.28	25.15	3.10	490.15	182.87	59.5%
GSe	**Woodville**	1,000	16.89	1.57	32.59	19.87	3.21	51.97	19.38	59.5%
		2,000	16.89	1.57	48.29	19.87	3.21	84.08	35.79	74.1%
		5,000	16.89	1.57	95.39	19.87	3.21	180.39	85.00	89.1%
		10,000	16.89	1.57	173.89	19.87	3.21	340.92	167.03	96.1%
		15,000	16.89	1.57	252.39	19.87	3.21	501.44	249.05	98.7%
GSe	**Wyoming**	1,000	17.36	1.45	31.86	20.75	2.46	45.35	13.49	42.3%
		2,000	17.36	1.45	46.36	20.75	2.46	69.95	23.59	50.9%
		5,000	17.36	1.45	89.86	20.75	2.46	143.75	53.89	60.0%
		10,000	17.36	1.45	162.36	20.75	2.46	266.75	104.39	64.3%
		15,000	17.36	1.45	234.86	20.75	2.46	389.75	154.89	66.0%
GSe	**Terrace Bay**	1,000	41.34	1.18	53.14	38.76	2.67	65.46	12.32	23.2%
		2,000	41.34	1.18	64.94	38.76	2.67	92.16	27.22	41.9%
		5,000	41.34	1.18	100.34	38.76	2.67	172.26	71.92	71.7%
		10,000	41.34	1.18	159.34	38.76	2.67	305.76	146.42	91.9%
		15,000	41.34	1.18	218.34	38.76	2.67	439.26	220.92	101.2%

New Rate Class: GSd

Bill Impacts of Proposed Distribution Rates exclude Riders

Classes		Scenario			Existing Dx Rates			Proposed Dx Rates			$ Incr	% Incr
					SrChg	base	Dx bill	SrChg	base	Dx bill		
New Class	**Old Class**	kWh	kW	LF	[$/month]	[$/kW]	[$/month]	[$/month]	[$/kW]	[$/month]		
GSd	**F1**	15,000	60	35%	28.61	7.06	452	56.51	9.44	623	171	37.8%
		43,164	133	45%	28.61	7.06	968	56.51	9.44	1,312	345	35.6%
with RRRP		100,000	500	28%	28.61	7.06	3,559	56.51	9.44	4,777	1,218	34.2%
		400,000	1000	56%	28.61	7.06	7,089	56.51	9.44	9,498	2,409	34.0%
		1,000,000	3000	46%	28.61	7.06	21,209	56.51	9.44	28,380	7,171	33.8%
		1,500,000	4000	52%	28.61	7.06	28,269	56.51	9.44	37,821	9,552	33.8%
GSd	**F1**	15,000	60	35%	60.71	7.06	484	56.51	9.44	623	139	28.6%
		43,164	133	45%	60.71	7.06	1,000	56.51	9.44	1,312	312	31.3%
no RRRP		100,000	500	28%	60.71	7.06	3,591	56.51	9.44	4,777	1,186	33.0%
		400,000	1000	56%	60.71	7.06	7,121	56.51	9.44	9,498	2,377	33.4%
		1,000,000	3000	46%	60.71	7.06	21,241	56.51	9.44	28,380	7,139	33.6%
		1,500,000	4000	52%	60.71	7.06	28,301	56.51	9.44	37,821	9,520	33.6%
GSd	**F3**	15,000	60	35%	30.16	10.87	682	51.21	9.44	618	(65)	-9.5%
		43,164	133	45%	30.16	10.87	1,476	51.21	9.44	1,307	(169)	-11.5%
with RRRP		100,000	500	28%	30.16	10.87	5,465	51.21	9.44	4,772	(693)	-12.7%
		400,000	1000	56%	30.16	10.87	10,900	51.21	9.44	9,492	(1,408)	-12.9%
		1,000,000	3000	46%	30.16	10.87	32,640	51.21	9.44	28,374	(4,266)	-13.1%
		1,500,000	4000	52%	30.16	10.87	43,510	51.21	9.44	37,815	(5,695)	-13.1%
GSd	**F3**	15,000	60	35%	53.91	10.87	706	51.21	9.44	618	(88)	-12.5%
		43,164	133	45%	53.91	10.87	1,500	51.21	9.44	1,307	(193)	-12.9%
no RRRP		100,000	500	28%	53.91	10.87	5,489	51.21	9.44	4,772	(717)	-13.1%
		400,000	1000	56%	53.91	10.87	10,924	51.21	9.44	9,492	(1,432)	-13.1%
		1,000,000	3000	46%	53.91	10.87	32,664	51.21	9.44	28,374	(4,290)	-13.1%
		1,500,000	4000	52%	53.91	10.87	43,534	51.21	9.44	37,815	(5,719)	-13.1%
GSd	**G1**	15,000	60	35%	36.93	9.59	612	38.68	9.44	605	(7)	-1.2%
		43,164	133	45%	36.93	9.59	1,312	38.68	9.44	1,294	(18)	-1.4%
		100,000	500	28%	36.93	9.59	4,832	38.68	9.44	4,759	(73)	-1.5%
		400,000	1000	56%	36.93	9.59	9,627	38.68	9.44	9,480	(147)	-1.5%
		1,000,000	3000	46%	36.93	9.59	28,807	38.68	9.44	28,362	(445)	-1.5%
		1,500,000	4000	52%	36.93	9.59	38,397	38.68	9.44	37,803	(594)	-1.5%

New Rate Class: GSd

Bill Impacts of Proposed Distribution Rates exclude Riders

Classes		Scenario			Existing Dx Rates			Proposed Dx Rates			$ Incr	% Incr
					SrChg	base	Dx bill	SrChg	base	Dx bill		
New Class	**Old Class**	kWh	kW	LF	[$/month]	[$/kW]	[$/month]	[$/month]	[$/kW]	[$/month]		
GSd	**G3**	15,000	60	35%	46.78	9.91	641	46.00	9.44	612	(29)	-4.5%
		43,164	133	45%	46.78	9.91	1,365	46.00	9.44	1,302	(63)	-4.6%
		100,000	500	28%	46.78	9.91	5,002	46.00	9.44	4,767	(235)	-4.7%
		400,000	1000	56%	46.78	9.91	9,957	46.00	9.44	9,487	(470)	-4.7%
		1,000,000	3000	46%	46.78	9.91	29,777	46.00	9.44	28,369	(1,408)	-4.7%
		1,500,000	4000	52%	46.78	9.91	39,687	46.00	9.44	37,810	(1,877)	-4.7%
GSd	**T**	15,000	60	35%	261.54	8.16	751	207.30	9.44	774	23	3.0%
		43,164	133	45%	261.54	8.16	1,347	207.30	9.44	1,463	116	8.6%
		100,000	500	28%	261.54	8.16	4,342	207.30	9.44	4,928	586	13.5%
		400,000	1000	56%	261.54	8.16	8,422	207.30	9.44	9,648	1,227	14.6%
		1,000,000	3000	46%	261.54	8.16	24,742	207.30	9.44	28,530	3,789	15.3%
		1,500,000	4000	52%	261.54	8.16	32,902	207.30	9.44	37,971	5,070	15.4%
GSd	**Ailsa Craig**	15,000	60	35%	17.31	4.19	269	24.36	9.00	564	296	110.0%
		43,164	133	45%	17.31	4.19	575	24.36	9.00	1,221	647	112.6%
		100,000	500	28%	17.31	4.19	2,112	24.36	9.00	4,524	2,412	114.2%
		400,000	1000	56%	17.31	4.19	4,207	24.36	9.00	9,024	4,817	114.5%
		1,000,000	3000	46%	17.31	4.19	12,587	24.36	9.00	27,024	14,437	114.7%
		1,500,000	4000	52%	17.31	4.19	16,777	24.36	9.00	36,024	19,247	114.7%
GSd	**Arkona**	15,000	60	35%	3.20	1.98	122	13.89	9.22	567	445	365.0%
	no customer	43,164	133	45%	3.20	1.98	267	13.89	9.22	1,241	974	365.5%
		100,000	500	28%	3.20	1.98	993	13.89	9.22	4,626	3,632	365.7%
		400,000	1000	56%	3.20	1.98	1,983	13.89	9.22	9,237	7,254	365.8%
		1,000,000	3000	46%	3.20	1.98	5,943	13.89	9.22	27,685	21,741	365.8%
		1,500,000	4000	52%	3.20	1.98	7,923	13.89	9.22	36,908	28,985	365.8%
UGd	**Arnprior**	15,000	60	35%	21.38	3.70	243	22.95	7.33	463	220	90.2%
		43,164	133	45%	21.38	3.70	513	22.95	7.33	998	485	94.4%
		100,000	500	28%	21.38	3.70	1,871	22.95	7.33	3,689	1,818	97.2%
		400,000	1000	56%	21.38	3.70	3,721	22.95	7.33	7,356	3,635	97.7%
		1,000,000	3000	46%	21.38	3.70	11,121	22.95	7.33	22,022	10,901	98.0%
		1,500,000	4000	52%	21.38	3.70	14,821	22.95	7.33	29,355	14,534	98.1%

New Rate Class: GSd

Bill Impacts of Proposed Distribution Rates exclude Riders

Classes		Scenario			Existing Dx Rates			Proposed Dx Rates			$ Incr	% Incr
					SrChg	base	Dx bill	SrChg	base	Dx bill		
New Class	Old Class	kWh	kW	LF	[$/month]	[$/kW]	[$/month]	[$/month]	[$/kW]	[$/month]		
GSd	Arran-Elderslie	15,000	60	35%	8.83	3.28	206	17.48	8.00	497	292	141.9%
		43,164	133	45%	8.83	3.28	445	17.48	8.00	1,081	636	143.0%
		100,000	500	28%	8.83	3.28	1,649	17.48	8.00	4,017	2,369	143.7%
		400,000	1000	56%	8.83	3.28	3,289	17.48	8.00	8,017	4,729	143.8%
		1,000,000	3000	46%	8.83	3.28	9,849	17.48	8.00	24,017	14,169	143.9%
		1,500,000	4000	52%	8.83	3.28	13,129	17.48	8.00	32,017	18,889	143.9%
GSd	Artemesia	15,000	60	35%	19.62	5.49	349	25.78	9.22	579	230	65.9%
		43,164	133	45%	19.62	5.49	750	25.78	9.22	1,253	503	67.0%
		100,000	500	28%	19.62	5.49	2,765	25.78	9.22	4,638	1,873	67.7%
		400,000	1000	56%	19.62	5.49	5,510	25.78	9.22	9,249	3,740	67.9%
		1,000,000	3000	46%	19.62	5.49	16,490	25.78	9.22	27,697	11,207	68.0%
		1,500,000	4000	52%	19.62	5.49	21,980	25.78	9.22	36,920	14,940	68.0%
GSd	Bancroft	15,000	60	35%	24.41	3.70	246	29.59	8.50	540	293	119.0%
		43,164	133	45%	24.41	3.70	517	29.59	8.50	1,160	644	124.6%
		100,000	500	28%	24.41	3.70	1,874	29.59	8.50	4,280	2,405	128.3%
		400,000	1000	56%	24.41	3.70	3,724	29.59	8.50	8,530	4,805	129.0%
		1,000,000	3000	46%	24.41	3.70	11,124	29.59	8.50	25,530	14,405	129.5%
		1,500,000	4000	52%	24.41	3.70	14,824	29.59	8.50	34,030	19,205	129.6%
GSd	Bath	15,000	60	35%	10.65	3.77	237	19.03	9.00	559	322	136.0%
		43,164	133	45%	10.65	3.77	512	19.03	9.00	1,216	704	137.5%
		100,000	500	28%	10.65	3.77	1,896	19.03	9.00	4,519	2,623	138.4%
		400,000	1000	56%	10.65	3.77	3,781	19.03	9.00	9,019	5,238	138.6%
		1,000,000	3000	46%	10.65	3.77	11,321	19.03	9.00	27,019	15,698	138.7%
		1,500,000	4000	52%	10.65	3.77	15,091	19.03	9.00	36,019	20,928	138.7%
GSd	Blandford-Blenheim	15,000	60	35%	23.85	3.63	242	28.73	8.90	563	321	132.9%
		43,164	133	45%	23.85	3.63	507	28.73	8.90	1,212	706	139.3%
		100,000	500	28%	23.85	3.63	1,839	28.73	8.90	4,479	2,640	143.6%
		400,000	1000	56%	23.85	3.63	3,654	28.73	8.90	8,929	5,275	144.4%
		1,000,000	3000	46%	23.85	3.63	10,914	28.73	8.90	26,729	15,815	144.9%
		1,500,000	4000	52%	23.85	3.63	14,544	28.73	8.90	35,629	21,085	145.0%

New Rate Class: GSd

Bill Impacts of Proposed Distribution Rates exclude Riders

Classes		Scenario			Existing Dx Rates			Proposed Dx Rates			$ Incr	% Incr
					SrChg	base	Dx bill	SrChg	base	Dx bill		
New Class	Old Class	kWh	kW	LF	[$/month]	[$/kW]	[$/month]	[$/month]	[$/kW]	[$/month]		
GSd	Blyth	15,000	60	35%	21.63	3.37	224	27.28	8.50	537	313	140.0%
		43,164	133	45%	21.63	3.37	470	27.28	8.50	1,158	688	146.4%
		100,000	500	28%	21.63	3.37	1,707	27.28	8.50	4,277	2,571	150.6%
		400,000	1000	56%	21.63	3.37	3,392	27.28	8.50	8,527	5,136	151.4%
		1,000,000	3000	46%	21.63	3.37	10,132	27.28	8.50	25,527	15,396	152.0%
		1,500,000	4000	52%	21.63	3.37	13,502	27.28	8.50	34,027	20,526	152.0%
GSd	Bobcaygeon	15,000	60	35%	23.20	4.35	284	28.89	9.22	582	298	104.9%
		43,164	133	45%	23.20	4.35	602	28.89	9.22	1,256	654	108.7%
		100,000	500	28%	23.20	4.35	2,198	28.89	9.22	4,641	2,442	111.1%
		400,000	1000	56%	23.20	4.35	4,373	28.89	9.22	9,252	4,879	111.6%
		1,000,000	3000	46%	23.20	4.35	13,073	28.89	9.22	27,700	14,626	111.9%
		1,500,000	4000	52%	23.20	4.35	17,423	28.89	9.22	36,923	19,500	111.9%
GSd	Brighton	15,000	60	35%	22.90	4.24	277	27.96	9.22	581	304	109.7%
		43,164	133	45%	22.90	4.24	587	27.96	9.22	1,255	668	113.8%
		100,000	500	28%	22.90	4.24	2,143	27.96	9.22	4,640	2,497	116.5%
		400,000	1000	56%	22.90	4.24	4,263	27.96	9.22	9,252	4,989	117.0%
		1,000,000	3000	46%	22.90	4.24	12,743	27.96	9.22	27,699	14,956	117.4%
		1,500,000	4000	52%	22.90	4.24	16,983	27.96	9.22	36,922	19,939	117.4%
UGd	Brockville	15,000	60	35%	21.65	2.49	171	22.89	6.70	425	254	148.4%
		43,164	133	45%	21.65	2.49	353	22.89	6.70	914	561	159.1%
		100,000	500	28%	21.65	2.49	1,267	22.89	6.70	3,373	2,106	166.3%
		400,000	1000	56%	21.65	2.49	2,512	22.89	6.70	6,723	4,211	167.7%
		1,000,000	3000	46%	21.65	2.49	7,492	22.89	6.70	20,123	12,631	168.6%
		1,500,000	4000	52%	21.65	2.49	9,982	22.89	6.70	26,823	16,841	168.7%
GSd	Caledon CH	15,000	60	35%	24.21	5.73	368	29.64	9.22	583	215	58.4%
		43,164	133	45%	24.21	5.73	786	29.64	9.22	1,256	470	59.8%
		100,000	500	28%	24.21	5.73	2,889	29.64	9.22	4,641	1,752	60.6%
		400,000	1000	56%	24.21	5.73	5,754	29.64	9.22	9,253	3,499	60.8%
		1,000,000	3000	46%	24.21	5.73	17,214	29.64	9.22	27,700	10,486	60.9%
		1,500,000	4000	52%	24.21	5.73	22,944	29.64	9.22	36,924	13,980	60.9%

New Rate Class: GSd

Bill Impacts of Proposed Distribution Rates exclude Riders

Classes		Scenario			Existing Dx Rates			Proposed Dx Rates			$ Incr	% Incr
					SrChg	base	Dx bill	SrChg	base	Dx bill		
New Class	Old Class	kWh	kW	LF	[$/month]	[$/kW]	[$/month]	[$/month]	[$/kW]	[$/month]		
GSd	Caledon OH	15,000	60	35%	25.56	5.35	347	30.30	9.22	584	237	68.4%
		43,164	133	45%	25.56	5.35	737	30.30	9.22	1,257	520	70.5%
		100,000	500	28%	25.56	5.35	2,701	30.30	9.22	4,642	1,942	71.9%
		400,000	1000	56%	25.56	5.35	5,376	30.30	9.22	9,254	3,878	72.1%
		1,000,000	3000	46%	25.56	5.35	16,076	30.30	9.22	27,701	11,625	72.3%
		1,500,000	4000	52%	25.56	5.35	21,426	30.30	9.22	36,925	15,499	72.3%
GSd	Campbellford-Seymour	15,000	60	35%	16.19	3.77	242	23.64	8.50	534	291	120.2%
		43,164	133	45%	16.19	3.77	518	23.64	8.50	1,154	637	123.0%
		100,000	500	28%	16.19	3.77	1,901	23.64	8.50	4,274	2,372	124.8%
		400,000	1000	56%	16.19	3.77	3,786	23.64	8.50	8,524	4,737	125.1%
		1,000,000	3000	46%	16.19	3.77	11,326	23.64	8.50	25,524	14,197	125.4%
		1,500,000	4000	52%	16.19	3.77	15,096	23.64	8.50	34,024	18,927	125.4%
UGd	Carleton Place	15,000	60	35%	23.65	5.31	342	24.39	7.33	464	122	35.7%
		43,164	133	45%	23.65	5.31	730	24.39	7.33	1,000	270	37.0%
		100,000	500	28%	23.65	5.31	2,679	24.39	7.33	3,691	1,012	37.8%
		400,000	1000	56%	23.65	5.31	5,334	24.39	7.33	7,357	2,024	37.9%
		1,000,000	3000	46%	23.65	5.31	15,954	24.39	7.33	22,024	6,070	38.0%
		1,500,000	4000	52%	23.65	5.31	21,264	24.39	7.33	29,357	8,093	38.1%
GSd	Cavan-Millbrook-North Monaghan	15,000	60	35%	22.28	4.67	302	28.12	9.22	582	279	92.3%
		43,164	133	45%	22.28	4.67	643	28.12	9.22	1,255	611	95.0%
		100,000	500	28%	22.28	4.67	2,357	28.12	9.22	4,640	2,283	96.8%
		400,000	1000	56%	22.28	4.67	4,692	28.12	9.22	9,252	4,559	97.2%
		1,000,000	3000	46%	22.28	4.67	14,032	28.12	9.22	27,699	13,667	97.4%
		1,500,000	4000	52%	22.28	4.67	18,702	28.12	9.22	36,922	18,220	97.4%
GSd	Centre Hastings	15,000	60	35%	18.38	3.07	203	25.09	7.70	487	285	140.4%
		43,164	133	45%	18.38	3.07	427	25.09	7.70	1,049	623	145.9%
		100,000	500	28%	18.38	3.07	1,553	25.09	7.70	3,875	2,322	149.5%
		400,000	1000	56%	18.38	3.07	3,088	25.09	7.70	7,725	4,637	150.1%
		1,000,000	3000	46%	18.38	3.07	9,228	25.09	7.70	23,125	13,897	150.6%
		1,500,000	4000	52%	18.38	3.07	12,298	25.09	7.70	30,825	18,527	150.6%

New Rate Class: GSd

Bill Impacts of Proposed Distribution Rates exclude Riders

Classes		Scenario			Existing Dx Rates			Proposed Dx Rates			$ Incr	% Incr
					SrChg [$/month]	base [$/kW]	Dx bill [$/month]	SrChg [$/month]	base [$/kW]	Dx bill [$/month]		
New Class	**Old Class**	kWh	kW	LF								
GSd	**Chalk River**	15,000	60	35%	21.33	5.70	363	27.36	9.22	581	217	59.8%
		43,164	133	45%	21.33	5.70	779	27.36	9.22	1,254	475	60.9%
		100,000	500	28%	21.33	5.70	2,871	27.36	9.22	4,639	1,768	61.6%
		400,000	1000	56%	21.33	5.70	5,721	27.36	9.22	9,251	3,530	61.7%
		1,000,000	3000	46%	21.33	5.70	17,121	27.36	9.22	27,698	10,577	61.8%
		1,500,000	4000	52%	21.33	5.70	22,821	27.36	9.22	36,922	14,100	61.8%
GSd	**Champlain**	15,000	60	35%	20.59	2.88	193	26.54	8.00	507	313	161.9%
		43,164	133	45%	20.59	2.88	404	26.54	8.00	1,091	687	170.2%
		100,000	500	28%	20.59	2.88	1,461	26.54	8.00	4,027	2,566	175.7%
		400,000	1000	56%	20.59	2.88	2,901	26.54	8.00	8,027	5,126	176.7%
		1,000,000	3000	46%	20.59	2.88	8,661	26.54	8.00	24,027	15,366	177.4%
		1,500,000	4000	52%	20.59	2.88	11,541	26.54	8.00	32,027	20,486	177.5%
GSd	**Cobden**	15,000	60	35%	21.93	6.49	411	27.21	9.22	581	169	41.2%
		43,164	133	45%	21.93	6.49	885	27.21	9.22	1,254	369	41.7%
		100,000	500	28%	21.93	6.49	3,267	27.21	9.22	4,639	1,372	42.0%
		400,000	1000	56%	21.93	6.49	6,512	27.21	9.22	9,251	2,739	42.1%
		1,000,000	3000	46%	21.93	6.49	19,492	27.21	9.22	27,698	8,206	42.1%
		1,500,000	4000	52%	21.93	6.49	25,982	27.21	9.22	36,922	10,940	42.1%
GSd	**Deep River**	15,000	60	35%	23.94	7.18	455	28.70	9.22	582	127	28.0%
		43,164	133	45%	23.94	7.18	979	28.70	9.22	1,255	277	28.3%
		100,000	500	28%	23.94	7.18	3,614	28.70	9.22	4,640	1,027	28.4%
		400,000	1000	56%	23.94	7.18	7,204	28.70	9.22	9,252	2,048	28.4%
		1,000,000	3000	46%	23.94	7.18	21,564	28.70	9.22	27,699	6,136	28.5%
		1,500,000	4000	52%	23.94	7.18	28,744	28.70	9.22	36,923	8,179	28.5%
GSd	**Deseronto**	15,000	60	35%	10.14	3.85	241	19.15	8.50	529	288	119.4%
		43,164	133	45%	10.14	3.85	522	19.15	8.50	1,150	627	120.2%
		100,000	500	28%	10.14	3.85	1,935	19.15	8.50	4,269	2,334	120.6%
		400,000	1000	56%	10.14	3.85	3,860	19.15	8.50	8,519	4,659	120.7%
		1,000,000	3000	46%	10.14	3.85	11,560	19.15	8.50	25,519	13,959	120.8%
		1,500,000	4000	52%	10.14	3.85	15,410	19.15	8.50	34,019	18,609	120.8%

New Rate Class: GSd

Bill Impacts of Proposed Distribution Rates exclude Riders

Classes		Scenario			Existing Dx Rates			Proposed Dx Rates			$ Incr	% Incr
					SrChg	base	Dx bill	SrChg	base	Dx bill		
New Class	Old Class	kWh	kW	LF	[$/month]	[$/kW]	[$/month]	[$/month]	[$/kW]	[$/month]		
UGd	Dryden	15,000	60	35%	19.11	3.29	217	21.52	7.33	462	245	113.2%
		43,164	133	45%	19.11	3.29	457	21.52	7.33	997	540	118.3%
		100,000	500	28%	19.11	3.29	1,664	21.52	7.33	3,688	2,024	121.6%
		400,000	1000	56%	19.11	3.29	3,309	21.52	7.33	7,355	4,045	122.3%
		1,000,000	3000	46%	19.11	3.29	9,889	21.52	7.33	22,021	12,132	122.7%
		1,500,000	4000	52%	19.11	3.29	13,179	21.52	7.33	29,354	16,175	122.7%
GSd	Dundalk	15,000	60	35%	23.56	5.17	334	28.80	9.22	582	248	74.4%
		43,164	133	45%	23.56	5.17	711	28.80	9.22	1,256	544	76.5%
		100,000	500	28%	23.56	5.17	2,609	28.80	9.22	4,641	2,032	77.9%
		400,000	1000	56%	23.56	5.17	5,194	28.80	9.22	9,252	4,059	78.2%
		1,000,000	3000	46%	23.56	5.17	15,534	28.80	9.22	27,700	12,166	78.3%
		1,500,000	4000	52%	23.56	5.17	20,704	28.80	9.22	36,923	16,220	78.3%
GSd	Durham	15,000	60	35%	24.12	4.31	283	29.66	9.22	583	300	106.2%
		43,164	133	45%	24.12	4.31	597	29.66	9.22	1,256	659	110.3%
		100,000	500	28%	24.12	4.31	2,179	29.66	9.22	4,641	2,462	113.0%
		400,000	1000	56%	24.12	4.31	4,334	29.66	9.22	9,253	4,919	113.5%
		1,000,000	3000	46%	24.12	4.31	12,954	29.66	9.22	27,700	14,746	113.8%
		1,500,000	4000	52%	24.12	4.31	17,264	29.66	9.22	36,924	19,660	113.9%
GSd	Eganville	15,000	60	35%	21.35	7.35	462	27.35	9.22	581	118	25.6%
		43,164	133	45%	21.35	7.35	999	27.35	9.22	1,254	255	25.5%
		100,000	500	28%	21.35	7.35	3,696	27.35	9.22	4,639	943	25.5%
		400,000	1000	56%	21.35	7.35	7,371	27.35	9.22	9,251	1,880	25.5%
		1,000,000	3000	46%	21.35	7.35	22,071	27.35	9.22	27,698	5,627	25.5%
		1,500,000	4000	52%	21.35	7.35	29,421	27.35	9.22	36,922	7,500	25.5%
GSd	Erin	15,000	60	35%	40.38	2.36	182	41.59	7.20	474	292	160.2%
		43,164	133	45%	40.38	2.36	354	41.59	7.20	999	645	182.1%
		100,000	500	28%	40.38	2.36	1,220	41.59	7.20	3,642	2,421	198.4%
		400,000	1000	56%	40.38	2.36	2,400	41.59	7.20	7,242	4,841	201.7%
		1,000,000	3000	46%	40.38	2.36	7,120	41.59	7.20	21,642	14,521	203.9%
		1,500,000	4000	52%	40.38	2.36	9,480	41.59	7.20	28,842	19,361	204.2%

New Rate Class: GSd

Bill Impacts of Proposed Distribution Rates exclude Riders

Classes		Scenario			Existing Dx Rates			Proposed Dx Rates			$ Incr	% Incr
					SrChg [$/month]	base [$/kW]	Dx bill [$/month]	SrChg [$/month]	base [$/kW]	Dx bill [$/month]		
New Class	**Old Class**	kWh	kW	LF								
GSd	**Exeter**	15,000	60	35%	11.36	4.11	258	19.85	8.95	557	299	115.9%
		43,164	133	45%	11.36	4.11	558	19.85	8.95	1,210	652	116.9%
		100,000	500	28%	11.36	4.11	2,066	19.85	8.95	4,495	2,428	117.5%
		400,000	1000	56%	11.36	4.11	4,121	19.85	8.95	8,970	4,848	117.6%
		1,000,000	3000	46%	11.36	4.11	12,341	19.85	8.95	26,870	14,528	117.7%
		1,500,000	4000	52%	11.36	4.11	16,451	19.85	8.95	35,820	19,368	117.7%
GSd	**Fenelon Falls**	15,000	60	35%	19.81	3.02	201	25.74	7.75	491	290	144.1%
		43,164	133	45%	19.81	3.02	421	25.74	7.75	1,056	635	150.7%
		100,000	500	28%	19.81	3.02	1,530	25.74	7.75	3,901	2,371	155.0%
		400,000	1000	56%	19.81	3.02	3,040	25.74	7.75	7,776	4,736	155.8%
		1,000,000	3000	46%	19.81	3.02	9,080	25.74	7.75	23,276	14,196	156.3%
		1,500,000	4000	52%	19.81	3.02	12,100	25.74	7.75	31,026	18,926	156.4%
GSd	**Forest**	15,000	60	35%	24.91	3.74	249	29.46	8.50	539	290	116.4%
		43,164	133	45%	24.91	3.74	522	29.46	8.50	1,160	638	122.1%
		100,000	500	28%	24.91	3.74	1,895	29.46	8.50	4,279	2,385	125.8%
		400,000	1000	56%	24.91	3.74	3,765	29.46	8.50	8,529	4,765	126.6%
		1,000,000	3000	46%	24.91	3.74	11,245	29.46	8.50	25,529	14,285	127.0%
		1,500,000	4000	52%	24.91	3.74	14,985	29.46	8.50	34,029	19,045	127.1%
UGd	**GBE**	15,000	60	35%	10.77	3.64	229	14.61	7.33	455	225	98.4%
		43,164	133	45%	10.77	3.64	495	14.61	7.33	990	495	100.0%
		100,000	500	28%	10.77	3.64	1,831	14.61	7.33	3,681	1,850	101.1%
		400,000	1000	56%	10.77	3.64	3,651	14.61	7.33	7,348	3,697	101.3%
		1,000,000	3000	46%	10.77	3.64	10,931	14.61	7.33	22,014	11,083	101.4%
		1,500,000	4000	52%	10.77	3.64	14,571	14.61	7.33	29,347	14,776	101.4%
GSd	**Georgina**	15,000	60	35%	17.40	5.10	323	24.34	9.22	578	254	78.6%
		43,164	133	45%	17.40	5.10	696	24.34	9.22	1,251	555	79.8%
		100,000	500	28%	17.40	5.10	2,567	24.34	9.22	4,636	2,069	80.6%
		400,000	1000	56%	17.40	5.10	5,117	24.34	9.22	9,248	4,131	80.7%
		1,000,000	3000	46%	17.40	5.10	15,317	24.34	9.22	27,695	12,378	80.8%
		1,500,000	4000	52%	17.40	5.10	20,417	24.34	9.22	36,919	16,501	80.8%

New Rate Class: GSd

Bill Impacts of Proposed Distribution Rates exclude Riders

Classes		Scenario			Existing Dx Rates			Proposed Dx Rates			$ Incr	% Incr
					SrChg	base	Dx bill	SrChg	base	Dx bill		
New Class	Old Class	kWh	kW	LF	[$/month]	[$/kW]	[$/month]	[$/month]	[$/kW]	[$/month]		
GSd	Glencoe	15,000	60	35%	11.37	2.55	164	19.85	7.40	464	299	182.2%
		43,164	133	45%	11.37	2.55	351	19.85	7.40	1,004	654	186.4%
		100,000	500	28%	11.37	2.55	1,286	19.85	7.40	3,720	2,433	189.2%
		400,000	1000	56%	11.37	2.55	2,561	19.85	7.40	7,420	4,858	189.7%
		1,000,000	3000	46%	11.37	2.55	7,661	19.85	7.40	22,220	14,558	190.0%
		1,500,000	4000	52%	11.37	2.55	10,211	19.85	7.40	29,620	19,408	190.1%
GSd	Grand Bend	15,000	60	35%	22.20	3.90	256	28.14	8.75	553	297	115.9%
		43,164	133	45%	22.20	3.90	541	28.14	8.75	1,192	651	120.4%
		100,000	500	28%	22.20	3.90	1,972	28.14	8.75	4,403	2,431	123.3%
		400,000	1000	56%	22.20	3.90	3,922	28.14	8.75	8,778	4,856	123.8%
		1,000,000	3000	46%	22.20	3.90	11,722	28.14	8.75	26,278	14,556	124.2%
		1,500,000	4000	52%	22.20	3.90	15,622	28.14	8.75	35,028	19,406	124.2%
GSd	Hastings	15,000	60	35%	22.89	5.32	342	27.97	9.22	581	239	69.9%
		43,164	133	45%	22.89	5.32	730	27.97	9.22	1,255	524	71.8%
		100,000	500	28%	22.89	5.32	2,683	27.97	9.22	4,640	1,957	72.9%
		400,000	1000	56%	22.89	5.32	5,343	27.97	9.22	9,252	3,909	73.2%
		1,000,000	3000	46%	22.89	5.32	15,983	27.97	9.22	27,699	11,716	73.3%
		1,500,000	4000	52%	22.89	5.32	21,303	27.97	9.22	36,922	15,619	73.3%
GSd	Havelock	15,000	60	35%	22.18	4.82	311	28.14	9.22	582	270	86.8%
		43,164	133	45%	22.18	4.82	663	28.14	9.22	1,255	592	89.2%
		100,000	500	28%	22.18	4.82	2,432	28.14	9.22	4,640	2,208	90.8%
		400,000	1000	56%	22.18	4.82	4,842	28.14	9.22	9,252	4,410	91.1%
		1,000,000	3000	46%	22.18	4.82	14,482	28.14	9.22	27,699	13,217	91.3%
		1,500,000	4000	52%	22.18	4.82	19,302	28.14	9.22	36,922	17,620	91.3%
GSd	Kirkfield	15,000	60	35%	14.69	5.92	370	22.02	9.22	575	206	55.6%
		43,164	133	45%	14.69	5.92	802	22.02	9.22	1,249	447	55.7%
		100,000	500	28%	14.69	5.92	2,975	22.02	9.22	4,634	1,659	55.8%
		400,000	1000	56%	14.69	5.92	5,935	22.02	9.22	9,246	3,311	55.8%
		1,000,000	3000	46%	14.69	5.92	17,775	22.02	9.22	27,693	9,918	55.8%
		1,500,000	4000	52%	14.69	5.92	23,695	22.02	9.22	36,916	13,222	55.8%

New Rate Class: GSd

Bill Impacts of Proposed Distribution Rates exclude Riders

Classes		Scenario			Existing Dx Rates			Proposed Dx Rates			$ Incr	% Incr
					SrChg	base	Dx bill	SrChg	base	Dx bill		
New Class	Old Class	kWh	kW	LF	[$/month]	[$/kW]	[$/month]	[$/month]	[$/kW]	[$/month]		
GSd	Lanark Highlands	15,000	60	35%	18.43	5.26	334	25.08	9.22	578	244	73.2%
		43,164	133	45%	18.43	5.26	718	25.08	9.22	1,252	534	74.3%
		100,000	500	28%	18.43	5.26	2,648	25.08	9.22	4,637	1,988	75.1%
		400,000	1000	56%	18.43	5.26	5,278	25.08	9.22	9,249	3,970	75.2%
		1,000,000	3000	46%	18.43	5.26	15,798	25.08	9.22	27,696	11,897	75.3%
		1,500,000	4000	52%	18.43	5.26	21,058	25.08	9.22	36,919	15,861	75.3%
GSd	Larder Lake	15,000	60	35%	20.18	4.30	278	26.64	9.22	580	302	108.5%
		43,164	133	45%	20.18	4.30	592	26.64	9.22	1,253	661	111.7%
		100,000	500	28%	20.18	4.30	2,170	26.64	9.22	4,638	2,468	113.7%
		400,000	1000	56%	20.18	4.30	4,320	26.64	9.22	9,250	4,930	114.1%
		1,000,000	3000	46%	20.18	4.30	12,920	26.64	9.22	27,697	14,777	114.4%
		1,500,000	4000	52%	20.18	4.30	17,220	26.64	9.22	36,921	19,701	114.4%
GSd	Latchford	15,000	60	35%	2.88	2.44	149	12.97	8.80	541	392	262.4%
		43,164	133	45%	2.88	2.44	327	12.97	8.80	1,183	856	261.4%
		100,000	500	28%	2.88	2.44	1,223	12.97	8.80	4,413	3,190	260.9%
		400,000	1000	56%	2.88	2.44	2,443	12.97	8.80	8,813	6,370	260.8%
		1,000,000	3000	46%	2.88	2.44	7,323	12.97	8.80	26,413	19,090	260.7%
		1,500,000	4000	52%	2.88	2.44	9,763	12.97	8.80	35,213	25,450	260.7%
UGd	Lindsay	15,000	60	35%	23.94	4.36	286	24.31	7.33	464	179	62.6%
		43,164	133	45%	23.94	4.36	604	24.31	7.33	1,000	396	65.5%
		100,000	500	28%	23.94	4.36	2,204	24.31	7.33	3,691	1,487	67.5%
		400,000	1000	56%	23.94	4.36	4,384	24.31	7.33	7,357	2,973	67.8%
		1,000,000	3000	46%	23.94	4.36	13,104	24.31	7.33	22,024	8,920	68.1%
		1,500,000	4000	52%	23.94	4.36	17,464	24.31	7.33	29,357	11,893	68.1%
GSd	Lucan Granton	15,000	60	35%	16.99	4.61	294	23.44	9.22	577	283	96.5%
		43,164	133	45%	16.99	4.61	630	23.44	9.22	1,250	620	98.4%
		100,000	500	28%	16.99	4.61	2,322	23.44	9.22	4,635	2,313	99.6%
		400,000	1000	56%	16.99	4.61	4,627	23.44	9.22	9,247	4,620	99.8%
		1,000,000	3000	46%	16.99	4.61	13,847	23.44	9.22	27,694	13,847	100.0%
		1,500,000	4000	52%	16.99	4.61	18,457	23.44	9.22	36,918	18,461	100.0%

New Rate Class: GSd

Bill Impacts of Proposed Distribution Rates exclude Riders

Classes		Scenario			Existing Dx Rates			Proposed Dx Rates			$ Incr	% Incr
					SrChg	base	Dx bill	SrChg	base	Dx bill		
New Class	Old Class	kWh	kW	LF	[$/month]	[$/kW]	[$/month]	[$/month]	[$/kW]	[$/month]		
GSd	Malahide	15,000	60	35%	15.99	5.42	341	22.69	9.22	576	235	68.9%
		43,164	133	45%	15.99	5.42	737	22.69	9.22	1,249	513	69.6%
		100,000	500	28%	15.99	5.42	2,726	22.69	9.22	4,634	1,908	70.0%
		400,000	1000	56%	15.99	5.42	5,436	22.69	9.22	9,246	3,810	70.1%
		1,000,000	3000	46%	15.99	5.42	16,276	22.69	9.22	27,693	11,417	70.1%
		1,500,000	4000	52%	15.99	5.42	21,696	22.69	9.22	36,917	15,221	70.2%
GSd	Mapleton	15,000	60	35%	21.55	5.42	347	27.30	9.22	581	234	67.5%
		43,164	133	45%	21.55	5.42	742	27.30	9.22	1,254	512	68.9%
		100,000	500	28%	21.55	5.42	2,732	27.30	9.22	4,639	1,908	69.8%
		400,000	1000	56%	21.55	5.42	5,442	27.30	9.22	9,251	3,809	70.0%
		1,000,000	3000	46%	21.55	5.42	16,282	27.30	9.22	27,698	11,416	70.1%
		1,500,000	4000	52%	21.55	5.42	21,702	27.30	9.22	36,922	15,220	70.1%
GSd	Markdale	15,000	60	35%	23.00	2.54	175	28.94	7.25	464	289	164.5%
		43,164	133	45%	23.00	2.54	361	28.94	7.25	993	632	175.3%
		100,000	500	28%	23.00	2.54	1,293	28.94	7.25	3,654	2,361	182.6%
		400,000	1000	56%	23.00	2.54	2,563	28.94	7.25	7,279	4,716	184.0%
		1,000,000	3000	46%	23.00	2.54	7,643	28.94	7.25	21,779	14,136	185.0%
		1,500,000	4000	52%	23.00	2.54	10,183	28.94	7.25	29,029	18,846	185.1%
GSd	Marmora	15,000	60	35%	10.02	3.33	210	19.18	8.00	499	289	137.9%
		43,164	133	45%	10.02	3.33	453	19.18	8.00	1,083	630	139.2%
		100,000	500	28%	10.02	3.33	1,675	19.18	8.00	4,019	2,344	139.9%
		400,000	1000	56%	10.02	3.33	3,340	19.18	8.00	8,019	4,679	140.1%
		1,000,000	3000	46%	10.02	3.33	10,000	19.18	8.00	24,019	14,019	140.2%
		1,500,000	4000	52%	10.02	3.33	13,330	19.18	8.00	32,019	18,689	140.2%
GSd	McGarry	15,000	60	35%	20.18	5.68	361	26.64	9.22	580	219	60.7%
		43,164	133	45%	20.18	5.68	776	26.64	9.22	1,253	478	61.6%
		100,000	500	28%	20.18	5.68	2,860	26.64	9.22	4,638	1,778	62.2%
		400,000	1000	56%	20.18	5.68	5,700	26.64	9.22	9,250	3,550	62.3%
		1,000,000	3000	46%	20.18	5.68	17,060	26.64	9.22	27,697	10,637	62.4%
		1,500,000	4000	52%	20.18	5.68	22,740	26.64	9.22	36,921	14,181	62.4%

New Rate Class: GSd

Bill Impacts of Proposed Distribution Rates exclude Riders

Classes		Scenario			Existing Dx Rates			Proposed Dx Rates			$ Incr	% Incr
					SrChg	base	Dx bill	SrChg	base	Dx bill		
New Class	Old Class	kWh	kW	LF	[$/month]	[$/kW]	[$/month]	[$/month]	[$/kW]	[$/month]		
GSd	Meaford	15,000	60	35%	24.05	3.90	258	29.68	8.75	555	297	114.9%
		43,164	133	45%	24.05	3.90	543	29.68	8.75	1,193	651	119.9%
		100,000	500	28%	24.05	3.90	1,974	29.68	8.75	4,405	2,431	123.1%
		400,000	1000	56%	24.05	3.90	3,924	29.68	8.75	8,780	4,856	123.7%
		1,000,000	3000	46%	24.05	3.90	11,724	29.68	8.75	26,280	14,556	124.2%
		1,500,000	4000	52%	24.05	3.90	15,624	29.68	8.75	35,030	19,406	124.2%
GSd	Middlesex Centre	15,000	60	35%	17.35	3.29	215	24.35	9.00	564	350	162.8%
		43,164	133	45%	17.35	3.29	455	24.35	9.00	1,221	766	168.5%
		100,000	500	28%	17.35	3.29	1,662	24.35	9.00	4,524	2,862	172.2%
		400,000	1000	56%	17.35	3.29	3,307	24.35	9.00	9,024	5,717	172.9%
		1,000,000	3000	46%	17.35	3.29	9,887	24.35	9.00	27,024	17,137	173.3%
		1,500,000	4000	52%	17.35	3.29	13,177	24.35	9.00	36,024	22,847	173.4%
GSd	Napanee	15,000	60	35%	22.17	4.04	265	28.15	8.90	562	298	112.5%
		43,164	133	45%	22.17	4.04	559	28.15	8.90	1,212	652	116.6%
		100,000	500	28%	22.17	4.04	2,042	28.15	8.90	4,478	2,436	119.3%
		400,000	1000	56%	22.17	4.04	4,062	28.15	8.90	8,928	4,866	119.8%
		1,000,000	3000	46%	22.17	4.04	12,142	28.15	8.90	26,728	14,586	120.1%
		1,500,000	4000	52%	22.17	4.04	16,182	28.15	8.90	35,628	19,446	120.2%
GSd	Nipigon	15,000	60	35%	23.32	3.38	226	28.86	8.80	557	331	146.3%
		43,164	133	45%	23.32	3.38	473	28.86	8.80	1,199	726	153.6%
		100,000	500	28%	23.32	3.38	1,713	28.86	8.80	4,429	2,716	158.5%
		400,000	1000	56%	23.32	3.38	3,403	28.86	8.80	8,829	5,426	159.4%
		1,000,000	3000	46%	23.32	3.38	10,163	28.86	8.80	26,429	16,266	160.0%
		1,500,000	4000	52%	23.32	3.38	13,543	28.86	8.80	35,229	21,686	160.1%
GSd	North Dorchester	15,000	60	35%	15.88	2.85	187	22.72	8.30	521	334	178.6%
		43,164	133	45%	15.88	2.85	395	22.72	8.30	1,127	732	185.3%
		100,000	500	28%	15.88	2.85	1,441	22.72	8.30	4,173	2,732	189.6%
		400,000	1000	56%	15.88	2.85	2,866	22.72	8.30	8,323	5,457	190.4%
		1,000,000	3000	46%	15.88	2.85	8,566	22.72	8.30	24,923	16,357	191.0%
		1,500,000	4000	52%	15.88	2.85	11,416	22.72	8.30	33,223	21,807	191.0%

New Rate Class: GSd

Bill Impacts of Proposed Distribution Rates exclude Riders

Classes		Scenario			Existing Dx Rates			Proposed Dx Rates			$ Incr	% Incr
					SrChg	base	Dx bill	SrChg	base	Dx bill		
New Class	Old Class	kWh	kW	LF	[$/month]	[$/kW]	[$/month]	[$/month]	[$/kW]	[$/month]		
GSd	North Dundas	15,000	60	35%	13.52	2.42	159	21.31	7.00	441	283	178.0%
		43,164	133	45%	13.52	2.42	335	21.31	7.00	952	617	183.9%
		100,000	500	28%	13.52	2.42	1,224	21.31	7.00	3,521	2,298	187.8%
		400,000	1000	56%	13.52	2.42	2,434	21.31	7.00	7,021	4,588	188.5%
		1,000,000	3000	46%	13.52	2.42	7,274	21.31	7.00	21,021	13,748	189.0%
		1,500,000	4000	52%	13.52	2.42	9,694	21.31	7.00	28,021	18,328	189.1%
GSd	North Glengarry	15,000	60	35%	17.72	2.82	187	24.26	7.70	486	299	160.1%
		43,164	133	45%	17.72	2.82	393	24.26	7.70	1,048	656	166.9%
		100,000	500	28%	17.72	2.82	1,428	24.26	7.70	3,874	2,447	171.4%
		400,000	1000	56%	17.72	2.82	2,838	24.26	7.70	7,724	4,887	172.2%
		1,000,000	3000	46%	17.72	2.82	8,478	24.26	7.70	23,124	14,647	172.8%
		1,500,000	4000	52%	17.72	2.82	11,298	24.26	7.70	30,824	19,527	172.8%
GSd	North Grenville	15,000	60	35%	20.42	5.41	345	26.58	9.22	580	235	68.1%
		43,164	133	45%	20.42	5.41	740	26.58	9.22	1,253	513	69.4%
		100,000	500	28%	20.42	5.41	2,725	26.58	9.22	4,638	1,913	70.2%
		400,000	1000	56%	20.42	5.41	5,430	26.58	9.22	9,250	3,820	70.3%
		1,000,000	3000	46%	20.42	5.41	16,250	26.58	9.22	27,697	11,447	70.4%
		1,500,000	4000	52%	20.42	5.41	21,660	26.58	9.22	36,921	15,260	70.5%
GSd	North Perth	15,000	60	35%	29.52	3.16	219	33.31	7.70	495	276	126.0%
		43,164	133	45%	29.52	3.16	450	33.31	7.70	1,057	608	135.1%
		100,000	500	28%	29.52	3.16	1,610	33.31	7.70	3,883	2,274	141.3%
		400,000	1000	56%	29.52	3.16	3,190	33.31	7.70	7,733	4,544	142.5%
		1,000,000	3000	46%	29.52	3.16	9,510	33.31	7.70	23,133	13,624	143.3%
		1,500,000	4000	52%	29.52	3.16	12,670	33.31	7.70	30,833	18,164	143.4%
GSd	North Stormont	15,000	60	35%	5.37	2.52	157	15.35	9.22	569	412	263.3%
	no customer	43,164	133	45%	5.37	2.52	341	15.35	9.22	1,242	902	264.7%
		100,000	500	28%	5.37	2.52	1,265	15.35	9.22	4,627	3,362	265.7%
		400,000	1000	56%	5.37	2.52	2,525	15.35	9.22	9,239	6,714	265.8%
		1,000,000	3000	46%	5.37	2.52	7,565	15.35	9.22	27,686	20,121	266.0%
		1,500,000	4000	52%	5.37	2.52	10,085	15.35	9.22	36,910	26,824	266.0%

New Rate Class: GSd

Bill Impacts of Proposed Distribution Rates exclude Riders

Classes		Scenario			Existing Dx Rates			Proposed Dx Rates			$ Incr	% Incr
					SrChg	base	Dx bill	SrChg	base	Dx bill		
New Class	Old Class	kWh	kW	LF	[$/month]	[$/kW]	[$/month]	[$/month]	[$/kW]	[$/month]		
GSd	Omemee	15,000	60	35%	21.28	4.64	300	27.37	9.22	581	281	93.8%
		43,164	133	45%	21.28	4.64	638	27.37	9.22	1,254	616	96.4%
		100,000	500	28%	21.28	4.64	2,341	27.37	9.22	4,639	2,298	98.1%
		400,000	1000	56%	21.28	4.64	4,661	27.37	9.22	9,251	4,590	98.5%
		1,000,000	3000	46%	21.28	4.64	13,941	27.37	9.22	27,698	13,757	98.7%
		1,500,000	4000	52%	21.28	4.64	18,581	27.37	9.22	36,922	18,340	98.7%
UGd	Perth	15,000	60	35%	19.92	2.87	192	21.32	7.15	450	258	134.4%
		43,164	133	45%	19.92	2.87	402	21.32	7.15	972	571	142.1%
		100,000	500	28%	19.92	2.87	1,455	21.32	7.15	3,596	2,141	147.2%
		400,000	1000	56%	19.92	2.87	2,890	21.32	7.15	7,171	4,281	148.1%
		1,000,000	3000	46%	19.92	2.87	8,630	21.32	7.15	21,471	12,841	148.8%
		1,500,000	4000	52%	19.92	2.87	11,500	21.32	7.15	28,621	17,121	148.9%
GSd	Perth East	15,000	60	35%	14.65	4.08	259	22.03	8.95	559	300	115.5%
		43,164	133	45%	14.65	4.08	557	22.03	8.95	1,212	655	117.5%
		100,000	500	28%	14.65	4.08	2,055	22.03	8.95	4,497	2,442	118.9%
		400,000	1000	56%	14.65	4.08	4,095	22.03	8.95	8,972	4,877	119.1%
		1,000,000	3000	46%	14.65	4.08	12,255	22.03	8.95	26,872	14,617	119.3%
		1,500,000	4000	52%	14.65	4.08	16,335	22.03	8.95	35,822	19,487	119.3%
GSd	Prince Edward	15,000	60	35%	22.85	4.45	290	27.98	9.22	581	292	100.6%
		43,164	133	45%	22.85	4.45	615	27.98	9.22	1,255	640	104.1%
		100,000	500	28%	22.85	4.45	2,248	27.98	9.22	4,640	2,392	106.4%
		400,000	1000	56%	22.85	4.45	4,473	27.98	9.22	9,252	4,779	106.8%
		1,000,000	3000	46%	22.85	4.45	13,373	27.98	9.22	27,699	14,326	107.1%
		1,500,000	4000	52%	22.85	4.45	17,823	27.98	9.22	36,922	19,099	107.2%
UGd	Quinte West	15,000	60	35%	3.74	3.32	203	9.36	7.33	449	246	121.4%
		43,164	133	45%	3.74	3.32	445	9.36	7.33	985	539	121.1%
		100,000	500	28%	3.74	3.32	1,664	9.36	7.33	3,676	2,012	120.9%
		400,000	1000	56%	3.74	3.32	3,324	9.36	7.33	7,342	4,019	120.9%
		1,000,000	3000	46%	3.74	3.32	9,964	9.36	7.33	22,009	12,045	120.9%
		1,500,000	4000	52%	3.74	3.32	13,284	9.36	7.33	29,342	16,058	120.9%

New Rate Class: GSd

Bill Impacts of Proposed Distribution Rates exclude Riders

Classes		Scenario			Existing Dx Rates			Proposed Dx Rates			$ Incr	% Incr
					SrChg	base	Dx bill	SrChg	base	Dx bill		
New Class	Old Class	kWh	kW	LF	[$/month]	[$/kW]	[$/month]	[$/month]	[$/kW]	[$/month]		
GSd	Rainy River	15,000	60	35%	19.29	5.59	355	25.87	9.22	579	225	63.3%
		43,164	133	45%	19.29	5.59	763	25.87	9.22	1,253	490	64.2%
		100,000	500	28%	19.29	5.59	2,814	25.87	9.22	4,638	1,823	64.8%
		400,000	1000	56%	19.29	5.59	5,609	25.87	9.22	9,249	3,640	64.9%
		1,000,000	3000	46%	19.29	5.59	16,789	25.87	9.22	27,697	10,907	65.0%
		1,500,000	4000	52%	19.29	5.59	22,379	25.87	9.22	36,920	14,541	65.0%
GSd	Ramara	15,000	60	35%	20.97	3.35	222	26.45	9.22	580	358	161.2%
		43,164	133	45%	20.97	3.35	467	26.45	9.22	1,253	787	168.6%
		100,000	500	28%	20.97	3.35	1,696	26.45	9.22	4,638	2,942	173.5%
		400,000	1000	56%	20.97	3.35	3,371	26.45	9.22	9,250	5,879	174.4%
		1,000,000	3000	46%	20.97	3.35	10,071	26.45	9.22	27,697	17,626	175.0%
		1,500,000	4000	52%	20.97	3.35	13,421	26.45	9.22	36,921	23,500	175.1%
GSd	Red Rock	15,000	60	35%	21.64	6.15	391	27.28	9.22	581	190	48.7%
		43,164	133	45%	21.64	6.15	840	27.28	9.22	1,254	414	49.4%
		100,000	500	28%	21.64	6.15	3,097	27.28	9.22	4,639	1,542	49.8%
		400,000	1000	56%	21.64	6.15	6,172	27.28	9.22	9,251	3,079	49.9%
		1,000,000	3000	46%	21.64	6.15	18,472	27.28	9.22	27,698	9,226	49.9%
		1,500,000	4000	52%	21.64	6.15	24,622	27.28	9.22	36,922	12,300	50.0%
GSd	Rockland	15,000	60	35%	7.27	2.59	163	16.87	7.25	452	289	177.8%
		43,164	133	45%	7.27	2.59	352	16.87	7.25	981	629	178.9%
		100,000	500	28%	7.27	2.59	1,302	16.87	7.25	3,642	2,340	179.7%
		400,000	1000	56%	7.27	2.59	2,597	16.87	7.25	7,267	4,670	179.8%
		1,000,000	3000	46%	7.27	2.59	7,777	16.87	7.25	21,767	13,990	179.9%
		1,500,000	4000	52%	7.27	2.59	10,367	16.87	7.25	29,017	18,650	179.9%
GSd	Russell	15,000	60	35%	19.26	7.10	445	25.87	9.22	579	134	30.1%
		43,164	133	45%	19.26	7.10	964	25.87	9.22	1,253	289	30.0%
		100,000	500	28%	19.26	7.10	3,569	25.87	9.22	4,638	1,068	29.9%
		400,000	1000	56%	19.26	7.10	7,119	25.87	9.22	9,249	2,130	29.9%
		1,000,000	3000	46%	19.26	7.10	21,319	25.87	9.22	27,697	6,377	29.9%
		1,500,000	4000	52%	19.26	7.10	28,419	25.87	9.22	36,920	8,501	29.9%

New Rate Class: GSd

Bill Impacts of Proposed Distribution Rates exclude Riders

Classes		Scenario			Existing Dx Rates			Proposed Dx Rates			$ Incr	% Incr
					SrChg	base	Dx bill	SrChg	base	Dx bill		
New Class	Old Class	kWh	kW	LF	[$/month]	[$/kW]	[$/month]	[$/month]	[$/kW]	[$/month]		
GSd	Schreiber	15,000	60	35%	20.70	7.36	462	26.51	9.22	580	118	25.4%
		43,164	133	45%	20.70	7.36	1,000	26.51	9.22	1,253	254	25.4%
		100,000	500	28%	20.70	7.36	3,701	26.51	9.22	4,638	938	25.3%
		400,000	1000	56%	20.70	7.36	7,381	26.51	9.22	9,250	1,869	25.3%
		1,000,000	3000	46%	20.70	7.36	22,101	26.51	9.22	27,697	5,597	25.3%
		1,500,000	4000	52%	20.70	7.36	29,461	26.51	9.22	36,921	7,460	25.3%
GSd	Severn	15,000	60	35%	22.17	3.35	223	28.15	8.70	550	327	146.5%
		43,164	133	45%	22.17	3.35	468	28.15	8.70	1,185	718	153.4%
		100,000	500	28%	22.17	3.35	1,697	28.15	8.70	4,378	2,681	158.0%
		400,000	1000	56%	22.17	3.35	3,372	28.15	8.70	8,728	5,356	158.8%
		1,000,000	3000	46%	22.17	3.35	10,072	28.15	8.70	26,128	16,056	159.4%
		1,500,000	4000	52%	22.17	3.35	13,422	28.15	8.70	34,828	21,406	159.5%
GSd	Shelburne	15,000	60	35%	20.01	2.78	187	26.69	7.25	462	275	147.1%
		43,164	133	45%	20.01	2.78	390	26.69	7.25	991	601	154.2%
		100,000	500	28%	20.01	2.78	1,410	26.69	7.25	3,652	2,242	159.0%
		400,000	1000	56%	20.01	2.78	2,800	26.69	7.25	7,277	4,477	159.9%
		1,000,000	3000	46%	20.01	2.78	8,360	26.69	7.25	21,777	13,417	160.5%
		1,500,000	4000	52%	20.01	2.78	11,140	26.69	7.25	29,027	17,887	160.6%
UGd	Smiths Falls	15,000	60	35%	9.84	3.33	210	13.84	7.33	454	244	116.5%
		43,164	133	45%	9.84	3.33	453	13.84	7.33	989	536	118.5%
		100,000	500	28%	9.84	3.33	1,675	13.84	7.33	3,680	2,006	119.7%
		400,000	1000	56%	9.84	3.33	3,340	13.84	7.33	7,347	4,007	120.0%
		1,000,000	3000	46%	9.84	3.33	10,000	13.84	7.33	22,013	12,013	120.1%
		1,500,000	4000	52%	9.84	3.33	13,330	13.84	7.33	29,346	16,016	120.2%
GSd	South Glengarry	15,000	60	35%	17.41	2.37	160	24.34	7.75	489	330	206.6%
		43,164	133	45%	17.41	2.37	333	24.34	7.75	1,055	722	217.2%
		100,000	500	28%	17.41	2.37	1,202	24.34	7.75	3,899	2,697	224.3%
		400,000	1000	56%	17.41	2.37	2,387	24.34	7.75	7,774	5,387	225.6%
		1,000,000	3000	46%	17.41	2.37	7,127	24.34	7.75	23,274	16,147	226.5%
		1,500,000	4000	52%	17.41	2.37	9,497	24.34	7.75	31,024	21,527	226.7%

New Rate Class: GSd

Bill Impacts of Proposed Distribution Rates exclude Riders

Classes		Scenario			Existing Dx Rates			Proposed Dx Rates			$ Incr	% Incr
					SrChg	base	Dx bill	SrChg	base	Dx bill		
New Class	Old Class	kWh	kW	LF	[$/month]	[$/kW]	[$/month]	[$/month]	[$/kW]	[$/month]		
GSd	South River	15,000	60	35%	22.11	4.87	314	28.16	9.22	582	267	85.0%
		43,164	133	45%	22.11	4.87	670	28.16	9.22	1,255	585	87.3%
		100,000	500	28%	22.11	4.87	2,457	28.16	9.22	4,640	2,183	88.8%
		400,000	1000	56%	22.11	4.87	4,892	28.16	9.22	9,252	4,360	89.1%
		1,000,000	3000	46%	22.11	4.87	14,632	28.16	9.22	27,699	13,067	89.3%
		1,500,000	4000	52%	22.11	4.87	19,502	28.16	9.22	36,922	17,420	89.3%
GSd	Springwater	15,000	60	35%	20.53	3.42	226	26.56	8.60	543	317	140.4%
		43,164	133	45%	20.53	3.42	475	26.56	8.60	1,170	695	146.2%
		100,000	500	28%	20.53	3.42	1,731	26.56	8.60	4,327	2,596	150.0%
		400,000	1000	56%	20.53	3.42	3,441	26.56	8.60	8,627	5,186	150.7%
		1,000,000	3000	46%	20.53	3.42	10,281	26.56	8.60	25,827	15,546	151.2%
		1,500,000	4000	52%	20.53	3.42	13,701	26.56	8.60	34,427	20,726	151.3%
GSd	Stirling-Rawdon	15,000	60	35%	24.12	4.11	271	29.66	9.22	583	312	115.4%
		43,164	133	45%	24.12	4.11	571	29.66	9.22	1,256	686	120.1%
		100,000	500	28%	24.12	4.11	2,079	29.66	9.22	4,641	2,562	123.2%
		400,000	1000	56%	24.12	4.11	4,134	29.66	9.22	9,253	5,119	123.8%
		1,000,000	3000	46%	24.12	4.11	12,354	29.66	9.22	27,700	15,346	124.2%
		1,500,000	4000	52%	24.12	4.11	16,464	29.66	9.22	36,924	20,460	124.3%
GSd	Thedford	15,000	60	35%	17.83	3.38	221	24.23	8.95	561	341	154.4%
		43,164	133	45%	17.83	3.38	467	24.23	8.95	1,215	747	159.9%
		100,000	500	28%	17.83	3.38	1,708	24.23	8.95	4,499	2,791	163.4%
		400,000	1000	56%	17.83	3.38	3,398	24.23	8.95	8,974	5,576	164.1%
		1,000,000	3000	46%	17.83	3.38	10,158	24.23	8.95	26,874	16,716	164.6%
		1,500,000	4000	52%	17.83	3.38	13,538	24.23	8.95	35,824	22,286	164.6%
GSd	Thessalon	15,000	60	35%	18.90	3.22	212	24.96	7.60	481	269	126.8%
		43,164	133	45%	18.90	3.22	447	24.96	7.60	1,036	589	131.6%
		100,000	500	28%	18.90	3.22	1,629	24.96	7.60	3,825	2,196	134.8%
		400,000	1000	56%	18.90	3.22	3,239	24.96	7.60	7,625	4,386	135.4%
		1,000,000	3000	46%	18.90	3.22	9,679	24.96	7.60	22,825	13,146	135.8%
		1,500,000	4000	52%	18.90	3.22	12,899	24.96	7.60	30,425	17,526	135.9%

New Rate Class: GSd

Bill Impacts of Proposed Distribution Rates exclude Riders

Classes		Scenario			Existing Dx Rates			Proposed Dx Rates			$ Incr	% Incr
					SrChg	base	Dx bill	SrChg	base	Dx bill		
New Class	Old Class	kWh	kW	LF	[$/month]	[$/kW]	[$/month]	[$/month]	[$/kW]	[$/month]		
GSd	Thorndale	15,000	60	35%	14.52	3.25	210	22.06	9.22	575	366	174.7%
		43,164	133	45%	14.52	3.25	447	22.06	9.22	1,249	802	179.5%
		100,000	500	28%	14.52	3.25	1,640	22.06	9.22	4,634	2,994	182.6%
		400,000	1000	56%	14.52	3.25	3,265	22.06	9.22	9,246	5,981	183.2%
		1,000,000	3000	46%	14.52	3.25	9,765	22.06	9.22	27,693	17,928	183.6%
		1,500,000	4000	52%	14.52	3.25	13,015	22.06	9.22	36,916	23,902	183.7%
UGd	Thorold	15,000	60	35%	22.63	4.76	308	23.64	7.33	464	155	50.4%
		43,164	133	45%	22.63	4.76	656	23.64	7.33	999	343	52.3%
		100,000	500	28%	22.63	4.76	2,403	23.64	7.33	3,690	1,288	53.6%
		400,000	1000	56%	22.63	4.76	4,783	23.64	7.33	7,357	2,574	53.8%
		1,000,000	3000	46%	22.63	4.76	14,303	23.64	7.33	22,023	7,720	54.0%
		1,500,000	4000	52%	22.63	4.76	19,063	23.64	7.33	29,356	10,293	54.0%
GSd	Tweed	15,000	60	35%	8.26	3.11	195	17.62	8.80	546	351	180.0%
		43,164	133	45%	8.26	3.11	422	17.62	8.80	1,188	766	181.6%
		100,000	500	28%	8.26	3.11	1,563	17.62	8.80	4,418	2,854	182.6%
		400,000	1000	56%	8.26	3.11	3,118	17.62	8.80	8,818	5,699	182.8%
		1,000,000	3000	46%	8.26	3.11	9,338	17.62	8.80	26,418	17,079	182.9%
		1,500,000	4000	52%	8.26	3.11	12,448	17.62	8.80	35,218	22,769	182.9%
GSd	Wardsville	15,000	60	35%	12.32	3.16	202	20.61	8.20	513	311	153.9%
		43,164	133	45%	12.32	3.16	433	20.61	8.20	1,111	679	156.9%
		100,000	500	28%	12.32	3.16	1,592	20.61	8.20	4,121	2,528	158.8%
		400,000	1000	56%	12.32	3.16	3,172	20.61	8.20	8,221	5,048	159.1%
		1,000,000	3000	46%	12.32	3.16	9,492	20.61	8.20	24,621	15,128	159.4%
		1,500,000	4000	52%	12.32	3.16	12,652	20.61	8.20	32,821	20,168	159.4%
GSd	Warkworth	15,000	60	35%	21.31	4.47	290	27.36	9.22	581	291	100.6%
		43,164	133	45%	21.31	4.47	616	27.36	9.22	1,254	638	103.6%
		100,000	500	28%	21.31	4.47	2,256	27.36	9.22	4,639	2,383	105.6%
		400,000	1000	56%	21.31	4.47	4,491	27.36	9.22	9,251	4,760	106.0%
		1,000,000	3000	46%	21.31	4.47	13,431	27.36	9.22	27,698	14,267	106.2%
		1,500,000	4000	52%	21.31	4.47	17,901	27.36	9.22	36,922	19,020	106.3%

New Rate Class: GSd

Bill Impacts of Proposed Distribution Rates exclude Riders

Classes		Scenario			Existing Dx Rates			Proposed Dx Rates			$ Incr	% Incr
					SrChg	base	Dx bill	SrChg	base	Dx bill		
New Class	Old Class	kWh	kW	LF	[$/month]	[$/kW]	[$/month]	[$/month]	[$/kW]	[$/month]		
GSd	West Elgin	15,000	60	35%	15.40	2.21	148	22.84	6.85	434	286	193.1%
		43,164	133	45%	15.40	2.21	309	22.84	6.85	934	625	201.9%
		100,000	500	28%	15.40	2.21	1,120	22.84	6.85	3,448	2,327	207.7%
		400,000	1000	56%	15.40	2.21	2,225	22.84	6.85	6,873	4,647	208.8%
		1,000,000	3000	46%	15.40	2.21	6,645	22.84	6.85	20,573	13,927	209.6%
		1,500,000	4000	52%	15.40	2.21	8,855	22.84	6.85	27,423	18,567	209.7%
UGd	Whitchurch Stouffville	15,000	60	35%	21.85	2.93	198	22.84	7.15	452	254	128.6%
		43,164	133	45%	21.85	2.93	412	22.84	7.15	974	562	136.6%
		100,000	500	28%	21.85	2.93	1,487	22.84	7.15	3,598	2,111	142.0%
		400,000	1000	56%	21.85	2.93	2,952	22.84	7.15	7,173	4,221	143.0%
		1,000,000	3000	46%	21.85	2.93	8,812	22.84	7.15	21,473	12,661	143.7%
		1,500,000	4000	52%	21.85	2.93	11,742	22.84	7.15	28,623	16,881	143.8%
GSd	Wiarton	15,000	60	35%	23.78	5.99	383	28.74	9.22	582	199	51.9%
		43,164	133	45%	23.78	5.99	820	28.74	9.22	1,255	435	53.0%
		100,000	500	28%	23.78	5.99	3,019	28.74	9.22	4,641	1,622	53.7%
		400,000	1000	56%	23.78	5.99	6,014	28.74	9.22	9,252	3,239	53.9%
		1,000,000	3000	46%	23.78	5.99	17,994	28.74	9.22	27,699	9,706	53.9%
		1,500,000	4000	52%	23.78	5.99	23,984	28.74	9.22	36,923	12,939	54.0%
GSd	Woodville	15,000	60	35%	16.89	4.34	277	23.47	9.22	577	300	108.0%
		43,164	133	45%	16.89	4.34	594	23.47	9.22	1,250	656	110.4%
		100,000	500	28%	16.89	4.34	2,187	23.47	9.22	4,635	2,448	112.0%
		400,000	1000	56%	16.89	4.34	4,357	23.47	9.22	9,247	4,890	112.2%
		1,000,000	3000	46%	16.89	4.34	13,037	23.47	9.22	27,694	14,657	112.4%
		1,500,000	4000	52%	16.89	4.34	17,377	23.47	9.22	36,918	19,541	112.5%
GSd	Wyoming	15,000	60	35%	17.36	4.57	292	24.35	9.22	578	286	98.2%
		43,164	133	45%	17.36	4.57	625	24.35	9.22	1,251	626	100.1%
		100,000	500	28%	17.36	4.57	2,302	24.35	9.22	4,636	2,334	101.4%
		400,000	1000	56%	17.36	4.57	4,587	24.35	9.22	9,248	4,661	101.6%
		1,000,000	3000	46%	17.36	4.57	13,727	24.35	9.22	27,695	13,968	101.8%
		1,500,000	4000	52%	17.36	4.57	18,297	24.35	9.22	36,919	18,621	101.8%

New Rate Class: GSd

Bill Impacts of Proposed Distribution Rates exclude Riders

Classes		Scenario			Existing Dx Rates			Proposed Dx Rates			$ Incr	% Incr
					SrChg	base	Dx bill	SrChg	base	Dx bill		
New Class	**Old Class**	kWh	kW	LF	[$/month]	[$/kW]	[$/month]	[$/month]	[$/kW]	[$/month]		
GSd	**Terrace Bay**	15,000	60	35%	293.24	4.00	533	231.38	9.22	785	251	47.1%
		43,164	133	45%	293.24	4.00	826	231.38	9.22	1,458	633	76.6%
		100,000	500	28%	293.24	4.00	2,294	231.38	9.22	4,843	2,549	111.1%
		400,000	1000	56%	293.24	4.00	4,295	231.38	9.22	9,455	5,160	120.1%
		1,000,000	3000	46%	293.24	4.00	12,299	231.38	9.22	27,902	15,603	126.9%
		1,500,000	4000	52%	293.24	4.00	16,301	231.38	9.22	37,126	20,824	127.7%

New Rate Class: Gse - Unmetered

Bill Impacts of Proposed Distribution Rates exclude Riders

Classes		Scenario	Existing Dx Rates			Proposed Dx Rates			$ Incr	% Incr
			SrChg	base	Dx bill	SrChg	base	Dx bill		
New Class	Old Class	kWh	[$/month]	[c/kWh]	[$/month]	[$/month]	[c/kWh]	[$/month]		
GSe	G1	100	22.16	3.12	25.28	22.84	5.38	28.22	2.94	11.6%
		250	22.16	3.12	29.96	22.84	5.38	36.28	6.32	21.1%
		500	22.16	3.12	37.76	22.84	5.38	49.73	11.97	31.7%
		750	22.16	3.12	45.56	22.84	5.38	63.18	17.62	38.7%
		1,000	22.16	3.12	53.36	22.84	5.38	76.63	23.27	43.6%
GSe	G3	100	6.29	3.07	9.36	10.81	3.60	14.41	5.05	53.9%
		250	6.29	3.07	13.97	10.81	3.60	19.81	5.84	41.8%
		500	6.29	3.07	21.64	10.81	3.60	28.81	7.17	33.1%
		750	6.29	3.07	29.32	10.81	3.60	37.81	8.49	29.0%
		1,000	6.29	3.07	36.99	10.81	3.60	46.81	9.82	26.5%
GSe	UG	100	0.79	2.74	3.53	6.18	3.50	9.68	6.15	174.2%
		250	0.79	2.74	7.64	6.18	3.50	14.93	7.29	95.4%
		500	0.79	2.74	14.49	6.18	3.50	23.68	9.19	63.4%
		750	0.79	2.74	21.34	6.18	3.50	32.43	11.09	52.0%
		1,000	0.79	2.74	28.19	6.18	3.50	41.18	12.99	46.1%
GSe	Ailsa Craig	100	8.20	1.32	9.52	12.33	2.00	14.33	4.81	50.5%
		250	8.20	1.32	11.50	12.33	2.00	17.33	5.83	50.7%
		500	8.20	1.32	14.80	12.33	2.00	22.33	7.53	50.9%
		750	8.20	1.32	18.10	12.33	2.00	27.33	9.23	51.0%
		1,000	8.20	1.32	21.40	12.33	2.00	32.33	10.93	51.1%
GSe	Arkona	100	1.14	0.86	2.00	7.09	2.00	9.09	7.09	354.6%
		250	1.14	0.86	3.29	7.09	2.00	12.09	8.80	267.6%
		500	1.14	0.86	5.44	7.09	2.00	17.09	11.65	214.2%
		750	1.14	0.86	7.59	7.09	2.00	22.09	14.50	191.1%
		1,000	1.14	0.86	9.74	7.09	2.00	27.09	17.35	178.2%

New Rate Class: Gse - Unmetered

Bill Impacts of Proposed Distribution Rates exclude Riders

Classes		Scenario	Existing Dx Rates			Proposed Dx Rates			$ Incr	% Incr
			SrChg [$/month]	base [c/kWh]	Dx bill [$/month]	SrChg [$/month]	base [c/kWh]	Dx bill [$/month]		
New Class	**Old Class**	kWh								
GSe	**Arnprior**	100	10.23	1.17	11.40	13.82	2.00	15.82	4.42	38.8%
		250	10.23	1.17	13.16	13.82	2.00	18.82	5.67	43.1%
		500	10.23	1.17	16.08	13.82	2.00	23.82	7.74	48.1%
		750	10.23	1.17	19.01	13.82	2.00	28.82	9.82	51.6%
		1,000	10.23	1.17	21.93	13.82	2.00	33.82	11.89	54.2%
GSe	**Arran-Elderslie**	100	3.95	1.03	4.98	8.39	2.00	10.39	5.41	108.6%
		250	3.95	1.03	6.53	8.39	2.00	13.39	6.87	105.2%
		500	3.95	1.03	9.10	8.39	2.00	18.39	9.29	102.1%
		750	3.95	1.03	11.68	8.39	2.00	23.39	11.72	100.3%
		1,000	3.95	1.03	14.25	8.39	2.00	28.39	14.14	99.2%
GSe	**Artemesia**	100	9.34	1.74	11.08	13.04	2.00	15.04	3.96	35.8%
		250	9.34	1.74	13.69	13.04	2.00	18.04	4.35	31.8%
		500	9.34	1.74	18.04	13.04	2.00	23.04	5.00	27.7%
		750	9.34	1.74	22.39	13.04	2.00	28.04	5.65	25.2%
		1,000	9.34	1.74	26.74	13.04	2.00	33.04	6.30	23.6%
GSe	**Bancroft**	100	11.73	1.18	12.91	14.45	2.00	16.45	3.54	27.4%
		250	11.73	1.18	14.68	14.45	2.00	19.45	4.77	32.5%
		500	11.73	1.18	17.63	14.45	2.00	24.45	6.82	38.7%
		750	11.73	1.18	20.58	14.45	2.00	29.45	8.87	43.1%
		1,000	11.73	1.18	23.53	14.45	2.00	34.45	10.92	46.4%
GSe	**Bath**	100	4.86	1.47	6.33	9.16	2.00	11.16	4.83	76.3%
		250	4.86	1.47	8.54	9.16	2.00	14.16	5.63	65.9%
		500	4.86	1.47	12.21	9.16	2.00	19.16	6.95	56.9%
		750	4.86	1.47	15.89	9.16	2.00	24.16	8.28	52.1%
		1,000	4.86	1.47	19.56	9.16	2.00	29.16	9.60	49.1%

New Rate Class: Gse - Unmetered

Bill Impacts of Proposed Distribution Rates exclude Riders

Classes		Scenario	Existing Dx Rates			Proposed Dx Rates			$ Incr	% Incr
			SrChg [$/month]	base [c/kWh]	Dx bill [$/month]	SrChg [$/month]	base [c/kWh]	Dx bill [$/month]		
New Class	Old Class	kWh								
GSe	Blandford-Blenheim	100	11.46	1.14	12.60	14.51	2.00	16.51	3.91	31.1%
		250	11.46	1.14	14.31	14.51	2.00	19.51	5.20	36.4%
		500	11.46	1.14	17.16	14.51	2.00	24.51	7.35	42.8%
		750	11.46	1.14	20.01	14.51	2.00	29.51	9.50	47.5%
		1,000	11.46	1.14	22.86	14.51	2.00	34.51	11.65	51.0%
GSe	Blyth	100	10.35	1.05	11.40	13.79	2.00	15.79	4.39	38.5%
		250	10.35	1.05	12.98	13.79	2.00	18.79	5.82	44.8%
		500	10.35	1.05	15.60	13.79	2.00	23.79	8.19	52.5%
		750	10.35	1.05	18.23	13.79	2.00	28.79	10.57	58.0%
		1,000	10.35	1.05	20.85	13.79	2.00	33.79	12.94	62.1%
GSe	Bobcaygeon	100	11.14	1.38	12.52	14.59	2.00	16.59	4.07	32.5%
		250	11.14	1.38	14.59	14.59	2.00	19.59	5.00	34.3%
		500	11.14	1.38	18.04	14.59	2.00	24.59	6.55	36.3%
		750	11.14	1.38	21.49	14.59	2.00	29.59	8.10	37.7%
		1,000	11.14	1.38	24.94	14.59	2.00	34.59	9.65	38.7%
GSe	Brighton	100	10.99	1.35	12.34	13.63	2.00	15.63	3.29	26.7%
		250	10.99	1.35	14.37	13.63	2.00	18.63	4.27	29.7%
		500	10.99	1.35	17.74	13.63	2.00	23.63	5.89	33.2%
		750	10.99	1.35	21.12	13.63	2.00	28.63	7.52	35.6%
		1,000	10.99	1.35	24.49	13.63	2.00	33.63	9.14	37.3%
GSe	Brockville	100	10.37	0.78	11.15	13.79	2.00	15.79	4.64	41.6%
		250	10.37	0.78	12.32	13.79	2.00	18.79	6.47	52.5%
		500	10.37	0.78	14.27	13.79	2.00	23.79	9.52	66.7%
		750	10.37	0.78	16.22	13.79	2.00	28.79	12.57	77.5%
		1,000	10.37	0.78	18.17	13.79	2.00	33.79	15.62	85.9%

New Rate Class: Gse - Unmetered

Bill Impacts of Proposed Distribution Rates exclude Riders

Classes		Scenario	Existing Dx Rates			Proposed Dx Rates			$ Incr	% Incr
			SrChg [$/month]	base [c/kWh]	Dx bill [$/month]	SrChg [$/month]	base [c/kWh]	Dx bill [$/month]		
New Class	**Old Class**	kWh								
GSe	**Caledon CH**	100	11.63	1.80	13.43	14.47	2.00	16.47	3.04	22.6%
		250	11.63	1.80	16.13	14.47	2.00	19.47	3.34	20.7%
		500	11.63	1.80	20.63	14.47	2.00	24.47	3.84	18.6%
		750	11.63	1.80	25.13	14.47	2.00	29.47	4.34	17.3%
		1,000	11.63	1.80	29.63	14.47	2.00	34.47	4.84	16.3%
GSe	**Campbellford-Seymour**	100	7.63	1.19	8.82	11.47	2.00	13.47	4.65	52.7%
		250	7.63	1.19	10.61	11.47	2.00	16.47	5.87	55.3%
		500	7.63	1.19	13.58	11.47	2.00	21.47	7.89	58.1%
		750	7.63	1.19	16.56	11.47	2.00	26.47	9.92	59.9%
		1,000	7.63	1.19	19.53	11.47	2.00	31.47	11.94	61.1%
GSe	**Carleton Place**	100	11.36	1.68	13.04	14.54	2.00	16.54	3.50	26.8%
		250	11.36	1.68	15.56	14.54	2.00	19.54	3.98	25.6%
		500	11.36	1.68	19.76	14.54	2.00	24.54	4.78	24.2%
		750	11.36	1.68	23.96	14.54	2.00	29.54	5.58	23.3%
		1,000	11.36	1.68	28.16	14.54	2.00	34.54	6.38	22.6%
GSe	**Cavan-Millbrook-North Monaghan**	100	10.68	1.50	12.18	13.71	2.00	15.71	3.53	29.0%
		250	10.68	1.50	14.43	13.71	2.00	18.71	4.28	29.6%
		500	10.68	1.50	18.18	13.71	2.00	23.71	5.53	30.4%
		750	10.68	1.50	21.93	13.71	2.00	28.71	6.78	30.9%
		1,000	10.68	1.50	25.68	13.71	2.00	33.71	8.03	31.3%
GSe	**Centre Hastings**	100	8.73	0.97	9.70	12.20	2.00	14.20	4.50	46.3%
		250	8.73	0.97	11.16	12.20	2.00	17.20	6.04	54.1%
		500	8.73	0.97	13.58	12.20	2.00	22.20	8.62	63.4%
		750	8.73	0.97	16.01	12.20	2.00	27.20	11.19	69.9%
		1,000	8.73	0.97	18.43	12.20	2.00	32.20	13.77	74.7%

New Rate Class: Gse - Unmetered

Bill Impacts of Proposed Distribution Rates exclude Riders

Classes		Scenario	Existing Dx Rates			Proposed Dx Rates			$ Incr	% Incr
			SrChg	base	Dx bill	SrChg	base	Dx bill		
New Class	Old Class	kWh	[$/month]	[c/kWh]	[$/month]	[$/month]	[c/kWh]	[$/month]		
GSe	Chalk River	100	10.20	1.79	11.99	13.83	2.00	15.83	3.84	32.0%
		250	10.20	1.79	14.68	13.83	2.00	18.83	4.15	28.3%
		500	10.20	1.79	19.15	13.83	2.00	23.83	4.68	24.4%
		750	10.20	1.79	23.63	13.83	2.00	28.83	5.20	22.0%
		1,000	10.20	1.79	28.10	13.83	2.00	33.83	5.73	20.4%
GSe	Champlain	100	9.83	0.91	10.74	12.92	2.00	14.92	4.18	38.9%
		250	9.83	0.91	12.11	12.92	2.00	17.92	5.82	48.0%
		500	9.83	0.91	14.38	12.92	2.00	22.92	8.54	59.4%
		750	9.83	0.91	16.66	12.92	2.00	27.92	11.27	67.6%
		1,000	9.83	0.91	18.93	12.92	2.00	32.92	13.99	73.9%
GSe	Cobden	100	10.50	2.13	12.63	13.75	2.00	15.75	3.12	24.7%
		250	10.50	2.13	15.83	13.75	2.00	18.75	2.93	18.5%
		500	10.50	2.13	21.15	13.75	2.00	23.75	2.60	12.3%
		750	10.50	2.13	26.48	13.75	2.00	28.75	2.28	8.6%
		1,000	10.50	2.13	31.80	13.75	2.00	33.75	1.95	6.1%
GSe	Deep River	100	11.50	2.26	13.76	14.50	2.00	16.50	2.74	19.9%
		250	11.50	2.26	17.15	14.50	2.00	19.50	2.35	13.7%
		500	11.50	2.26	22.80	14.50	2.00	24.50	1.70	7.5%
		750	11.50	2.26	28.45	14.50	2.00	29.50	1.05	3.7%
		1,000	11.50	2.26	34.10	14.50	2.00	34.50	0.40	1.2%
GSe	Deseronto	100	4.61	1.35	5.96	9.23	2.00	11.23	5.27	88.3%
		250	4.61	1.35	7.99	9.23	2.00	14.23	6.24	78.1%
		500	4.61	1.35	11.36	9.23	2.00	19.23	7.87	69.2%
		750	4.61	1.35	14.74	9.23	2.00	24.23	9.49	64.4%
		1,000	4.61	1.35	18.11	9.23	2.00	29.23	11.12	61.4%

New Rate Class: Gse - Unmetered

Bill Impacts of Proposed Distribution Rates exclude Riders

Classes		Scenario	Existing Dx Rates			Proposed Dx Rates			$ Incr	% Incr
			SrChg	base	Dx bill	SrChg	base	Dx bill		
New Class	Old Class	kWh	[$/month]	[c/kWh]	[$/month]	[$/month]	[c/kWh]	[$/month]		
GSe	Dryden	100	9.09	1.03	10.12	13.11	2.00	15.11	4.99	49.3%
		250	9.09	1.03	11.67	13.11	2.00	18.11	6.44	55.2%
		500	9.09	1.03	14.24	13.11	2.00	23.11	8.87	62.3%
		750	9.09	1.03	16.82	13.11	2.00	28.11	11.29	67.1%
		1,000	9.09	1.03	19.39	13.11	2.00	33.11	13.72	70.7%
GSe	Dundalk	100	11.32	1.64	12.96	14.55	2.00	16.55	3.59	27.7%
		250	11.32	1.64	15.42	14.55	2.00	19.55	4.13	26.8%
		500	11.32	1.64	19.52	14.55	2.00	24.55	5.03	25.8%
		750	11.32	1.64	23.62	14.55	2.00	29.55	5.93	25.1%
		1,000	11.32	1.64	27.72	14.55	2.00	34.55	6.83	24.6%
GSe	Durham	100	11.59	1.37	12.96	14.48	2.00	16.48	3.52	27.2%
		250	11.59	1.37	15.02	14.48	2.00	19.48	4.47	29.7%
		500	11.59	1.37	18.44	14.48	2.00	24.48	6.04	32.8%
		750	11.59	1.37	21.87	14.48	2.00	29.48	7.62	34.8%
		1,000	11.59	1.37	25.29	14.48	2.00	34.48	9.19	36.3%
GSe	Eganville	100	10.22	2.32	12.54	13.82	2.00	15.82	3.28	26.2%
		250	10.22	2.32	16.02	13.82	2.00	18.82	2.80	17.5%
		500	10.22	2.32	21.82	13.82	2.00	23.82	2.00	9.2%
		750	10.22	2.32	27.62	13.82	2.00	28.82	1.20	4.4%
		1,000	10.22	2.32	33.42	13.82	2.00	33.82	0.40	1.2%
GSe	Erin	100	19.72	0.73	20.45	20.45	2.00	22.45	2.00	9.8%
		250	19.72	0.73	21.55	20.45	2.00	25.45	3.90	18.1%
		500	19.72	0.73	23.37	20.45	2.00	30.45	7.08	30.3%
		750	19.72	0.73	25.20	20.45	2.00	35.45	10.25	40.7%
		1,000	19.72	0.73	27.02	20.45	2.00	40.45	13.43	49.7%

New Rate Class: Gse - Unmetered

Bill Impacts of Proposed Distribution Rates exclude Riders

Classes		Scenario	Existing Dx Rates			Proposed Dx Rates			$ Incr	% Incr
			SrChg [$/month]	base [c/kWh]	Dx bill [$/month]	SrChg [$/month]	base [c/kWh]	Dx bill [$/month]		
New Class	Old Class	kWh								
GSe	Exeter	100	5.21	1.30	6.51	10.08	2.00	12.08	5.57	85.5%
		250	5.21	1.30	8.46	10.08	2.00	15.08	6.62	78.2%
		500	5.21	1.30	11.71	10.08	2.00	20.08	8.37	71.4%
		750	5.21	1.30	14.96	10.08	2.00	25.08	10.12	67.6%
		1,000	5.21	1.30	18.21	10.08	2.00	30.08	11.87	65.2%
GSe	Fenelon Falls	100	9.43	0.95	10.38	13.02	2.00	15.02	4.64	44.7%
		250	9.43	0.95	11.81	13.02	2.00	18.02	6.22	52.6%
		500	9.43	0.95	14.18	13.02	2.00	23.02	8.84	62.3%
		750	9.43	0.95	16.56	13.02	2.00	28.02	11.47	69.3%
		1,000	9.43	0.95	18.93	13.02	2.00	33.02	14.09	74.4%
GSe	Forest	100	11.98	1.18	13.16	14.38	2.00	16.38	3.22	24.5%
		250	11.98	1.18	14.93	14.38	2.00	19.38	4.45	29.8%
		500	11.98	1.18	17.88	14.38	2.00	24.38	6.50	36.4%
		750	11.98	1.18	20.83	14.38	2.00	29.38	8.55	41.1%
		1,000	11.98	1.18	23.78	14.38	2.00	34.38	10.60	44.6%
GSe	GBE	100	4.92	1.14	6.06	9.15	2.00	11.15	5.09	84.0%
		250	4.92	1.14	7.77	9.15	2.00	14.15	6.38	82.1%
		500	4.92	1.14	10.62	9.15	2.00	19.15	8.53	80.3%
		750	4.92	1.14	13.47	9.15	2.00	24.15	10.68	79.3%
		1,000	4.92	1.14	16.32	9.15	2.00	29.15	12.83	78.6%
GSe	Georgina	100	8.24	1.62	9.86	12.32	2.00	14.32	4.46	45.2%
		250	8.24	1.62	12.29	12.32	2.00	17.32	5.03	40.9%
		500	8.24	1.62	16.34	12.32	2.00	22.32	5.98	36.6%
		750	8.24	1.62	20.39	12.32	2.00	27.32	6.93	34.0%
		1,000	8.24	1.62	24.44	12.32	2.00	32.32	7.88	32.2%

New Rate Class: Gse - Unmetered

Bill Impacts of Proposed Distribution Rates exclude Riders

Classes		Scenario	Existing Dx Rates			Proposed Dx Rates			$ Incr	% Incr
			SrChg	base	Dx bill	SrChg	base	Dx bill		
New Class	Old Class	kWh	[$/month]	[c/kWh]	[$/month]	[$/month]	[c/kWh]	[$/month]		
GSe	Glencoe	100	5.21	0.81	6.02	10.08	2.00	12.08	6.06	100.6%
		250	5.21	0.81	7.24	10.08	2.00	15.08	7.84	108.4%
		500	5.21	0.81	9.26	10.08	2.00	20.08	10.82	116.8%
		750	5.21	0.81	11.29	10.08	2.00	25.08	13.79	122.2%
		1,000	5.21	0.81	13.31	10.08	2.00	30.08	16.77	126.0%
GSe	Grand Bend	100	10.63	1.23	11.86	13.72	2.00	15.72	3.86	32.5%
		250	10.63	1.23	13.71	13.72	2.00	18.72	5.02	36.6%
		500	10.63	1.23	16.78	13.72	2.00	23.72	6.94	41.4%
		750	10.63	1.23	19.86	13.72	2.00	28.72	8.87	44.6%
		1,000	10.63	1.23	22.93	13.72	2.00	33.72	10.79	47.1%
GSe	Hastings	100	10.98	1.69	12.67	13.63	2.00	15.63	2.96	23.4%
		250	10.98	1.69	15.21	13.63	2.00	18.63	3.43	22.5%
		500	10.98	1.69	19.43	13.63	2.00	23.63	4.20	21.6%
		750	10.98	1.69	23.66	13.63	2.00	28.63	4.98	21.0%
		1,000	10.98	1.69	27.88	13.63	2.00	33.63	5.75	20.6%
GSe	Havelock	100	10.63	1.52	12.15	13.72	2.00	15.72	3.57	29.4%
		250	10.63	1.52	14.43	13.72	2.00	18.72	4.29	29.7%
		500	10.63	1.52	18.23	13.72	2.00	23.72	5.49	30.1%
		750	10.63	1.52	22.03	13.72	2.00	28.72	6.69	30.4%
		1,000	10.63	1.52	25.83	13.72	2.00	33.72	7.89	30.5%
GSe	Kirkfield	100	6.88	1.95	8.83	10.66	2.00	12.66	3.83	43.3%
		250	6.88	1.95	11.76	10.66	2.00	15.66	3.90	33.2%
		500	6.88	1.95	16.63	10.66	2.00	20.66	4.03	24.2%
		750	6.88	1.95	21.51	10.66	2.00	25.66	4.15	19.3%
		1,000	6.88	1.95	26.38	10.66	2.00	30.66	4.28	16.2%

New Rate Class: Gse - Unmetered

Bill Impacts of Proposed Distribution Rates exclude Riders

Classes		Scenario	Existing Dx Rates			Proposed Dx Rates			$ Incr	% Incr
			SrChg [$/month]	base [c/kWh]	Dx bill [$/month]	SrChg [$/month]	base [c/kWh]	Dx bill [$/month]		
New Class	**Old Class**	kWh								
GSe	**Lanark Highlands**	100	8.75	1.99	10.74	12.19	2.00	14.19	3.45	32.1%
		250	8.75	1.99	13.73	12.19	2.00	17.19	3.47	25.2%
		500	8.75	1.99	18.70	12.19	2.00	22.19	3.49	18.7%
		750	8.75	1.99	23.68	12.19	2.00	27.19	3.52	14.8%
		1,000	8.75	1.99	28.65	12.19	2.00	32.19	3.54	12.4%
GSe	**Larder Lake**	100	9.62	1.58	11.20	12.97	2.00	14.97	3.77	33.7%
		250	9.62	1.58	13.57	12.97	2.00	17.97	4.40	32.4%
		500	9.62	1.58	17.52	12.97	2.00	22.97	5.45	31.1%
		750	9.62	1.58	21.47	12.97	2.00	27.97	6.50	30.3%
		1,000	9.62	1.58	25.42	12.97	2.00	32.97	7.55	29.7%
GSe	**Latchford**	100	0.97	1.02	1.99	6.14	2.00	8.14	6.15	308.8%
		250	0.97	1.02	3.52	6.14	2.00	11.14	7.62	216.3%
		500	0.97	1.02	6.07	6.14	2.00	16.14	10.07	165.8%
		750	0.97	1.02	8.62	6.14	2.00	21.14	12.52	145.2%
		1,000	0.97	1.02	11.17	6.14	2.00	26.14	14.97	134.0%
GSe	**Lindsay**	100	11.50	1.38	12.88	14.50	2.00	16.50	3.62	28.1%
		250	11.50	1.38	14.95	14.50	2.00	19.50	4.55	30.5%
		500	11.50	1.38	18.40	14.50	2.00	24.50	6.10	33.2%
		750	11.50	1.38	21.85	14.50	2.00	29.50	7.65	35.0%
		1,000	11.50	1.38	25.30	14.50	2.00	34.50	9.20	36.4%
GSe	**Lucan Granton**	100	8.03	1.47	9.50	12.37	2.00	14.37	4.87	51.3%
		250	8.03	1.47	11.71	12.37	2.00	17.37	5.67	48.4%
		500	8.03	1.47	15.38	12.37	2.00	22.37	6.99	45.5%
		750	8.03	1.47	19.06	12.37	2.00	27.37	8.32	43.6%
		1,000	8.03	1.47	22.73	12.37	2.00	32.37	9.64	42.4%

New Rate Class: Gse - Unmetered

Bill Impacts of Proposed Distribution Rates exclude Riders

Classes		Scenario	Existing Dx Rates			Proposed Dx Rates			$ Incr	% Incr
			SrChg [$/month]	base [c/kWh]	Dx bill [$/month]	SrChg [$/month]	base [c/kWh]	Dx bill [$/month]		
New Class	**Old Class**	kWh								
GSe	**Malahide**	100	7.45	1.98	9.43	11.52	2.00	13.52	4.09	43.3%
		250	7.45	1.98	12.40	11.52	2.00	16.52	4.12	33.2%
		500	7.45	1.98	17.35	11.52	2.00	21.52	4.17	24.0%
		750	7.45	1.98	22.30	11.52	2.00	26.52	4.22	18.9%
		1,000	7.45	1.98	27.25	11.52	2.00	31.52	4.27	15.7%
GSe	**Mapleton**	100	10.32	1.71	12.03	13.80	2.00	15.80	3.77	31.3%
		250	10.32	1.71	14.60	13.80	2.00	18.80	4.20	28.8%
		500	10.32	1.71	18.87	13.80	2.00	23.80	4.93	26.1%
		750	10.32	1.71	23.15	13.80	2.00	28.80	5.65	24.4%
		1,000	10.32	1.71	27.42	13.80	2.00	33.80	6.38	23.3%
GSe	**Markdale**	100	11.04	0.80	11.84	14.62	2.00	16.62	4.78	40.4%
		250	11.04	0.80	13.04	14.62	2.00	19.62	6.58	50.4%
		500	11.04	0.80	15.04	14.62	2.00	24.62	9.58	63.7%
		750	11.04	0.80	17.04	14.62	2.00	29.62	12.58	73.8%
		1,000	11.04	0.80	19.04	14.62	2.00	34.62	15.58	81.8%
GSe	**Marmora**	100	4.54	1.05	5.59	9.24	2.00	11.24	5.65	101.1%
		250	4.54	1.05	7.17	9.24	2.00	14.24	7.08	98.8%
		500	4.54	1.05	9.79	9.24	2.00	19.24	9.45	96.6%
		750	4.54	1.05	12.42	9.24	2.00	24.24	11.83	95.3%
		1,000	4.54	1.05	15.04	9.24	2.00	29.24	14.20	94.4%
GSe	**McGarry**	100	9.52	2.00	11.52	13.00	2.00	15.00	3.48	30.2%
		250	9.52	2.00	14.52	13.00	2.00	18.00	3.48	24.0%
		500	9.52	2.00	19.52	13.00	2.00	23.00	3.48	17.8%
		750	9.52	2.00	24.52	13.00	2.00	28.00	3.48	14.2%
		1,000	9.52	2.00	29.52	13.00	2.00	33.00	3.48	11.8%

New Rate Class: Gse - Unmetered

Bill Impacts of Proposed Distribution Rates exclude Riders

Classes		Scenario	Existing Dx Rates			Proposed Dx Rates			$ Incr	% Incr
			SrChg [$/month]	base [c/kWh]	Dx bill [$/month]	SrChg [$/month]	base [c/kWh]	Dx bill [$/month]		
New Class	**Old Class**	kWh								
GSe	**Meaford**	100	11.55	1.23	12.78	14.49	2.00	16.49	3.71	29.0%
		250	11.55	1.23	14.63	14.49	2.00	19.49	4.87	33.3%
		500	11.55	1.23	17.70	14.49	2.00	24.49	6.79	38.4%
		750	11.55	1.23	20.78	14.49	2.00	29.49	8.72	42.0%
		1,000	11.55	1.23	23.85	14.49	2.00	34.49	10.64	44.6%
GSe	**Middlesex Centre**	100	8.21	1.37	9.58	12.33	2.00	14.33	4.75	49.5%
		250	8.21	1.37	11.64	12.33	2.00	17.33	5.69	48.9%
		500	8.21	1.37	15.06	12.33	2.00	22.33	7.27	48.2%
		750	8.21	1.37	18.49	12.33	2.00	27.33	8.84	47.8%
		1,000	8.21	1.37	21.91	12.33	2.00	32.33	10.42	47.5%
GSe	**Napanee**	100	10.62	1.28	11.90	13.72	2.00	15.72	3.82	32.1%
		250	10.62	1.28	13.82	13.72	2.00	18.72	4.90	35.5%
		500	10.62	1.28	17.02	13.72	2.00	23.72	6.70	39.4%
		750	10.62	1.28	20.22	13.72	2.00	28.72	8.50	42.1%
		1,000	10.62	1.28	23.42	13.72	2.00	33.72	10.30	44.0%
GSe	**Nipigon**	100	11.19	1.05	12.24	14.58	2.00	16.58	4.34	35.5%
		250	11.19	1.05	13.82	14.58	2.00	19.58	5.77	41.7%
		500	11.19	1.05	16.44	14.58	2.00	24.58	8.14	49.5%
		750	11.19	1.05	19.07	14.58	2.00	29.58	10.52	55.2%
		1,000	11.19	1.05	21.69	14.58	2.00	34.58	12.89	59.4%
GSe	**North Dorchester**	100	7.47	0.90	8.37	11.51	2.00	13.51	5.14	61.4%
		250	7.47	0.90	9.72	11.51	2.00	16.51	6.79	69.9%
		500	7.47	0.90	11.97	11.51	2.00	21.51	9.54	79.7%
		750	7.47	0.90	14.22	11.51	2.00	26.51	12.29	86.4%
		1,000	7.47	0.90	16.47	11.51	2.00	31.51	15.04	91.3%

New Rate Class: Gse - Unmetered

Bill Impacts of Proposed Distribution Rates exclude Riders

Classes		Scenario	Existing Dx Rates			Proposed Dx Rates			$ Incr	% Incr
			SrChg [$/month]	base [c/kWh]	Dx bill [$/month]	SrChg [$/month]	base [c/kWh]	Dx bill [$/month]		
New Class	**Old Class**	kWh								
GSe	**North Dundas**	100	6.29	0.83	7.12	10.81	2.00	12.81	5.69	79.8%
		250	6.29	0.83	8.37	10.81	2.00	15.81	7.44	88.9%
		500	6.29	0.83	10.44	10.81	2.00	20.81	10.37	99.3%
		750	6.29	0.83	12.52	10.81	2.00	25.81	13.29	106.2%
		1,000	6.29	0.83	14.59	10.81	2.00	30.81	16.22	111.1%
GSe	**North Glengarry**	100	8.40	0.90	9.30	12.28	2.00	14.28	4.98	53.5%
		250	8.40	0.90	10.65	12.28	2.00	17.28	6.63	62.2%
		500	8.40	0.90	12.90	12.28	2.00	22.28	9.38	72.7%
		750	8.40	0.90	15.15	12.28	2.00	27.28	12.13	80.1%
		1,000	8.40	0.90	17.40	12.28	2.00	32.28	14.88	85.5%
GSe	**North Grenville**	100	9.74	1.71	11.45	12.94	2.00	14.94	3.49	30.5%
		250	9.74	1.71	14.02	12.94	2.00	17.94	3.93	28.0%
		500	9.74	1.71	18.29	12.94	2.00	22.94	4.65	25.4%
		750	9.74	1.71	22.57	12.94	2.00	27.94	5.38	23.8%
		1,000	9.74	1.71	26.84	12.94	2.00	32.94	6.10	22.7%
GSe	**North Perth**	100	14.30	1.00	15.30	16.80	2.00	18.80	3.50	22.9%
		250	14.30	1.00	16.80	16.80	2.00	21.80	5.00	29.8%
		500	14.30	1.00	19.30	16.80	2.00	26.80	7.50	38.9%
		750	14.30	1.00	21.80	16.80	2.00	31.80	10.00	45.9%
		1,000	14.30	1.00	24.30	16.80	2.00	36.80	12.50	51.5%
GSe	**North Stormont**	100	2.22	0.78	3.00	7.82	2.00	9.82	6.82	227.4%
		250	2.22	0.78	4.17	7.82	2.00	12.82	8.65	207.5%
		500	2.22	0.78	6.12	7.82	2.00	17.82	11.70	191.2%
		750	2.22	0.78	8.07	7.82	2.00	22.82	14.75	182.8%
		1,000	2.22	0.78	10.02	7.82	2.00	27.82	17.80	177.7%

New Rate Class: Gse - Unmetered

Bill Impacts of Proposed Distribution Rates exclude Riders

Classes		Scenario	Existing Dx Rates			Proposed Dx Rates			$ Incr	% Incr
			SrChg [$/month]	base [c/kWh]	Dx bill [$/month]	SrChg [$/month]	base [c/kWh]	Dx bill [$/month]		
New Class	Old Class	kWh								
GSe	Omemee	100	10.18	1.47	11.65	13.83	2.00	15.83	4.18	35.9%
		250	10.18	1.47	13.86	13.83	2.00	18.83	4.98	35.9%
		500	10.18	1.47	17.53	13.83	2.00	23.83	6.30	36.0%
		750	10.18	1.47	21.21	13.83	2.00	28.83	7.63	36.0%
		1,000	10.18	1.47	24.88	13.83	2.00	33.83	8.95	36.0%
GSe	Perth	100	9.49	0.92	10.41	13.01	2.00	15.01	4.60	44.1%
		250	9.49	0.92	11.79	13.01	2.00	18.01	6.22	52.7%
		500	9.49	0.92	14.09	13.01	2.00	23.01	8.92	63.3%
		750	9.49	0.92	16.39	13.01	2.00	28.01	11.62	70.9%
		1,000	9.49	0.92	18.69	13.01	2.00	33.01	14.32	76.6%
GSe	Perth East	100	6.86	1.29	8.15	10.66	2.00	12.66	4.51	55.4%
		250	6.86	1.29	10.09	10.66	2.00	15.66	5.58	55.3%
		500	6.86	1.29	13.31	10.66	2.00	20.66	7.35	55.2%
		750	6.86	1.29	16.54	10.66	2.00	25.66	9.13	55.2%
		1,000	6.86	1.29	19.76	10.66	2.00	30.66	10.90	55.2%
GSe	Prince Edward	100	10.96	1.42	12.38	13.64	2.00	15.64	3.26	26.3%
		250	10.96	1.42	14.51	13.64	2.00	18.64	4.13	28.4%
		500	10.96	1.42	18.06	13.64	2.00	23.64	5.58	30.9%
		750	10.96	1.42	21.61	13.64	2.00	28.64	7.03	32.5%
		1,000	10.96	1.42	25.16	13.64	2.00	33.64	8.48	33.7%
GSe	Quinte West	100	1.41	1.05	2.46	7.03	2.00	9.03	6.57	266.9%
		250	1.41	1.05	4.04	7.03	2.00	12.03	7.99	198.0%
		500	1.41	1.05	6.66	7.03	2.00	17.03	10.37	155.6%
		750	1.41	1.05	9.29	7.03	2.00	22.03	12.74	137.2%
		1,000	1.41	1.05	11.91	7.03	2.00	27.03	15.12	126.9%

New Rate Class: Gse - Unmetered

Bill Impacts of Proposed Distribution Rates exclude Riders

Classes		Scenario	Existing Dx Rates			Proposed Dx Rates			$ Incr	% Incr
			SrChg [$/month]	base [c/kWh]	Dx bill [$/month]	SrChg [$/month]	base [c/kWh]	Dx bill [$/month]		
New Class	**Old Class**	kWh								
GSe	**Rainy River**	100	9.18	1.76	10.94	13.08	2.00	15.08	4.14	37.9%
		250	9.18	1.76	13.58	13.08	2.00	18.08	4.50	33.2%
		500	9.18	1.76	17.98	13.08	2.00	23.08	5.10	28.4%
		750	9.18	1.76	22.38	13.08	2.00	28.08	5.70	25.5%
		1,000	9.18	1.76	26.78	13.08	2.00	33.08	6.30	23.5%
GSe	**Ramara**	100	10.02	1.06	11.08	13.87	2.00	15.87	4.79	43.3%
		250	10.02	1.06	12.67	13.87	2.00	18.87	6.20	49.0%
		500	10.02	1.06	15.32	13.87	2.00	23.87	8.55	55.8%
		750	10.02	1.06	17.97	13.87	2.00	28.87	10.90	60.7%
		1,000	10.02	1.06	20.62	13.87	2.00	33.87	13.25	64.3%
GSe	**Red Rock**	100	10.36	1.94	12.30	13.79	2.00	15.79	3.49	28.4%
		250	10.36	1.94	15.21	13.79	2.00	18.79	3.58	23.5%
		500	10.36	1.94	20.06	13.79	2.00	23.79	3.73	18.6%
		750	10.36	1.94	24.91	13.79	2.00	28.79	3.88	15.6%
		1,000	10.36	1.94	29.76	13.79	2.00	33.79	4.03	13.5%
GSe	**Rockland**	100	3.16	1.00	4.16	8.59	2.00	10.59	6.43	154.5%
		250	3.16	1.00	5.66	8.59	2.00	13.59	7.93	140.1%
		500	3.16	1.00	8.16	8.59	2.00	18.59	10.43	127.8%
		750	3.16	1.00	10.66	8.59	2.00	23.59	12.93	121.3%
		1,000	3.16	1.00	13.16	8.59	2.00	28.59	15.43	117.2%
GSe	**Russell**	100	9.17	2.24	11.41	13.09	2.00	15.09	3.68	32.2%
		250	9.17	2.24	14.77	13.09	2.00	18.09	3.32	22.4%
		500	9.17	2.24	20.37	13.09	2.00	23.09	2.72	13.3%
		750	9.17	2.24	25.97	13.09	2.00	28.09	2.12	8.1%
		1,000	9.17	2.24	31.57	13.09	2.00	33.09	1.52	4.8%

New Rate Class: Gse - Unmetered

Bill Impacts of Proposed Distribution Rates exclude Riders

Classes		Scenario	Existing Dx Rates			Proposed Dx Rates			$ Incr	% Incr
			SrChg [$/month]	base [c/kWh]	Dx bill [$/month]	SrChg [$/month]	base [c/kWh]	Dx bill [$/month]		
New Class	**Old Class**	kWh								
GSe	**Schreiber**	100	9.88	2.51	12.39	12.91	2.00	14.91	2.52	20.3%
		250	9.88	2.51	16.16	12.91	2.00	17.91	1.75	10.8%
		500	9.88	2.51	22.43	12.91	2.00	22.91	0.48	2.1%
		750	9.88	2.51	28.71	12.91	2.00	27.91	(0.80)	-2.8%
		1,000	9.88	2.51	34.98	12.91	2.00	32.91	(2.07)	-5.9%
GSe	**Severn**	100	10.62	1.06	11.68	13.72	2.00	15.72	4.04	34.6%
		250	10.62	1.06	13.27	13.72	2.00	18.72	5.45	41.1%
		500	10.62	1.06	15.92	13.72	2.00	23.72	7.80	49.0%
		750	10.62	1.06	18.57	13.72	2.00	28.72	10.15	54.7%
		1,000	10.62	1.06	21.22	13.72	2.00	33.72	12.50	58.9%
GSe	**Shelburne**	100	9.53	0.87	10.40	13.00	2.00	15.00	4.60	44.2%
		250	9.53	0.87	11.71	13.00	2.00	18.00	6.29	53.7%
		500	9.53	0.87	13.88	13.00	2.00	23.00	9.12	65.7%
		750	9.53	0.87	16.06	13.00	2.00	28.00	11.94	74.4%
		1,000	9.53	0.87	18.23	13.00	2.00	33.00	14.77	81.0%
GSe	**Smiths Falls**	100	4.46	1.05	5.51	9.26	2.00	11.26	5.75	104.4%
		250	4.46	1.05	7.09	9.26	2.00	14.26	7.18	101.3%
		500	4.46	1.05	9.71	9.26	2.00	19.26	9.55	98.4%
		750	4.46	1.05	12.34	9.26	2.00	24.26	11.93	96.7%
		1,000	4.46	1.05	14.96	9.26	2.00	29.26	14.30	95.6%
GSe	**South Glengarry**	100	8.25	0.75	9.00	12.32	2.00	14.32	5.32	59.1%
		250	8.25	0.75	10.13	12.32	2.00	17.32	7.19	71.0%
		500	8.25	0.75	12.00	12.32	2.00	22.32	10.32	86.0%
		750	8.25	0.75	13.88	12.32	2.00	27.32	13.44	96.9%
		1,000	8.25	0.75	15.75	12.32	2.00	32.32	16.57	105.2%

New Rate Class: Gse - Unmetered

Bill Impacts of Proposed Distribution Rates exclude Riders

Classes		Scenario	Existing Dx Rates			Proposed Dx Rates			$ Incr	% Incr
			SrChg [$/month]	base [c/kWh]	Dx bill [$/month]	SrChg [$/month]	base [c/kWh]	Dx bill [$/month]		
New Class	**Old Class**	kWh								
GSe	**South River**	100	10.59	1.58	12.17	13.73	2.00	15.73	3.56	29.3%
		250	10.59	1.58	14.54	13.73	2.00	18.73	4.19	28.8%
		500	10.59	1.58	18.49	13.73	2.00	23.73	5.24	28.3%
		750	10.59	1.58	22.44	13.73	2.00	28.73	6.29	28.0%
		1,000	10.59	1.58	26.39	13.73	2.00	33.73	7.34	27.8%
GSe	**Springwater**	100	9.80	1.07	10.87	12.93	2.00	14.93	4.06	37.3%
		250	9.80	1.07	12.48	12.93	2.00	17.93	5.45	43.7%
		500	9.80	1.07	15.15	12.93	2.00	22.93	7.78	51.3%
		750	9.80	1.07	17.83	12.93	2.00	27.93	10.10	56.7%
		1,000	9.80	1.07	20.50	12.93	2.00	32.93	12.43	60.6%
GSe	**Stirling-Rawdon**	100	11.59	1.30	12.89	14.48	2.00	16.48	3.59	27.9%
		250	11.59	1.30	14.84	14.48	2.00	19.48	4.64	31.3%
		500	11.59	1.30	18.09	14.48	2.00	24.48	6.39	35.3%
		750	11.59	1.30	21.34	14.48	2.00	29.48	8.14	38.1%
		1,000	11.59	1.30	24.59	14.48	2.00	34.48	9.89	40.2%
GSe	**Thedford**	100	8.45	1.06	9.51	12.27	2.00	14.27	4.76	50.0%
		250	8.45	1.06	11.10	12.27	2.00	17.27	6.17	55.5%
		500	8.45	1.06	13.75	12.27	2.00	22.27	8.52	61.9%
		750	8.45	1.06	16.40	12.27	2.00	27.27	10.87	66.3%
		1,000	8.45	1.06	19.05	12.27	2.00	32.27	13.22	69.4%
GSe	**Thessalon**	100	8.99	1.55	10.54	12.13	2.00	14.13	3.59	34.1%
		250	8.99	1.55	12.87	12.13	2.00	17.13	4.27	33.2%
		500	8.99	1.55	16.74	12.13	2.00	22.13	5.39	32.2%
		750	8.99	1.55	20.62	12.13	2.00	27.13	6.52	31.6%
		1,000	8.99	1.55	24.49	12.13	2.00	32.13	7.64	31.2%

New Rate Class: Gse - Unmetered

Bill Impacts of Proposed Distribution Rates exclude Riders

Classes		Scenario	Existing Dx Rates			Proposed Dx Rates			$ Incr	% Incr
			SrChg [$/month]	base [c/kWh]	Dx bill [$/month]	SrChg [$/month]	base [c/kWh]	Dx bill [$/month]		
New Class	**Old Class**	kWh								
GSe	**Thorndale**	100	6.79	1.02	7.81	10.68	2.00	12.68	4.87	62.4%
		250	6.79	1.02	9.34	10.68	2.00	15.68	6.34	67.9%
		500	6.79	1.02	11.89	10.68	2.00	20.68	8.79	73.9%
		750	6.79	1.02	14.44	10.68	2.00	25.68	11.24	77.8%
		1,000	6.79	1.02	16.99	10.68	2.00	30.68	13.69	80.6%
GSe	**Thorold**	100	10.85	1.50	12.35	13.67	2.00	15.67	3.32	26.8%
		250	10.85	1.50	14.60	13.67	2.00	18.67	4.07	27.8%
		500	10.85	1.50	18.35	13.67	2.00	23.67	5.32	29.0%
		750	10.85	1.50	22.10	13.67	2.00	28.67	6.57	29.7%
		1,000	10.85	1.50	25.85	13.67	2.00	33.67	7.82	30.2%
GSe	**Tweed**	100	3.67	0.97	4.64	8.46	2.00	10.46	5.82	125.4%
		250	3.67	0.97	6.10	8.46	2.00	13.46	7.37	120.8%
		500	3.67	0.97	8.52	8.46	2.00	18.46	9.94	116.7%
		750	3.67	0.97	10.95	8.46	2.00	23.46	12.52	114.3%
		1,000	3.67	0.97	13.37	8.46	2.00	28.46	15.09	112.9%
GSe	**Wardsville**	100	5.70	1.00	6.70	9.95	2.00	11.95	5.25	78.4%
		250	5.70	1.00	8.20	9.95	2.00	14.95	6.75	82.4%
		500	5.70	1.00	10.70	9.95	2.00	19.95	9.25	86.5%
		750	5.70	1.00	13.20	9.95	2.00	24.95	11.75	89.0%
		1,000	5.70	1.00	15.70	9.95	2.00	29.95	14.25	90.8%
GSe	**Warkworth**	100	10.20	1.52	11.72	13.83	2.00	15.83	4.11	35.0%
		250	10.20	1.52	14.00	13.83	2.00	18.83	4.83	34.5%
		500	10.20	1.52	17.80	13.83	2.00	23.83	6.03	33.9%
		750	10.20	1.52	21.60	13.83	2.00	28.83	7.23	33.5%
		1,000	10.20	1.52	25.40	13.83	2.00	33.83	8.43	33.2%

New Rate Class: Gse - Unmetered

Bill Impacts of Proposed Distribution Rates exclude Riders

Classes		Scenario	Existing Dx Rates			Proposed Dx Rates			$ Incr	% Incr
			SrChg [$/month]	base [c/kWh]	Dx bill [$/month]	SrChg [$/month]	base [c/kWh]	Dx bill [$/month]		
New Class	**Old Class**	kWh								
GSe	**West Elgin**	100	7.23	0.70	7.93	11.57	2.00	13.57	5.64	71.1%
		250	7.23	0.70	8.98	11.57	2.00	16.57	7.59	84.5%
		500	7.23	0.70	10.73	11.57	2.00	21.57	10.84	101.0%
		750	7.23	0.70	12.48	11.57	2.00	26.57	14.09	112.9%
		1,000	7.23	0.70	14.23	11.57	2.00	31.57	17.34	121.9%
GSe	**Whitchurch Stouffville**	100	10.46	0.93	11.39	13.76	2.00	15.76	4.37	38.4%
		250	10.46	0.93	12.79	13.76	2.00	18.76	5.98	46.8%
		500	10.46	0.93	15.11	13.76	2.00	23.76	8.65	57.3%
		750	10.46	0.93	17.44	13.76	2.00	28.76	11.33	65.0%
		1,000	10.46	0.93	19.76	13.76	2.00	33.76	14.00	70.9%
GSe	**Wiarton**	100	11.42	1.89	13.31	14.52	2.00	16.52	3.21	24.1%
		250	11.42	1.89	16.15	14.52	2.00	19.52	3.38	20.9%
		500	11.42	1.89	20.87	14.52	2.00	24.52	3.65	17.5%
		750	11.42	1.89	25.60	14.52	2.00	29.52	3.93	15.3%
		1,000	11.42	1.89	30.32	14.52	2.00	34.52	4.20	13.9%
GSe	**Woodville**	100	7.98	1.57	9.55	11.38	2.00	13.38	3.83	40.1%
		250	7.98	1.57	11.91	11.38	2.00	16.38	4.48	37.6%
		500	7.98	1.57	15.83	11.38	2.00	21.38	5.55	35.1%
		750	7.98	1.57	19.76	11.38	2.00	26.38	6.63	33.5%
		1,000	7.98	1.57	23.68	11.38	2.00	31.38	7.70	32.5%
GSe	**Wyoming**	100	8.22	1.45	9.67	12.32	2.00	14.32	4.65	48.1%
		250	8.22	1.45	11.85	12.32	2.00	17.32	5.48	46.2%
		500	8.22	1.45	15.47	12.32	2.00	22.32	6.85	44.3%
		750	8.22	1.45	19.10	12.32	2.00	27.32	8.23	43.1%
		1,000	8.22	1.45	22.72	12.32	2.00	32.32	9.60	42.3%

New Rate Class: Gse - Unmetered

Bill Impacts of Proposed Distribution Rates exclude Riders

Classes		**Scenario**	Existing Dx Rates			Proposed Dx Rates			$ Incr	% Incr
			SrChg	base	Dx bill	SrChg	base	Dx bill		
New Class	**Old Class**	kWh	[$/month]	[c/kWh]	[$/month]	[$/month]	[c/kWh]	[$/month]		
GSe	**Terrace Bay**	100	20.53	1.29	21.82	21.25	2.00	23.25	1.43	6.5%
		250	20.53	1.29	23.76	21.25	2.00	26.25	2.49	10.5%
		500	20.53	1.29	26.98	21.25	2.00	31.25	4.27	15.8%
		750	20.53	1.29	30.21	21.25	2.00	36.25	6.04	20.0%
		1,000	20.53	1.29	33.43	21.25	2.00	41.25	7.82	23.4%

New Rate Class: DGen

Bill Impacts of Proposed Distribution Rates exclude Riders

Classes		Scenario			Existing Dx Rates			Proposed Dx Rates			$ Incr	% Incr
					SrChg	base	Dx bill	SrChg	base	Dx bill		
New Class	Old Class	kWh	kW	LF	[$/month]	[$/kW]	[$/month]	[$/month]	[$/kW]	[$/month]		
Dgen	**G3**	5,000	10	69%	46.78	9.91	146	36.66	7.07	107	(38.5)	-26.4%
	D-billed	5,000	20	35%	46.78	9.91	245	36.66	7.07	178	(67.0)	-27.3%
		5,000	30	23%	46.78	9.91	344	36.66	7.07	249	(95.4)	-27.7%
		5,000	40	17%	46.78	9.91	443	36.66	7.07	319	(123.8)	-27.9%
		5,000	50	14%	46.78	9.91	542	36.66	7.07	390	(152.2)	-28.1%
		5,000	60	12%	46.78	9.91	641	36.66	7.07	461	(180.6)	-28.2%
		35,000	90	54%	46.78	9.91	936	36.66	7.07	671	(265.1)	-28.3%
					[$/month]	[$/kW]	[$/month]					
Dgen	**T**	5,000	10	69%	261.54	8.16	343	36.66	7.07	107	(235.8)	-68.7%
	D-billed	5,000	20	35%	261.54	8.16	425	36.66	7.07	178	(246.7)	-58.1%
		5,000	30	23%	261.54	8.16	506	36.66	7.07	249	(257.6)	-50.9%
		5,000	40	17%	261.54	8.16	588	36.66	7.07	319	(268.6)	-45.7%
		5,000	50	14%	261.54	8.16	670	36.66	7.07	390	(279.5)	-41.7%
		5,000	60	12%	261.54	8.16	751	36.66	7.07	461	(290.4)	-38.7%
		7,700	200	5%	261.54	8.16	1,895	36.66	7.07	1,451	(443.4)	-23.4%
					[$/month]	[c/kWh]	[$/month]					
Dgen	**G3**	5,000	10	69%	46.78	3.07	200	36.66	7.07	107	(92.9)	-46.4%
	E-billed	5,000	20	35%	46.78	3.07	200	36.66	7.07	178	(22.3)	-11.1%
		5,000	30	23%	46.78	3.07	200	36.66	7.07	249	48.4	24.2%
		5,000	40	17%	46.78	3.07	200	36.66	7.07	319	119.1	59.5%
		5,000	50	14%	46.78	3.07	200	36.66	7.07	390	189.8	94.8%
		5,000	60	12%	46.78	3.07	200	36.66	7.07	461	260.5	130.0%
		802	8	14%	46.78	3.07	71	36.66	7.07	94	22.9	32.1%
					[$/month]	[c/kWh]	[$/month]					
Dgen	**T**	5,000	10	69%	261.54	2.43	383	36.66	7.07	107	(275.7)	-72.0%
	E-billed	5,000	20	35%	261.54	2.43	383	36.66	7.07	178	(205.0)	-53.5%
		5,000	30	23%	261.54	2.43	383	36.66	7.07	249	(134.3)	-35.1%
		5,000	40	17%	261.54	2.43	383	36.66	7.07	319	(63.7)	-16.6%
		5,000	50	14%	261.54	2.43	383	36.66	7.07	390	7.0	1.8%
		5,000	60	12%	261.54	2.43	383	36.66	7.07	461	77.7	20.3%
		846	26	5%	261.54	2.43	282	36.66	7.07	220	(62.0)	-22.0%
					[$/month]	[c/kWh]	[$/month]					
Dgen	**Eganville**	5,000	10	69%	21.35	2.32	137	36.66	7.07	107	(30.0)	-21.8%
	E-billed	5,000	20	35%	21.35	2.32	137	36.66	7.07	178	40.7	29.6%
		5,000	30	23%	21.35	2.32	137	36.66	7.07	249	111.4	81.1%
		5,000	40	17%	21.35	2.32	137	36.66	7.07	319	182.0	132.5%
		5,000	50	14%	21.35	2.32	137	36.66	7.07	390	252.7	184.0%
		5,000	60	12%	21.35	2.32	137	36.66	7.07	461	323.4	235.4%
		6	1	1%	21.35	2.32	21	36.66	7.07	45	23.6	110.0%

New Rate Class: GSe - Low Use Secondary

Bill Impacts of Proposed Distribution Rates exclude Riders

Classes		Scenario	Existing Dx Rates			Proposed Dx Rates			$ Incr	% Incr
			SrChg	base	Dx bill	SrChg	base	Dx bill		
New Class	**Old Class**	kWh	[$/month]	[c/kWh]	[$/month]	[$/month]	[c/kWh]	[$/month]		
GSe	**F1**	50	-	2.37	1.19	6.19	3.39	7.89	6.70	565.6%
		75	-	2.37	1.78	6.19	3.39	8.73	6.96	391.3%
	F1	100	-	2.37	2.37	6.19	3.39	9.58	7.21	304.2%
		125	-	2.37	2.96	6.19	3.39	10.43	7.46	252.0%
		150	-	2.37	3.56	6.19	3.39	11.27	7.72	217.1%
		200	-	2.37	4.74	6.19	3.39	12.97	8.23	173.6%
		400	-	2.37	9.48	6.19	3.39	19.74	10.26	108.2%
GSe	**F3**	50	-	3.20	1.60	6.19	3.39	7.89	6.29	392.9%
		75	-	3.20	2.40	6.19	3.39	8.73	6.33	263.9%
	F3, G3	100	-	3.20	3.20	6.19	3.39	9.58	6.38	199.4%
		125	-	3.20	4.00	6.19	3.39	10.43	6.43	160.7%
		150	-	3.20	4.80	6.19	3.39	11.27	6.47	134.9%
		200	-	3.20	6.40	6.19	3.39	12.97	6.57	102.6%
		400	-	3.20	12.80	6.19	3.39	19.74	6.94	54.2%
GSe	**G1**	50	-	3.25	1.63	6.19	3.39	7.89	6.26	385.4%
		75	-	3.25	2.44	6.19	3.39	8.73	6.30	258.3%
	R1,R2,R3	100	-	3.25	3.25	6.19	3.39	9.58	6.33	194.8%
	R4,G1	125	-	3.25	4.06	6.19	3.39	10.43	6.36	156.7%
		150	-	3.25	4.88	6.19	3.39	11.27	6.40	131.3%
		200	-	3.25	6.50	6.19	3.39	12.97	6.47	99.5%
		400	-	3.25	13.00	6.19	3.39	19.74	6.74	51.8%

New Rate Class: UR

Bill Impacts of Proposed Distribution Rates include Riders

Classes		Scenario	Existing Dx Rates						New Dx Rates						$ Incr	% Incr
			SrChg	base	Rider1	Rider2	VarChg	[$/month]	SrChg	base	Rider2	Rider3	VarChg	[$/month]		
New Class	Old Class	kWh	[$/month]	[c/kWh]	[c/kWh]	[c/kWh]	[c/kWh]		[$/month]	[c/kWh]	[c/kWh]	[c/kWh]	[c/kWh]			
UR	UR	100	14.32	1.83	0.20	0.05	2.08	16.40	14.00	2.44	0.05	(0.02)	2.47	16.47	0.07	0.4%
		250	14.32	1.83	0.20	0.05	2.08	19.52	14.00	2.44	0.05	(0.02)	2.47	20.16	0.64	3.3%
		500	14.32	1.83	0.20	0.05	2.08	24.72	14.00	2.44	0.05	(0.02)	2.47	26.33	1.61	6.5%
		750	14.32	1.83	0.20	0.05	2.08	29.92	14.00	2.44	0.05	(0.02)	2.47	32.49	2.57	8.6%
		1,000	14.32	1.83	0.20	0.05	2.08	35.12	14.00	2.44	0.05	(0.02)	2.47	38.66	3.54	10.1%
		1,500	14.32	1.83	0.20	0.05	2.08	45.52	14.00	2.44	0.05	(0.02)	2.47	50.99	5.47	12.0%
		2,000	14.32	1.83	0.20	0.05	2.08	55.92	14.00	2.44	0.05	(0.02)	2.47	63.31	7.39	13.2%
			-	-	-	-	-	-								
UR	R1	100	19.04	2.38	0.15	0.07	2.60	21.64	14.00	2.44	0.05	(0.02)	2.47	16.47	(5.17)	-23.9%
		250	19.04	2.38	0.15	0.07	2.60	25.54	14.00	2.44	0.05	(0.02)	2.47	20.16	(5.38)	-21.0%
		500	19.04	2.38	0.15	0.07	2.60	32.04	14.00	2.44	0.05	(0.02)	2.47	26.33	(5.71)	-17.8%
		750	19.04	2.38	0.15	0.07	2.60	38.54	14.00	2.44	0.05	(0.02)	2.47	32.49	(6.05)	-15.7%
		1,000	19.04	2.38	0.15	0.07	2.60	45.04	14.00	2.44	0.05	(0.02)	2.47	38.66	(6.38)	-14.2%
		1,500	19.04	2.38	0.15	0.07	2.60	58.04	14.00	2.44	0.05	(0.02)	2.47	50.99	(7.05)	-12.2%
		2,000	19.04	2.38	0.15	0.07	2.60	71.04	14.00	2.44	0.05	(0.02)	2.47	63.31	(7.73)	-10.9%
			-	-	-	-	-	-								
UR	R2	100	29.22	1.94	0.12	0.13	2.19	31.41	14.00	2.44	0.05	(0.02)	2.47	16.47	(14.94)	-47.6%
		250	29.22	1.94	0.12	0.13	2.19	34.70	14.00	2.44	0.05	(0.02)	2.47	20.16	(14.53)	-41.9%
		500	29.22	1.94	0.12	0.13	2.19	40.17	14.00	2.44	0.05	(0.02)	2.47	26.33	(13.84)	-34.5%
		750	29.22	1.94	0.12	0.13	2.19	45.65	14.00	2.44	0.05	(0.02)	2.47	32.49	(13.15)	-28.8%
		1,000	29.22	1.94	0.12	0.13	2.19	51.12	14.00	2.44	0.05	(0.02)	2.47	38.66	(12.46)	-24.4%
		1,500	29.22	1.94	0.12	0.13	2.19	62.07	14.00	2.44	0.05	(0.02)	2.47	50.99	(11.08)	-17.9%
		2,000	29.22	1.94	0.12	0.13	2.19	73.02	14.00	2.44	0.05	(0.02)	2.47	63.31	(9.71)	-13.3%
			-	-	-	-	-	-								
UR	F1	100	28.61	2.24	0.08	0.10	2.42	31.03	14.00	2.44	0.05	(0.02)	2.47	16.47	(14.56)	-46.9%
		250	28.61	2.24	0.08	0.10	2.42	34.66	14.00	2.44	0.05	(0.02)	2.47	20.16	(14.50)	-41.8%
		500	28.61	2.24	0.08	0.10	2.42	40.71	14.00	2.44	0.05	(0.02)	2.47	26.33	(14.38)	-35.3%
		750	28.61	2.24	0.08	0.10	2.42	46.76	14.00	2.44	0.05	(0.02)	2.47	32.49	(14.27)	-30.5%
		1,000	28.61	2.24	0.08	0.10	2.42	52.81	14.00	2.44	0.05	(0.02)	2.47	38.66	(14.15)	-26.8%
		1,500	28.61	2.24	0.08	0.10	2.42	64.91	14.00	2.44	0.05	(0.02)	2.47	50.99	(13.92)	-21.5%
		2,000	28.61	2.24	0.08	0.10	2.42	77.01	14.00	2.44	0.05	(0.02)	2.47	63.31	(13.70)	-17.8%

New Rate Class: UR

Bill Impacts of Proposed Distribution Rates include Riders

Classes		Scenario	Existing Dx Rates						New Dx Rates						$ Incr	% Incr
			SrChg	base	Rider1	Rider2	VarChg	[$/month]	SrChg	base	Rider2	Rider3	VarChg	[$/month]		
New Class	Old Class	kWh	[$/month]	[c/kWh]	[c/kWh]	[c/kWh]	[c/kWh]		[$/month]	[c/kWh]	[c/kWh]	[c/kWh]	[c/kWh]			
UR	Arnprior	100	11.54	1.47	0.49	0.18	2.14	13.68	11.70	2.40	0.18	(0.02)	2.55	14.25	0.57	4.1%
		250	11.54	1.47	0.49	0.18	2.14	16.89	11.70	2.40	0.18	(0.02)	2.55	18.07	1.18	7.0%
		500	11.54	1.47	0.49	0.18	2.14	22.24	11.70	2.40	0.18	(0.02)	2.55	24.45	2.21	9.9%
		750	11.54	1.47	0.49	0.18	2.14	27.59	11.70	2.40	0.18	(0.02)	2.55	30.83	3.24	11.7%
		1,000	11.54	1.47	0.49	0.18	2.14	32.94	11.70	2.40	0.18	(0.02)	2.55	37.20	4.26	12.9%
		1,500	11.54	1.47	0.49	0.18	2.14	43.64	11.70	2.40	0.18	(0.02)	2.55	49.96	6.32	14.5%
		2,000	11.54	1.47	0.49	0.18	2.14	54.34	11.70	2.40	0.18	(0.02)	2.55	62.71	8.37	15.4%
			-	-	-	-	-	-								
UR	Brockville	100	12.33	0.93	0.48	0.16	1.57	13.90	12.50	2.40	0.16	(0.02)	2.53	15.03	1.13	8.1%
		250	12.33	0.93	0.48	0.16	1.57	16.26	12.50	2.40	0.16	(0.02)	2.53	18.82	2.57	15.8%
		500	12.33	0.93	0.48	0.16	1.57	20.18	12.50	2.40	0.16	(0.02)	2.53	25.15	4.97	24.6%
		750	12.33	0.93	0.48	0.16	1.57	24.11	12.50	2.40	0.16	(0.02)	2.53	31.48	7.37	30.6%
		1,000	12.33	0.93	0.48	0.16	1.57	28.03	12.50	2.40	0.16	(0.02)	2.53	37.81	9.78	34.9%
		1,500	12.33	0.93	0.48	0.16	1.57	35.88	12.50	2.40	0.16	(0.02)	2.53	50.46	14.58	40.6%
		2,000	12.33	0.93	0.48	0.16	1.57	43.73	12.50	2.40	0.16	(0.02)	2.53	63.12	19.39	44.3%
			-	-	-	-	-	-								
UR	Caledon OH 01	100	18.52	0.57	0.42	0.16	1.15	19.67	16.95	2.15	0.16	(0.02)	2.29	19.24	(0.43)	-2.2%
		250	18.52	0.57	0.42	0.16	1.15	21.40	16.95	2.15	0.16	(0.02)	2.29	22.66	1.27	5.9%
		500	18.52	0.57	0.42	0.16	1.15	24.27	16.95	2.15	0.16	(0.02)	2.29	28.38	4.11	16.9%
		750	18.52	0.57	0.42	0.16	1.15	27.15	16.95	2.15	0.16	(0.02)	2.29	34.09	6.94	25.6%
		1,000	18.52	0.57	0.42	0.16	1.15	30.02	16.95	2.15	0.16	(0.02)	2.29	39.80	9.78	32.6%
		1,500	18.52	0.57	0.42	0.16	1.15	35.77	16.95	2.15	0.16	(0.02)	2.29	51.23	15.46	43.2%
		2,000	18.52	0.57	0.42	0.16	1.15	41.52	16.95	2.15	0.16	(0.02)	2.29	62.65	21.13	50.9%
			-	-	-	-	-	-								
UR	Carleton Place	100	14.17	1.79	0.38	0.15	2.32	16.49	14.04	2.40	0.15	(0.02)	2.52	16.56	0.07	0.4%
		250	14.17	1.79	0.38	0.15	2.32	19.97	14.04	2.40	0.15	(0.02)	2.52	20.34	0.37	1.9%
		500	14.17	1.79	0.38	0.15	2.32	25.77	14.04	2.40	0.15	(0.02)	2.52	26.64	0.87	3.4%
		750	14.17	1.79	0.38	0.15	2.32	31.57	14.04	2.40	0.15	(0.02)	2.52	32.94	1.37	4.4%
		1,000	14.17	1.79	0.38	0.15	2.32	37.37	14.04	2.40	0.15	(0.02)	2.52	39.25	1.88	5.0%
		1,500	14.17	1.79	0.38	0.15	2.32	48.97	14.04	2.40	0.15	(0.02)	2.52	51.85	2.88	5.9%
		2,000	14.17	1.79	0.38	0.15	2.32	60.57	14.04	2.40	0.15	(0.02)	2.52	64.46	3.89	6.4%

New Rate Class: UR

Bill Impacts of Proposed Distribution Rates include Riders

Classes		Scenario	Existing Dx Rates						New Dx Rates						$ Incr	% Incr
			SrChg	base	Rider1	Rider2	VarChg	[$/month]	SrChg	base	Rider2	Rider3	VarChg	[$/month]		
New Class	Old Class	kWh	[$/month]	[c/kWh]	[c/kWh]	[c/kWh]	[c/kWh]		[$/month]	[c/kWh]	[c/kWh]	[c/kWh]	[c/kWh]			
UR	Dryden	100	14.28	1.65	0.43	0.18	2.26	16.54	14.01	2.40	0.18	(0.02)	2.55	16.56	0.02	0.1%
		250	14.28	1.65	0.43	0.18	2.26	19.93	14.01	2.40	0.18	(0.02)	2.55	20.39	0.46	2.3%
		500	14.28	1.65	0.43	0.18	2.26	25.58	14.01	2.40	0.18	(0.02)	2.55	26.76	1.18	4.6%
		750	14.28	1.65	0.43	0.18	2.26	31.23	14.01	2.40	0.18	(0.02)	2.55	33.14	1.91	6.1%
		1,000	14.28	1.65	0.43	0.18	2.26	36.88	14.01	2.40	0.18	(0.02)	2.55	39.52	2.64	7.2%
		1,500	14.28	1.65	0.43	0.18	2.26	48.18	14.01	2.40	0.18	(0.02)	2.55	52.27	4.09	8.5%
		2,000	14.28	1.65	0.43	0.18	2.26	59.48	14.01	2.40	0.18	(0.02)	2.55	65.03	5.55	9.3%
			-	-	-	-	-	-								
UR	GBE	100	9.68	0.95	0.46	0.13	1.54	11.22	10.16	2.35	0.13	(0.02)	2.46	12.62	1.40	12.4%
		250	9.68	0.95	0.46	0.13	1.54	13.53	10.16	2.35	0.13	(0.02)	2.46	16.30	2.77	20.5%
		500	9.68	0.95	0.46	0.13	1.54	17.38	10.16	2.35	0.13	(0.02)	2.46	22.44	5.06	29.1%
		750	9.68	0.95	0.46	0.13	1.54	21.23	10.16	2.35	0.13	(0.02)	2.46	28.57	7.34	34.6%
		1,000	9.68	0.95	0.46	0.13	1.54	25.08	10.16	2.35	0.13	(0.02)	2.46	34.71	9.63	38.4%
		1,500	9.68	0.95	0.46	0.13	1.54	32.78	10.16	2.35	0.13	(0.02)	2.46	46.99	14.21	43.3%
		2,000	9.68	0.95	0.46	0.13	1.54	40.48	10.16	2.35	0.13	(0.02)	2.46	59.26	18.78	46.4%
			-	-	-	-	-	-								
UR	Lindsay	100	15.81	1.01	0.41	0.14	1.56	17.37	14.63	2.40	0.14	(0.02)	2.51	17.14	(0.23)	-1.3%
		250	15.81	1.01	0.41	0.14	1.56	19.71	14.63	2.40	0.14	(0.02)	2.51	20.90	1.19	6.1%
		500	15.81	1.01	0.41	0.14	1.56	23.61	14.63	2.40	0.14	(0.02)	2.51	27.18	3.57	15.1%
		750	15.81	1.01	0.41	0.14	1.56	27.51	14.63	2.40	0.14	(0.02)	2.51	33.46	5.95	21.6%
		1,000	15.81	1.01	0.41	0.14	1.56	31.41	14.63	2.40	0.14	(0.02)	2.51	39.74	8.33	26.5%
		1,500	15.81	1.01	0.41	0.14	1.56	39.21	14.63	2.40	0.14	(0.02)	2.51	52.29	13.08	33.4%
		2,000	15.81	1.01	0.41	0.14	1.56	47.01	14.63	2.40	0.14	(0.02)	2.51	64.85	17.84	37.9%
			-	-	-	-	-	-								
UR	Perth	100	14.47	1.22	0.50	0.18	1.90	16.37	13.96	2.40	0.18	(0.02)	2.55	16.51	0.14	0.9%
		250	14.47	1.22	0.50	0.18	1.90	19.22	13.96	2.40	0.18	(0.02)	2.55	20.34	1.12	5.8%
		500	14.47	1.22	0.50	0.18	1.90	23.97	13.96	2.40	0.18	(0.02)	2.55	26.72	2.75	11.5%
		750	14.47	1.22	0.50	0.18	1.90	28.72	13.96	2.40	0.18	(0.02)	2.55	33.09	4.37	15.2%
		1,000	14.47	1.22	0.50	0.18	1.90	33.47	13.96	2.40	0.18	(0.02)	2.55	39.47	6.00	17.9%
		1,500	14.47	1.22	0.50	0.18	1.90	42.97	13.96	2.40	0.18	(0.02)	2.55	52.23	9.26	21.5%
		2,000	14.47	1.22	0.50	0.18	1.90	52.47	13.96	2.40	0.18	(0.02)	2.55	64.98	12.51	23.8%

New Rate Class: UR

Bill Impacts of Proposed Distribution Rates include Riders

Classes		Scenario	Existing Dx Rates						New Dx Rates						$ Incr	% Incr
			SrChg	base	Rider1	Rider2	VarChg	[$/month]	SrChg	base	Rider2	Rider3	VarChg	[$/month]		
New Class	Old Class	kWh	[$/month]	[c/kWh]	[c/kWh]	[c/kWh]	[c/kWh]		[$/month]	[c/kWh]	[c/kWh]	[c/kWh]	[c/kWh]			
UR	Quinte West	100	6.58	0.92	0.39	0.11	1.42	8.00	7.94	2.10	0.11	(0.02)	2.19	10.12	2.12	26.5%
		250	6.58	0.92	0.39	0.11	1.42	10.13	7.94	2.10	0.11	(0.02)	2.19	13.40	3.27	32.3%
		500	6.58	0.92	0.39	0.11	1.42	13.68	7.94	2.10	0.11	(0.02)	2.19	18.86	5.18	37.9%
		750	6.58	0.92	0.39	0.11	1.42	17.23	7.94	2.10	0.11	(0.02)	2.19	24.32	7.09	41.2%
		1,000	6.58	0.92	0.39	0.11	1.42	20.78	7.94	2.10	0.11	(0.02)	2.19	29.79	9.01	43.3%
		1,500	6.58	0.92	0.39	0.11	1.42	27.88	7.94	2.10	0.11	(0.02)	2.19	40.71	12.83	46.0%
		2,000	6.58	0.92	0.39	0.11	1.42	34.98	7.94	2.10	0.11	(0.02)	2.19	51.64	16.66	47.6%
			-	-	-	-	-	-								
UR	Smiths Falls	100	12.63	1.42	0.46	0.17	2.05	14.68	12.42	2.40	0.17	(0.02)	2.54	14.96	0.28	1.9%
		250	12.63	1.42	0.46	0.17	2.05	17.76	12.42	2.40	0.17	(0.02)	2.54	18.77	1.02	5.7%
		500	12.63	1.42	0.46	0.17	2.05	22.88	12.42	2.40	0.17	(0.02)	2.54	25.13	2.25	9.8%
		750	12.63	1.42	0.46	0.17	2.05	28.01	12.42	2.40	0.17	(0.02)	2.54	31.48	3.47	12.4%
		1,000	12.63	1.42	0.46	0.17	2.05	33.13	12.42	2.40	0.17	(0.02)	2.54	37.83	4.70	14.2%
		1,500	12.63	1.42	0.46	0.17	2.05	43.38	12.42	2.40	0.17	(0.02)	2.54	50.54	7.16	16.5%
		2,000	12.63	1.42	0.46	0.17	2.05	53.63	12.42	2.40	0.17	(0.02)	2.54	63.24	9.61	17.9%
			-	-	-	-	-	-								
UR	Thorold	100	13.68	1.47	0.41	0.14	2.02	15.70	13.16	2.40	0.14	(0.02)	2.51	15.67	(0.03)	-0.2%
		250	13.68	1.47	0.41	0.14	2.02	18.73	13.16	2.40	0.14	(0.02)	2.51	19.44	0.71	3.8%
		500	13.68	1.47	0.41	0.14	2.02	23.78	13.16	2.40	0.14	(0.02)	2.51	25.71	1.93	8.1%
		750	13.68	1.47	0.41	0.14	2.02	28.83	13.16	2.40	0.14	(0.02)	2.51	31.99	3.16	11.0%
		1,000	13.68	1.47	0.41	0.14	2.02	33.88	13.16	2.40	0.14	(0.02)	2.51	38.27	4.39	13.0%
		1,500	13.68	1.47	0.41	0.14	2.02	43.98	13.16	2.40	0.14	(0.02)	2.51	50.82	6.84	15.6%
		2,000	13.68	1.47	0.41	0.14	2.02	54.08	13.16	2.40	0.14	(0.02)	2.51	63.38	9.30	17.2%
			-	-	-	-	-	-								
UR	Whitchurch Stouffville	100	10.54	1.02	0.36	0.12	1.50	12.04	10.95	2.30	0.12	(0.02)	2.40	13.34	1.30	10.8%
		250	10.54	1.02	0.36	0.12	1.50	14.29	10.95	2.30	0.12	(0.02)	2.40	16.93	2.64	18.5%
		500	10.54	1.02	0.36	0.12	1.50	18.04	10.95	2.30	0.12	(0.02)	2.40	22.92	4.88	27.1%
		750	10.54	1.02	0.36	0.12	1.50	21.79	10.95	2.30	0.12	(0.02)	2.40	28.91	7.12	32.7%
		1,000	10.54	1.02	0.36	0.12	1.50	25.54	10.95	2.30	0.12	(0.02)	2.40	34.90	9.36	36.6%
		1,500	10.54	1.02	0.36	0.12	1.50	33.04	10.95	2.30	0.12	(0.02)	2.40	46.87	13.83	41.9%
		2,000	10.54	1.02	0.36	0.12	1.50	40.54	10.95	2.30	0.12	(0.02)	2.40	58.85	18.31	45.2%

New Rate Class: R1

Bill Impacts of Proposed Distribution Rates including Riders

Classes		Scenario	Existing Dx Rates						New Dx Rates						$ Incr	% Incr
			SrChg	base	Rider1	Rider2	VarChg	[$/month]	SrChg	base	Rider2	Rider3	VarChg	[$/month]		
New Class	**Old Class**	kWh	[$/month	[c/kWh]	[c/kWh]	[c/kWh]	[c/kWh]		[$/month]	[c/kWh]	[c/kWh]	[c/kWh]	[c/kWh]			
R1	**R1**	100	19.04	2.38	0.15	0.07	2.60	21.64	19.00	2.81	0.07	(0.04)	2.84	21.84	0.20	0.9%
		250	19.04	2.38	0.15	0.07	2.60	25.54	19.00	2.81	0.07	(0.04)	2.84	26.10	0.56	2.2%
		500	19.04	2.38	0.15	0.07	2.60	32.04	19.00	2.81	0.07	(0.04)	2.84	33.19	1.15	3.6%
		750	19.04	2.38	0.15	0.07	2.60	38.54	19.00	2.81	0.07	(0.04)	2.84	40.29	1.75	4.5%
		1,000	19.04	2.38	0.15	0.07	2.60	45.04	19.00	2.81	0.07	(0.04)	2.84	47.38	2.34	5.2%
		1,500	19.04	2.38	0.15	0.07	2.60	58.04	19.00	2.81	0.07	(0.04)	2.84	61.58	3.54	6.1%
		2,000	19.04	2.38	0.15	0.07	2.60	71.04	19.00	2.81	0.07	(0.04)	2.84	75.77	4.73	6.7%
			-	-	-	-	-	-								
R1	**Ailsa Craig**	100	10.51	0.82	0.35	0.11	1.28	11.79	12.13	1.85	0.11	(0.04)	1.92	14.06	2.27	19.2%
		250	10.51	0.82	0.35	0.11	1.28	13.71	12.13	1.85	0.11	(0.04)	1.92	16.94	3.23	23.6%
		500	10.51	0.82	0.35	0.11	1.28	16.91	12.13	1.85	0.11	(0.04)	1.92	21.75	4.84	28.6%
		750	10.51	0.82	0.35	0.11	1.28	20.11	12.13	1.85	0.11	(0.04)	1.92	26.55	6.44	32.0%
		1,000	10.51	0.82	0.35	0.11	1.28	23.31	12.13	1.85	0.11	(0.04)	1.92	31.36	8.05	34.5%
		1,500	10.51	0.82	0.35	0.11	1.28	29.71	12.13	1.85	0.11	(0.04)	1.92	40.98	11.27	37.9%
		2,000	10.51	0.82	0.35	0.11	1.28	36.11	12.13	1.85	0.11	(0.04)	1.92	50.59	14.48	40.1%
			-	-	-	-	-	-								
R1	**Arkona**	100	5.84	0.26	0.68	0.33	1.27	7.11	8.30	1.50	0.33	(0.04)	1.79	10.09	2.98	42.0%
		250	5.84	0.26	0.68	0.33	1.27	9.02	8.30	1.50	0.33	(0.04)	1.79	12.78	3.77	41.8%
		500	5.84	0.26	0.68	0.33	1.27	12.19	8.30	1.50	0.33	(0.04)	1.79	17.26	5.07	41.6%
		750	5.84	0.26	0.68	0.33	1.27	15.37	8.30	1.50	0.33	(0.04)	1.79	21.75	6.38	41.5%
		1,000	5.84	0.26	0.68	0.33	1.27	18.54	8.30	1.50	0.33	(0.04)	1.79	26.23	7.69	41.5%
		1,500	5.84	0.26	0.68	0.33	1.27	24.89	8.30	1.50	0.33	(0.04)	1.79	35.19	10.30	41.4%
		2,000	5.84	0.26	0.68	0.33	1.27	31.24	8.30	1.50	0.33	(0.04)	1.79	44.16	12.92	41.3%
			-	-	-	-	-	-								
UR	**Arnprior**	100	11.54	1.47	0.49	0.18	2.14	13.68	11.70	2.40	0.18	(0.02)	2.55	14.25	0.57	4.1%
		250	11.54	1.47	0.49	0.18	2.14	16.89	11.70	2.40	0.18	(0.02)	2.55	18.07	1.18	7.0%
		500	11.54	1.47	0.49	0.18	2.14	22.24	11.70	2.40	0.18	(0.02)	2.55	24.45	2.21	9.9%
		750	11.54	1.47	0.49	0.18	2.14	27.59	11.70	2.40	0.18	(0.02)	2.55	30.83	3.24	11.7%
		1,000	11.54	1.47	0.49	0.18	2.14	32.94	11.70	2.40	0.18	(0.02)	2.55	37.20	4.26	12.9%
		1,500	11.54	1.47	0.49	0.18	2.14	43.64	11.70	2.40	0.18	(0.02)	2.55	49.96	6.32	14.5%
		2,000	11.54	1.47	0.49	0.18	2.14	54.34	11.70	2.40	0.18	(0.02)	2.55	62.71	8.37	15.4%

New Rate Class: R1

Bill Impacts of Proposed Distribution Rates including Riders

Classes		Scenario	Existing Dx Rates						New Dx Rates						$ Incr	% Incr
			SrChg	base	Rider1	Rider2	VarChg	[$/month]	SrChg	base	Rider2	Rider3	VarChg	[$/month]		
New Class	Old Class	kWh	[$/month	[c/kWh]	[c/kWh]	[c/kWh]	[c/kWh]		[$/month]	[c/kWh]	[c/kWh]	[c/kWh]	[c/kWh]			
R1	**Arran-Elderslie**	100	9.02	0.95	0.35	0.15	1.45	10.47	11.51	1.90	0.15	(0.04)	2.01	13.52	3.05	29.1%
		250	9.02	0.95	0.35	0.15	1.45	12.65	11.51	1.90	0.15	(0.04)	2.01	16.54	3.89	30.8%
		500	9.02	0.95	0.35	0.15	1.45	16.27	11.51	1.90	0.15	(0.04)	2.01	21.57	5.30	32.6%
		750	9.02	0.95	0.35	0.15	1.45	19.90	11.51	1.90	0.15	(0.04)	2.01	26.60	6.71	33.7%
		1,000	9.02	0.95	0.35	0.15	1.45	23.52	11.51	1.90	0.15	(0.04)	2.01	31.63	8.11	34.5%
		1,500	9.02	0.95	0.35	0.15	1.45	30.77	11.51	1.90	0.15	(0.04)	2.01	41.70	10.93	35.5%
		2,000	9.02	0.95	0.35	0.15	1.45	38.02	11.51	1.90	0.15	(0.04)	2.01	51.76	13.74	36.1%
			-	-	-	-	-	-								
R1	**Artemesia**	100	12.73	0.93	0.59	0.34	1.86	14.59	13.58	2.35	0.34	(0.04)	2.65	16.23	1.64	11.2%
		250	12.73	0.93	0.59	0.34	1.86	17.38	13.58	2.35	0.34	(0.04)	2.65	20.21	2.83	16.3%
		500	12.73	0.93	0.59	0.34	1.86	22.03	13.58	2.35	0.34	(0.04)	2.65	26.84	4.81	21.8%
		750	12.73	0.93	0.59	0.34	1.86	26.68	13.58	2.35	0.34	(0.04)	2.65	33.47	6.79	25.5%
		1,000	12.73	0.93	0.59	0.34	1.86	31.33	13.58	2.35	0.34	(0.04)	2.65	40.11	8.78	28.0%
		1,500	12.73	0.93	0.59	0.34	1.86	40.63	13.58	2.35	0.34	(0.04)	2.65	53.37	12.74	31.4%
		2,000	12.73	0.93	0.59	0.34	1.86	49.93	13.58	2.35	0.34	(0.04)	2.65	66.63	16.70	33.5%
			-	-	-	-	-	-								
R1	**Bancroft**	100	13.48	0.95	0.34	0.12	1.41	14.89	14.39	2.10	0.12	(0.04)	2.18	16.57	1.68	11.3%
		250	13.48	0.95	0.34	0.12	1.41	17.01	14.39	2.10	0.12	(0.04)	2.18	19.85	2.84	16.7%
		500	13.48	0.95	0.34	0.12	1.41	20.53	14.39	2.10	0.12	(0.04)	2.18	25.30	4.77	23.3%
		750	13.48	0.95	0.34	0.12	1.41	24.06	14.39	2.10	0.12	(0.04)	2.18	30.76	6.71	27.9%
		1,000	13.48	0.95	0.34	0.12	1.41	27.58	14.39	2.10	0.12	(0.04)	2.18	36.22	8.64	31.3%
		1,500	13.48	0.95	0.34	0.12	1.41	34.63	14.39	2.10	0.12	(0.04)	2.18	47.13	12.50	36.1%
		2,000	13.48	0.95	0.34	0.12	1.41	41.68	14.39	2.10	0.12	(0.04)	2.18	58.05	16.37	39.3%
			-	-	-	-	-	-								
R1	**Bath**	100	13.38	0.86	0.68	0.38	1.92	15.30	14.42	2.35	0.38	(0.04)	2.69	17.11	1.81	11.8%
		250	13.38	0.86	0.68	0.38	1.92	18.18	14.42	2.35	0.38	(0.04)	2.69	21.15	2.97	16.3%
		500	13.38	0.86	0.68	0.38	1.92	22.98	14.42	2.35	0.38	(0.04)	2.69	27.88	4.90	21.3%
		750	13.38	0.86	0.68	0.38	1.92	27.78	14.42	2.35	0.38	(0.04)	2.69	34.61	6.83	24.6%
		1,000	13.38	0.86	0.68	0.38	1.92	32.58	14.42	2.35	0.38	(0.04)	2.69	41.34	8.76	26.9%
		1,500	13.38	0.86	0.68	0.38	1.92	42.18	14.42	2.35	0.38	(0.04)	2.69	54.81	12.63	29.9%
		2,000	13.38	0.86	0.68	0.38	1.92	51.78	14.42	2.35	0.38	(0.04)	2.69	68.27	16.49	31.9%

New Rate Class: R1

Bill Impacts of Proposed Distribution Rates including Riders

Classes		Scenario	Existing Dx Rates						New Dx Rates						$ Incr	% Incr
			SrChg	base	Rider1	Rider2	VarChg	[$/month]	SrChg	base	Rider2	Rider3	VarChg	[$/month]		
New Class	**Old Class**	kWh	[$/month	[c/kWh]	[c/kWh]	[c/kWh]	[c/kWh]		[$/month]	[c/kWh]	[c/kWh]	[c/kWh]	[c/kWh]			
R1	**Blandford-Blenheim**	100	11.63	0.90	0.63	0.33	1.86	13.49	12.85	2.30	0.33	(0.04)	2.59	15.45	1.96	14.5%
		250	11.63	0.90	0.63	0.33	1.86	16.28	12.85	2.30	0.33	(0.04)	2.59	19.33	3.05	18.8%
		500	11.63	0.90	0.63	0.33	1.86	20.93	12.85	2.30	0.33	(0.04)	2.59	25.82	4.89	23.3%
		750	11.63	0.90	0.63	0.33	1.86	25.58	12.85	2.30	0.33	(0.04)	2.59	32.30	6.72	26.3%
		1,000	11.63	0.90	0.63	0.33	1.86	30.23	12.85	2.30	0.33	(0.04)	2.59	38.78	8.55	28.3%
		1,500	11.63	0.90	0.63	0.33	1.86	39.53	12.85	2.30	0.33	(0.04)	2.59	51.75	12.22	30.9%
		2,000	11.63	0.90	0.63	0.33	1.86	48.83	12.85	2.30	0.33	(0.04)	2.59	64.71	15.88	32.5%
			-	-	-	-	-	-								
R1	**Blyth**	100	7.19	0.91	0.54	0.27	1.72	8.91	9.96	2.00	0.27	(0.04)	2.23	12.20	3.29	36.9%
		250	7.19	0.91	0.54	0.27	1.72	11.49	9.96	2.00	0.27	(0.04)	2.23	15.54	4.05	35.3%
		500	7.19	0.91	0.54	0.27	1.72	15.79	9.96	2.00	0.27	(0.04)	2.23	21.13	5.34	33.8%
		750	7.19	0.91	0.54	0.27	1.72	20.09	9.96	2.00	0.27	(0.04)	2.23	26.71	6.62	32.9%
		1,000	7.19	0.91	0.54	0.27	1.72	24.39	9.96	2.00	0.27	(0.04)	2.23	32.29	7.90	32.4%
		1,500	7.19	0.91	0.54	0.27	1.72	32.99	9.96	2.00	0.27	(0.04)	2.23	43.46	10.47	31.7%
		2,000	7.19	0.91	0.54	0.27	1.72	41.59	9.96	2.00	0.27	(0.04)	2.23	54.62	13.03	31.3%
			-	-	-	-	-	-								
R1	**Bobcaygeon**	100	14.47	0.97	0.28	0.10	1.35	15.82	15.14	2.05	0.10	(0.04)	2.11	17.26	1.44	9.1%
		250	14.47	0.97	0.28	0.10	1.35	17.85	15.14	2.05	0.10	(0.04)	2.11	20.42	2.58	14.5%
		500	14.47	0.97	0.28	0.10	1.35	21.22	15.14	2.05	0.10	(0.04)	2.11	25.71	4.49	21.1%
		750	14.47	0.97	0.28	0.10	1.35	24.60	15.14	2.05	0.10	(0.04)	2.11	30.99	6.39	26.0%
		1,000	14.47	0.97	0.28	0.10	1.35	27.97	15.14	2.05	0.10	(0.04)	2.11	36.27	8.30	29.7%
		1,500	14.47	0.97	0.28	0.10	1.35	34.72	15.14	2.05	0.10	(0.04)	2.11	46.84	12.12	34.9%
		2,000	14.47	0.97	0.28	0.10	1.35	41.47	15.14	2.05	0.10	(0.04)	2.11	57.40	15.93	38.4%
			-	-	-	-	-	-								
R1	**Brighton**	100	11.61	1.07	0.37	0.11	1.55	13.16	12.86	2.20	0.11	(0.04)	2.27	15.13	1.97	15.0%
		250	11.61	1.07	0.37	0.11	1.55	15.49	12.86	2.20	0.11	(0.04)	2.27	18.54	3.05	19.7%
		500	11.61	1.07	0.37	0.11	1.55	19.36	12.86	2.20	0.11	(0.04)	2.27	24.22	4.86	25.1%
		750	11.61	1.07	0.37	0.11	1.55	23.24	12.86	2.20	0.11	(0.04)	2.27	29.90	6.67	28.7%
		1,000	11.61	1.07	0.37	0.11	1.55	27.11	12.86	2.20	0.11	(0.04)	2.27	35.59	8.48	31.3%
		1,500	11.61	1.07	0.37	0.11	1.55	34.86	12.86	2.20	0.11	(0.04)	2.27	46.95	12.09	34.7%
		2,000	11.61	1.07	0.37	0.11	1.55	42.61	12.86	2.20	0.11	(0.04)	2.27	58.31	15.70	36.9%

New Rate Class: R1

Bill Impacts of Proposed Distribution Rates including Riders

Classes		Scenario	Existing Dx Rates						New Dx Rates						$ Incr	% Incr
			SrChg	base	Rider1	Rider2	VarChg	[$/month]	SrChg	base	Rider2	Rider3	VarChg	[$/month]		
New Class	**Old Class**	kWh	[$/month	[c/kWh]	[c/kWh]	[c/kWh]	[c/kWh]		[$/month]	[c/kWh]	[c/kWh]	[c/kWh]	[c/kWh]			
UR	**Brockville**	100	12.33	0.93	0.48	0.16	1.57	13.90	12.50	2.40	0.16	(0.02)	2.53	15.03	1.13	8.1%
		250	12.33	0.93	0.48	0.16	1.57	16.26	12.50	2.40	0.16	(0.02)	2.53	18.82	2.57	15.8%
		500	12.33	0.93	0.48	0.16	1.57	20.18	12.50	2.40	0.16	(0.02)	2.53	25.15	4.97	24.6%
		750	12.33	0.93	0.48	0.16	1.57	24.11	12.50	2.40	0.16	(0.02)	2.53	31.48	7.37	30.6%
		1,000	12.33	0.93	0.48	0.16	1.57	28.03	12.50	2.40	0.16	(0.02)	2.53	37.81	9.78	34.9%
		1,500	12.33	0.93	0.48	0.16	1.57	35.88	12.50	2.40	0.16	(0.02)	2.53	50.46	14.58	40.6%
		2,000	12.33	0.93	0.48	0.16	1.57	43.73	12.50	2.40	0.16	(0.02)	2.53	63.12	19.39	44.3%
			-	-	-	-	-	-								
R1	**Caledon CH 02**	100	15.19	1.02	0.28	0.08	1.38	16.57	15.96	2.10	0.08	(0.04)	2.14	18.11	1.54	9.3%
		250	15.19	1.02	0.28	0.08	1.38	18.64	15.96	2.10	0.08	(0.04)	2.14	21.32	2.68	14.4%
		500	15.19	1.02	0.28	0.08	1.38	22.09	15.96	2.10	0.08	(0.04)	2.14	26.68	4.59	20.8%
		750	15.19	1.02	0.28	0.08	1.38	25.54	15.96	2.10	0.08	(0.04)	2.14	32.03	6.49	25.4%
		1,000	15.19	1.02	0.28	0.08	1.38	28.99	15.96	2.10	0.08	(0.04)	2.14	37.39	8.40	29.0%
		1,500	15.19	1.02	0.28	0.08	1.38	35.89	15.96	2.10	0.08	(0.04)	2.14	48.11	12.22	34.0%
		2,000	15.19	1.02	0.28	0.08	1.38	42.79	15.96	2.10	0.08	(0.04)	2.14	58.82	16.03	37.5%
			-	-	-	-	-	-								
R1	**Campbellford-Seymou**	100	12.30	1.07	0.41	0.12	1.60	13.90	13.69	2.25	0.12	(0.04)	2.33	16.02	2.12	15.2%
		250	12.30	1.07	0.41	0.12	1.60	16.30	13.69	2.25	0.12	(0.04)	2.33	19.52	3.22	19.7%
		500	12.30	1.07	0.41	0.12	1.60	20.30	13.69	2.25	0.12	(0.04)	2.33	25.35	5.05	24.9%
		750	12.30	1.07	0.41	0.12	1.60	24.30	13.69	2.25	0.12	(0.04)	2.33	31.18	6.88	28.3%
		1,000	12.30	1.07	0.41	0.12	1.60	28.30	13.69	2.25	0.12	(0.04)	2.33	37.01	8.71	30.8%
		1,500	12.30	1.07	0.41	0.12	1.60	36.30	13.69	2.25	0.12	(0.04)	2.33	48.68	12.38	34.1%
		2,000	12.30	1.07	0.41	0.12	1.60	44.30	13.69	2.25	0.12	(0.04)	2.33	60.34	16.04	36.2%
			-	-	-	-	-	-								
UR	**Carleton Place**	100	14.17	1.79	0.38	0.15	2.32	16.49	14.04	2.40	0.15	(0.02)	2.52	16.56	0.07	0.4%
		250	14.17	1.79	0.38	0.15	2.32	19.97	14.04	2.40	0.15	(0.02)	2.52	20.34	0.37	1.9%
		500	14.17	1.79	0.38	0.15	2.32	25.77	14.04	2.40	0.15	(0.02)	2.52	26.64	0.87	3.4%
		750	14.17	1.79	0.38	0.15	2.32	31.57	14.04	2.40	0.15	(0.02)	2.52	32.94	1.37	4.4%
		1,000	14.17	1.79	0.38	0.15	2.32	37.37	14.04	2.40	0.15	(0.02)	2.52	39.25	1.88	5.0%
		1,500	14.17	1.79	0.38	0.15	2.32	48.97	14.04	2.40	0.15	(0.02)	2.52	51.85	2.88	5.9%
		2,000	14.17	1.79	0.38	0.15	2.32	60.57	14.04	2.40	0.15	(0.02)	2.52	64.46	3.89	6.4%

New Rate Class: R1

Bill Impacts of Proposed Distribution Rates including Riders

Classes		Scenario	Existing Dx Rates						New Dx Rates						$ Incr	% Incr
			SrChg	base	Rider1	Rider2	VarChg	[$/month]	SrChg	base	Rider2	Rider3	VarChg	[$/month]		
New Class	**Old Class**	kWh	[$/month	[c/kWh]	[c/kWh]	[c/kWh]	[c/kWh]		[$/month]	[c/kWh]	[c/kWh]	[c/kWh]	[c/kWh]			
R1	**Cavan-Millbrook-Nortl**	100	15.01	1.34	0.68	0.40	2.42	17.43	16.01	2.71	0.40	(0.04)	3.08	19.08	1.65	9.5%
		250	15.01	1.34	0.68	0.40	2.42	21.06	16.01	2.71	0.40	(0.04)	3.08	23.70	2.64	12.5%
		500	15.01	1.34	0.68	0.40	2.42	27.11	16.01	2.71	0.40	(0.04)	3.08	31.39	4.28	15.8%
		750	15.01	1.34	0.68	0.40	2.42	33.16	16.01	2.71	0.40	(0.04)	3.08	39.08	5.92	17.9%
		1000	15.01	1.34	0.68	0.40	2.42	39.21	16.01	2.71	0.40	(0.04)	3.08	46.77	7.56	19.3%
		1500	15.01	1.34	0.68	0.40	2.42	51.31	16.01	2.71	0.40	(0.04)	3.08	62.15	10.84	21.1%
		2000	15.01	1.34	0.68	0.40	2.42	63.41	16.01	2.71	0.40	(0.04)	3.08	77.53	14.12	22.3%
R1	**Centre Hastings**	100	11.67	0.96	0.29	0.11	1.36	13.03	12.84	2.00	0.11	(0.04)	2.07	14.92	1.89	14.5%
		250	11.67	0.96	0.29	0.11	1.36	15.07	12.84	2.00	0.11	(0.04)	2.07	18.02	2.95	19.6%
		500	11.67	0.96	0.29	0.11	1.36	18.47	12.84	2.00	0.11	(0.04)	2.07	23.21	4.74	25.6%
		750	11.67	0.96	0.29	0.11	1.36	21.87	12.84	2.00	0.11	(0.04)	2.07	28.39	6.52	29.8%
		1000	11.67	0.96	0.29	0.11	1.36	25.27	12.84	2.00	0.11	(0.04)	2.07	33.57	8.30	32.8%
		1500	11.67	0.96	0.29	0.11	1.36	32.07	12.84	2.00	0.11	(0.04)	2.07	43.94	11.87	37.0%
		2000	11.67	0.96	0.29	0.11	1.36	38.87	12.84	2.00	0.11	(0.04)	2.07	54.30	15.43	39.7%
R1	**Chalk River**	100	14.03	1.37	0.61	0.42	2.40	16.43	15.25	2.71	0.42	(0.04)	3.10	18.35	1.92	11.7%
		250	14.03	1.37	0.61	0.42	2.40	20.03	15.25	2.71	0.42	(0.04)	3.10	22.99	2.96	14.8%
		500	14.03	1.37	0.61	0.42	2.40	26.03	15.25	2.71	0.42	(0.04)	3.10	30.73	4.70	18.1%
		750	14.03	1.37	0.61	0.42	2.40	32.03	15.25	2.71	0.42	(0.04)	3.10	38.47	6.44	20.1%
		1000	14.03	1.37	0.61	0.42	2.40	38.03	15.25	2.71	0.42	(0.04)	3.10	46.22	8.19	21.5%
		1500	14.03	1.37	0.61	0.42	2.40	50.03	15.25	2.71	0.42	(0.04)	3.10	61.70	11.67	23.3%
		2000	14.03	1.37	0.61	0.42	2.40	62.03	15.25	2.71	0.42	(0.04)	3.10	77.18	15.15	24.4%
R1	**Champlain**	100	10.36	0.88	0.45	0.23	1.56	11.92	12.17	2.00	0.23	(0.04)	2.19	14.36	2.44	20.5%
		250	10.36	0.88	0.45	0.23	1.56	14.26	12.17	2.00	0.23	(0.04)	2.19	17.65	3.39	23.8%
		500	10.36	0.88	0.45	0.23	1.56	18.16	12.17	2.00	0.23	(0.04)	2.19	23.13	4.97	27.4%
		750	10.36	0.88	0.45	0.23	1.56	22.06	12.17	2.00	0.23	(0.04)	2.19	28.62	6.56	29.7%
		1000	10.36	0.88	0.45	0.23	1.56	25.96	12.17	2.00	0.23	(0.04)	2.19	34.10	8.14	31.4%
		1500	10.36	0.88	0.45	0.23	1.56	33.76	12.17	2.00	0.23	(0.04)	2.19	45.06	11.30	33.5%
		2000	10.36	0.88	0.45	0.23	1.56	41.56	12.17	2.00	0.23	(0.04)	2.19	56.03	14.47	34.8%

New Rate Class: R1

Bill Impacts of Proposed Distribution Rates including Riders

Classes		Scenario	Existing Dx Rates						New Dx Rates						$ Incr	% Incr
			SrChg	base	Rider1	Rider2	VarChg	[$/month]	SrChg	base	Rider2	Rider3	VarChg	[$/month]		
New Class	**Old Class**	kWh	[$/month	[c/kWh]	[c/kWh]	[c/kWh]	[c/kWh]		[$/month]	[c/kWh]	[c/kWh]	[c/kWh]	[c/kWh]			
R1	**Cobden**	100	13.07	1.76	0.68	0.41	2.85	15.92	14.49	2.71	0.41	(0.04)	3.09	17.58	1.66	10.4%
		250	13.07	1.76	0.68	0.41	2.85	20.20	14.49	2.71	0.41	(0.04)	3.09	22.21	2.01	10.0%
		500	13.07	1.76	0.68	0.41	2.85	27.32	14.49	2.71	0.41	(0.04)	3.09	29.92	2.60	9.5%
		750	13.07	1.76	0.68	0.41	2.85	34.45	14.49	2.71	0.41	(0.04)	3.09	37.64	3.19	9.3%
		1000	13.07	1.76	0.68	0.41	2.85	41.57	14.49	2.71	0.41	(0.04)	3.09	45.36	3.79	9.1%
		1500	13.07	1.76	0.68	0.41	2.85	55.82	14.49	2.71	0.41	(0.04)	3.09	60.79	4.97	8.9%
		2000	13.07	1.76	0.68	0.41	2.85	70.07	14.49	2.71	0.41	(0.04)	3.09	76.22	6.15	8.8%
R1	**Deep River**	100	16.62	2.29	0.38	0.25	2.92	19.54	16.61	2.71	0.25	(0.04)	2.93	19.53	(0.01)	0.0%
		250	16.62	2.29	0.38	0.25	2.92	23.92	16.61	2.71	0.25	(0.04)	2.93	23.92	0.00	0.0%
		500	16.62	2.29	0.38	0.25	2.92	31.22	16.61	2.71	0.25	(0.04)	2.93	31.24	0.02	0.1%
		750	16.62	2.29	0.38	0.25	2.92	38.52	16.61	2.71	0.25	(0.04)	2.93	38.55	0.03	0.1%
		1000	16.62	2.29	0.38	0.25	2.92	45.82	16.61	2.71	0.25	(0.04)	2.93	45.87	0.05	0.1%
		1500	16.62	2.29	0.38	0.25	2.92	60.42	16.61	2.71	0.25	(0.04)	2.93	60.50	0.08	0.1%
		2000	16.62	2.29	0.38	0.25	2.92	75.02	16.61	2.71	0.25	(0.04)	2.93	75.13	0.11	0.1%
R1	**Deseronto**	100	12.89	1.12	0.37	0.11	1.60	14.49	13.54	2.30	0.11	(0.04)	2.37	15.91	1.42	9.8%
		250	12.89	1.12	0.37	0.11	1.60	16.89	13.54	2.30	0.11	(0.04)	2.37	19.47	2.58	15.3%
		500	12.89	1.12	0.37	0.11	1.60	20.89	13.54	2.30	0.11	(0.04)	2.37	25.40	4.51	21.6%
		750	12.89	1.12	0.37	0.11	1.60	24.89	13.54	2.30	0.11	(0.04)	2.37	31.33	6.44	25.9%
		1000	12.89	1.12	0.37	0.11	1.60	28.89	13.54	2.30	0.11	(0.04)	2.37	37.27	8.38	29.0%
		1500	12.89	1.12	0.37	0.11	1.60	36.89	13.54	2.30	0.11	(0.04)	2.37	49.13	12.24	33.2%
		2000	12.89	1.12	0.37	0.11	1.60	44.89	13.54	2.30	0.11	(0.04)	2.37	60.99	16.10	35.9%
UR	**Dryden**	100	14.28	1.65	0.43	0.18	2.26	16.54	14.01	2.40	0.18	(0.02)	2.55	16.56	0.02	0.1%
		250	14.28	1.65	0.43	0.18	2.26	19.93	14.01	2.40	0.18	(0.02)	2.55	20.39	0.46	2.3%
		500	14.28	1.65	0.43	0.18	2.26	25.58	14.01	2.40	0.18	(0.02)	2.55	26.76	1.18	4.6%
		750	14.28	1.65	0.43	0.18	2.26	31.23	14.01	2.40	0.18	(0.02)	2.55	33.14	1.91	6.1%
		1000	14.28	1.65	0.43	0.18	2.26	36.88	14.01	2.40	0.18	(0.02)	2.55	39.52	2.64	7.2%
		1500	14.28	1.65	0.43	0.18	2.26	48.18	14.01	2.40	0.18	(0.02)	2.55	52.27	4.09	8.5%
		2000	14.28	1.65	0.43	0.18	2.26	59.48	14.01	2.40	0.18	(0.02)	2.55	65.03	5.55	9.3%

New Rate Class: R1

Bill Impacts of Proposed Distribution Rates including Riders

Classes		Scenario	Existing Dx Rates						New Dx Rates						$ Incr	% Incr
			SrChg	base	Rider1	Rider2	VarChg	[$/month]	SrChg	base	Rider2	Rider3	VarChg	[$/month]		
New Class	**Old Class**	kWh	[$/month	[c/kWh]	[c/kWh]	[c/kWh]	[c/kWh]		[$/month]	[c/kWh]	[c/kWh]	[c/kWh]	[c/kWh]			
R1	**Dundalk**	100	14.47	1.08	0.39	0.13	1.60	16.07	15.14	2.30	0.13	(0.04)	2.39	17.54	1.47	9.1%
		250	14.47	1.08	0.39	0.13	1.60	18.47	15.14	2.30	0.13	(0.04)	2.39	21.12	2.65	14.4%
		500	14.47	1.08	0.39	0.13	1.60	22.47	15.14	2.30	0.13	(0.04)	2.39	27.11	4.64	20.6%
		750	14.47	1.08	0.39	0.13	1.60	26.47	15.14	2.30	0.13	(0.04)	2.39	33.09	6.62	25.0%
		1000	14.47	1.08	0.39	0.13	1.60	30.47	15.14	2.30	0.13	(0.04)	2.39	39.07	8.60	28.2%
		1500	14.47	1.08	0.39	0.13	1.60	38.47	15.14	2.30	0.13	(0.04)	2.39	51.04	12.57	32.7%
		2000	14.47	1.08	0.39	0.13	1.60	46.47	15.14	2.30	0.13	(0.04)	2.39	63.00	16.53	35.6%
R1	**Durham**	100	16.35	1.24	0.46	0.16	1.86	18.21	16.67	2.60	0.16	(0.04)	2.72	19.40	1.19	6.5%
		250	16.35	1.24	0.46	0.16	1.86	21.00	16.67	2.60	0.16	(0.04)	2.72	23.48	2.48	11.8%
		500	16.35	1.24	0.46	0.16	1.86	25.65	16.67	2.60	0.16	(0.04)	2.72	30.29	4.64	18.1%
		750	16.35	1.24	0.46	0.16	1.86	30.30	16.67	2.60	0.16	(0.04)	2.72	37.09	6.79	22.4%
		1000	16.35	1.24	0.46	0.16	1.86	34.95	16.67	2.60	0.16	(0.04)	2.72	43.90	8.95	25.6%
		1500	16.35	1.24	0.46	0.16	1.86	44.25	16.67	2.60	0.16	(0.04)	2.72	57.52	13.27	30.0%
		2000	16.35	1.24	0.46	0.16	1.86	53.55	16.67	2.60	0.16	(0.04)	2.72	71.13	17.58	32.8%
R1	**Eganville**	100	13.86	1.53	0.29	0.12	1.94	15.80	14.30	2.71	0.12	(0.04)	2.80	17.09	1.29	8.2%
		250	13.86	1.53	0.29	0.12	1.94	18.71	14.30	2.71	0.12	(0.04)	2.80	21.29	2.58	13.8%
		500	13.86	1.53	0.29	0.12	1.94	23.56	14.30	2.71	0.12	(0.04)	2.80	28.28	4.72	20.0%
		750	13.86	1.53	0.29	0.12	1.94	28.41	14.30	2.71	0.12	(0.04)	2.80	35.27	6.86	24.1%
		1000	13.86	1.53	0.29	0.12	1.94	33.26	14.30	2.71	0.12	(0.04)	2.80	42.26	9.00	27.1%
		1500	13.86	1.53	0.29	0.12	1.94	42.96	14.30	2.71	0.12	(0.04)	2.80	56.24	13.28	30.9%
		2000	13.86	1.53	0.29	0.12	1.94	52.66	14.30	2.71	0.12	(0.04)	2.80	70.22	17.56	33.3%
R1	**Erin**	100	13.13	1.90	0.83	0.40	3.13	16.26	14.48	2.71	0.40	(0.04)	3.08	17.55	1.29	8.0%
		250	13.13	1.90	0.83	0.40	3.13	20.96	14.48	2.71	0.40	(0.04)	3.08	22.17	1.21	5.8%
		500	13.13	1.90	0.83	0.40	3.13	28.78	14.48	2.71	0.40	(0.04)	3.08	29.86	1.08	3.7%
		750	13.13	1.90	0.83	0.40	3.13	36.61	14.48	2.71	0.40	(0.04)	3.08	37.55	0.94	2.6%
		1000	13.13	1.90	0.83	0.40	3.13	44.43	14.48	2.71	0.40	(0.04)	3.08	45.24	0.81	1.8%
		1500	13.13	1.90	0.83	0.40	3.13	60.08	14.48	2.71	0.40	(0.04)	3.08	60.62	0.54	0.9%
		2000	13.13	1.90	0.83	0.40	3.13	75.73	14.48	2.71	0.40	(0.04)	3.08	76.00	0.27	0.4%

New Rate Class: R1

Bill Impacts of Proposed Distribution Rates including Riders

Classes		Scenario	Existing Dx Rates						New Dx Rates						$ Incr	% Incr
			SrChg	base	Rider1	Rider2	VarChg	[$/month]	SrChg	base	Rider2	Rider3	VarChg	[$/month]		
New Class	**Old Class**	kWh	[$/month	[c/kWh]	[c/kWh]	[c/kWh]	[c/kWh]		[$/month]	[c/kWh]	[c/kWh]	[c/kWh]	[c/kWh]			
R1	**Exeter**	100	15.10	0.96	0.45	0.15	1.56	16.66	15.99	2.25	0.15	(0.04)	2.36	18.35	1.69	10.1%
		250	15.10	0.96	0.45	0.15	1.56	19.00	15.99	2.25	0.15	(0.04)	2.36	21.89	2.89	15.2%
		500	15.10	0.96	0.45	0.15	1.56	22.90	15.99	2.25	0.15	(0.04)	2.36	27.80	4.90	21.4%
		750	15.10	0.96	0.45	0.15	1.56	26.80	15.99	2.25	0.15	(0.04)	2.36	33.71	6.91	25.8%
		1000	15.10	0.96	0.45	0.15	1.56	30.70	15.99	2.25	0.15	(0.04)	2.36	39.61	8.91	29.0%
		1500	15.10	0.96	0.45	0.15	1.56	38.50	15.99	2.25	0.15	(0.04)	2.36	51.43	12.93	33.6%
		2000	15.10	0.96	0.45	0.15	1.56	46.30	15.99	2.25	0.15	(0.04)	2.36	63.24	16.94	36.6%
R1	**Fenelon Falls**	100	6.09	0.96	0.25	0.08	1.29	7.38	9.24	1.70	0.08	(0.04)	1.74	10.98	3.60	48.8%
		250	6.09	0.96	0.25	0.08	1.29	9.32	9.24	1.70	0.08	(0.04)	1.74	13.59	4.28	45.9%
		500	6.09	0.96	0.25	0.08	1.29	12.54	9.24	1.70	0.08	(0.04)	1.74	17.95	5.41	43.2%
		750	6.09	0.96	0.25	0.08	1.29	15.77	9.24	1.70	0.08	(0.04)	1.74	22.31	6.54	41.5%
		1000	6.09	0.96	0.25	0.08	1.29	18.99	9.24	1.70	0.08	(0.04)	1.74	26.67	7.68	40.4%
		1500	6.09	0.96	0.25	0.08	1.29	25.44	9.24	1.70	0.08	(0.04)	1.74	35.38	9.94	39.1%
		2000	6.09	0.96	0.25	0.08	1.29	31.89	9.24	1.70	0.08	(0.04)	1.74	44.09	12.20	38.3%
R1	**Forest**	100	15.26	0.95	0.41	0.15	1.51	16.77	15.95	2.20	0.15	(0.04)	2.31	18.26	1.49	8.9%
		250	15.26	0.95	0.41	0.15	1.51	19.04	15.95	2.20	0.15	(0.04)	2.31	21.73	2.69	14.1%
		500	15.26	0.95	0.41	0.15	1.51	22.81	15.95	2.20	0.15	(0.04)	2.31	27.51	4.70	20.6%
		750	15.26	0.95	0.41	0.15	1.51	26.59	15.95	2.20	0.15	(0.04)	2.31	33.29	6.71	25.2%
		1000	15.26	0.95	0.41	0.15	1.51	30.36	15.95	2.20	0.15	(0.04)	2.31	39.07	8.71	28.7%
		1500	15.26	0.95	0.41	0.15	1.51	37.91	15.95	2.20	0.15	(0.04)	2.31	50.64	12.73	33.6%
		2000	15.26	0.95	0.41	0.15	1.51	45.46	15.95	2.20	0.15	(0.04)	2.31	62.20	16.74	36.8%
UR	**GBE**	100	9.68	0.95	0.46	0.13	1.54	11.22	10.16	2.35	0.13	(0.02)	2.46	12.62	1.40	12.4%
		250	9.68	0.95	0.46	0.13	1.54	13.53	10.16	2.35	0.13	(0.02)	2.46	16.30	2.77	20.5%
		500	9.68	0.95	0.46	0.13	1.54	17.38	10.16	2.35	0.13	(0.02)	2.46	22.44	5.06	29.1%
		750	9.68	0.95	0.46	0.13	1.54	21.23	10.16	2.35	0.13	(0.02)	2.46	28.57	7.34	34.6%
		1000	9.68	0.95	0.46	0.13	1.54	25.08	10.16	2.35	0.13	(0.02)	2.46	34.71	9.63	38.4%
		1500	9.68	0.95	0.46	0.13	1.54	32.78	10.16	2.35	0.13	(0.02)	2.46	46.99	14.21	43.3%
		2000	9.68	0.95	0.46	0.13	1.54	40.48	10.16	2.35	0.13	(0.02)	2.46	59.26	18.78	46.4%

New Rate Class: R1

Bill Impacts of Proposed Distribution Rates including Riders

Classes		Scenario	Existing Dx Rates						New Dx Rates						$ Incr	% Incr
			SrChg	base	Rider1	Rider2	VarChg	[$/month]	SrChg	base	Rider2	Rider3	VarChg	[$/month]		
New Class	Old Class	kWh	[$/month	[c/kWh]	[c/kWh]	[c/kWh]	[c/kWh]		[$/month]	[c/kWh]	[c/kWh]	[c/kWh]	[c/kWh]			
R1	Georgina	100	11.72	0.98	0.31	0.09	1.38	13.10	12.83	2.05	0.09	(0.04)	2.10	14.93	1.83	14.0%
		250	11.72	0.98	0.31	0.09	1.38	15.17	12.83	2.05	0.09	(0.04)	2.10	18.09	2.92	19.2%
		500	11.72	0.98	0.31	0.09	1.38	18.62	12.83	2.05	0.09	(0.04)	2.10	23.34	4.72	25.4%
		750	11.72	0.98	0.31	0.09	1.38	22.07	12.83	2.05	0.09	(0.04)	2.10	28.60	6.53	29.6%
		1000	11.72	0.98	0.31	0.09	1.38	25.52	12.83	2.05	0.09	(0.04)	2.10	33.86	8.34	32.7%
		1500	11.72	0.98	0.31	0.09	1.38	32.42	12.83	2.05	0.09	(0.04)	2.10	44.37	11.95	36.9%
		2000	11.72	0.98	0.31	0.09	1.38	39.32	12.83	2.05	0.09	(0.04)	2.10	54.89	15.57	39.6%
R1	Glencoe	100	12.90	0.77	0.89	0.43	2.09	14.99	13.54	2.55	0.43	(0.04)	2.94	16.48	1.49	9.9%
		250	12.90	0.77	0.89	0.43	2.09	18.13	13.54	2.55	0.43	(0.04)	2.94	20.89	2.77	15.3%
		500	12.90	0.77	0.89	0.43	2.09	23.35	13.54	2.55	0.43	(0.04)	2.94	28.25	4.90	21.0%
		750	12.90	0.77	0.89	0.43	2.09	28.58	13.54	2.55	0.43	(0.04)	2.94	35.61	7.03	24.6%
		1000	12.90	0.77	0.89	0.43	2.09	33.80	13.54	2.55	0.43	(0.04)	2.94	42.96	9.16	27.1%
		1500	12.90	0.77	0.89	0.43	2.09	44.25	13.54	2.55	0.43	(0.04)	2.94	57.68	13.43	30.3%
		2000	12.90	0.77	0.89	0.43	2.09	54.70	13.54	2.55	0.43	(0.04)	2.94	72.39	17.69	32.3%
R1	Grand Bend	100	13.58	0.87	0.42	0.13	1.42	15.00	14.37	2.10	0.13	(0.04)	2.19	16.56	1.56	10.4%
		250	13.58	0.87	0.42	0.13	1.42	17.13	14.37	2.10	0.13	(0.04)	2.19	19.85	2.72	15.9%
		500	13.58	0.87	0.42	0.13	1.42	20.68	14.37	2.10	0.13	(0.04)	2.19	25.33	4.65	22.5%
		750	13.58	0.87	0.42	0.13	1.42	24.23	14.37	2.10	0.13	(0.04)	2.19	30.81	6.58	27.2%
		1000	13.58	0.87	0.42	0.13	1.42	27.78	14.37	2.10	0.13	(0.04)	2.19	36.29	8.51	30.6%
		1500	13.58	0.87	0.42	0.13	1.42	34.88	14.37	2.10	0.13	(0.04)	2.19	47.26	12.38	35.5%
		2000	13.58	0.87	0.42	0.13	1.42	41.98	14.37	2.10	0.13	(0.04)	2.19	58.22	16.24	38.7%
R1	Hastings	100	16.44	1.35	0.37	0.12	1.84	18.28	16.65	2.65	0.12	(0.04)	2.73	19.38	1.10	6.0%
		250	16.44	1.35	0.37	0.12	1.84	21.04	16.65	2.65	0.12	(0.04)	2.73	23.48	2.44	11.6%
		500	16.44	1.35	0.37	0.12	1.84	25.64	16.65	2.65	0.12	(0.04)	2.73	30.31	4.67	18.2%
		750	16.44	1.35	0.37	0.12	1.84	30.24	16.65	2.65	0.12	(0.04)	2.73	37.15	6.91	22.8%
		1000	16.44	1.35	0.37	0.12	1.84	34.84	16.65	2.65	0.12	(0.04)	2.73	43.98	9.14	26.2%
		1500	16.44	1.35	0.37	0.12	1.84	44.04	16.65	2.65	0.12	(0.04)	2.73	57.64	13.60	30.9%
		2000	16.44	1.35	0.37	0.12	1.84	53.24	16.65	2.65	0.12	(0.04)	2.73	71.31	18.07	33.9%

New Rate Class: R1

Bill Impacts of Proposed Distribution Rates including Riders

Classes		Scenario	Existing Dx Rates						New Dx Rates						$ Incr	% Incr
			SrChg	base	Rider1	Rider2	VarChg	[$/month]	SrChg	base	Rider2	Rider3	VarChg	[$/month]		
New Class	Old Class	kWh	[$/month	[c/kWh]	[c/kWh]	[c/kWh]	[c/kWh]		[$/month]	[c/kWh]	[c/kWh]	[c/kWh]	[c/kWh]			
R1	**Havelock**	100	15.17	1.14	0.32	0.13	1.59	16.76	15.97	2.30	0.13	(0.04)	2.39	18.36	1.60	9.5%
		250	15.17	1.14	0.32	0.13	1.59	19.15	15.97	2.30	0.13	(0.04)	2.39	21.95	2.80	14.6%
		500	15.17	1.14	0.32	0.13	1.59	23.12	15.97	2.30	0.13	(0.04)	2.39	27.93	4.81	20.8%
		750	15.17	1.14	0.32	0.13	1.59	27.10	15.97	2.30	0.13	(0.04)	2.39	33.91	6.82	25.2%
		1000	15.17	1.14	0.32	0.13	1.59	31.07	15.97	2.30	0.13	(0.04)	2.39	39.90	8.83	28.4%
		1500	15.17	1.14	0.32	0.13	1.59	39.02	15.97	2.30	0.13	(0.04)	2.39	51.86	12.84	32.9%
		2000	15.17	1.14	0.32	0.13	1.59	46.97	15.97	2.30	0.13	(0.04)	2.39	63.82	16.85	35.9%
R1	**Kirkfield**	100	5.34	1.00	0.48	0.26	1.74	7.08	8.43	2.00	0.26	(0.04)	2.22	10.65	3.57	50.4%
		250	5.34	1.00	0.48	0.26	1.74	9.69	8.43	2.00	0.26	(0.04)	2.22	13.98	4.29	44.3%
		500	5.34	1.00	0.48	0.26	1.74	14.04	8.43	2.00	0.26	(0.04)	2.22	19.54	5.50	39.2%
		750	5.34	1.00	0.48	0.26	1.74	18.39	8.43	2.00	0.26	(0.04)	2.22	25.10	6.71	36.5%
		1000	5.34	1.00	0.48	0.26	1.74	22.74	8.43	2.00	0.26	(0.04)	2.22	30.65	7.91	34.8%
		1500	5.34	1.00	0.48	0.26	1.74	31.44	8.43	2.00	0.26	(0.04)	2.22	41.77	10.33	32.8%
		2000	5.34	1.00	0.48	0.26	1.74	40.14	8.43	2.00	0.26	(0.04)	2.22	52.88	12.74	31.7%
R1	**Lanark Highlands**	100	11.31	1.02	0.56	0.40	1.98	13.29	12.93	2.35	0.40	(0.04)	2.71	15.65	2.36	17.7%
		250	11.31	1.02	0.56	0.40	1.98	16.26	12.93	2.35	0.40	(0.04)	2.71	19.71	3.45	21.2%
		500	11.31	1.02	0.56	0.40	1.98	21.21	12.93	2.35	0.40	(0.04)	2.71	26.50	5.29	24.9%
		750	11.31	1.02	0.56	0.40	1.98	26.16	12.93	2.35	0.40	(0.04)	2.71	33.28	7.12	27.2%
		1000	11.31	1.02	0.56	0.40	1.98	31.11	12.93	2.35	0.40	(0.04)	2.71	40.06	8.95	28.8%
		1500	11.31	1.02	0.56	0.40	1.98	41.01	12.93	2.35	0.40	(0.04)	2.71	53.63	12.62	30.8%
		2000	11.31	1.02	0.56	0.40	1.98	50.91	12.93	2.35	0.40	(0.04)	2.71	67.19	16.28	32.0%
R1	**Larder Lake**	100	15.84	1.01	0.68	0.43	2.12	17.96	15.80	2.70	0.43	(0.04)	3.09	18.89	0.93	5.2%
		250	15.84	1.01	0.68	0.43	2.12	21.14	15.80	2.70	0.43	(0.04)	3.09	23.53	2.39	11.3%
		500	15.84	1.01	0.68	0.43	2.12	26.44	15.80	2.70	0.43	(0.04)	3.09	31.26	4.82	18.2%
		750	15.84	1.01	0.68	0.43	2.12	31.74	15.80	2.70	0.43	(0.04)	3.09	39.00	7.26	22.9%
		1000	15.84	1.01	0.68	0.43	2.12	37.04	15.80	2.70	0.43	(0.04)	3.09	46.73	9.69	26.2%
		1500	15.84	1.01	0.68	0.43	2.12	47.64	15.80	2.70	0.43	(0.04)	3.09	62.19	14.55	30.5%
		2000	15.84	1.01	0.68	0.43	2.12	58.24	15.80	2.70	0.43	(0.04)	3.09	77.66	19.42	33.3%

New Rate Class: R1

Bill Impacts of Proposed Distribution Rates including Riders

Classes		Scenario	Existing Dx Rates						New Dx Rates						$ Incr	% Incr
			SrChg	base	Rider1	Rider2	VarChg	[$/month]	SrChg	base	Rider2	Rider3	VarChg	[$/month]		
New Class	**Old Class**	kWh	[$/month	[c/kWh]	[c/kWh]	[c/kWh]	[c/kWh]		[$/month]	[c/kWh]	[c/kWh]	[c/kWh]	[c/kWh]			
R1	**Latchford**	100	13.31	0.88	1.04	0.45	2.37	15.68	14.43	2.71	0.45	(0.04)	3.13	17.56	1.88	12.0%
		250	13.31	0.88	1.04	0.45	2.37	19.24	14.43	2.71	0.45	(0.04)	3.13	22.25	3.01	15.7%
		500	13.31	0.88	1.04	0.45	2.37	25.16	14.43	2.71	0.45	(0.04)	3.13	30.06	4.90	19.5%
		750	13.31	0.88	1.04	0.45	2.37	31.09	14.43	2.71	0.45	(0.04)	3.13	37.88	6.79	21.9%
		1000	13.31	0.88	1.04	0.45	2.37	37.01	14.43	2.71	0.45	(0.04)	3.13	45.70	8.69	23.5%
		1500	13.31	0.88	1.04	0.45	2.37	48.86	14.43	2.71	0.45	(0.04)	3.13	61.33	12.47	25.5%
		2000	13.31	0.88	1.04	0.45	2.37	60.71	14.43	2.71	0.45	(0.04)	3.13	76.96	16.25	26.8%
UR	**Lindsay**	100	15.81	1.01	0.41	0.14	1.56	17.37	14.63	2.40	0.14	(0.02)	2.51	17.14	(0.23)	-1.3%
		250	15.81	1.01	0.41	0.14	1.56	19.71	14.63	2.40	0.14	(0.02)	2.51	20.90	1.19	6.1%
		500	15.81	1.01	0.41	0.14	1.56	23.61	14.63	2.40	0.14	(0.02)	2.51	27.18	3.57	15.1%
		750	15.81	1.01	0.41	0.14	1.56	27.51	14.63	2.40	0.14	(0.02)	2.51	33.46	5.95	21.6%
		1000	15.81	1.01	0.41	0.14	1.56	31.41	14.63	2.40	0.14	(0.02)	2.51	39.74	8.33	26.5%
		1500	15.81	1.01	0.41	0.14	1.56	39.21	14.63	2.40	0.14	(0.02)	2.51	52.29	13.08	33.4%
		2000	15.81	1.01	0.41	0.14	1.56	47.01	14.63	2.40	0.14	(0.02)	2.51	64.85	17.84	37.9%
R1	**Lucan Granton**	100	11.72	1.42	0.37	0.17	1.96	13.68	12.83	2.60	0.17	(0.04)	2.73	15.56	1.88	13.8%
		250	11.72	1.42	0.37	0.17	1.96	16.62	12.83	2.60	0.17	(0.04)	2.73	19.66	3.04	18.3%
		500	11.72	1.42	0.37	0.17	1.96	21.52	12.83	2.60	0.17	(0.04)	2.73	26.49	4.97	23.1%
		750	11.72	1.42	0.37	0.17	1.96	26.42	12.83	2.60	0.17	(0.04)	2.73	33.33	6.91	26.1%
		1000	11.72	1.42	0.37	0.17	1.96	31.32	12.83	2.60	0.17	(0.04)	2.73	40.16	8.84	28.2%
		1500	11.72	1.42	0.37	0.17	1.96	41.12	12.83	2.60	0.17	(0.04)	2.73	53.82	12.70	30.9%
		2000	11.72	1.42	0.37	0.17	1.96	50.92	12.83	2.60	0.17	(0.04)	2.73	67.49	16.57	32.5%
R1	**Malahide**	100	11.17	0.87	0.78	0.34	1.99	13.16	12.97	2.40	0.34	(0.04)	2.70	15.67	2.51	19.1%
		250	11.17	0.87	0.78	0.34	1.99	16.15	12.97	2.40	0.34	(0.04)	2.70	19.72	3.58	22.2%
		500	11.17	0.87	0.78	0.34	1.99	21.12	12.97	2.40	0.34	(0.04)	2.70	26.48	5.36	25.4%
		750	11.17	0.87	0.78	0.34	1.99	26.10	12.97	2.40	0.34	(0.04)	2.70	33.24	7.14	27.4%
		1000	11.17	0.87	0.78	0.34	1.99	31.07	12.97	2.40	0.34	(0.04)	2.70	40.00	8.93	28.7%
		1500	11.17	0.87	0.78	0.34	1.99	41.02	12.97	2.40	0.34	(0.04)	2.70	53.51	12.49	30.4%
		2000	11.17	0.87	0.78	0.34	1.99	50.97	12.97	2.40	0.34	(0.04)	2.70	67.02	16.05	31.5%

New Rate Class: R1

Bill Impacts of Proposed Distribution Rates including Riders

Classes		Scenario	Existing Dx Rates						New Dx Rates						$ Incr	% Incr
			SrChg	base	Rider1	Rider2	VarChg	[$/month]	SrChg	base	Rider2	Rider3	VarChg	[$/month]		
New Class	**Old Class**	kWh	[$/month	[c/kWh]	[c/kWh]	[c/kWh]	[c/kWh]		[$/month]	[c/kWh]	[c/kWh]	[c/kWh]	[c/kWh]			
R1	**Mapleton**	100	13.47	0.92	0.65	0.39	1.96	15.43	14.39	2.40	0.39	(0.04)	2.75	17.15	1.72	11.1%
		250	13.47	0.92	0.65	0.39	1.96	18.37	14.39	2.40	0.39	(0.04)	2.75	21.27	2.90	15.8%
		500	13.47	0.92	0.65	0.39	1.96	23.27	14.39	2.40	0.39	(0.04)	2.75	28.16	4.89	21.0%
		750	13.47	0.92	0.65	0.39	1.96	28.17	14.39	2.40	0.39	(0.04)	2.75	35.04	6.87	24.4%
		1000	13.47	0.92	0.65	0.39	1.96	33.07	14.39	2.40	0.39	(0.04)	2.75	41.92	8.85	26.8%
		1500	13.47	0.92	0.65	0.39	1.96	42.87	14.39	2.40	0.39	(0.04)	2.75	55.69	12.82	29.9%
		2000	13.47	0.92	0.65	0.39	1.96	52.67	14.39	2.40	0.39	(0.04)	2.75	69.45	16.78	31.9%
R1	**Markdale**	100	14.30	0.86	0.44	0.16	1.46	15.76	15.19	2.10	0.16	(0.04)	2.22	17.41	1.65	10.5%
		250	14.30	0.86	0.44	0.16	1.46	17.95	15.19	2.10	0.16	(0.04)	2.22	20.74	2.79	15.6%
		500	14.30	0.86	0.44	0.16	1.46	21.60	15.19	2.10	0.16	(0.04)	2.22	26.30	4.70	21.8%
		750	14.30	0.86	0.44	0.16	1.46	25.25	15.19	2.10	0.16	(0.04)	2.22	31.86	6.61	26.2%
		1000	14.30	0.86	0.44	0.16	1.46	28.90	15.19	2.10	0.16	(0.04)	2.22	37.41	8.51	29.5%
		1500	14.30	0.86	0.44	0.16	1.46	36.20	15.19	2.10	0.16	(0.04)	2.22	48.53	12.33	34.1%
		2000	14.30	0.86	0.44	0.16	1.46	43.50	15.19	2.10	0.16	(0.04)	2.22	59.64	16.14	37.1%
R1	**Marmora**	100	11.59	0.92	0.33	0.11	1.36	12.95	12.86	2.00	0.11	(0.04)	2.07	14.94	1.99	15.3%
		250	11.59	0.92	0.33	0.11	1.36	14.99	12.86	2.00	0.11	(0.04)	2.07	18.04	3.05	20.4%
		500	11.59	0.92	0.33	0.11	1.36	18.39	12.86	2.00	0.11	(0.04)	2.07	23.23	4.84	26.3%
		750	11.59	0.92	0.33	0.11	1.36	21.79	12.86	2.00	0.11	(0.04)	2.07	28.41	6.62	30.4%
		1000	11.59	0.92	0.33	0.11	1.36	25.19	12.86	2.00	0.11	(0.04)	2.07	33.59	8.40	33.4%
		1500	11.59	0.92	0.33	0.11	1.36	31.99	12.86	2.00	0.11	(0.04)	2.07	43.96	11.97	37.4%
		2000	11.59	0.92	0.33	0.11	1.36	38.79	12.86	2.00	0.11	(0.04)	2.07	54.32	15.53	40.0%
R1	**McGarry**	100	12.85	0.93	0.71	0.45	2.09	14.94	13.55	2.50	0.45	(0.04)	2.91	16.46	1.52	10.2%
		250	12.85	0.93	0.71	0.45	2.09	18.08	13.55	2.50	0.45	(0.04)	2.91	20.83	2.75	15.2%
		500	12.85	0.93	0.71	0.45	2.09	23.30	13.55	2.50	0.45	(0.04)	2.91	28.11	4.81	20.7%
		750	12.85	0.93	0.71	0.45	2.09	28.53	13.55	2.50	0.45	(0.04)	2.91	35.39	6.87	24.1%
		1000	12.85	0.93	0.71	0.45	2.09	33.75	13.55	2.50	0.45	(0.04)	2.91	42.68	8.93	26.4%
		1500	12.85	0.93	0.71	0.45	2.09	44.20	13.55	2.50	0.45	(0.04)	2.91	57.24	13.04	29.5%
		2000	12.85	0.93	0.71	0.45	2.09	54.65	13.55	2.50	0.45	(0.04)	2.91	71.80	17.15	31.4%

New Rate Class: R1

Bill Impacts of Proposed Distribution Rates including Riders

Classes		Scenario	Existing Dx Rates						New Dx Rates						$ Incr	% Incr
			SrChg	base	Rider1	Rider2	VarChg	[$/month]	SrChg	base	Rider2	Rider3	VarChg	[$/month]		
New Class	**Old Class**	kWh	[$/month	[c/kWh]	[c/kWh]	[c/kWh]	[c/kWh]		[$/month]	[c/kWh]	[c/kWh]	[c/kWh]	[c/kWh]			
R1	**Meaford**	100	12.75	0.97	0.40	0.12	1.49	14.24	13.57	2.20	0.12	(0.04)	2.28	15.86	1.62	11.3%
		250	12.75	0.97	0.40	0.12	1.49	16.48	13.57	2.20	0.12	(0.04)	2.28	19.28	2.80	17.0%
		500	12.75	0.97	0.40	0.12	1.49	20.20	13.57	2.20	0.12	(0.04)	2.28	24.99	4.79	23.7%
		750	12.75	0.97	0.40	0.12	1.49	23.93	13.57	2.20	0.12	(0.04)	2.28	30.69	6.77	28.3%
		1000	12.75	0.97	0.40	0.12	1.49	27.65	13.57	2.20	0.12	(0.04)	2.28	36.40	8.75	31.6%
		1500	12.75	0.97	0.40	0.12	1.49	35.10	13.57	2.20	0.12	(0.04)	2.28	47.82	12.72	36.2%
		2000	12.75	0.97	0.40	0.12	1.49	42.55	13.57	2.20	0.12	(0.04)	2.28	59.23	16.68	39.2%
R1	**Middlesex Centre**	100	14.19	0.78	0.65	0.40	1.83	16.02	15.21	2.25	0.40	(0.04)	2.61	17.83	1.81	11.3%
		250	14.19	0.78	0.65	0.40	1.83	18.77	15.21	2.25	0.40	(0.04)	2.61	21.74	2.98	15.9%
		500	14.19	0.78	0.65	0.40	1.83	23.34	15.21	2.25	0.40	(0.04)	2.61	28.28	4.94	21.2%
		750	14.19	0.78	0.65	0.40	1.83	27.92	15.21	2.25	0.40	(0.04)	2.61	34.81	6.89	24.7%
		1000	14.19	0.78	0.65	0.40	1.83	32.49	15.21	2.25	0.40	(0.04)	2.61	41.34	8.85	27.2%
		1500	14.19	0.78	0.65	0.40	1.83	41.64	15.21	2.25	0.40	(0.04)	2.61	54.41	12.77	30.7%
		2000	14.19	0.78	0.65	0.40	1.83	50.79	15.21	2.25	0.40	(0.04)	2.61	67.47	16.68	32.8%
R1	**Napanee**	100	14.70	1.02	0.43	0.14	1.59	16.29	15.09	2.35	0.14	(0.04)	2.45	17.54	1.25	7.7%
		250	14.70	1.02	0.43	0.14	1.59	18.68	15.09	2.35	0.14	(0.04)	2.45	21.22	2.54	13.6%
		500	14.70	1.02	0.43	0.14	1.59	22.65	15.09	2.35	0.14	(0.04)	2.45	27.35	4.70	20.7%
		750	14.70	1.02	0.43	0.14	1.59	26.63	15.09	2.35	0.14	(0.04)	2.45	33.48	6.86	25.8%
		1000	14.70	1.02	0.43	0.14	1.59	30.60	15.09	2.35	0.14	(0.04)	2.45	39.61	9.01	29.5%
		1500	14.70	1.02	0.43	0.14	1.59	38.55	15.09	2.35	0.14	(0.04)	2.45	51.88	13.33	34.6%
		2000	14.70	1.02	0.43	0.14	1.59	46.50	15.09	2.35	0.14	(0.04)	2.45	64.14	17.64	37.9%
R1	**Nipigon**	100	14.23	1.42	1.27	0.72	3.41	17.64	15.20	2.71	0.72	(0.04)	3.40	18.60	0.96	5.4%
		250	14.23	1.42	1.27	0.72	3.41	22.76	15.20	2.71	0.72	(0.04)	3.40	23.69	0.94	4.1%
		500	14.23	1.42	1.27	0.72	3.41	31.28	15.20	2.71	0.72	(0.04)	3.40	32.18	0.90	2.9%
		750	14.23	1.42	1.27	0.72	3.41	39.81	15.20	2.71	0.72	(0.04)	3.40	40.67	0.87	2.2%
		1000	14.23	1.42	1.27	0.72	3.41	48.33	15.20	2.71	0.72	(0.04)	3.40	49.17	0.84	1.7%
		1500	14.23	1.42	1.27	0.72	3.41	65.38	15.20	2.71	0.72	(0.04)	3.40	66.15	0.77	1.2%
		2000	14.23	1.42	1.27	0.72	3.41	82.43	15.20	2.71	0.72	(0.04)	3.40	83.13	0.70	0.8%

New Rate Class: R1

Bill Impacts of Proposed Distribution Rates including Riders

Classes		Scenario	Existing Dx Rates						New Dx Rates						$ Incr	% Incr
			SrChg	base	Rider1	Rider2	VarChg	[$/month]	SrChg	base	Rider2	Rider3	VarChg	[$/month]		
New Class	Old Class	kWh	[$/month	[c/kWh]	[c/kWh]	[c/kWh]	[c/kWh]		[$/month]	[c/kWh]	[c/kWh]	[c/kWh]	[c/kWh]			
R1	North Dorchester	100	8.97	0.86	0.67	0.40	1.93	10.90	10.52	2.25	0.40	(0.04)	2.61	13.13	2.23	20.5%
		250	8.97	0.86	0.67	0.40	1.93	13.80	10.52	2.25	0.40	(0.04)	2.61	17.05	3.25	23.6%
		500	8.97	0.86	0.67	0.40	1.93	18.62	10.52	2.25	0.40	(0.04)	2.61	23.58	4.96	26.6%
		750	8.97	0.86	0.67	0.40	1.93	23.45	10.52	2.25	0.40	(0.04)	2.61	30.11	6.67	28.4%
		1000	8.97	0.86	0.67	0.40	1.93	28.27	10.52	2.25	0.40	(0.04)	2.61	36.65	8.38	29.6%
		1500	8.97	0.86	0.67	0.40	1.93	37.92	10.52	2.25	0.40	(0.04)	2.61	49.71	11.79	31.1%
		2000	8.97	0.86	0.67	0.40	1.93	47.57	10.52	2.25	0.40	(0.04)	2.61	62.77	15.20	32.0%
R1	North Dundas	100	11.17	0.97	0.55	0.14	1.66	12.83	12.97	2.25	0.14	(0.04)	2.35	15.32	2.49	19.4%
		250	11.17	0.97	0.55	0.14	1.66	15.32	12.97	2.25	0.14	(0.04)	2.35	18.85	3.53	23.0%
		500	11.17	0.97	0.55	0.14	1.66	19.47	12.97	2.25	0.14	(0.04)	2.35	24.73	5.26	27.0%
		750	11.17	0.97	0.55	0.14	1.66	23.62	12.97	2.25	0.14	(0.04)	2.35	30.61	6.99	29.6%
		1000	11.17	0.97	0.55	0.14	1.66	27.77	12.97	2.25	0.14	(0.04)	2.35	36.50	8.73	31.4%
		1500	11.17	0.97	0.55	0.14	1.66	36.07	12.97	2.25	0.14	(0.04)	2.35	48.26	12.19	33.8%
		2000	11.17	0.97	0.55	0.14	1.66	44.37	12.97	2.25	0.14	(0.04)	2.35	60.02	15.65	35.3%
R1	North Glengarry	100	7.74	1.02	0.52	0.22	1.76	9.50	9.83	2.20	0.22	(0.04)	2.38	12.21	2.71	28.5%
		250	7.74	1.02	0.52	0.22	1.76	12.14	9.83	2.20	0.22	(0.04)	2.38	15.78	3.64	30.0%
		500	7.74	1.02	0.52	0.22	1.76	16.54	9.83	2.20	0.22	(0.04)	2.38	21.74	5.20	31.4%
		750	7.74	1.02	0.52	0.22	1.76	20.94	9.83	2.20	0.22	(0.04)	2.38	27.70	6.76	32.3%
		1000	7.74	1.02	0.52	0.22	1.76	25.34	9.83	2.20	0.22	(0.04)	2.38	33.65	8.31	32.8%
		1500	7.74	1.02	0.52	0.22	1.76	34.14	9.83	2.20	0.22	(0.04)	2.38	45.57	11.43	33.5%
		2000	7.74	1.02	0.52	0.22	1.76	42.94	9.83	2.20	0.22	(0.04)	2.38	57.48	14.54	33.9%
R1	North Grenville	100	14.40	1.65	0.37	0.16	2.18	16.58	15.16	2.71	0.16	(0.04)	2.84	18.00	1.42	8.5%
		250	14.40	1.65	0.37	0.16	2.18	19.85	15.16	2.71	0.16	(0.04)	2.84	22.25	2.40	12.1%
		500	14.40	1.65	0.37	0.16	2.18	25.30	15.16	2.71	0.16	(0.04)	2.84	29.34	4.04	16.0%
		750	14.40	1.65	0.37	0.16	2.18	30.75	15.16	2.71	0.16	(0.04)	2.84	36.43	5.68	18.5%
		1000	14.40	1.65	0.37	0.16	2.18	36.20	15.16	2.71	0.16	(0.04)	2.84	43.52	7.32	20.2%
		1500	14.40	1.65	0.37	0.16	2.18	47.10	15.16	2.71	0.16	(0.04)	2.84	57.70	10.60	22.5%
		2000	14.40	1.65	0.37	0.16	2.18	58.00	15.16	2.71	0.16	(0.04)	2.84	71.89	13.89	23.9%

New Rate Class: R1

Bill Impacts of Proposed Distribution Rates including Riders

Classes		Scenario	Existing Dx Rates						New Dx Rates						$ Incr	% Incr
			SrChg	base	Rider1	Rider2	VarChg	[$/month]	SrChg	base	Rider2	Rider3	VarChg	[$/month]		
New Class	**Old Class**	kWh	[$/month	[c/kWh]	[c/kWh]	[c/kWh]	[c/kWh]		[$/month]	[c/kWh]	[c/kWh]	[c/kWh]	[c/kWh]			
R1	**North Perth**	100	14.73	1.05	0.47	0.16	1.68	16.41	15.08	2.40	0.16	(0.04)	2.52	17.60	1.19	7.3%
		250	14.73	1.05	0.47	0.16	1.68	18.93	15.08	2.40	0.16	(0.04)	2.52	21.38	2.45	13.0%
		500	14.73	1.05	0.47	0.16	1.68	23.13	15.08	2.40	0.16	(0.04)	2.52	27.69	4.56	19.7%
		750	14.73	1.05	0.47	0.16	1.68	27.33	15.08	2.40	0.16	(0.04)	2.52	34.00	6.67	24.4%
		1000	14.73	1.05	0.47	0.16	1.68	31.53	15.08	2.40	0.16	(0.04)	2.52	40.31	8.78	27.8%
		1500	14.73	1.05	0.47	0.16	1.68	39.93	15.08	2.40	0.16	(0.04)	2.52	52.92	12.99	32.5%
		2000	14.73	1.05	0.47	0.16	1.68	48.33	15.08	2.40	0.16	(0.04)	2.52	65.53	17.20	35.6%
R1	**North Stormont**	100	5.42	0.92	0.62	0.36	1.90	7.32	8.41	2.10	0.36	(0.04)	2.42	10.83	3.51	47.9%
		250	5.42	0.92	0.62	0.36	1.90	10.17	8.41	2.10	0.36	(0.04)	2.42	14.46	4.29	42.2%
		500	5.42	0.92	0.62	0.36	1.90	14.92	8.41	2.10	0.36	(0.04)	2.42	20.52	5.60	37.5%
		750	5.42	0.92	0.62	0.36	1.90	19.67	8.41	2.10	0.36	(0.04)	2.42	26.58	6.91	35.1%
		1000	5.42	0.92	0.62	0.36	1.90	24.42	8.41	2.10	0.36	(0.04)	2.42	32.63	8.21	33.6%
		1500	5.42	0.92	0.62	0.36	1.90	33.92	8.41	2.10	0.36	(0.04)	2.42	44.75	10.83	31.9%
		2000	5.42	0.92	0.62	0.36	1.90	43.42	8.41	2.10	0.36	(0.04)	2.42	56.86	13.44	31.0%
R1	**Omemee**	100	14.99	1.50	0.36	0.14	2.00	16.99	15.01	2.71	0.14	(0.04)	2.82	17.83	0.84	4.9%
		250	14.99	1.50	0.36	0.14	2.00	19.99	15.01	2.71	0.14	(0.04)	2.82	22.05	2.06	10.3%
		500	14.99	1.50	0.36	0.14	2.00	24.99	15.01	2.71	0.14	(0.04)	2.82	29.09	4.10	16.4%
		750	14.99	1.50	0.36	0.14	2.00	29.99	15.01	2.71	0.14	(0.04)	2.82	36.13	6.14	20.5%
		1000	14.99	1.50	0.36	0.14	2.00	34.99	15.01	2.71	0.14	(0.04)	2.82	43.18	8.19	23.4%
		1500	14.99	1.50	0.36	0.14	2.00	44.99	15.01	2.71	0.14	(0.04)	2.82	57.26	12.27	27.3%
		2000	14.99	1.50	0.36	0.14	2.00	54.99	15.01	2.71	0.14	(0.04)	2.82	71.34	16.35	29.7%
UR	**Perth**	100	14.47	1.22	0.50	0.18	1.90	16.37	13.96	2.40	0.18	(0.02)	2.55	16.51	0.14	0.9%
		250	14.47	1.22	0.50	0.18	1.90	19.22	13.96	2.40	0.18	(0.02)	2.55	20.34	1.12	5.8%
		500	14.47	1.22	0.50	0.18	1.90	23.97	13.96	2.40	0.18	(0.02)	2.55	26.72	2.75	11.5%
		750	14.47	1.22	0.50	0.18	1.90	28.72	13.96	2.40	0.18	(0.02)	2.55	33.09	4.37	15.2%
		1000	14.47	1.22	0.50	0.18	1.90	33.47	13.96	2.40	0.18	(0.02)	2.55	39.47	6.00	17.9%
		1500	14.47	1.22	0.50	0.18	1.90	42.97	13.96	2.40	0.18	(0.02)	2.55	52.23	9.26	21.5%
		2000	14.47	1.22	0.50	0.18	1.90	52.47	13.96	2.40	0.18	(0.02)	2.55	64.98	12.51	23.8%

New Rate Class: R1

Bill Impacts of Proposed Distribution Rates including Riders

Classes		Scenario	Existing Dx Rates						New Dx Rates						$ Incr	% Incr
			SrChg	base	Rider1	Rider2	VarChg	[$/month]	SrChg	base	Rider2	Rider3	VarChg	[$/month]		
New Class	**Old Class**	kWh	[$/month	[c/kWh]	[c/kWh]	[c/kWh]	[c/kWh]		[$/month]	[c/kWh]	[c/kWh]	[c/kWh]	[c/kWh]			
R1	**Perth East**	100	5.95	0.78	0.26	0.06	1.10	7.05	8.27	1.60	0.06	(0.04)	1.62	9.90	2.85	40.4%
		250	5.95	0.78	0.26	0.06	1.10	8.70	8.27	1.60	0.06	(0.04)	1.62	12.33	3.63	41.7%
		500	5.95	0.78	0.26	0.06	1.10	11.45	8.27	1.60	0.06	(0.04)	1.62	16.39	4.94	43.1%
		750	5.95	0.78	0.26	0.06	1.10	14.20	8.27	1.60	0.06	(0.04)	1.62	20.44	6.24	44.0%
		1000	5.95	0.78	0.26	0.06	1.10	16.95	8.27	1.60	0.06	(0.04)	1.62	24.50	7.55	44.5%
		1500	5.95	0.78	0.26	0.06	1.10	22.45	8.27	1.60	0.06	(0.04)	1.62	32.62	10.17	45.3%
		2000	5.95	0.78	0.26	0.06	1.10	27.95	8.27	1.60	0.06	(0.04)	1.62	40.73	12.78	45.7%
R1	**Prince Edward**	100	14.25	1.05	0.39	0.13	1.57	15.82	15.20	2.25	0.13	(0.04)	2.34	17.54	1.72	10.9%
		250	14.25	1.05	0.39	0.13	1.57	18.18	15.20	2.25	0.13	(0.04)	2.34	21.05	2.88	15.8%
		500	14.25	1.05	0.39	0.13	1.57	22.10	15.20	2.25	0.13	(0.04)	2.34	26.91	4.81	21.8%
		750	14.25	1.05	0.39	0.13	1.57	26.03	15.20	2.25	0.13	(0.04)	2.34	32.77	6.74	25.9%
		1000	14.25	1.05	0.39	0.13	1.57	29.95	15.20	2.25	0.13	(0.04)	2.34	38.63	8.68	29.0%
		1500	14.25	1.05	0.39	0.13	1.57	37.80	15.20	2.25	0.13	(0.04)	2.34	50.34	12.54	33.2%
		2000	14.25	1.05	0.39	0.13	1.57	45.65	15.20	2.25	0.13	(0.04)	2.34	62.05	16.40	35.9%
UR	**Quinte West**	100	6.58	0.92	0.39	0.11	1.42	8.00	7.94	2.10	0.11	(0.02)	2.19	10.12	2.12	26.5%
		250	6.58	0.92	0.39	0.11	1.42	10.13	7.94	2.10	0.11	(0.02)	2.19	13.40	3.27	32.3%
		500	6.58	0.92	0.39	0.11	1.42	13.68	7.94	2.10	0.11	(0.02)	2.19	18.86	5.18	37.9%
		750	6.58	0.92	0.39	0.11	1.42	17.23	7.94	2.10	0.11	(0.02)	2.19	24.32	7.09	41.2%
		1000	6.58	0.92	0.39	0.11	1.42	20.78	7.94	2.10	0.11	(0.02)	2.19	29.79	9.01	43.3%
		1500	6.58	0.92	0.39	0.11	1.42	27.88	7.94	2.10	0.11	(0.02)	2.19	40.71	12.83	46.0%
		2000	6.58	0.92	0.39	0.11	1.42	34.98	7.94	2.10	0.11	(0.02)	2.19	51.64	16.66	47.6%
R1	**Rainy River**	100	15.04	1.02	0.75	0.50	2.27	17.31	16.00	2.65	0.50	(0.04)	3.11	19.11	1.80	10.4%
		250	15.04	1.02	0.75	0.50	2.27	20.72	16.00	2.65	0.50	(0.04)	3.11	23.78	3.07	14.8%
		500	15.04	1.02	0.75	0.50	2.27	26.39	16.00	2.65	0.50	(0.04)	3.11	31.56	5.17	19.6%
		750	15.04	1.02	0.75	0.50	2.27	32.07	16.00	2.65	0.50	(0.04)	3.11	39.35	7.28	22.7%
		1000	15.04	1.02	0.75	0.50	2.27	37.74	16.00	2.65	0.50	(0.04)	3.11	47.13	9.39	24.9%
		1500	15.04	1.02	0.75	0.50	2.27	49.09	16.00	2.65	0.50	(0.04)	3.11	62.69	13.60	27.7%
		2000	15.04	1.02	0.75	0.50	2.27	60.44	16.00	2.65	0.50	(0.04)	3.11	78.26	17.82	29.5%

New Rate Class: R1

Bill Impacts of Proposed Distribution Rates including Riders

Classes		Scenario	Existing Dx Rates						New Dx Rates						$ Incr	% Incr
			SrChg	base	Rider1	Rider2	VarChg	[$/month]	SrChg	base	Rider2	Rider3	VarChg	[$/month]		
New Class	**Old Class**	kWh	[$/month	[c/kWh]	[c/kWh]	[c/kWh]	[c/kWh]		[$/month]	[c/kWh]	[c/kWh]	[c/kWh]	[c/kWh]			
R1	**Ramara**	100	6.52	0.95	0.55	0.35	1.85	8.37	9.13	2.10	0.35	(0.04)	2.41	11.54	3.17	37.9%
		250	6.52	0.95	0.55	0.35	1.85	11.15	9.13	2.10	0.35	(0.04)	2.41	15.16	4.02	36.0%
		500	6.52	0.95	0.55	0.35	1.85	15.77	9.13	2.10	0.35	(0.04)	2.41	21.19	5.42	34.4%
		750	6.52	0.95	0.55	0.35	1.85	20.40	9.13	2.10	0.35	(0.04)	2.41	27.23	6.83	33.5%
		1000	6.52	0.95	0.55	0.35	1.85	25.02	9.13	2.10	0.35	(0.04)	2.41	33.26	8.24	32.9%
		1500	6.52	0.95	0.55	0.35	1.85	34.27	9.13	2.10	0.35	(0.04)	2.41	45.32	11.05	32.3%
		2000	6.52	0.95	0.55	0.35	1.85	43.52	9.13	2.10	0.35	(0.04)	2.41	57.39	13.87	31.9%
R1	**Red Rock**	100	15.21	2.07	0.77	0.54	3.38	18.59	15.96	2.71	0.54	(0.04)	3.22	19.17	0.58	3.1%
		250	15.21	2.07	0.77	0.54	3.38	23.66	15.96	2.71	0.54	(0.04)	3.22	24.00	0.34	1.4%
		500	15.21	2.07	0.77	0.54	3.38	32.11	15.96	2.71	0.54	(0.04)	3.22	32.04	(0.07)	-0.2%
		750	15.21	2.07	0.77	0.54	3.38	40.56	15.96	2.71	0.54	(0.04)	3.22	40.08	(0.48)	-1.2%
		1000	15.21	2.07	0.77	0.54	3.38	49.01	15.96	2.71	0.54	(0.04)	3.22	48.12	(0.89)	-1.8%
		1500	15.21	2.07	0.77	0.54	3.38	65.91	15.96	2.71	0.54	(0.04)	3.22	64.20	(1.71)	-2.6%
		2000	15.21	2.07	0.77	0.54	3.38	82.81	15.96	2.71	0.54	(0.04)	3.22	80.28	(2.53)	-3.1%
R1	**Rockland**	100	9.41	0.92	0.65	0.37	1.94	11.35	11.41	2.30	0.37	(0.04)	2.63	14.04	2.69	23.7%
		250	9.41	0.92	0.65	0.37	1.94	14.26	11.41	2.30	0.37	(0.04)	2.63	17.99	3.73	26.2%
		500	9.41	0.92	0.65	0.37	1.94	19.11	11.41	2.30	0.37	(0.04)	2.63	24.57	5.46	28.6%
		750	9.41	0.92	0.65	0.37	1.94	23.96	11.41	2.30	0.37	(0.04)	2.63	31.15	7.19	30.0%
		1000	9.41	0.92	0.65	0.37	1.94	28.81	11.41	2.30	0.37	(0.04)	2.63	37.74	8.93	31.0%
		1500	9.41	0.92	0.65	0.37	1.94	38.51	11.41	2.30	0.37	(0.04)	2.63	50.90	12.39	32.2%
		2000	9.41	0.92	0.65	0.37	1.94	48.21	11.41	2.30	0.37	(0.04)	2.63	64.06	15.85	32.9%
R1	**Russell**	100	13.11	1.44	0.28	0.11	1.83	14.94	14.48	2.50	0.11	(0.04)	2.57	17.06	2.12	14.2%
		250	13.11	1.44	0.28	0.11	1.83	17.69	14.48	2.50	0.11	(0.04)	2.57	20.91	3.23	18.3%
		500	13.11	1.44	0.28	0.11	1.83	22.26	14.48	2.50	0.11	(0.04)	2.57	27.35	5.09	22.9%
		750	13.11	1.44	0.28	0.11	1.83	26.84	14.48	2.50	0.11	(0.04)	2.57	33.78	6.94	25.9%
		1000	13.11	1.44	0.28	0.11	1.83	31.41	14.48	2.50	0.11	(0.04)	2.57	40.21	8.80	28.0%
		1500	13.11	1.44	0.28	0.11	1.83	40.56	14.48	2.50	0.11	(0.04)	2.57	53.08	12.52	30.9%
		2000	13.11	1.44	0.28	0.11	1.83	49.71	14.48	2.50	0.11	(0.04)	2.57	65.94	16.23	32.6%

New Rate Class: R1

Bill Impacts of Proposed Distribution Rates including Riders

Classes		**Scenario**	Existing Dx Rates						New Dx Rates						$ Incr	% Incr
			SrChg	base	Rider1	Rider2	VarChg	[$/month]	SrChg	base	Rider2	Rider3	VarChg	[$/month]		
New Class	**Old Class**	kWh	[$/month	[c/kWh]	[c/kWh]	[c/kWh]	[c/kWh]		[$/month]	[c/kWh]	[c/kWh]	[c/kWh]	[c/kWh]			
R1	**Schreiber**	100	16.32	1.84	0.68	0.44	2.96	19.28	16.68	2.71	0.44	(0.04)	3.12	19.80	0.52	2.7%
		250	16.32	1.84	0.68	0.44	2.96	23.72	16.68	2.71	0.44	(0.04)	3.12	24.47	0.75	3.2%
		500	16.32	1.84	0.68	0.44	2.96	31.12	16.68	2.71	0.44	(0.04)	3.12	32.26	1.14	3.7%
		750	16.32	1.84	0.68	0.44	2.96	38.52	16.68	2.71	0.44	(0.04)	3.12	40.05	1.53	4.0%
		1000	16.32	1.84	0.68	0.44	2.96	45.92	16.68	2.71	0.44	(0.04)	3.12	47.84	1.92	4.2%
		1500	16.32	1.84	0.68	0.44	2.96	60.72	16.68	2.71	0.44	(0.04)	3.12	63.42	2.70	4.5%
		2000	16.32	1.84	0.68	0.44	2.96	75.52	16.68	2.71	0.44	(0.04)	3.12	79.01	3.49	4.6%
R1	**Severn**	100	10.60	0.90	0.59	0.32	1.81	12.41	12.11	2.25	0.32	(0.04)	2.53	14.64	2.23	18.0%
		250	10.60	0.90	0.59	0.32	1.81	15.13	12.11	2.25	0.32	(0.04)	2.53	18.44	3.32	21.9%
		500	10.60	0.90	0.59	0.32	1.81	19.65	12.11	2.25	0.32	(0.04)	2.53	24.77	5.12	26.1%
		750	10.60	0.90	0.59	0.32	1.81	24.18	12.11	2.25	0.32	(0.04)	2.53	31.11	6.93	28.7%
		1000	10.60	0.90	0.59	0.32	1.81	28.70	12.11	2.25	0.32	(0.04)	2.53	37.44	8.74	30.4%
		1500	10.60	0.90	0.59	0.32	1.81	37.75	12.11	2.25	0.32	(0.04)	2.53	50.10	12.35	32.7%
		2000	10.60	0.90	0.59	0.32	1.81	46.80	12.11	2.25	0.32	(0.04)	2.53	62.77	15.97	34.1%
R1	**Shelburne**	100	14.14	1.33	0.39	0.14	1.86	16.00	15.23	2.55	0.14	(0.04)	2.65	17.88	1.88	11.7%
		250	14.14	1.33	0.39	0.14	1.86	18.79	15.23	2.55	0.14	(0.04)	2.65	21.86	3.07	16.3%
		500	14.14	1.33	0.39	0.14	1.86	23.44	15.23	2.55	0.14	(0.04)	2.65	28.49	5.05	21.5%
		750	14.14	1.33	0.39	0.14	1.86	28.09	15.23	2.55	0.14	(0.04)	2.65	35.12	7.03	25.0%
		1000	14.14	1.33	0.39	0.14	1.86	32.74	15.23	2.55	0.14	(0.04)	2.65	41.75	9.01	27.5%
		1500	14.14	1.33	0.39	0.14	1.86	42.04	15.23	2.55	0.14	(0.04)	2.65	55.02	12.98	30.9%
		2000	14.14	1.33	0.39	0.14	1.86	51.34	15.23	2.55	0.14	(0.04)	2.65	68.28	16.94	33.0%
UR	**Smiths Falls**	100	12.63	1.42	0.46	0.17	2.05	14.68	12.42	2.40	0.17	(0.02)	2.54	14.96	0.28	1.9%
		250	12.63	1.42	0.46	0.17	2.05	17.76	12.42	2.40	0.17	(0.02)	2.54	18.77	1.02	5.7%
		500	12.63	1.42	0.46	0.17	2.05	22.88	12.42	2.40	0.17	(0.02)	2.54	25.13	2.25	9.8%
		750	12.63	1.42	0.46	0.17	2.05	28.01	12.42	2.40	0.17	(0.02)	2.54	31.48	3.47	12.4%
		1000	12.63	1.42	0.46	0.17	2.05	33.13	12.42	2.40	0.17	(0.02)	2.54	37.83	4.70	14.2%
		1500	12.63	1.42	0.46	0.17	2.05	43.38	12.42	2.40	0.17	(0.02)	2.54	50.54	7.16	16.5%
		2000	12.63	1.42	0.46	0.17	2.05	53.63	12.42	2.40	0.17	(0.02)	2.54	63.24	9.61	17.9%

New Rate Class: R1

Bill Impacts of Proposed Distribution Rates including Riders

Classes		Scenario	Existing Dx Rates						New Dx Rates						$ Incr	% Incr
			SrChg	base	Rider1	Rider2	VarChg	[$/month]	SrChg	base	Rider2	Rider3	VarChg	[$/month]		
New Class	Old Class	kWh	[$/month	[c/kWh]	[c/kWh]	[c/kWh]	[c/kWh]		[$/month]	[c/kWh]	[c/kWh]	[c/kWh]	[c/kWh]			
R1	**South Glengarry**	100	9.46	0.75	0.52	0.36	1.63	11.09	11.40	1.95	0.36	(0.04)	2.27	13.67	2.58	23.2%
		250	9.46	0.75	0.52	0.36	1.63	13.54	11.40	1.95	0.36	(0.04)	2.27	17.08	3.54	26.2%
		500	9.46	0.75	0.52	0.36	1.63	17.61	11.40	1.95	0.36	(0.04)	2.27	22.76	5.15	29.2%
		750	9.46	0.75	0.52	0.36	1.63	21.69	11.40	1.95	0.36	(0.04)	2.27	28.44	6.76	31.2%
		1000	9.46	0.75	0.52	0.36	1.63	25.76	11.40	1.95	0.36	(0.04)	2.27	34.12	8.36	32.5%
		1500	9.46	0.75	0.52	0.36	1.63	33.91	11.40	1.95	0.36	(0.04)	2.27	45.49	11.58	34.1%
		2000	9.46	0.75	0.52	0.36	1.63	42.06	11.40	1.95	0.36	(0.04)	2.27	56.85	14.79	35.2%
R1	**South River**	100	14.22	1.25	0.63	0.41	2.29	16.51	15.21	2.71	0.41	(0.04)	3.09	18.29	1.78	10.8%
		250	14.22	1.25	0.63	0.41	2.29	19.95	15.21	2.71	0.41	(0.04)	3.09	22.92	2.98	14.9%
		500	14.22	1.25	0.63	0.41	2.29	25.67	15.21	2.71	0.41	(0.04)	3.09	30.64	4.97	19.3%
		750	14.22	1.25	0.63	0.41	2.29	31.40	15.21	2.71	0.41	(0.04)	3.09	38.35	6.96	22.2%
		1000	14.22	1.25	0.63	0.41	2.29	37.12	15.21	2.71	0.41	(0.04)	3.09	46.07	8.95	24.1%
		1500	14.22	1.25	0.63	0.41	2.29	48.57	15.21	2.71	0.41	(0.04)	3.09	61.50	12.93	26.6%
		2000	14.22	1.25	0.63	0.41	2.29	60.02	15.21	2.71	0.41	(0.04)	3.09	76.93	16.91	28.2%
R1	**Springwater**	100	11.79	0.82	0.61	0.31	1.74	13.53	12.81	2.25	0.31	(0.04)	2.52	15.34	1.81	13.3%
		250	11.79	0.82	0.61	0.31	1.74	16.14	12.81	2.25	0.31	(0.04)	2.52	19.12	2.98	18.5%
		500	11.79	0.82	0.61	0.31	1.74	20.49	12.81	2.25	0.31	(0.04)	2.52	25.43	4.94	24.1%
		750	11.79	0.82	0.61	0.31	1.74	24.84	12.81	2.25	0.31	(0.04)	2.52	31.73	6.89	27.8%
		1000	11.79	0.82	0.61	0.31	1.74	29.19	12.81	2.25	0.31	(0.04)	2.52	38.04	8.85	30.3%
		1500	11.79	0.82	0.61	0.31	1.74	37.89	12.81	2.25	0.31	(0.04)	2.52	50.66	12.77	33.7%
		2000	11.79	0.82	0.61	0.31	1.74	46.59	12.81	2.25	0.31	(0.04)	2.52	63.27	16.68	35.8%
R1	**Stirling-Rawdon**	100	12.55	1.03	0.38	0.12	1.53	14.08	13.62	2.20	0.12	(0.04)	2.28	15.91	1.83	13.0%
		250	12.55	1.03	0.38	0.12	1.53	16.38	13.62	2.20	0.12	(0.04)	2.28	19.33	2.95	18.0%
		500	12.55	1.03	0.38	0.12	1.53	20.20	13.62	2.20	0.12	(0.04)	2.28	25.04	4.84	23.9%
		750	12.55	1.03	0.38	0.12	1.53	24.03	13.62	2.20	0.12	(0.04)	2.28	30.74	6.72	28.0%
		1000	12.55	1.03	0.38	0.12	1.53	27.85	13.62	2.20	0.12	(0.04)	2.28	36.45	8.60	30.9%
		1500	12.55	1.03	0.38	0.12	1.53	35.50	13.62	2.20	0.12	(0.04)	2.28	47.87	12.37	34.8%
		2000	12.55	1.03	0.38	0.12	1.53	43.15	13.62	2.20	0.12	(0.04)	2.28	59.28	16.13	37.4%

New Rate Class: R1

Bill Impacts of Proposed Distribution Rates including Riders

Classes		Scenario	Existing Dx Rates						New Dx Rates						$ Incr	% Incr
			SrChg	base	Rider1	Rider2	VarChg	[$/month]	SrChg	base	Rider2	Rider3	VarChg	[$/month]		
New Class	Old Class	kWh	[$/month	[c/kWh]	[c/kWh]	[c/kWh]	[c/kWh]		[$/month]	[c/kWh]	[c/kWh]	[c/kWh]	[c/kWh]			
R1	Thedford	100	12.75	0.81	0.82	0.52	2.15	14.90	13.57	2.50	0.52	(0.04)	2.98	16.56	1.66	11.1%
		250	12.75	0.81	0.82	0.52	2.15	18.13	13.57	2.50	0.52	(0.04)	2.98	21.03	2.90	16.0%
		500	12.75	0.81	0.82	0.52	2.15	23.50	13.57	2.50	0.52	(0.04)	2.98	28.49	4.99	21.2%
		750	12.75	0.81	0.82	0.52	2.15	28.88	13.57	2.50	0.52	(0.04)	2.98	35.94	7.07	24.5%
		1000	12.75	0.81	0.82	0.52	2.15	34.25	13.57	2.50	0.52	(0.04)	2.98	43.40	9.15	26.7%
		1500	12.75	0.81	0.82	0.52	2.15	45.00	13.57	2.50	0.52	(0.04)	2.98	58.32	13.32	29.6%
		2000	12.75	0.81	0.82	0.52	2.15	55.75	13.57	2.50	0.52	(0.04)	2.98	73.23	17.48	31.4%
R1	Thessalon	100	15.56	1.05	0.28	0.12	1.45	17.01	15.87	2.20	0.12	(0.04)	2.28	18.15	1.14	6.7%
		250	15.56	1.05	0.28	0.12	1.45	19.19	15.87	2.20	0.12	(0.04)	2.28	21.58	2.39	12.5%
		500	15.56	1.05	0.28	0.12	1.45	22.81	15.87	2.20	0.12	(0.04)	2.28	27.28	4.47	19.6%
		750	15.56	1.05	0.28	0.12	1.45	26.44	15.87	2.20	0.12	(0.04)	2.28	32.99	6.56	24.8%
		1000	15.56	1.05	0.28	0.12	1.45	30.06	15.87	2.20	0.12	(0.04)	2.28	38.70	8.64	28.7%
		1500	15.56	1.05	0.28	0.12	1.45	37.31	15.87	2.20	0.12	(0.04)	2.28	50.11	12.80	34.3%
		2000	15.56	1.05	0.28	0.12	1.45	44.56	15.87	2.20	0.12	(0.04)	2.28	61.53	16.97	38.1%
R1	Thorndale	100	4.32	0.88	0.62	0.32	1.82	6.14	7.68	2.00	0.32	(0.04)	2.28	9.96	3.82	62.3%
		250	4.32	0.88	0.62	0.32	1.82	8.87	7.68	2.00	0.32	(0.04)	2.28	13.39	4.52	50.9%
		500	4.32	0.88	0.62	0.32	1.82	13.42	7.68	2.00	0.32	(0.04)	2.28	19.09	5.67	42.3%
		750	4.32	0.88	0.62	0.32	1.82	17.97	7.68	2.00	0.32	(0.04)	2.28	24.80	6.83	38.0%
		1000	4.32	0.88	0.62	0.32	1.82	22.52	7.68	2.00	0.32	(0.04)	2.28	30.51	7.99	35.5%
		1500	4.32	0.88	0.62	0.32	1.82	31.62	7.68	2.00	0.32	(0.04)	2.28	41.92	10.30	32.6%
		2000	4.32	0.88	0.62	0.32	1.82	40.72	7.68	2.00	0.32	(0.04)	2.28	53.34	12.62	31.0%
UR	Thorold	100	13.68	1.47	0.41	0.14	2.02	15.70	13.16	2.40	0.14	(0.02)	2.51	15.67	(0.03)	-0.2%
		250	13.68	1.47	0.41	0.14	2.02	18.73	13.16	2.40	0.14	(0.02)	2.51	19.44	0.71	3.8%
		500	13.68	1.47	0.41	0.14	2.02	23.78	13.16	2.40	0.14	(0.02)	2.51	25.71	1.93	8.1%
		750	13.68	1.47	0.41	0.14	2.02	28.83	13.16	2.40	0.14	(0.02)	2.51	31.99	3.16	11.0%
		1000	13.68	1.47	0.41	0.14	2.02	33.88	13.16	2.40	0.14	(0.02)	2.51	38.27	4.39	13.0%
		1500	13.68	1.47	0.41	0.14	2.02	43.98	13.16	2.40	0.14	(0.02)	2.51	50.82	6.84	15.6%
		2000	13.68	1.47	0.41	0.14	2.02	54.08	13.16	2.40	0.14	(0.02)	2.51	63.38	9.30	17.2%

New Rate Class: R1

Bill Impacts of Proposed Distribution Rates including Riders

Classes		Scenario	Existing Dx Rates						New Dx Rates						$ Incr	% Incr
			SrChg	base	Rider1	Rider2	VarChg	[$/month]	SrChg	base	Rider2	Rider3	VarChg	[$/month]		
New Class	**Old Class**	kWh	[$/month	[c/kWh]	[c/kWh]	[c/kWh]	[c/kWh]		[$/month]	[c/kWh]	[c/kWh]	[c/kWh]	[c/kWh]			
R1	**Tweed**	100	4.48	0.95	0.61	0.37	1.93	6.41	7.64	2.10	0.37	(0.04)	2.43	10.07	3.66	57.1%
		250	4.48	0.95	0.61	0.37	1.93	9.31	7.64	2.10	0.37	(0.04)	2.43	13.72	4.42	47.5%
		500	4.48	0.95	0.61	0.37	1.93	14.13	7.64	2.10	0.37	(0.04)	2.43	19.80	5.67	40.2%
		750	4.48	0.95	0.61	0.37	1.93	18.96	7.64	2.10	0.37	(0.04)	2.43	25.89	6.93	36.6%
		1000	4.48	0.95	0.61	0.37	1.93	23.78	7.64	2.10	0.37	(0.04)	2.43	31.97	8.19	34.4%
		1500	4.48	0.95	0.61	0.37	1.93	33.43	7.64	2.10	0.37	(0.04)	2.43	44.13	10.70	32.0%
		2000	4.48	0.95	0.61	0.37	1.93	43.08	7.64	2.10	0.37	(0.04)	2.43	56.30	13.22	30.7%
R1	**Wardsville**	100	9.64	0.97	0.36	0.10	1.43	11.07	11.35	2.00	0.10	(0.04)	2.06	13.41	2.34	21.2%
		250	9.64	0.97	0.36	0.10	1.43	13.22	11.35	2.00	0.10	(0.04)	2.06	16.51	3.29	24.9%
		500	9.64	0.97	0.36	0.10	1.43	16.79	11.35	2.00	0.10	(0.04)	2.06	21.66	4.87	29.0%
		750	9.64	0.97	0.36	0.10	1.43	20.37	11.35	2.00	0.10	(0.04)	2.06	26.82	6.46	31.7%
		1000	9.64	0.97	0.36	0.10	1.43	23.94	11.35	2.00	0.10	(0.04)	2.06	31.98	8.04	33.6%
		1500	9.64	0.97	0.36	0.10	1.43	31.09	11.35	2.00	0.10	(0.04)	2.06	42.29	11.20	36.0%
		2000	9.64	0.97	0.36	0.10	1.43	38.24	11.35	2.00	0.10	(0.04)	2.06	52.61	14.37	37.6%
R1	**Warkworth**	100	15.25	1.18	0.66	0.43	2.27	17.52	15.95	2.71	0.43	(0.04)	3.11	19.05	1.53	8.8%
		250	15.25	1.18	0.66	0.43	2.27	20.93	15.95	2.71	0.43	(0.04)	3.11	23.71	2.79	13.3%
		500	15.25	1.18	0.66	0.43	2.27	26.60	15.95	2.71	0.43	(0.04)	3.11	31.48	4.88	18.3%
		750	15.25	1.18	0.66	0.43	2.27	32.28	15.95	2.71	0.43	(0.04)	3.11	39.24	6.97	21.6%
		1000	15.25	1.18	0.66	0.43	2.27	37.95	15.95	2.71	0.43	(0.04)	3.11	47.01	9.06	23.9%
		1500	15.25	1.18	0.66	0.43	2.27	49.30	15.95	2.71	0.43	(0.04)	3.11	62.54	13.24	26.9%
		2000	15.25	1.18	0.66	0.43	2.27	60.65	15.95	2.71	0.43	(0.04)	3.11	78.07	17.42	28.7%
R1	**West Elgin**	100	13.30	1.42	0.63	0.35	2.40	15.70	14.44	2.71	0.35	(0.04)	3.03	17.46	1.76	11.2%
		250	13.30	1.42	0.63	0.35	2.40	19.30	14.44	2.71	0.35	(0.04)	3.03	22.00	2.70	14.0%
		500	13.30	1.42	0.63	0.35	2.40	25.30	14.44	2.71	0.35	(0.04)	3.03	29.57	4.27	16.9%
		750	13.30	1.42	0.63	0.35	2.40	31.30	14.44	2.71	0.35	(0.04)	3.03	37.13	5.83	18.6%
		1000	13.30	1.42	0.63	0.35	2.40	37.30	14.44	2.71	0.35	(0.04)	3.03	44.70	7.40	19.8%
		1500	13.30	1.42	0.63	0.35	2.40	49.30	14.44	2.71	0.35	(0.04)	3.03	59.83	10.53	21.4%
		2000	13.30	1.42	0.63	0.35	2.40	61.30	14.44	2.71	0.35	(0.04)	3.03	74.96	13.66	22.3%

New Rate Class: R1

Bill Impacts of Proposed Distribution Rates including Riders

Classes		Scenario	Existing Dx Rates						New Dx Rates						$ Incr	% Incr
			SrChg	base	Rider1	Rider2	VarChg	[$/month]	SrChg	base	Rider2	Rider3	VarChg	[$/month]		
New Class	**Old Class**	kWh	[$/month	[c/kWh]	[c/kWh]	[c/kWh]	[c/kWh]		[$/month]	[c/kWh]	[c/kWh]	[c/kWh]	[c/kWh]			
UR	**Whitchurch Stouffville**	100	10.54	1.02	0.36	0.12	1.50	12.04	10.95	2.30	0.12	(0.02)	2.40	13.34	1.30	10.8%
		250	10.54	1.02	0.36	0.12	1.50	14.29	10.95	2.30	0.12	(0.02)	2.40	16.93	2.64	18.5%
		500	10.54	1.02	0.36	0.12	1.50	18.04	10.95	2.30	0.12	(0.02)	2.40	22.92	4.88	27.1%
		750	10.54	1.02	0.36	0.12	1.50	21.79	10.95	2.30	0.12	(0.02)	2.40	28.91	7.12	32.7%
		1000	10.54	1.02	0.36	0.12	1.50	25.54	10.95	2.30	0.12	(0.02)	2.40	34.90	9.36	36.6%
		1500	10.54	1.02	0.36	0.12	1.50	33.04	10.95	2.30	0.12	(0.02)	2.40	46.87	13.83	41.9%
		2000	10.54	1.02	0.36	0.12	1.50	40.54	10.95	2.30	0.12	(0.02)	2.40	58.85	18.31	45.2%
R1	**Wiarton**	100	15.83	1.55	0.37	0.14	2.06	17.89	15.80	2.71	0.14	(0.04)	2.82	18.62	0.73	4.1%
		250	15.83	1.55	0.37	0.14	2.06	20.98	15.80	2.71	0.14	(0.04)	2.82	22.84	1.86	8.9%
		500	15.83	1.55	0.37	0.14	2.06	26.13	15.80	2.71	0.14	(0.04)	2.82	29.88	3.75	14.4%
		750	15.83	1.55	0.37	0.14	2.06	31.28	15.80	2.71	0.14	(0.04)	2.82	36.92	5.64	18.0%
		1000	15.83	1.55	0.37	0.14	2.06	36.43	15.80	2.71	0.14	(0.04)	2.82	43.97	7.54	20.7%
		1500	15.83	1.55	0.37	0.14	2.06	46.73	15.80	2.71	0.14	(0.04)	2.82	58.05	11.32	24.2%
		2000	15.83	1.55	0.37	0.14	2.06	57.03	15.80	2.71	0.14	(0.04)	2.82	72.13	15.10	26.5%
R1	**Woodville**	100	3.78	0.95	0.51	0.26	1.72	5.50	6.82	2.00	0.26	(0.04)	2.22	9.04	3.54	64.3%
		250	3.78	0.95	0.51	0.26	1.72	8.08	6.82	2.00	0.26	(0.04)	2.22	12.37	4.29	53.1%
		500	3.78	0.95	0.51	0.26	1.72	12.38	6.82	2.00	0.26	(0.04)	2.22	17.93	5.55	44.8%
		750	3.78	0.95	0.51	0.26	1.72	16.68	6.82	2.00	0.26	(0.04)	2.22	23.49	6.81	40.8%
		1000	3.78	0.95	0.51	0.26	1.72	20.98	6.82	2.00	0.26	(0.04)	2.22	29.04	8.06	38.4%
		1500	3.78	0.95	0.51	0.26	1.72	29.58	6.82	2.00	0.26	(0.04)	2.22	40.16	10.58	35.8%
		2000	3.78	0.95	0.51	0.26	1.72	38.18	6.82	2.00	0.26	(0.04)	2.22	51.27	13.09	34.3%
R1	**Wyoming**	100	11.52	0.81	0.36	0.11	1.28	12.80	12.88	1.90	0.11	(0.04)	1.97	14.85	2.05	16.0%
		250	11.52	0.81	0.36	0.11	1.28	14.72	12.88	1.90	0.11	(0.04)	1.97	17.81	3.09	21.0%
		500	11.52	0.81	0.36	0.11	1.28	17.92	12.88	1.90	0.11	(0.04)	1.97	22.74	4.82	26.9%
		750	11.52	0.81	0.36	0.11	1.28	21.12	12.88	1.90	0.11	(0.04)	1.97	27.68	6.56	31.0%
		1000	11.52	0.81	0.36	0.11	1.28	24.32	12.88	1.90	0.11	(0.04)	1.97	32.61	8.29	34.1%
		1500	11.52	0.81	0.36	0.11	1.28	30.72	12.88	1.90	0.11	(0.04)	1.97	42.47	11.75	38.3%
		2000	11.52	0.81	0.36	0.11	1.28	37.12	12.88	1.90	0.11	(0.04)	1.97	52.34	15.22	41.0%

New Rate Class: R1

Bill Impacts of Proposed Distribution Rates including Riders

Classes		**Scenario**	Existing Dx Rates						New Dx Rates						$ Incr	% Incr
			SrChg	base	Rider1	Rider2	VarChg	[$/month]	SrChg	base	Rider2	Rider3	VarChg	[$/month]		
New Class	**Old Class**	kWh	[$/month	[c/kWh]	[c/kWh]	[c/kWh]	[c/kWh]		[$/month]	[c/kWh]	[c/kWh]	[c/kWh]	[c/kWh]			
R1	**Terrace Bay**	100	20.81	1.45	0.97	-	2.42	23.23	19.56	2.71	-	(0.04)	2.68	22.23	(1.00)	-4.3%
		250	20.81	1.45	0.97	-	2.42	26.86	19.56	2.71	-	(0.04)	2.68	26.25	(0.61)	-2.3%
		500	20.81	1.45	0.97	-	2.42	32.91	19.56	2.71	-	(0.04)	2.68	32.94	0.03	0.1%
		750	20.81	1.45	0.97	-	2.42	38.96	19.56	2.71	-	(0.04)	2.68	39.63	0.67	1.7%
		1000	20.81	1.45	0.97	-	2.42	45.01	19.56	2.71	-	(0.04)	2.68	46.32	1.31	2.9%
		1500	20.81	1.45	0.97	-	2.42	57.11	19.56	2.71	-	(0.04)	2.68	59.70	2.59	4.5%
		2000	20.81	1.45	0.97	-	2.42	69.21	19.56	2.71	-	(0.04)	2.68	73.08	3.87	5.6%

New Rate Class: R2

Bill Impacts of Proposed Distribution Rates including Riders

Classes		Scenario	Existing Dx Rates						New Dx Rates						$ Incr	% Incr
New Class	Old Class	kWh	SrChg [$/month]	base [c/kWh]	Rider1 [c/kWh]	Rider2 [c/kWh]	VarChg [c/kWh]	[$/month]	SrChg [$/month]	base [c/kWh]	Rider2 [c/kWh]	Rider3 [c/kWh]	VarChg [c/kWh]	[$/month]		
R2	**R2**	100	29.22	1.94	0.12	0.13	2.19	31.41	27.05	2.68	0.13	(0.05)	2.76	29.80	(1.61)	-5.1%
		250	29.22	1.94	0.12	0.13	2.19	34.70	27.05	2.68	0.13	(0.05)	2.76	33.94	(0.75)	-2.2%
		500	29.22	1.94	0.12	0.13	2.19	40.17	27.05	2.68	0.13	(0.05)	2.76	40.84	0.67	1.7%
		750	29.22	1.94	0.12	0.13	2.19	45.65	27.05	2.68	0.13	(0.05)	2.76	47.73	2.09	4.6%
		1,000	29.22	1.94	0.12	0.13	2.19	51.12	27.05	2.68	0.13	(0.05)	2.76	54.62	3.50	6.9%
		1,500	29.22	1.94	0.12	0.13	2.19	62.07	27.05	2.68	0.13	(0.05)	2.76	68.41	6.34	10.2%
		2,000	29.22	1.94	0.12	0.13	2.19	73.02	27.05	2.68	0.13	(0.05)	2.76	82.20	9.18	12.6%
			-	-	-	-	-	-								
R2	**F1**	100	28.61	2.24	0.08	0.10	2.42	31.03	26.20	2.68	0.10	(0.05)	2.73	28.93	(2.10)	-6.8%
		250	28.61	2.24	0.08	0.10	2.42	34.66	26.20	2.68	0.10	(0.05)	2.73	33.02	(1.64)	-4.7%
		500	28.61	2.24	0.08	0.10	2.42	40.71	26.20	2.68	0.10	(0.05)	2.73	39.84	(0.87)	-2.1%
		750	28.61	2.24	0.08	0.10	2.42	46.76	26.20	2.68	0.10	(0.05)	2.73	46.66	(0.10)	-0.2%
		1,000	28.61	2.24	0.08	0.10	2.42	52.81	26.20	2.68	0.10	(0.05)	2.73	53.48	0.67	1.3%
		1,500	28.61	2.24	0.08	0.10	2.42	64.91	26.20	2.68	0.10	(0.05)	2.73	67.12	2.21	3.4%
		2,000	28.61	2.24	0.08	0.10	2.42	77.01	26.20	2.68	0.10	(0.05)	2.73	80.76	3.75	4.9%
			-	-	-	-	-	-								
R2	**F3**	100	30.16	2.89	0.03	0.04	2.96	33.12	27.81	2.68	0.04	(0.05)	2.67	30.48	(2.64)	-8.0%
		250	30.16	2.89	0.03	0.04	2.96	37.56	27.81	2.68	0.04	(0.05)	2.67	34.48	(3.08)	-8.2%
		500	30.16	2.89	0.03	0.04	2.96	44.96	27.81	2.68	0.04	(0.05)	2.67	41.15	(3.81)	-8.5%
		750	30.16	2.89	0.03	0.04	2.96	52.36	27.81	2.68	0.04	(0.05)	2.67	47.82	(4.54)	-8.7%
		1,000	30.16	2.89	0.03	0.04	2.96	59.76	27.81	2.68	0.04	(0.05)	2.67	54.49	(5.27)	-8.8%
		1,500	30.16	2.89	0.03	0.04	2.96	74.56	27.81	2.68	0.04	(0.05)	2.67	67.83	(6.73)	-9.0%
		2,000	30.16	2.89	0.03	0.04	2.96	89.36	27.81	2.68	0.04	(0.05)	2.67	81.17	(8.19)	-9.2%
			-	-	-	-	-	-								
R2	**Caledon OH 06**	100	34.85	0.50	0.25	0.11	0.86	35.71	30.64	2.20	0.11	(0.05)	2.26	32.90	(2.81)	-7.9%
		250	34.85	0.50	0.25	0.11	0.86	37.00	30.64	2.20	0.11	(0.05)	2.26	36.29	(0.71)	-1.9%
		500	34.85	0.50	0.25	0.11	0.86	39.15	30.64	2.20	0.11	(0.05)	2.26	41.94	2.79	7.1%
		750	34.85	0.50	0.25	0.11	0.86	41.30	30.64	2.20	0.11	(0.05)	2.26	47.60	6.30	15.2%
		1,000	34.85	0.50	0.25	0.11	0.86	43.45	30.64	2.20	0.11	(0.05)	2.26	53.25	9.80	22.6%
		1,500	34.85	0.50	0.25	0.11	0.86	47.75	30.64	2.20	0.11	(0.05)	2.26	64.56	16.81	35.2%
		2,000	34.85	0.50	0.25	0.11	0.86	52.05	30.64	2.20	0.11	(0.05)	2.26	75.86	23.81	45.7%

New Rate Class: Seasonal

Bill Impacts of Proposed Distribution Rates including Riders

Classes		Scenario	Existing Dx Rates						New Dx Rates						$ Incr	% Incr
			SrChg	base	Rider1	Rider2	VarChg	[$/month]	SrChg	base	Rider2	Rider3	VarChg	[$/month]		
New Class	**Old Class**	kWh	[$/month]	[c/kWh]	[c/kWh]	[c/kWh]	[c/kWh]		[$/month]	[c/kWh]	[c/kWh]	[c/kWh]	[c/kWh]			
Seasonal	**R3**	100	19.51	2.74	0.35	0.15	3.24	22.75	19.00	4.69	0.15	0.02	4.86	23.86	1.11	4.9%
		250	19.51	2.74	0.35	0.15	3.24	27.61	19.00	4.69	0.15	0.02	4.86	31.14	3.53	12.8%
		500	19.51	2.74	0.35	0.15	3.24	35.71	19.00	4.69	0.15	0.02	4.86	43.28	7.57	21.2%
		750	19.51	2.74	0.35	0.15	3.24	43.81	19.00	4.69	0.15	0.02	4.86	55.42	11.61	26.5%
		1,000	19.51	2.74	0.35	0.15	3.24	51.91	19.00	4.69	0.15	0.02	4.86	67.56	15.65	30.1%
		1,500	19.51	2.74	0.35	0.15	3.24	68.11	19.00	4.69	0.15	0.02	4.86	91.84	23.73	34.8%
		2,000	19.51	2.74	0.35	0.15	3.24	84.31	19.00	4.69	0.15	0.02	4.86	116.12	31.81	37.7%
Seasonal	**R4**	100	36.36	1.92	0.36	0.24	2.52	38.88	31.79	4.70	0.24	0.02	4.95	36.74	(2.14)	-5.5%
		250	36.36	1.92	0.36	0.24	2.52	42.66	31.79	4.70	0.24	0.02	4.95	44.17	1.51	3.5%
		500	36.36	1.92	0.36	0.24	2.52	48.96	31.79	4.70	0.24	0.02	4.95	56.56	7.60	15.5%
		750	36.36	1.92	0.36	0.24	2.52	55.26	31.79	4.70	0.24	0.02	4.95	68.94	13.68	24.8%
		1,000	36.36	1.92	0.36	0.24	2.52	61.56	31.79	4.70	0.24	0.02	4.95	81.33	19.77	32.1%
		1,500	36.36	1.92	0.36	0.24	2.52	74.16	31.79	4.70	0.24	0.02	4.95	106.10	31.94	43.1%
		2,000	36.36	1.92	0.36	0.24	2.52	86.76	31.79	4.70	0.24	0.02	4.95	130.87	44.11	50.8%
Seasonal	**Caledon OH 07**	100	38.78	1.04	0.43	0.25	1.72	40.50	33.18	3.20	0.25	0.02	3.47	36.65	(3.85)	-9.5%
		250	38.78	1.04	0.43	0.25	1.72	43.08	33.18	3.20	0.25	0.02	3.47	41.85	(1.23)	-2.9%
		500	38.78	1.04	0.43	0.25	1.72	47.38	33.18	3.20	0.25	0.02	3.47	50.52	3.14	6.6%
		750	38.78	1.04	0.43	0.25	1.72	51.68	33.18	3.20	0.25	0.02	3.47	59.18	7.50	14.5%
		1,000	38.78	1.04	0.43	0.25	1.72	55.98	33.18	3.20	0.25	0.02	3.47	67.85	11.87	21.2%
		1,500	38.78	1.04	0.43	0.25	1.72	64.58	33.18	3.20	0.25	0.02	3.47	85.18	20.60	31.9%
		2,000	38.78	1.04	0.43	0.25	1.72	73.18	33.18	3.20	0.25	0.02	3.47	102.52	29.34	40.1%

New Rate Class: UGe

Bill Impacts of Proposed Distribution Rates include Riders

Classes		Scenario	Existing Dx Rates						New Dx Rates						$ Incr	% Incr
			SrChg	base	Rider1	Rider2	VarChg	[$/month]	SrChg	base	Rider2	Rider3	VarChg	[$/month]		
New Class	Old Class	kWh	[$/month]	[c/kWh]	[c/kWh]	[c/kWh]	[c/kWh]		[$/month]	[c/kWh]	[c/kWh]	[c/kWh]	[c/kWh]			
UGe	UG	1,000	15.79	2.74	0.03	0.03	2.80	43.79	14.27	2.00	0.03	(0.06)	1.98	34.03	(9.76)	-22.3%
		2,000	15.79	2.74	0.03	0.03	2.80	71.79	14.27	2.00	0.03	(0.06)	1.98	53.78	(18.01)	-25.1%
		5,000	15.79	2.74	0.03	0.03	2.80	155.79	14.27	2.00	0.03	(0.06)	1.98	113.04	(42.75)	-27.4%
		10,000	15.79	2.74	0.03	0.03	2.80	295.79	14.27	2.00	0.03	(0.06)	1.98	211.81	(83.98)	-28.4%
		15,000	15.79	2.74	0.03	0.03	2.80	435.79	14.27	2.00	0.03	(0.06)	1.98	310.58	(125.21)	-28.7%
UGe	F1	1,000	60.71	2.24	0.08	0.10	2.42	84.91	14.27	2.00	0.03	(0.06)	1.98	34.03	(50.88)	-59.9%
		2,000	60.71	2.24	0.08	0.10	2.42	109.11	14.27	2.00	0.03	(0.06)	1.98	53.78	(55.33)	-50.7%
		5,000	60.71	2.24	0.08	0.10	2.42	181.71	14.27	2.00	0.03	(0.06)	1.98	113.04	(68.67)	-37.8%
		10,000	60.71	2.24	0.08	0.10	2.42	302.71	14.27	2.00	0.03	(0.06)	1.98	211.81	(90.90)	-30.0%
		15,000	60.71	2.24	0.08	0.10	2.42	423.71	14.27	2.00	0.03	(0.06)	1.98	310.58	(113.13)	-26.7%
UGe	G1	1,000	36.93	3.12	0.09	0.09	3.30	69.93	14.27	2.00	0.03	(0.06)	1.98	34.03	(35.90)	-51.3%
		2,000	36.93	3.12	0.09	0.09	3.30	102.93	14.27	2.00	0.03	(0.06)	1.98	53.78	(49.15)	-47.8%
		5,000	36.93	3.12	0.09	0.09	3.30	201.93	14.27	2.00	0.03	(0.06)	1.98	113.04	(88.89)	-44.0%
		10,000	36.93	3.12	0.09	0.09	3.30	366.93	14.27	2.00	0.03	(0.06)	1.98	211.81	(155.12)	-42.3%
		15,000	36.93	3.12	0.09	0.09	3.30	531.93	14.27	2.00	0.03	(0.06)	1.98	310.58	(221.35)	-41.6%
UGe	G3	1,000	46.78	3.07	0.02	0.05	3.14	78.18	14.27	2.00	0.03	(0.06)	1.98	34.03	(44.15)	-56.5%
		2,000	46.78	3.07	0.02	0.05	3.14	109.58	14.27	2.00	0.03	(0.06)	1.98	53.78	(55.80)	-50.9%
		5,000	46.78	3.07	0.02	0.05	3.14	203.78	14.27	2.00	0.03	(0.06)	1.98	113.04	(90.74)	-44.5%
		10,000	46.78	3.07	0.02	0.05	3.14	360.78	14.27	2.00	0.03	(0.06)	1.98	211.81	(148.97)	-41.3%
		15,000	46.78	3.07	0.02	0.05	3.14	517.78	14.27	2.00	0.03	(0.06)	1.98	310.58	(207.20)	-40.0%

New Rate Class: UGe

Bill Impacts of Proposed Distribution Rates include Riders

Classes		Scenario	Existing Dx Rates						New Dx Rates						$ Incr	% Incr
			SrChg [$/month]	base [c/kWh]	Rider1 [c/kWh]	Rider2 [c/kWh]	VarChg [c/kWh]	[$/month]	SrChg [$/month]	base [c/kWh]	Rider2 [c/kWh]	Rider3 [c/kWh]	VarChg [c/kWh]	[$/month]		
New Class	**Old Class**	kWh														
UGe	**Arnprior**	1,000	21.38	1.17	0.16	0.06	1.39	35.28	18.74	2.00	0.06	(0.06)	2.01	38.79	3.51	10.0%
		2,000	21.38	1.17	0.16	0.06	1.39	49.18	18.74	2.00	0.06	(0.06)	2.01	58.85	9.67	19.7%
		5,000	21.38	1.17	0.16	0.06	1.39	90.88	18.74	2.00	0.06	(0.06)	2.01	119.01	28.13	31.0%
		10,000	21.38	1.17	0.16	0.06	1.39	160.38	18.74	2.00	0.06	(0.06)	2.01	219.28	58.90	36.7%
		15,000	21.38	1.17	0.16	0.06	1.39	229.88	18.74	2.00	0.06	(0.06)	2.01	319.55	89.67	39.0%
UGe	**Brockville**	1,000	21.65	0.78	0.13	0.04	0.95	31.15	18.67	2.00	0.04	(0.06)	1.99	38.52	7.37	23.7%
		2,000	21.65	0.78	0.13	0.04	0.95	40.65	18.67	2.00	0.04	(0.06)	1.99	58.38	17.73	43.6%
		5,000	21.65	0.78	0.13	0.04	0.95	69.15	18.67	2.00	0.04	(0.06)	1.99	117.94	48.79	70.6%
		10,000	21.65	0.78	0.13	0.04	0.95	116.65	18.67	2.00	0.04	(0.06)	1.99	217.21	100.56	86.2%
		15,000	21.65	0.78	0.13	0.04	0.95	164.15	18.67	2.00	0.04	(0.06)	1.99	316.48	152.33	92.8%
UGe	**Carleton Place**	1,000	23.65	1.68	0.13	0.07	1.88	42.45	20.17	2.00	0.07	(0.06)	2.02	40.32	(2.13)	-5.0%
		2,000	23.65	1.68	0.13	0.07	1.88	61.25	20.17	2.00	0.07	(0.06)	2.02	60.48	(0.77)	-1.3%
		5,000	23.65	1.68	0.13	0.07	1.88	117.65	20.17	2.00	0.07	(0.06)	2.02	120.94	3.29	2.8%
		10,000	23.65	1.68	0.13	0.07	1.88	211.65	20.17	2.00	0.07	(0.06)	2.02	221.71	10.06	4.8%
		15,000	23.65	1.68	0.13	0.07	1.88	305.65	20.17	2.00	0.07	(0.06)	2.02	322.48	16.83	5.5%
UGe	**Dryden**	1,000	19.11	1.03	0.12	0.04	1.19	31.01	17.31	2.00	0.04	(0.06)	1.99	37.16	6.15	19.8%
		2,000	19.11	1.03	0.12	0.04	1.19	42.91	17.31	2.00	0.04	(0.06)	1.99	57.01	14.10	32.9%
		5,000	19.11	1.03	0.12	0.04	1.19	78.61	17.31	2.00	0.04	(0.06)	1.99	116.58	37.97	48.3%
		10,000	19.11	1.03	0.12	0.04	1.19	138.11	17.31	2.00	0.04	(0.06)	1.99	215.85	77.74	56.3%
		15,000	19.11	1.03	0.12	0.04	1.19	197.61	17.31	2.00	0.04	(0.06)	1.99	315.11	117.50	59.5%

New Rate Class: UGe

Bill Impacts of Proposed Distribution Rates include Riders

Classes		Scenario	Existing Dx Rates						New Dx Rates						$ Incr	% Incr
			SrChg	base	Rider1	Rider2	VarChg	[$/month]	SrChg	base	Rider2	Rider3	VarChg	[$/month]		
New Class	**Old Class**	kWh	[$/month]	[c/kWh]	[c/kWh]	[c/kWh]	[c/kWh]		[$/month]	[c/kWh]	[c/kWh]	[c/kWh]	[c/kWh]			
UGe	**GBE**	1,000	10.77	1.14	0.16	0.06	1.36	24.37	10.39	2.00	0.06	(0.06)	2.01	30.44	6.07	24.9%
		2,000	10.77	1.14	0.16	0.06	1.36	37.97	10.39	2.00	0.06	(0.06)	2.01	50.50	12.53	33.0%
		5,000	10.77	1.14	0.16	0.06	1.36	78.77	10.39	2.00	0.06	(0.06)	2.01	110.66	31.89	40.5%
		10,000	10.77	1.14	0.16	0.06	1.36	146.77	10.39	2.00	0.06	(0.06)	2.01	210.93	64.16	43.7%
		15,000	10.77	1.14	0.16	0.06	1.36	214.77	10.39	2.00	0.06	(0.06)	2.01	311.20	96.43	44.9%
UGe	**Lindsay**	1,000	23.94	1.38	0.15	0.06	1.59	39.84	20.10	2.00	0.06	(0.06)	2.01	40.15	0.31	0.8%
		2,000	23.94	1.38	0.15	0.06	1.59	55.74	20.10	2.00	0.06	(0.06)	2.01	60.21	4.47	8.0%
		5,000	23.94	1.38	0.15	0.06	1.59	103.44	20.10	2.00	0.06	(0.06)	2.01	120.37	16.93	16.4%
		10,000	23.94	1.38	0.15	0.06	1.59	182.94	20.10	2.00	0.06	(0.06)	2.01	220.64	37.70	20.6%
		15,000	23.94	1.38	0.15	0.06	1.59	262.44	20.10	2.00	0.06	(0.06)	2.01	320.91	58.47	22.3%
UGe	**Perth**	1,000	19.92	0.92	0.13	0.04	1.09	30.82	17.10	2.00	0.04	(0.06)	1.99	36.96	6.14	19.9%
		2,000	19.92	0.92	0.13	0.04	1.09	41.72	17.10	2.00	0.04	(0.06)	1.99	56.81	15.09	36.2%
		5,000	19.92	0.92	0.13	0.04	1.09	74.42	17.10	2.00	0.04	(0.06)	1.99	116.37	41.95	56.4%
		10,000	19.92	0.92	0.13	0.04	1.09	128.92	17.10	2.00	0.04	(0.06)	1.99	215.64	86.72	67.3%
		15,000	19.92	0.92	0.13	0.04	1.09	183.42	17.10	2.00	0.04	(0.06)	1.99	314.91	131.49	71.7%
UGe	**Quinte West**	1,000	3.74	1.05	0.14	0.06	1.25	16.24	5.15	2.00	0.06	(0.06)	2.01	25.20	8.96	55.2%
		2,000	3.74	1.05	0.14	0.06	1.25	28.74	5.15	2.00	0.06	(0.06)	2.01	45.26	16.52	57.5%
		5,000	3.74	1.05	0.14	0.06	1.25	66.24	5.15	2.00	0.06	(0.06)	2.01	105.42	39.18	59.1%
		10,000	3.74	1.05	0.14	0.06	1.25	128.74	5.15	2.00	0.06	(0.06)	2.01	205.69	76.95	59.8%
		15,000	3.74	1.05	0.14	0.06	1.25	191.24	5.15	2.00	0.06	(0.06)	2.01	305.96	114.72	60.0%

New Rate Class: UGe

Bill Impacts of Proposed Distribution Rates include Riders

Classes		Scenario	Existing Dx Rates						New Dx Rates						$ Incr	% Incr
			SrChg	base	Rider1	Rider2	VarChg	[$/month]	SrChg	base	Rider2	Rider3	VarChg	[$/month]		
New Class	Old Class	kWh	[$/month]	[c/kWh]	[c/kWh]	[c/kWh]	[c/kWh]		[$/month]	[c/kWh]	[c/kWh]	[c/kWh]	[c/kWh]			
UGe	**Smiths Falls**	1,000	9.84	1.05	0.12	0.04	1.21	21.94	9.62	2.00	0.04	(0.06)	1.99	29.48	7.54	34.4%
		2,000	9.84	1.05	0.12	0.04	1.21	34.04	9.62	2.00	0.04	(0.06)	1.99	49.33	15.29	44.9%
		5,000	9.84	1.05	0.12	0.04	1.21	70.34	9.62	2.00	0.04	(0.06)	1.99	108.89	38.55	54.8%
		10,000	9.84	1.05	0.12	0.04	1.21	130.84	9.62	2.00	0.04	(0.06)	1.99	208.16	77.32	59.1%
		15,000	9.84	1.05	0.12	0.04	1.21	191.34	9.62	2.00	0.04	(0.06)	1.99	307.43	116.09	60.7%
UGe	**Thorold**	1,000	22.63	1.50	0.15	0.06	1.71	39.73	19.43	2.00	0.06	(0.06)	2.01	39.48	(0.25)	-0.6%
		2,000	22.63	1.50	0.15	0.06	1.71	56.83	19.43	2.00	0.06	(0.06)	2.01	59.53	2.70	4.8%
		5,000	22.63	1.50	0.15	0.06	1.71	108.13	19.43	2.00	0.06	(0.06)	2.01	119.70	11.57	10.7%
		10,000	22.63	1.50	0.15	0.06	1.71	193.63	19.43	2.00	0.06	(0.06)	2.01	219.97	26.34	13.6%
		15,000	22.63	1.50	0.15	0.06	1.71	279.13	19.43	2.00	0.06	(0.06)	2.01	320.23	41.10	14.7%
UGe	**Whitchurch Stouffville**	1,000	21.85	0.93	0.11	0.04	1.08	32.65	18.62	2.00	0.04	(0.06)	1.99	38.47	5.82	17.8%
		2,000	21.85	0.93	0.11	0.04	1.08	43.45	18.62	2.00	0.04	(0.06)	1.99	58.33	14.88	34.2%
		5,000	21.85	0.93	0.11	0.04	1.08	75.85	18.62	2.00	0.04	(0.06)	1.99	117.89	42.04	55.4%
		10,000	21.85	0.93	0.11	0.04	1.08	129.85	18.62	2.00	0.04	(0.06)	1.99	217.16	87.31	67.2%
		15,000	21.85	0.93	0.11	0.04	1.08	183.85	18.62	2.00	0.04	(0.06)	1.99	316.43	132.58	72.1%

New Rate Class: UGd

Bill Impacts of Proposed Distribution Rates include Riders

Classes		Scenario			Existing Dx Rates						New Dx Rates						$ Incr	% Incr
					SrChg [$/month]	base [$/kW]	Rider1 [$/kW]	Rider2 [$/kW]	VarChg [$/kW]	[$/month]	SrChg [$/month]	base [$/kW]	Rider2 [$/kW]	Rider3 [$/kW]	VarChg [$/kW]	[$/month]		
New Class	**Old Class**	kWh	kW	LF														
UGd	**UG**	15,000	60	35%	15.79	8.44	0.10	0.11	8.65	534.8	18.49	7.42	0.11	(0.27)	7.26	454.2	(80.6)	-15.1%
		43,164	133	45%	15.79	8.44	0.10	0.11	8.65	1,166.2	18.49	7.42	0.11	(0.27)	7.26	984.3	(181.9)	-15.6%
		100,000	500	28%	15.79	8.44	0.10	0.11	8.65	4,340.8	18.49	7.42	0.11	(0.27)	7.26	3,649.3	(691.4)	-15.9%
		400,000	1000	56%	15.79	8.44	0.10	0.11	8.65	8,665.8	18.49	7.42	0.11	(0.27)	7.26	7,280.2	(1,385.6)	-16.0%
		1,000,000	3000	46%	15.79	8.44	0.10	0.11	8.65	25,965.8	18.49	7.42	0.11	(0.27)	7.26	21,803.6	(4,162.2)	-16.0%
		1,500,000	4000	52%	15.79	8.44	0.10	0.11	8.65	34,615.8	18.49	7.42	0.11	(0.27)	7.26	29,065.3	(5,550.5)	-16.0%
UGd	**G1**	15,000	60	35%	36.93	9.59	0.26	0.29	10.14	645.3	18.49	7.42	0.11	(0.27)	7.26	454.2	(191.1)	-29.6%
		43,164	133	45%	36.93	9.59	0.26	0.29	10.14	1,385.6	18.49	7.42	0.11	(0.27)	7.26	984.3	(401.3)	-29.0%
		100,000	500	28%	36.93	9.59	0.26	0.29	10.14	5,106.9	18.49	7.42	0.11	(0.27)	7.26	3,649.3	(1,457.6)	-28.5%
		400,000	1000	56%	36.93	9.59	0.26	0.29	10.14	10,176.9	18.49	7.42	0.11	(0.27)	7.26	7,280.2	(2,896.7)	-28.5%
		1,000,000	3000	46%	36.93	9.59	0.26	0.29	10.14	30,456.9	18.49	7.42	0.11	(0.27)	7.26	21,803.6	(8,653.3)	-28.4%
		1,500,000	4000	52%	36.93	9.59	0.26	0.29	10.14	40,596.9	18.49	7.42	0.11	(0.27)	7.26	29,065.3	(11,531.6)	-28.4%
UGd	**G3**	15,000	60	35%	46.78	9.91	0.08	0.15	10.14	655.2	18.49	7.42	0.11	(0.27)	7.26	454.2	(201.0)	-30.7%
		43,164	133	45%	46.78	9.91	0.08	0.15	10.14	1,395.4	18.49	7.42	0.11	(0.27)	7.26	984.3	(411.1)	-29.5%
		100,000	500	28%	46.78	9.91	0.08	0.15	10.14	5,116.8	18.49	7.42	0.11	(0.27)	7.26	3,649.3	(1,467.4)	-28.7%
		400,000	1000	56%	46.78	9.91	0.08	0.15	10.14	10,186.8	18.49	7.42	0.11	(0.27)	7.26	7,280.2	(2,906.6)	-28.5%
		1,000,000	3000	46%	46.78	9.91	0.08	0.15	10.14	30,466.8	18.49	7.42	0.11	(0.27)	7.26	21,803.6	(8,663.2)	-28.4%
		1,500,000	4000	52%	46.78	9.91	0.08	0.15	10.14	40,606.8	18.49	7.42	0.11	(0.27)	7.26	29,065.3	(11,541.5)	-28.4%
UGd	**Arnprior**	15,000	60	35%	21.38	3.70	0.50	0.20	4.40	285.4	22.95	7.33	0.20	(0.27)	7.26	458.6	173.2	60.7%
		43,164	133	45%	21.38	3.70	0.50	0.20	4.40	606.6	22.95	7.33	0.20	(0.27)	7.26	988.6	382.0	63.0%
		100,000	500	28%	21.38	3.70	0.50	0.20	4.40	2,221.4	22.95	7.33	0.20	(0.27)	7.26	3,653.1	1,431.7	64.4%
		400,000	1000	56%	21.38	3.70	0.50	0.20	4.40	4,421.4	22.95	7.33	0.20	(0.27)	7.26	7,283.2	2,861.8	64.7%
		1,000,000	3000	46%	21.38	3.70	0.50	0.20	4.40	13,221.4	22.95	7.33	0.20	(0.27)	7.26	21,803.6	8,582.2	64.9%
		1,500,000	4000	52%	21.38	3.70	0.50	0.20	4.40	17,621.4	22.95	7.33	0.20	(0.27)	7.26	29,063.8	11,442.4	64.9%

New Rate Class: UGd

Bill Impacts of Proposed Distribution Rates include Riders

Classes		Scenario			Existing Dx Rates						New Dx Rates						$ Incr	% Incr
					SrChg [$/month]	base [$/kW]	Rider1 [$/kW]	Rider2 [$/kW]	VarChg [$/kW]	[$/month]	SrChg [$/month]	base [$/kW]	Rider2 [$/kW]	Rider3 [$/kW]	VarChg [$/kW]	[$/month]		
New Class	**Old Class**	kWh	kW	LF														
UGd	**Brockville**	15,000	60	35%	21.65	2.49	0.41	0.12	3.02	202.9	22.89	6.70	0.12	(0.27)	6.55	415.7	212.9	104.9%
		43,164	133	45%	21.65	2.49	0.41	0.12	3.02	423.3	22.89	6.70	0.12	(0.27)	6.55	893.7	470.3	111.1%
		100,000	500	28%	21.65	2.49	0.41	0.12	3.02	1,531.7	22.89	6.70	0.12	(0.27)	6.55	3,296.4	1,764.8	115.2%
		400,000	1000	56%	21.65	2.49	0.41	0.12	3.02	3,041.7	22.89	6.70	0.12	(0.27)	6.55	6,570.0	3,528.4	116.0%
		1,000,000	3000	46%	21.65	2.49	0.41	0.12	3.02	9,081.7	22.89	6.70	0.12	(0.27)	6.55	19,664.3	10,582.6	116.5%
		1,500,000	4000	52%	21.65	2.49	0.41	0.12	3.02	12,101.7	22.89	6.70	0.12	(0.27)	6.55	26,211.4	14,109.7	116.6%
UGd	**Carleton Place**	15,000	60	35%	23.65	5.31	0.42	0.22	5.95	380.7	24.39	7.33	0.22	(0.27)	7.28	461.2	80.5	21.2%
		43,164	133	45%	23.65	5.31	0.42	0.22	5.95	815.0	24.39	7.33	0.22	(0.27)	7.28	992.7	177.7	21.8%
		100,000	500	28%	23.65	5.31	0.42	0.22	5.95	2,998.7	24.39	7.33	0.22	(0.27)	7.28	3,664.5	665.8	22.2%
		400,000	1000	56%	23.65	5.31	0.42	0.22	5.95	5,973.7	24.39	7.33	0.22	(0.27)	7.28	7,304.6	1,330.9	22.3%
		1,000,000	3000	46%	23.65	5.31	0.42	0.22	5.95	17,873.7	24.39	7.33	0.22	(0.27)	7.28	21,865.0	3,991.3	22.3%
		1,500,000	4000	52%	23.65	5.31	0.42	0.22	5.95	23,823.7	24.39	7.33	0.22	(0.27)	7.28	29,145.2	5,321.6	22.3%
UGd	**Dryden**	15,000	60	35%	19.11	3.29	0.38	0.13	3.80	247.1	21.52	7.33	0.13	(0.27)	7.19	452.9	205.8	83.3%
		43,164	133	45%	19.11	3.29	0.38	0.13	3.80	524.5	21.52	7.33	0.13	(0.27)	7.19	977.8	453.3	86.4%
		100,000	500	28%	19.11	3.29	0.38	0.13	3.80	1,919.1	21.52	7.33	0.13	(0.27)	7.19	3,616.6	1,697.5	88.5%
		400,000	1000	56%	19.11	3.29	0.38	0.13	3.80	3,819.1	21.52	7.33	0.13	(0.27)	7.19	7,211.7	3,392.6	88.8%
		1,000,000	3000	46%	19.11	3.29	0.38	0.13	3.80	11,419.1	21.52	7.33	0.13	(0.27)	7.19	21,592.1	10,173.0	89.1%
		1,500,000	4000	52%	19.11	3.29	0.38	0.13	3.80	15,219.1	21.52	7.33	0.13	(0.27)	7.19	28,782.3	13,563.2	89.1%
UGd	**GBE**	15,000	60	35%	10.77	3.64	0.49	0.19	4.32	270.0	14.61	7.33	0.19	(0.27)	7.25	449.6	179.6	66.5%
		43,164	133	45%	10.77	3.64	0.49	0.19	4.32	585.3	14.61	7.33	0.19	(0.27)	7.25	978.9	393.6	67.2%
		100,000	500	28%	10.77	3.64	0.49	0.19	4.32	2,170.8	14.61	7.33	0.19	(0.27)	7.25	3,639.7	1,468.9	67.7%
		400,000	1000	56%	10.77	3.64	0.49	0.19	4.32	4,330.8	14.61	7.33	0.19	(0.27)	7.25	7,264.8	2,934.0	67.7%
		1,000,000	3000	46%	10.77	3.64	0.49	0.19	4.32	12,970.8	14.61	7.33	0.19	(0.27)	7.25	21,765.2	8,794.4	67.8%
		1,500,000	4000	52%	10.77	3.64	0.49	0.19	4.32	17,290.8	14.61	7.33	0.19	(0.27)	7.25	29,015.4	11,724.7	67.8%

New Rate Class: UGd

Bill Impacts of Proposed Distribution Rates include Riders

Classes		Scenario			Existing Dx Rates						New Dx Rates						$ Incr	% Incr
					SrChg	base	Rider1	Rider2	VarChg	[$/month]	SrChg	base	Rider2	Rider3	VarChg	[$/month]		
New Class	**Old Class**	kWh	kW	LF	[$/month]	[$/kW]	[$/kW]	[$/kW]	[$/kW]		[$/month]	[$/kW]	[$/kW]	[$/kW]	[$/kW]			
UGd	**Lindsay**	15,000	60	35%	23.94	4.36	0.49	0.19	5.04	326.3	24.31	7.33	0.19	(0.27)	7.25	459.3	133.0	40.8%
		43,164	133	45%	23.94	4.36	0.49	0.19	5.04	694.3	24.31	7.33	0.19	(0.27)	7.25	988.6	294.3	42.4%
		100,000	500	28%	23.94	4.36	0.49	0.19	5.04	2,543.9	24.31	7.33	0.19	(0.27)	7.25	3,649.4	1,105.5	43.5%
		400,000	1000	56%	23.94	4.36	0.49	0.19	5.04	5,063.9	24.31	7.33	0.19	(0.27)	7.25	7,274.5	2,210.6	43.7%
		1,000,000	3000	46%	23.94	4.36	0.49	0.19	5.04	15,143.9	24.31	7.33	0.19	(0.27)	7.25	21,774.9	6,631.0	43.8%
		1,500,000	4000	52%	23.94	4.36	0.49	0.19	5.04	20,183.9	24.31	7.33	0.19	(0.27)	7.25	29,025.1	8,841.2	43.8%
UGd	**Perth**	15,000	60	35%	19.92	2.87	0.42	0.12	3.41	224.5	21.32	7.15	0.12	(0.27)	7.00	441.1	216.6	96.5%
		43,164	133	45%	19.92	2.87	0.42	0.12	3.41	473.5	21.32	7.15	0.12	(0.27)	7.00	951.9	478.5	101.1%
		100,000	500	28%	19.92	2.87	0.42	0.12	3.41	1,724.9	21.32	7.15	0.12	(0.27)	7.00	3,519.9	1,795.0	104.1%
		400,000	1000	56%	19.92	2.87	0.42	0.12	3.41	3,429.9	21.32	7.15	0.12	(0.27)	7.00	7,018.4	3,588.5	104.6%
		1,000,000	3000	46%	19.92	2.87	0.42	0.12	3.41	10,249.9	21.32	7.15	0.12	(0.27)	7.00	21,012.7	10,762.8	105.0%
		1,500,000	4000	52%	19.92	2.87	0.42	0.12	3.41	13,659.9	21.32	7.15	0.12	(0.27)	7.00	28,009.8	14,349.9	105.1%
UGd	**Quinte West**	15,000	60	35%	3.74	3.32	0.46	0.18	3.96	241.3	9.36	7.33	0.18	(0.27)	7.24	443.8	202.4	83.9%
		43,164	133	45%	3.74	3.32	0.46	0.18	3.96	530.4	9.36	7.33	0.18	(0.27)	7.24	972.3	441.9	83.3%
		100,000	500	28%	3.74	3.32	0.46	0.18	3.96	1,983.7	9.36	7.33	0.18	(0.27)	7.24	3,629.5	1,645.7	83.0%
		400,000	1000	56%	3.74	3.32	0.46	0.18	3.96	3,963.7	9.36	7.33	0.18	(0.27)	7.24	7,249.6	3,285.8	82.9%
		1,000,000	3000	46%	3.74	3.32	0.46	0.18	3.96	11,883.7	9.36	7.33	0.18	(0.27)	7.24	21,730.0	9,846.2	82.9%
		1,500,000	4000	52%	3.74	3.32	0.46	0.18	3.96	15,843.7	9.36	7.33	0.18	(0.27)	7.24	28,970.2	13,126.4	82.8%
UGd	**Smiths Falls**	15,000	60	35%	9.84	3.33	0.39	0.13	3.85	240.8	13.84	7.33	0.13	(0.27)	7.19	445.2	204.4	84.9%
		43,164	133	45%	9.84	3.33	0.39	0.13	3.85	521.9	13.84	7.33	0.13	(0.27)	7.19	970.1	448.2	85.9%
		100,000	500	28%	9.84	3.33	0.39	0.13	3.85	1,934.8	13.84	7.33	0.13	(0.27)	7.19	3,608.9	1,674.1	86.5%
		400,000	1000	56%	9.84	3.33	0.39	0.13	3.85	3,859.8	13.84	7.33	0.13	(0.27)	7.19	7,204.0	3,344.2	86.6%
		1,000,000	3000	46%	9.84	3.33	0.39	0.13	3.85	11,559.8	13.84	7.33	0.13	(0.27)	7.19	21,584.5	10,024.6	86.7%
		1,500,000	4000	52%	9.84	3.33	0.39	0.13	3.85	15,409.8	13.84	7.33	0.13	(0.27)	7.19	28,774.7	13,364.8	86.7%

New Rate Class: UGd

Bill Impacts of Proposed Distribution Rates include Riders

Classes		Scenario			Existing Dx Rates						New Dx Rates						$ Incr	% Incr
					SrChg	base	Rider1	Rider2	VarChg	[$/month]	SrChg	base	Rider2	Rider3	VarChg	[$/month]		
New Class	Old Class	kWh	kW	LF	[$/month]	[$/kW]	[$/kW]	[$/kW]	[$/kW]		[$/month]	[$/kW]	[$/kW]	[$/kW]	[$/kW]			
UGd	Thorold	15,000	60	35%	22.63	4.76	0.46	0.20	5.42	347.8	23.64	7.33	0.20	(0.27)	7.26	459.3	111.4	32.0%
		43,164	133	45%	22.63	4.76	0.46	0.20	5.42	743.5	23.64	7.33	0.20	(0.27)	7.26	989.2	245.8	33.1%
		100,000	500	28%	22.63	4.76	0.46	0.20	5.42	2,732.6	23.64	7.33	0.20	(0.27)	7.26	3,653.7	921.1	33.7%
		400,000	1000	56%	22.63	4.76	0.46	0.20	5.42	5,442.6	23.64	7.33	0.20	(0.27)	7.26	7,283.8	1,841.2	33.8%
		1,000,000	3000	46%	22.63	4.76	0.46	0.20	5.42	16,282.6	23.64	7.33	0.20	(0.27)	7.26	21,804.3	5,521.6	33.9%
		1,500,000	4000	52%	22.63	4.76	0.46	0.20	5.42	21,702.6	23.64	7.33	0.20	(0.27)	7.26	29,064.5	7,361.8	33.9%
UGd	Whitchurch Stouffvill	15,000	60	35%	21.85	2.93	0.35	0.13	3.41	226.5	22.84	7.15	0.13	(0.27)	7.01	443.3	216.8	95.7%
		43,164	133	45%	21.85	2.93	0.35	0.13	3.41	475.4	22.84	7.15	0.13	(0.27)	7.01	954.8	479.4	100.8%
		100,000	500	28%	21.85	2.93	0.35	0.13	3.41	1,726.9	22.84	7.15	0.13	(0.27)	7.01	3,526.4	1,799.5	104.2%
		400,000	1000	56%	21.85	2.93	0.35	0.13	3.41	3,431.9	22.84	7.15	0.13	(0.27)	7.01	7,030.0	3,598.1	104.8%
		1,000,000	3000	46%	21.85	2.93	0.35	0.13	3.41	10,251.9	22.84	7.15	0.13	(0.27)	7.01	21,044.2	10,792.4	105.3%
		1,500,000	4000	52%	21.85	2.93	0.35	0.13	3.41	13,661.9	22.84	7.15	0.13	(0.27)	7.01	28,051.3	14,389.5	105.3%

New Rate Class: GSe

Bill Impacts of Proposed Distribution Rates include Riders

Classes		Scenario	Existing Dx Rates						New Dx Rates						$ Incr	% Incr
			SrChg [$/month]	base [c/kWh]	Rider1 [c/kWh]	Rider2 [c/kWh]	VarChg [c/kWh]	[$/month]	SrChg [$/month]	base [c/kWh]	Rider2 [c/kWh]	Rider3 [c/kWh]	VarChg [c/kWh]	[$/month]		
New Class	Old Class	kWh														
GSe	F1	1,000	60.71	2.24	0.08	0.10	2.42	84.91	52.91	3.38	0.10	(0.06)	3.42	87.12	2.21	2.6%
		2,000	60.71	2.24	0.08	0.10	2.42	109.11	52.91	3.38	0.10	(0.06)	3.42	121.32	12.21	11.2%
		5,000	60.71	2.24	0.08	0.10	2.42	181.71	52.91	3.38	0.10	(0.06)	3.42	223.92	42.21	23.2%
		10,000	60.71	2.24	0.08	0.10	2.42	302.71	52.91	3.38	0.10	(0.06)	3.42	394.93	92.22	30.5%
		15,000	60.71	2.24	0.08	0.10	2.42	423.71	52.91	3.38	0.10	(0.06)	3.42	565.94	142.23	33.6%
GSe	F3	1,000	53.91	2.89	0.03	0.04	2.96	83.51	47.61	3.38	0.04	(0.06)	3.36	81.22	(2.29)	-2.7%
		2,000	53.91	2.89	0.03	0.04	2.96	113.11	47.61	3.38	0.04	(0.06)	3.36	114.82	1.71	1.5%
		5,000	53.91	2.89	0.03	0.04	2.96	201.91	47.61	3.38	0.04	(0.06)	3.36	215.62	13.71	6.8%
		10,000	53.91	2.89	0.03	0.04	2.96	349.91	47.61	3.38	0.04	(0.06)	3.36	383.63	33.72	9.6%
		15,000	53.91	2.89	0.03	0.04	2.96	497.91	47.61	3.38	0.04	(0.06)	3.36	551.64	53.73	10.8%
GSe	G1	1,000	36.93	3.12	0.09	0.09	3.30	69.93	35.09	3.38	0.09	(0.06)	3.41	69.19	(0.74)	-1.1%
		2,000	36.93	3.12	0.09	0.09	3.30	102.93	35.09	3.38	0.09	(0.06)	3.41	103.29	0.36	0.4%
		5,000	36.93	3.12	0.09	0.09	3.30	201.93	35.09	3.38	0.09	(0.06)	3.41	205.60	3.67	1.8%
		10,000	36.93	3.12	0.09	0.09	3.30	366.93	35.09	3.38	0.09	(0.06)	3.41	376.10	9.17	2.5%
		15,000	36.93	3.12	0.09	0.09	3.30	531.93	35.09	3.38	0.09	(0.06)	3.41	546.61	14.68	2.8%
GSe	G3	1,000	46.78	3.07	0.02	0.05	3.14	78.18	42.40	3.38	0.05	(0.06)	3.37	76.11	(2.07)	-2.7%
		2,000	46.78	3.07	0.02	0.05	3.14	109.58	42.40	3.38	0.05	(0.06)	3.37	109.81	0.23	0.2%
		5,000	46.78	3.07	0.02	0.05	3.14	203.78	42.40	3.38	0.05	(0.06)	3.37	210.91	7.13	3.5%
		10,000	46.78	3.07	0.02	0.05	3.14	360.78	42.40	3.38	0.05	(0.06)	3.37	379.42	18.64	5.2%
		15,000	46.78	3.07	0.02	0.05	3.14	517.78	42.40	3.38	0.05	(0.06)	3.37	547.93	30.15	5.8%
GSe	T	1,000	261.54	2.43	0.01	0.03	2.47	286.24	203.71	3.38	0.03	(0.06)	3.35	237.21	(49.03)	-17.1%
		2,000	261.54	2.43	0.01	0.03	2.47	310.94	203.71	3.38	0.03	(0.06)	3.35	270.71	(40.23)	-12.9%
		5,000	261.54	2.43	0.01	0.03	2.47	385.04	203.71	3.38	0.03	(0.06)	3.35	371.22	(13.82)	-3.6%
		10,000	261.54	2.43	0.01	0.03	2.47	508.54	203.71	3.38	0.03	(0.06)	3.35	538.72	30.18	5.9%
		15,000	261.54	2.43	0.01	0.03	2.47	632.04	203.71	3.38	0.03	(0.06)	3.35	706.23	74.19	11.7%

New Rate Class: GSe

Bill Impacts of Proposed Distribution Rates include Riders

Classes		**Scenario**	Existing Dx Rates						New Dx Rates						$ Incr	% Incr
			SrChg	base	Rider1	Rider2	VarChg	[$/month]	SrChg	base	Rider2	Rider3	VarChg	[$/month]		
New Class	**Old Class**	kWh	[$/month]	[c/kWh]	[c/kWh]	[c/kWh]	[c/kWh]		[$/month]	[c/kWh]	[c/kWh]	[c/kWh]	[c/kWh]			
GSe	**Ailsa Craig**	1,000	17.31	1.32	0.17	0.09	1.58	33.11	20.76	2.34	0.09	(0.06)	2.37	44.50	11.39	34.4%
		2,000	17.31	1.32	0.17	0.09	1.58	48.91	20.76	2.34	0.09	(0.06)	2.37	68.23	19.32	39.5%
		5,000	17.31	1.32	0.17	0.09	1.58	96.31	20.76	2.34	0.09	(0.06)	2.37	139.43	43.12	44.8%
		10,000	17.31	1.32	0.17	0.09	1.58	175.31	20.76	2.34	0.09	(0.06)	2.37	258.09	82.78	47.2%
		15,000	17.31	1.32	0.17	0.09	1.58	254.31	20.76	2.34	0.09	(0.06)	2.37	376.75	122.44	48.1%
GSe	**Arkona**	1,000	3.20	0.86	0.51	0.36	1.73	20.50	10.29	1.98	0.36	(0.06)	2.28	33.12	12.62	61.6%
		2,000	3.20	0.86	0.51	0.36	1.73	37.80	10.29	1.98	0.36	(0.06)	2.28	55.96	18.16	48.0%
		5,000	3.20	0.86	0.51	0.36	1.73	89.70	10.29	1.98	0.36	(0.06)	2.28	124.46	34.76	38.7%
		10,000	3.20	0.86	0.51	0.36	1.73	176.20	10.29	1.98	0.36	(0.06)	2.28	238.62	62.42	35.4%
		15,000	3.20	0.86	0.51	0.36	1.73	262.70	10.29	1.98	0.36	(0.06)	2.28	352.78	90.08	34.3%
UGe	**Arnprior**	1,000	21.38	1.17	0.16	0.06	1.39	35.28	18.74	2.00	0.06	(0.06)	2.01	38.79	3.51	10.0%
		2,000	21.38	1.17	0.16	0.06	1.39	49.18	18.74	2.00	0.06	(0.06)	2.01	58.85	9.67	19.7%
		5,000	21.38	1.17	0.16	0.06	1.39	90.88	18.74	2.00	0.06	(0.06)	2.01	119.01	28.13	31.0%
		10,000	21.38	1.17	0.16	0.06	1.39	160.38	18.74	2.00	0.06	(0.06)	2.01	219.28	58.90	36.7%
		15,000	21.38	1.17	0.16	0.06	1.39	229.88	18.74	2.00	0.06	(0.06)	2.01	319.55	89.67	39.0%
GSe	**Arran-Elderslie**	1,000	8.83	1.03	0.17	0.09	1.29	21.73	13.88	1.90	0.09	(0.06)	1.93	33.22	11.49	52.9%
		2,000	8.83	1.03	0.17	0.09	1.29	34.63	13.88	1.90	0.09	(0.06)	1.93	52.55	17.92	51.7%
		5,000	8.83	1.03	0.17	0.09	1.29	73.33	13.88	1.90	0.09	(0.06)	1.93	110.55	37.22	50.8%
		10,000	8.83	1.03	0.17	0.09	1.29	137.83	13.88	1.90	0.09	(0.06)	1.93	207.21	69.38	50.3%
		15,000	8.83	1.03	0.17	0.09	1.29	202.33	13.88	1.90	0.09	(0.06)	1.93	303.87	101.54	50.2%
GSe	**Artemesia**	1,000	19.62	1.74	0.49	0.34	2.57	45.32	22.19	3.21	0.34	(0.06)	3.49	57.12	11.80	26.0%
		2,000	19.62	1.74	0.49	0.34	2.57	71.02	22.19	3.21	0.34	(0.06)	3.49	92.06	21.04	29.6%
		5,000	19.62	1.74	0.49	0.34	2.57	148.12	22.19	3.21	0.34	(0.06)	3.49	196.87	48.75	32.9%
		10,000	19.62	1.74	0.49	0.34	2.57	276.62	22.19	3.21	0.34	(0.06)	3.49	371.56	94.94	34.3%
		15,000	19.62	1.74	0.49	0.34	2.57	405.12	22.19	3.21	0.34	(0.06)	3.49	546.25	141.13	34.8%

New Rate Class: GSe

Bill Impacts of Proposed Distribution Rates include Riders

Classes		Scenario	Existing Dx Rates						New Dx Rates						$ Incr	% Incr
			SrChg	base	Rider1	Rider2	VarChg	[$/month]	SrChg	base	Rider2	Rider3	VarChg	[$/month]		
New Class	Old Class	kWh	[$/month]	[c/kWh]	[c/kWh]	[c/kWh]	[c/kWh]		[$/month]	[c/kWh]	[c/kWh]	[c/kWh]	[c/kWh]			
GSe	Bancroft	1,000	24.41	1.18	0.17	0.08	1.43	38.71	25.99	2.30	0.08	(0.06)	2.32	49.22	10.51	27.2%
		2,000	24.41	1.18	0.17	0.08	1.43	53.01	25.99	2.30	0.08	(0.06)	2.32	72.45	19.44	36.7%
		5,000	24.41	1.18	0.17	0.08	1.43	95.91	25.99	2.30	0.08	(0.06)	2.32	142.15	46.24	48.2%
		10,000	24.41	1.18	0.17	0.08	1.43	167.41	25.99	2.30	0.08	(0.06)	2.32	258.32	90.91	54.3%
		15,000	24.41	1.18	0.17	0.08	1.43	238.91	25.99	2.30	0.08	(0.06)	2.32	374.48	135.57	56.7%
GSe	Bath	1,000	10.65	1.47	0.29	0.24	2.00	30.65	15.43	2.55	0.24	(0.06)	2.73	42.76	12.11	39.5%
		2,000	10.65	1.47	0.29	0.24	2.00	50.65	15.43	2.55	0.24	(0.06)	2.73	70.09	19.44	38.4%
		5,000	10.65	1.47	0.29	0.24	2.00	110.65	15.43	2.55	0.24	(0.06)	2.73	152.09	41.44	37.5%
		10,000	10.65	1.47	0.29	0.24	2.00	210.65	15.43	2.55	0.24	(0.06)	2.73	288.76	78.11	37.1%
		15,000	10.65	1.47	0.29	0.24	2.00	310.65	15.43	2.55	0.24	(0.06)	2.73	425.42	114.77	36.9%
GSe	Blandford-Blenheim	1,000	23.85	1.14	0.28	0.20	1.62	40.05	25.13	2.40	0.20	(0.06)	2.54	50.56	10.51	26.2%
		2,000	23.85	1.14	0.28	0.20	1.62	56.25	25.13	2.40	0.20	(0.06)	2.54	75.99	19.74	35.1%
		5,000	23.85	1.14	0.28	0.20	1.62	104.85	25.13	2.40	0.20	(0.06)	2.54	152.29	47.44	45.2%
		10,000	23.85	1.14	0.28	0.20	1.62	185.85	25.13	2.40	0.20	(0.06)	2.54	279.46	93.61	50.4%
		15,000	23.85	1.14	0.28	0.20	1.62	266.85	25.13	2.40	0.20	(0.06)	2.54	406.62	139.77	52.4%
GSe	Blyth	1,000	21.63	1.05	0.26	0.20	1.51	36.73	23.68	2.20	0.20	(0.06)	2.34	47.12	10.39	28.3%
		2,000	21.63	1.05	0.26	0.20	1.51	51.83	23.68	2.20	0.20	(0.06)	2.34	70.55	18.72	36.1%
		5,000	21.63	1.05	0.26	0.20	1.51	97.13	23.68	2.20	0.20	(0.06)	2.34	140.85	43.72	45.0%
		10,000	21.63	1.05	0.26	0.20	1.51	172.63	23.68	2.20	0.20	(0.06)	2.34	258.01	85.38	49.5%
		15,000	21.63	1.05	0.26	0.20	1.51	248.13	23.68	2.20	0.20	(0.06)	2.34	375.17	127.04	51.2%
GSe	Bobcaygeon	1,000	23.20	1.38	0.18	0.09	1.65	39.70	25.29	2.50	0.09	(0.06)	2.53	50.62	10.92	27.5%
		2,000	23.20	1.38	0.18	0.09	1.65	56.20	25.29	2.50	0.09	(0.06)	2.53	75.96	19.76	35.2%
		5,000	23.20	1.38	0.18	0.09	1.65	105.70	25.29	2.50	0.09	(0.06)	2.53	151.96	46.26	43.8%
		10,000	23.20	1.38	0.18	0.09	1.65	188.20	25.29	2.50	0.09	(0.06)	2.53	278.62	90.42	48.0%
		15,000	23.20	1.38	0.18	0.09	1.65	270.70	25.29	2.50	0.09	(0.06)	2.53	405.28	134.58	49.7%

New Rate Class: GSe

Bill Impacts of Proposed Distribution Rates include Riders

Classes		Scenario	Existing Dx Rates						New Dx Rates						$ Incr	% Incr
			SrChg	base	Rider1	Rider2	VarChg	[$/month]	SrChg	base	Rider2	Rider3	VarChg	[$/month]		
New Class	Old Class	kWh	[$/month]	[c/kWh]	[c/kWh]	[c/kWh]	[c/kWh]		[$/month]	[c/kWh]	[c/kWh]	[c/kWh]	[c/kWh]			
GSe	**Brighton**	1,000	22.90	1.35	0.20	0.08	1.63	39.20	24.37	2.50	0.08	(0.06)	2.52	49.60	10.40	26.5%
		2,000	22.90	1.35	0.20	0.08	1.63	55.50	24.37	2.50	0.08	(0.06)	2.52	74.83	19.33	34.8%
		5,000	22.90	1.35	0.20	0.08	1.63	104.40	24.37	2.50	0.08	(0.06)	2.52	150.53	46.13	44.2%
		10,000	22.90	1.35	0.20	0.08	1.63	185.90	24.37	2.50	0.08	(0.06)	2.52	276.69	90.79	48.8%
		15,000	22.90	1.35	0.20	0.08	1.63	267.40	24.37	2.50	0.08	(0.06)	2.52	402.86	135.46	50.7%
UGe	**Brockville**	1,000	21.65	0.78	0.13	0.04	0.95	31.15	18.67	2.00	0.04	(0.06)	1.99	38.52	7.37	23.7%
		2,000	21.65	0.78	0.13	0.04	0.95	40.65	18.67	2.00	0.04	(0.06)	1.99	58.38	17.73	43.6%
		5,000	21.65	0.78	0.13	0.04	0.95	69.15	18.67	2.00	0.04	(0.06)	1.99	117.94	48.79	70.6%
		10,000	21.65	0.78	0.13	0.04	0.95	116.65	18.67	2.00	0.04	(0.06)	1.99	217.21	100.56	86.2%
		15,000	21.65	0.78	0.13	0.04	0.95	164.15	18.67	2.00	0.04	(0.06)	1.99	316.48	152.33	92.8%
GSe	**Caledon CH**	1,000	24.21	1.80	0.14	0.08	2.02	44.41	26.04	2.90	0.08	(0.06)	2.92	55.27	10.86	24.5%
		2,000	24.21	1.80	0.14	0.08	2.02	64.61	26.04	2.90	0.08	(0.06)	2.92	84.50	19.89	30.8%
		5,000	24.21	1.80	0.14	0.08	2.02	125.21	26.04	2.90	0.08	(0.06)	2.92	172.20	46.99	37.5%
		10,000	24.21	1.80	0.14	0.08	2.02	226.21	26.04	2.90	0.08	(0.06)	2.92	318.37	92.16	40.7%
		15,000	24.21	1.80	0.14	0.08	2.02	327.21	26.04	2.90	0.08	(0.06)	2.92	464.53	137.32	42.0%
GSe	**Caledon OH**	1,000	25.56	1.70	0.16	0.07	1.93	44.86	26.70	2.90	0.07	(0.06)	2.91	55.83	10.97	24.5%
		2,000	25.56	1.70	0.16	0.07	1.93	64.16	26.70	2.90	0.07	(0.06)	2.91	84.97	20.81	32.4%
		5,000	25.56	1.70	0.16	0.07	1.93	122.06	26.70	2.90	0.07	(0.06)	2.91	172.37	50.31	41.2%
		10,000	25.56	1.70	0.16	0.07	1.93	218.56	26.70	2.90	0.07	(0.06)	2.91	318.03	99.47	45.5%
		15,000	25.56	1.70	0.16	0.07	1.93	315.06	26.70	2.90	0.07	(0.06)	2.91	463.69	148.63	47.2%
GSe	**Campbellford-Seymour**	1,000	16.19	1.19	0.17	0.05	1.41	30.29	20.04	2.15	0.05	(0.06)	2.14	41.48	11.19	36.9%
		2,000	16.19	1.19	0.17	0.05	1.41	44.39	20.04	2.15	0.05	(0.06)	2.14	62.91	18.52	41.7%
		5,000	16.19	1.19	0.17	0.05	1.41	86.69	20.04	2.15	0.05	(0.06)	2.14	127.21	40.52	46.7%
		10,000	16.19	1.19	0.17	0.05	1.41	157.19	20.04	2.15	0.05	(0.06)	2.14	234.37	77.18	49.1%
		15,000	16.19	1.19	0.17	0.05	1.41	227.69	20.04	2.15	0.05	(0.06)	2.14	341.53	113.84	50.0%

New Rate Class: GSe

Bill Impacts of Proposed Distribution Rates include Riders

Classes		Scenario	Existing Dx Rates						New Dx Rates						$ Incr	% Incr
			SrChg	base	Rider1	Rider2	VarChg	[$/month]	SrChg	base	Rider2	Rider3	VarChg	[$/month]		
New Class	Old Class	kWh	[$/month]	[c/kWh]	[c/kWh]	[c/kWh]	[c/kWh]		[$/month]	[c/kWh]	[c/kWh]	[c/kWh]	[c/kWh]			
UGe	Carleton Place	1,000	23.65	1.68	0.13	0.07	1.88	42.45	20.17	2.00	0.07	(0.06)	2.02	40.32	(2.13)	-5.0%
		2,000	23.65	1.68	0.13	0.07	1.88	61.25	20.17	2.00	0.07	(0.06)	2.02	60.48	(0.77)	-1.3%
		5,000	23.65	1.68	0.13	0.07	1.88	117.65	20.17	2.00	0.07	(0.06)	2.02	120.94	3.29	2.8%
		10,000	23.65	1.68	0.13	0.07	1.88	211.65	20.17	2.00	0.07	(0.06)	2.02	221.71	10.06	4.8%
		15,000	23.65	1.68	0.13	0.07	1.88	305.65	20.17	2.00	0.07	(0.06)	2.02	322.48	16.83	5.5%
GSe	Cavan-Millbrook-North M	1,000	22.28	1.50	0.33	0.26	2.09	43.18	24.52	2.80	0.26	(0.06)	3.00	54.55	11.37	26.3%
		2,000	22.28	1.50	0.33	0.26	2.09	64.08	24.52	2.80	0.26	(0.06)	3.00	84.59	20.51	32.0%
		5,000	22.28	1.50	0.33	0.26	2.09	126.78	24.52	2.80	0.26	(0.06)	3.00	174.69	47.91	37.8%
		10,000	22.28	1.50	0.33	0.26	2.09	231.28	24.52	2.80	0.26	(0.06)	3.00	324.85	93.57	40.5%
		15,000	22.28	1.50	0.33	0.26	2.09	335.78	24.52	2.80	0.26	(0.06)	3.00	475.01	139.23	41.5%
GSe	Centre Hastings	1,000	18.38	0.97	0.14	0.06	1.17	30.08	21.50	1.94	0.06	(0.06)	1.94	40.93	10.85	36.1%
		2,000	18.38	0.97	0.14	0.06	1.17	41.78	21.50	1.94	0.06	(0.06)	1.94	60.36	18.58	44.5%
		5,000	18.38	0.97	0.14	0.06	1.17	76.88	21.50	1.94	0.06	(0.06)	1.94	118.66	41.78	54.3%
		10,000	18.38	0.97	0.14	0.06	1.17	135.38	21.50	1.94	0.06	(0.06)	1.94	215.82	80.44	59.4%
		15,000	18.38	0.97	0.14	0.06	1.17	193.88	21.50	1.94	0.06	(0.06)	1.94	312.99	119.11	61.4%
GSe	Chalk River	1,000	21.33	1.79	0.39	0.34	2.52	46.53	23.76	3.18	0.34	(0.06)	3.46	58.39	11.86	25.5%
		2,000	21.33	1.79	0.39	0.34	2.52	71.73	23.76	3.18	0.34	(0.06)	3.46	93.02	21.29	29.7%
		5,000	21.33	1.79	0.39	0.34	2.52	147.33	23.76	3.18	0.34	(0.06)	3.46	196.92	49.59	33.7%
		10,000	21.33	1.79	0.39	0.34	2.52	273.33	23.76	3.18	0.34	(0.06)	3.46	370.09	96.76	35.4%
		15,000	21.33	1.79	0.39	0.34	2.52	399.33	23.76	3.18	0.34	(0.06)	3.46	543.25	143.92	36.0%
GSe	Champlain	1,000	20.59	0.91	0.26	0.15	1.32	33.79	22.94	2.05	0.15	(0.06)	2.14	44.38	10.59	31.3%
		2,000	20.59	0.91	0.26	0.15	1.32	46.99	22.94	2.05	0.15	(0.06)	2.14	65.81	18.82	40.1%
		5,000	20.59	0.91	0.26	0.15	1.32	86.59	22.94	2.05	0.15	(0.06)	2.14	130.11	43.52	50.3%
		10,000	20.59	0.91	0.26	0.15	1.32	152.59	22.94	2.05	0.15	(0.06)	2.14	237.27	84.68	55.5%
		15,000	20.59	0.91	0.26	0.15	1.32	218.59	22.94	2.05	0.15	(0.06)	2.14	344.43	125.84	57.6%

New Rate Class: GSe

Bill Impacts of Proposed Distribution Rates include Riders

Classes		Scenario	Existing Dx Rates						New Dx Rates						$ Incr	% Incr
			SrChg	base	Rider1	Rider2	VarChg	[$/month]	SrChg	base	Rider2	Rider3	VarChg	[$/month]		
New Class	Old Class	kWh	[$/month]	[c/kWh]	[c/kWh]	[c/kWh]	[c/kWh]		[$/month]	[c/kWh]	[c/kWh]	[c/kWh]	[c/kWh]			
GSe	Cobden	1,000	21.93	2.13	0.36	0.30	2.79	49.83	23.61	3.21	0.30	(0.06)	3.45	58.15	8.32	16.7%
		2,000	21.93	2.13	0.36	0.30	2.79	77.73	23.61	3.21	0.30	(0.06)	3.45	92.68	14.95	19.2%
		5,000	21.93	2.13	0.36	0.30	2.79	161.43	23.61	3.21	0.30	(0.06)	3.45	196.30	34.87	21.6%
		10,000	21.93	2.13	0.36	0.30	2.79	300.93	23.61	3.21	0.30	(0.06)	3.45	368.98	68.05	22.6%
		15,000	21.93	2.13	0.36	0.30	2.79	440.43	23.61	3.21	0.30	(0.06)	3.45	541.67	101.24	23.0%
GSe	Deep River	1,000	23.94	2.26	0.15	0.14	2.55	49.44	25.11	3.21	0.14	(0.06)	3.29	58.04	8.60	17.4%
		2,000	23.94	2.26	0.15	0.14	2.55	74.94	25.11	3.21	0.14	(0.06)	3.29	90.98	16.04	21.4%
		5,000	23.94	2.26	0.15	0.14	2.55	151.44	25.11	3.21	0.14	(0.06)	3.29	189.79	38.35	25.3%
		10,000	23.94	2.26	0.15	0.14	2.55	278.94	25.11	3.21	0.14	(0.06)	3.29	354.48	75.54	27.1%
		15,000	23.94	2.26	0.15	0.14	2.55	406.44	25.11	3.21	0.14	(0.06)	3.29	519.17	112.73	27.7%
GSe	Deseronto	1,000	10.14	1.35	0.13	0.05	1.53	25.44	15.56	2.18	0.05	(0.06)	2.17	37.29	11.85	46.6%
		2,000	10.14	1.35	0.13	0.05	1.53	40.74	15.56	2.18	0.05	(0.06)	2.17	59.02	18.28	44.9%
		5,000	10.14	1.35	0.13	0.05	1.53	86.64	15.56	2.18	0.05	(0.06)	2.17	124.22	37.58	43.4%
		10,000	10.14	1.35	0.13	0.05	1.53	163.14	15.56	2.18	0.05	(0.06)	2.17	232.88	69.74	42.8%
		15,000	10.14	1.35	0.13	0.05	1.53	239.64	15.56	2.18	0.05	(0.06)	2.17	341.55	101.91	42.5%
UGe	Dryden	1,000	19.11	1.03	0.12	0.04	1.19	31.01	17.31	2.00	0.04	(0.06)	1.99	37.16	6.15	19.8%
		2,000	19.11	1.03	0.12	0.04	1.19	42.91	17.31	2.00	0.04	(0.06)	1.99	57.01	14.10	32.9%
		5,000	19.11	1.03	0.12	0.04	1.19	78.61	17.31	2.00	0.04	(0.06)	1.99	116.58	37.97	48.3%
		10,000	19.11	1.03	0.12	0.04	1.19	138.11	17.31	2.00	0.04	(0.06)	1.99	215.85	77.74	56.3%
		15,000	19.11	1.03	0.12	0.04	1.19	197.61	17.31	2.00	0.04	(0.06)	1.99	315.11	117.50	59.5%
GSe	Dundalk	1,000	23.56	1.64	0.23	0.09	1.96	43.16	25.20	2.85	0.09	(0.06)	2.88	54.03	10.87	25.2%
		2,000	23.56	1.64	0.23	0.09	1.96	62.76	25.20	2.85	0.09	(0.06)	2.88	82.87	20.11	32.0%
		5,000	23.56	1.64	0.23	0.09	1.96	121.56	25.20	2.85	0.09	(0.06)	2.88	169.37	47.81	39.3%
		10,000	23.56	1.64	0.23	0.09	1.96	219.56	25.20	2.85	0.09	(0.06)	2.88	313.53	93.97	42.8%
		15,000	23.56	1.64	0.23	0.09	1.96	317.56	25.20	2.85	0.09	(0.06)	2.88	457.69	140.13	44.1%

New Rate Class: GSe

Bill Impacts of Proposed Distribution Rates include Riders

Classes		Scenario	Existing Dx Rates						New Dx Rates						$ Incr	% Incr
			SrChg	base	Rider1	Rider2	VarChg	[$/month]	SrChg	base	Rider2	Rider3	VarChg	[$/month]		
New Class	Old Class	kWh	[$/month]	[c/kWh]	[c/kWh]	[c/kWh]	[c/kWh]		[$/month]	[c/kWh]	[c/kWh]	[c/kWh]	[c/kWh]			
GSe	**Durham**	1,000	24.12	1.37	0.15	0.06	1.58	39.92	26.06	2.48	0.06	(0.06)	2.48	50.89	10.97	27.5%
		2,000	24.12	1.37	0.15	0.06	1.58	55.72	26.06	2.48	0.06	(0.06)	2.48	75.73	20.01	35.9%
		5,000	24.12	1.37	0.15	0.06	1.58	103.12	26.06	2.48	0.06	(0.06)	2.48	150.23	47.11	45.7%
		10,000	24.12	1.37	0.15	0.06	1.58	182.12	26.06	2.48	0.06	(0.06)	2.48	274.39	92.27	50.7%
		15,000	24.12	1.37	0.15	0.06	1.58	261.12	26.06	2.48	0.06	(0.06)	2.48	398.55	137.43	52.6%
GSe	**Eganville**	1,000	21.35	2.32	0.17	0.12	2.61	47.45	23.75	3.21	0.12	(0.06)	3.27	56.49	9.04	19.1%
		2,000	21.35	2.32	0.17	0.12	2.61	73.55	23.75	3.21	0.12	(0.06)	3.27	89.23	15.68	21.3%
		5,000	21.35	2.32	0.17	0.12	2.61	151.85	23.75	3.21	0.12	(0.06)	3.27	187.44	35.59	23.4%
		10,000	21.35	2.32	0.17	0.12	2.61	282.35	23.75	3.21	0.12	(0.06)	3.27	351.13	68.78	24.4%
		15,000	21.35	2.32	0.17	0.12	2.61	412.85	23.75	3.21	0.12	(0.06)	3.27	514.82	101.97	24.7%
GSe	**Erin**	1,000	40.38	0.73	0.19	0.08	1.00	50.38	38.00	2.10	0.08	(0.06)	2.12	59.23	8.85	17.6%
		2,000	40.38	0.73	0.19	0.08	1.00	60.38	38.00	2.10	0.08	(0.06)	2.12	80.46	20.08	33.3%
		5,000	40.38	0.73	0.19	0.08	1.00	90.38	38.00	2.10	0.08	(0.06)	2.12	144.16	53.78	59.5%
		10,000	40.38	0.73	0.19	0.08	1.00	140.38	38.00	2.10	0.08	(0.06)	2.12	250.32	109.94	78.3%
		15,000	40.38	0.73	0.19	0.08	1.00	190.38	38.00	2.10	0.08	(0.06)	2.12	356.49	166.11	87.2%
GSe	**Exeter**	1,000	11.36	1.30	0.15	0.06	1.51	26.46	16.25	2.18	0.06	(0.06)	2.18	38.08	11.62	43.9%
		2,000	11.36	1.30	0.15	0.06	1.51	41.56	16.25	2.18	0.06	(0.06)	2.18	59.92	18.36	44.2%
		5,000	11.36	1.30	0.15	0.06	1.51	86.86	16.25	2.18	0.06	(0.06)	2.18	125.42	38.56	44.4%
		10,000	11.36	1.30	0.15	0.06	1.51	162.36	16.25	2.18	0.06	(0.06)	2.18	234.58	72.22	44.5%
		15,000	11.36	1.30	0.15	0.06	1.51	237.86	16.25	2.18	0.06	(0.06)	2.18	343.74	105.88	44.5%
GSe	**Fenelon Falls**	1,000	19.81	0.95	0.15	0.08	1.18	31.61	22.14	1.98	0.08	(0.06)	2.00	42.17	10.56	33.4%
		2,000	19.81	0.95	0.15	0.08	1.18	43.41	22.14	1.98	0.08	(0.06)	2.00	62.20	18.79	43.3%
		5,000	19.81	0.95	0.15	0.08	1.18	78.81	22.14	1.98	0.08	(0.06)	2.00	122.30	43.49	55.2%
		10,000	19.81	0.95	0.15	0.08	1.18	137.81	22.14	1.98	0.08	(0.06)	2.00	222.47	84.66	61.4%
		15,000	19.81	0.95	0.15	0.08	1.18	196.81	22.14	1.98	0.08	(0.06)	2.00	322.63	125.82	63.9%

New Rate Class: GSe

Bill Impacts of Proposed Distribution Rates include Riders

Classes		Scenario	Existing Dx Rates						New Dx Rates						$ Incr	% Incr
			SrChg [$/month]	base [c/kWh]	Rider1 [c/kWh]	Rider2 [c/kWh]	VarChg [c/kWh]	[$/month]	SrChg [$/month]	base [c/kWh]	Rider2 [c/kWh]	Rider3 [c/kWh]	VarChg [c/kWh]	[$/month]		
New Class	Old Class	kWh														
GSe	Forest	1,000	24.91	1.18	0.16	0.06	1.40	38.91	25.86	2.32	0.06	(0.06)	2.32	49.10	10.19	26.2%
		2,000	24.91	1.18	0.16	0.06	1.40	52.91	25.86	2.32	0.06	(0.06)	2.32	72.33	19.42	36.7%
		5,000	24.91	1.18	0.16	0.06	1.40	94.91	25.86	2.32	0.06	(0.06)	2.32	142.03	47.12	49.6%
		10,000	24.91	1.18	0.16	0.06	1.40	164.91	25.86	2.32	0.06	(0.06)	2.32	258.19	93.28	56.6%
		15,000	24.91	1.18	0.16	0.06	1.40	234.91	25.86	2.32	0.06	(0.06)	2.32	374.35	139.44	59.4%
UGe	GBE	1,000	10.77	1.14	0.16	0.06	1.36	24.37	10.39	2.00	0.06	(0.06)	2.01	30.44	6.07	24.9%
		2,000	10.77	1.14	0.16	0.06	1.36	37.97	10.39	2.00	0.06	(0.06)	2.01	50.50	12.53	33.0%
		5,000	10.77	1.14	0.16	0.06	1.36	78.77	10.39	2.00	0.06	(0.06)	2.01	110.66	31.89	40.5%
		10,000	10.77	1.14	0.16	0.06	1.36	146.77	10.39	2.00	0.06	(0.06)	2.01	210.93	64.16	43.7%
		15,000	10.77	1.14	0.16	0.06	1.36	214.77	10.39	2.00	0.06	(0.06)	2.01	311.20	96.43	44.9%
GSe	Georgina	1,000	17.40	1.62	0.16	0.08	1.86	36.00	20.74	2.65	0.08	(0.06)	2.67	47.47	11.47	31.9%
		2,000	17.40	1.62	0.16	0.08	1.86	54.60	20.74	2.65	0.08	(0.06)	2.67	74.21	19.61	35.9%
		5,000	17.40	1.62	0.16	0.08	1.86	110.40	20.74	2.65	0.08	(0.06)	2.67	154.41	44.01	39.9%
		10,000	17.40	1.62	0.16	0.08	1.86	203.40	20.74	2.65	0.08	(0.06)	2.67	288.07	84.67	41.6%
		15,000	17.40	1.62	0.16	0.08	1.86	296.40	20.74	2.65	0.08	(0.06)	2.67	421.73	125.33	42.3%
GSe	Glencoe	1,000	11.37	0.81	0.22	0.14	1.17	23.07	16.25	1.74	0.14	(0.06)	1.82	34.48	11.41	49.5%
		2,000	11.37	0.81	0.22	0.14	1.17	34.77	16.25	1.74	0.14	(0.06)	1.82	52.71	17.94	51.6%
		5,000	11.37	0.81	0.22	0.14	1.17	69.87	16.25	1.74	0.14	(0.06)	1.82	107.41	37.54	53.7%
		10,000	11.37	0.81	0.22	0.14	1.17	128.37	16.25	1.74	0.14	(0.06)	1.82	198.58	70.21	54.7%
		15,000	11.37	0.81	0.22	0.14	1.17	186.87	16.25	1.74	0.14	(0.06)	1.82	289.74	102.87	55.0%
GSe	Grand Bend	1,000	22.20	1.23	0.19	0.07	1.49	37.10	24.54	2.34	0.07	(0.06)	2.35	48.07	10.97	29.6%
		2,000	22.20	1.23	0.19	0.07	1.49	52.00	24.54	2.34	0.07	(0.06)	2.35	71.61	19.61	37.7%
		5,000	22.20	1.23	0.19	0.07	1.49	96.70	24.54	2.34	0.07	(0.06)	2.35	142.21	45.51	47.1%
		10,000	22.20	1.23	0.19	0.07	1.49	171.20	24.54	2.34	0.07	(0.06)	2.35	259.87	88.67	51.8%
		15,000	22.20	1.23	0.19	0.07	1.49	245.70	24.54	2.34	0.07	(0.06)	2.35	377.53	131.83	53.7%

New Rate Class: GSe

Bill Impacts of Proposed Distribution Rates include Riders

Classes		Scenario	Existing Dx Rates						New Dx Rates						$ Incr	% Incr
			SrChg	base	Rider1	Rider2	VarChg	[$/month]	SrChg	base	Rider2	Rider3	VarChg	[$/month]		
New Class	Old Class	kWh	[$/month]	[c/kWh]	[c/kWh]	[c/kWh]	[c/kWh]		[$/month]	[c/kWh]	[c/kWh]	[c/kWh]	[c/kWh]			
GSe	Hastings	1,000	22.89	1.69	0.23	0.09	2.01	42.99	24.37	2.93	0.09	(0.06)	2.96	54.00	11.01	25.6%
		2,000	22.89	1.69	0.23	0.09	2.01	63.09	24.37	2.93	0.09	(0.06)	2.96	83.63	20.54	32.6%
		5,000	22.89	1.69	0.23	0.09	2.01	123.39	24.37	2.93	0.09	(0.06)	2.96	172.53	49.14	39.8%
		10,000	22.89	1.69	0.23	0.09	2.01	223.89	24.37	2.93	0.09	(0.06)	2.96	320.70	96.81	43.2%
		15,000	22.89	1.69	0.23	0.09	2.01	324.39	24.37	2.93	0.09	(0.06)	2.96	468.86	144.47	44.5%
GSe	Havelock	1,000	22.18	1.52	0.16	0.09	1.77	39.88	24.55	2.60	0.09	(0.06)	2.63	50.88	11.00	27.6%
		2,000	22.18	1.52	0.16	0.09	1.77	57.58	24.55	2.60	0.09	(0.06)	2.63	77.21	19.63	34.1%
		5,000	22.18	1.52	0.16	0.09	1.77	110.68	24.55	2.60	0.09	(0.06)	2.63	156.21	45.53	41.1%
		10,000	22.18	1.52	0.16	0.09	1.77	199.18	24.55	2.60	0.09	(0.06)	2.63	287.87	88.69	44.5%
		15,000	22.18	1.52	0.16	0.09	1.77	287.68	24.55	2.60	0.09	(0.06)	2.63	419.54	131.86	45.8%
GSe	Kirkfield	1,000	14.69	1.95	0.61	0.44	3.00	44.69	18.42	3.21	0.44	(0.06)	3.59	54.36	9.67	21.6%
		2,000	14.69	1.95	0.61	0.44	3.00	74.69	18.42	3.21	0.44	(0.06)	3.59	90.29	15.60	20.9%
		5,000	14.69	1.95	0.61	0.44	3.00	164.69	18.42	3.21	0.44	(0.06)	3.59	198.11	33.42	20.3%
		10,000	14.69	1.95	0.61	0.44	3.00	314.69	18.42	3.21	0.44	(0.06)	3.59	377.79	63.10	20.1%
		15,000	14.69	1.95	0.61	0.44	3.00	464.69	18.42	3.21	0.44	(0.06)	3.59	557.48	92.79	20.0%
GSe	Lanark Highlands	1,000	18.43	1.99	0.63	0.50	3.12	49.63	21.48	3.21	0.50	(0.06)	3.65	58.02	8.39	16.9%
		2,000	18.43	1.99	0.63	0.50	3.12	80.83	21.48	3.21	0.50	(0.06)	3.65	94.56	13.73	17.0%
		5,000	18.43	1.99	0.63	0.50	3.12	174.43	21.48	3.21	0.50	(0.06)	3.65	204.17	29.74	17.1%
		10,000	18.43	1.99	0.63	0.50	3.12	330.43	21.48	3.21	0.50	(0.06)	3.65	386.86	56.43	17.1%
		15,000	18.43	1.99	0.63	0.50	3.12	486.43	21.48	3.21	0.50	(0.06)	3.65	569.55	83.12	17.1%
GSe	Larder Lake	1,000	20.18	1.58	0.51	0.36	2.45	44.68	23.05	3.05	0.36	(0.06)	3.35	56.58	11.90	26.6%
		2,000	20.18	1.58	0.51	0.36	2.45	69.18	23.05	3.05	0.36	(0.06)	3.35	90.11	20.93	30.3%
		5,000	20.18	1.58	0.51	0.36	2.45	142.68	23.05	3.05	0.36	(0.06)	3.35	190.71	48.03	33.7%
		10,000	20.18	1.58	0.51	0.36	2.45	265.18	23.05	3.05	0.36	(0.06)	3.35	358.37	93.19	35.1%
		15,000	20.18	1.58	0.51	0.36	2.45	387.68	23.05	3.05	0.36	(0.06)	3.35	526.04	138.36	35.7%

New Rate Class: GSe

Bill Impacts of Proposed Distribution Rates include Riders

Classes		Scenario	Existing Dx Rates						New Dx Rates						$ Incr	% Incr
			SrChg	base	Rider1	Rider2	VarChg	[$/month]	SrChg	base	Rider2	Rider3	VarChg	[$/month]		
New Class	Old Class	kWh	[$/month]	[c/kWh]	[c/kWh]	[c/kWh]	[c/kWh]		[$/month]	[c/kWh]	[c/kWh]	[c/kWh]	[c/kWh]			
GSe	**Latchford**	1,000	2.88	1.02	0.65	0.20	1.87	21.58	9.37	2.32	0.20	(0.06)	2.46	34.00	12.42	57.6%
		2,000	2.88	1.02	0.65	0.20	1.87	40.28	9.37	2.32	0.20	(0.06)	2.46	58.64	18.36	45.6%
		5,000	2.88	1.02	0.65	0.20	1.87	96.38	9.37	2.32	0.20	(0.06)	2.46	132.54	36.16	37.5%
		10,000	2.88	1.02	0.65	0.20	1.87	189.88	9.37	2.32	0.20	(0.06)	2.46	255.70	65.82	34.7%
		15,000	2.88	1.02	0.65	0.20	1.87	283.38	9.37	2.32	0.20	(0.06)	2.46	378.86	95.48	33.7%
UGe	**Lindsay**	1,000	23.94	1.38	0.15	0.06	1.59	39.84	20.10	2.00	0.06	(0.06)	2.01	40.15	0.31	0.8%
		2,000	23.94	1.38	0.15	0.06	1.59	55.74	20.10	2.00	0.06	(0.06)	2.01	60.21	4.47	8.0%
		5,000	23.94	1.38	0.15	0.06	1.59	103.44	20.10	2.00	0.06	(0.06)	2.01	120.37	16.93	16.4%
		10,000	23.94	1.38	0.15	0.06	1.59	182.94	20.10	2.00	0.06	(0.06)	2.01	220.64	37.70	20.6%
		15,000	23.94	1.38	0.15	0.06	1.59	262.44	20.10	2.00	0.06	(0.06)	2.01	320.91	58.47	22.3%
GSe	**Lucan Granton**	1,000	16.99	1.47	0.17	0.10	1.74	34.39	19.84	2.53	0.10	(0.06)	2.57	45.58	11.19	32.5%
		2,000	16.99	1.47	0.17	0.10	1.74	51.79	19.84	2.53	0.10	(0.06)	2.57	71.31	19.52	37.7%
		5,000	16.99	1.47	0.17	0.10	1.74	103.99	19.84	2.53	0.10	(0.06)	2.57	148.51	44.52	42.8%
		10,000	16.99	1.47	0.17	0.10	1.74	190.99	19.84	2.53	0.10	(0.06)	2.57	277.17	86.18	45.1%
		15,000	16.99	1.47	0.17	0.10	1.74	277.99	19.84	2.53	0.10	(0.06)	2.57	405.83	127.84	46.0%
GSe	**Malahide**	1,000	15.84	1.98	0.81	0.49	3.28	48.64	19.13	3.21	0.49	(0.06)	3.64	55.57	6.93	14.2%
		2,000	15.84	1.98	0.81	0.49	3.28	81.44	19.13	3.21	0.49	(0.06)	3.64	92.01	10.57	13.0%
		5,000	15.84	1.98	0.81	0.49	3.28	179.84	19.13	3.21	0.49	(0.06)	3.64	201.32	21.48	11.9%
		10,000	15.84	1.98	0.81	0.49	3.28	343.84	19.13	3.21	0.49	(0.06)	3.64	383.51	39.67	11.5%
		15,000	15.84	1.98	0.81	0.49	3.28	507.84	19.13	3.21	0.49	(0.06)	3.64	565.69	57.85	11.4%
GSe	**Mapleton**	1,000	21.55	1.71	0.40	0.29	2.40	45.55	23.70	3.11	0.29	(0.06)	3.34	57.14	11.59	25.4%
		2,000	21.55	1.71	0.40	0.29	2.40	69.55	23.70	3.11	0.29	(0.06)	3.34	90.57	21.02	30.2%
		5,000	21.55	1.71	0.40	0.29	2.40	141.55	23.70	3.11	0.29	(0.06)	3.34	190.87	49.32	34.8%
		10,000	21.55	1.71	0.40	0.29	2.40	261.55	23.70	3.11	0.29	(0.06)	3.34	358.03	96.48	36.9%
		15,000	21.55	1.71	0.40	0.29	2.40	381.55	23.70	3.11	0.29	(0.06)	3.34	525.19	143.64	37.6%

New Rate Class: GSe

Bill Impacts of Proposed Distribution Rates include Riders

Classes		Scenario	Existing Dx Rates						New Dx Rates						$ Incr	% Incr
			SrChg	base	Rider1	Rider2	VarChg	[$/month]	SrChg	base	Rider2	Rider3	VarChg	[$/month]		
New Class	Old Class	kWh	[$/month]	[c/kWh]	[c/kWh]	[c/kWh]	[c/kWh]		[$/month]	[c/kWh]	[c/kWh]	[c/kWh]	[c/kWh]			
GSe	Markdale	1,000	23.00	0.80	0.15	0.04	0.99	32.90	25.34	1.82	0.04	(0.06)	1.80	43.37	10.47	31.8%
		2,000	23.00	0.80	0.15	0.04	0.99	42.80	25.34	1.82	0.04	(0.06)	1.80	61.41	18.61	43.5%
		5,000	23.00	0.80	0.15	0.04	0.99	72.50	25.34	1.82	0.04	(0.06)	1.80	115.51	43.01	59.3%
		10,000	23.00	0.80	0.15	0.04	0.99	122.00	25.34	1.82	0.04	(0.06)	1.80	205.67	83.67	68.6%
		15,000	23.00	0.80	0.15	0.04	0.99	171.50	25.34	1.82	0.04	(0.06)	1.80	295.83	124.33	72.5%
GSe	Marmora	1,000	10.02	1.05	0.15	0.05	1.25	22.52	15.59	1.88	0.05	(0.06)	1.87	34.32	11.80	52.4%
		2,000	10.02	1.05	0.15	0.05	1.25	35.02	15.59	1.88	0.05	(0.06)	1.87	53.05	18.03	51.5%
		5,000	10.02	1.05	0.15	0.05	1.25	72.52	15.59	1.88	0.05	(0.06)	1.87	109.25	36.73	50.6%
		10,000	10.02	1.05	0.15	0.05	1.25	135.02	15.59	1.88	0.05	(0.06)	1.87	202.91	67.89	50.3%
		15,000	10.02	1.05	0.15	0.05	1.25	197.52	15.59	1.88	0.05	(0.06)	1.87	296.58	99.06	50.2%
GSe	McGarry	1,000	19.99	2.00	0.57	0.50	3.07	50.69	22.09	3.21	0.50	(0.06)	3.65	58.63	7.94	15.7%
		2,000	19.99	2.00	0.57	0.50	3.07	81.39	22.09	3.21	0.50	(0.06)	3.65	95.17	13.78	16.9%
		5,000	19.99	2.00	0.57	0.50	3.07	173.49	22.09	3.21	0.50	(0.06)	3.65	204.78	31.29	18.0%
		10,000	19.99	2.00	0.57	0.50	3.07	326.99	22.09	3.21	0.50	(0.06)	3.65	387.47	60.48	18.5%
		15,000	19.99	2.00	0.57	0.50	3.07	480.49	22.09	3.21	0.50	(0.06)	3.65	570.16	89.67	18.7%
GSe	Meaford	1,000	24.05	1.23	0.16	0.07	1.46	38.65	26.08	2.32	0.07	(0.06)	2.33	49.41	10.76	27.8%
		2,000	24.05	1.23	0.16	0.07	1.46	53.25	26.08	2.32	0.07	(0.06)	2.33	72.74	19.49	36.6%
		5,000	24.05	1.23	0.16	0.07	1.46	97.05	26.08	2.32	0.07	(0.06)	2.33	142.74	45.69	47.1%
		10,000	24.05	1.23	0.16	0.07	1.46	170.05	26.08	2.32	0.07	(0.06)	2.33	259.41	89.36	52.5%
		15,000	24.05	1.23	0.16	0.07	1.46	243.05	26.08	2.32	0.07	(0.06)	2.33	376.07	133.02	54.7%
GSe	Middlesex Centre	1,000	17.35	1.37	0.44	0.35	2.16	38.95	20.75	2.70	0.35	(0.06)	2.99	50.69	11.74	30.1%
		2,000	17.35	1.37	0.44	0.35	2.16	60.55	20.75	2.70	0.35	(0.06)	2.99	80.62	20.07	33.1%
		5,000	17.35	1.37	0.44	0.35	2.16	125.35	20.75	2.70	0.35	(0.06)	2.99	170.42	45.07	36.0%
		10,000	17.35	1.37	0.44	0.35	2.16	233.35	20.75	2.70	0.35	(0.06)	2.99	320.08	86.73	37.2%
		15,000	17.35	1.37	0.44	0.35	2.16	341.35	20.75	2.70	0.35	(0.06)	2.99	469.74	128.39	37.6%

New Rate Class: GSe

Bill Impacts of Proposed Distribution Rates include Riders

Classes		Scenario	Existing Dx Rates						New Dx Rates						$ Incr	% Incr
			SrChg	base	Rider1	Rider2	VarChg	[$/month]	SrChg	base	Rider2	Rider3	VarChg	[$/month]		
New Class	Old Class	kWh	[$/month]	[c/kWh]	[c/kWh]	[c/kWh]	[c/kWh]		[$/month]	[c/kWh]	[c/kWh]	[c/kWh]	[c/kWh]			
GSe	**Napanee**	1,000	22.17	1.28	0.16	0.06	1.50	37.17	24.55	2.35	0.06	(0.06)	2.35	48.08	10.91	29.4%
		2,000	22.17	1.28	0.16	0.06	1.50	52.17	24.55	2.35	0.06	(0.06)	2.35	71.61	19.44	37.3%
		5,000	22.17	1.28	0.16	0.06	1.50	97.17	24.55	2.35	0.06	(0.06)	2.35	142.21	45.04	46.4%
		10,000	22.17	1.28	0.16	0.06	1.50	172.17	24.55	2.35	0.06	(0.06)	2.35	259.88	87.71	50.9%
		15,000	22.17	1.28	0.16	0.06	1.50	247.17	24.55	2.35	0.06	(0.06)	2.35	377.54	130.37	52.7%
GSe	**Nipigon**	1,000	23.32	1.05	0.34	0.21	1.60	39.32	25.26	2.34	0.21	(0.06)	2.49	50.19	10.87	27.7%
		2,000	23.32	1.05	0.34	0.21	1.60	55.32	25.26	2.34	0.21	(0.06)	2.49	75.13	19.81	35.8%
		5,000	23.32	1.05	0.34	0.21	1.60	103.32	25.26	2.34	0.21	(0.06)	2.49	149.93	46.61	45.1%
		10,000	23.32	1.05	0.34	0.21	1.60	183.32	25.26	2.34	0.21	(0.06)	2.49	274.59	91.27	49.8%
		15,000	23.32	1.05	0.34	0.21	1.60	263.32	25.26	2.34	0.21	(0.06)	2.49	399.25	135.93	51.6%
GSe	**North Dorchester**	1,000	15.88	0.90	0.35	0.26	1.51	30.98	19.12	2.08	0.26	(0.06)	2.28	41.95	10.97	35.4%
		2,000	15.88	0.90	0.35	0.26	1.51	46.08	19.12	2.08	0.26	(0.06)	2.28	64.79	18.71	40.6%
		5,000	15.88	0.90	0.35	0.26	1.51	91.38	19.12	2.08	0.26	(0.06)	2.28	133.29	41.91	45.9%
		10,000	15.88	0.90	0.35	0.26	1.51	166.88	19.12	2.08	0.26	(0.06)	2.28	247.45	80.57	48.3%
		15,000	15.88	0.90	0.35	0.26	1.51	242.38	19.12	2.08	0.26	(0.06)	2.28	361.61	119.23	49.2%
GSe	**North Dundas**	1,000	13.52	0.83	0.16	0.04	1.03	23.82	17.71	1.72	0.04	(0.06)	1.70	34.74	10.92	45.9%
		2,000	13.52	0.83	0.16	0.04	1.03	34.12	17.71	1.72	0.04	(0.06)	1.70	51.78	17.66	51.8%
		5,000	13.52	0.83	0.16	0.04	1.03	65.02	17.71	1.72	0.04	(0.06)	1.70	102.88	37.86	58.2%
		10,000	13.52	0.83	0.16	0.04	1.03	116.52	17.71	1.72	0.04	(0.06)	1.70	188.04	71.52	61.4%
		15,000	13.52	0.83	0.16	0.04	1.03	168.02	17.71	1.72	0.04	(0.06)	1.70	273.20	105.18	62.6%
GSe	**North Glengarry**	1,000	17.72	0.90	0.21	0.12	1.23	30.02	20.66	1.95	0.12	(0.06)	2.01	40.79	10.77	35.9%
		2,000	17.72	0.90	0.21	0.12	1.23	42.32	20.66	1.95	0.12	(0.06)	2.01	60.93	18.61	44.0%
		5,000	17.72	0.90	0.21	0.12	1.23	79.22	20.66	1.95	0.12	(0.06)	2.01	121.33	42.11	53.1%
		10,000	17.72	0.90	0.21	0.12	1.23	140.72	20.66	1.95	0.12	(0.06)	2.01	221.99	81.27	57.8%
		15,000	17.72	0.90	0.21	0.12	1.23	202.22	20.66	1.95	0.12	(0.06)	2.01	322.65	120.43	59.6%

New Rate Class: GSe

Bill Impacts of Proposed Distribution Rates include Riders

Classes		Scenario	Existing Dx Rates						New Dx Rates						$ Incr	% Incr
			SrChg	base	Rider1	Rider2	VarChg	[$/month]	SrChg	base	Rider2	Rider3	VarChg	[$/month]		
New Class	Old Class	kWh	[$/month]	[c/kWh]	[c/kWh]	[c/kWh]	[c/kWh]		[$/month]	[c/kWh]	[c/kWh]	[c/kWh]	[c/kWh]			
GSe	**North Grenville**	1,000	20.42	1.71	0.14	0.08	1.93	39.72	22.99	2.79	0.08	(0.06)	2.81	51.12	11.40	28.7%
		2,000	20.42	1.71	0.14	0.08	1.93	59.02	22.99	2.79	0.08	(0.06)	2.81	79.25	20.23	34.3%
		5,000	20.42	1.71	0.14	0.08	1.93	116.92	22.99	2.79	0.08	(0.06)	2.81	163.65	46.73	40.0%
		10,000	20.42	1.71	0.14	0.08	1.93	213.42	22.99	2.79	0.08	(0.06)	2.81	304.31	90.89	42.6%
		15,000	20.42	1.71	0.14	0.08	1.93	309.92	22.99	2.79	0.08	(0.06)	2.81	444.98	135.06	43.6%
GSe	**North Perth**	1,000	29.52	1.00	0.12	0.04	1.16	41.12	29.71	2.15	0.04	(0.06)	2.13	51.04	9.92	24.1%
		2,000	29.52	1.00	0.12	0.04	1.16	52.72	29.71	2.15	0.04	(0.06)	2.13	72.38	19.66	37.3%
		5,000	29.52	1.00	0.12	0.04	1.16	87.52	29.71	2.15	0.04	(0.06)	2.13	136.38	48.86	55.8%
		10,000	29.52	1.00	0.12	0.04	1.16	145.52	29.71	2.15	0.04	(0.06)	2.13	243.04	97.52	67.0%
		15,000	29.52	1.00	0.12	0.04	1.16	203.52	29.71	2.15	0.04	(0.06)	2.13	349.70	146.18	71.8%
GSe	**North Stormont**	1,000	5.37	0.78	0.37	0.26	1.41	19.47	11.75	1.78	0.26	(0.06)	1.98	31.58	12.11	62.2%
		2,000	5.37	0.78	0.37	0.26	1.41	33.57	11.75	1.78	0.26	(0.06)	1.98	51.41	17.84	53.2%
		5,000	5.37	0.78	0.37	0.26	1.41	75.87	11.75	1.78	0.26	(0.06)	1.98	110.91	35.04	46.2%
		10,000	5.37	0.78	0.37	0.26	1.41	146.37	11.75	1.78	0.26	(0.06)	1.98	210.08	63.71	43.5%
		15,000	5.37	0.78	0.37	0.26	1.41	216.87	11.75	1.78	0.26	(0.06)	1.98	309.24	92.37	42.6%
GSe	**Omemee**	1,000	21.28	1.47	0.18	0.09	1.74	38.68	23.77	2.55	0.09	(0.06)	2.58	49.60	10.92	28.2%
		2,000	21.28	1.47	0.18	0.09	1.74	56.08	23.77	2.55	0.09	(0.06)	2.58	75.44	19.36	34.5%
		5,000	21.28	1.47	0.18	0.09	1.74	108.28	23.77	2.55	0.09	(0.06)	2.58	152.94	44.66	41.2%
		10,000	21.28	1.47	0.18	0.09	1.74	195.28	23.77	2.55	0.09	(0.06)	2.58	282.10	86.82	44.5%
		15,000	21.28	1.47	0.18	0.09	1.74	282.28	23.77	2.55	0.09	(0.06)	2.58	411.26	128.98	45.7%
UGe	**Perth**	1,000	19.92	0.92	0.13	0.04	1.09	30.82	17.10	2.00	0.04	(0.06)	1.99	36.96	6.14	19.9%
		2,000	19.92	0.92	0.13	0.04	1.09	41.72	17.10	2.00	0.04	(0.06)	1.99	56.81	15.09	36.2%
		5,000	19.92	0.92	0.13	0.04	1.09	74.42	17.10	2.00	0.04	(0.06)	1.99	116.37	41.95	56.4%
		10,000	19.92	0.92	0.13	0.04	1.09	128.92	17.10	2.00	0.04	(0.06)	1.99	215.64	86.72	67.3%
		15,000	19.92	0.92	0.13	0.04	1.09	183.42	17.10	2.00	0.04	(0.06)	1.99	314.91	131.49	71.7%

New Rate Class: GSe

Bill Impacts of Proposed Distribution Rates include Riders

Classes		Scenario	Existing Dx Rates						New Dx Rates						$ Incr	% Incr
			SrChg	base	Rider1	Rider2	VarChg	[$/month]	SrChg	base	Rider2	Rider3	VarChg	[$/month]		
New Class	Old Class	kWh	[$/month]	[c/kWh]	[c/kWh]	[c/kWh]	[c/kWh]		[$/month]	[c/kWh]	[c/kWh]	[c/kWh]	[c/kWh]			
GSe	**Perth East**	1,000	14.65	1.29	0.16	0.09	1.54	30.05	18.43	2.25	0.09	(0.06)	2.28	41.26	11.21	37.3%
		2,000	14.65	1.29	0.16	0.09	1.54	45.45	18.43	2.25	0.09	(0.06)	2.28	64.09	18.64	41.0%
		5,000	14.65	1.29	0.16	0.09	1.54	91.65	18.43	2.25	0.09	(0.06)	2.28	132.59	40.94	44.7%
		10,000	14.65	1.29	0.16	0.09	1.54	168.65	18.43	2.25	0.09	(0.06)	2.28	246.76	78.11	46.3%
		15,000	14.65	1.29	0.16	0.09	1.54	245.65	18.43	2.25	0.09	(0.06)	2.28	360.92	115.27	46.9%
GSe	**Prince Edward**	1,000	22.85	1.42	0.18	0.08	1.68	39.65	24.38	2.57	0.08	(0.06)	2.59	50.31	10.66	26.9%
		2,000	22.85	1.42	0.18	0.08	1.68	56.45	24.38	2.57	0.08	(0.06)	2.59	76.24	19.79	35.1%
		5,000	22.85	1.42	0.18	0.08	1.68	106.85	24.38	2.57	0.08	(0.06)	2.59	154.04	47.19	44.2%
		10,000	22.85	1.42	0.18	0.08	1.68	190.85	24.38	2.57	0.08	(0.06)	2.59	283.71	92.86	48.7%
		15,000	22.85	1.42	0.18	0.08	1.68	274.85	24.38	2.57	0.08	(0.06)	2.59	413.37	138.52	50.4%
UGe	**Quinte West**	1,000	3.74	1.05	0.14	0.06	1.25	16.24	5.15	2.00	0.06	(0.06)	2.01	25.20	8.96	55.2%
		2,000	3.74	1.05	0.14	0.06	1.25	28.74	5.15	2.00	0.06	(0.06)	2.01	45.26	16.52	57.5%
		5,000	3.74	1.05	0.14	0.06	1.25	66.24	5.15	2.00	0.06	(0.06)	2.01	105.42	39.18	59.1%
		10,000	3.74	1.05	0.14	0.06	1.25	128.74	5.15	2.00	0.06	(0.06)	2.01	205.69	76.95	59.8%
		15,000	3.74	1.05	0.14	0.06	1.25	191.24	5.15	2.00	0.06	(0.06)	2.01	305.96	114.72	60.0%
GSe	**Rainy River**	1,000	19.29	1.76	0.45	0.36	2.57	44.99	22.27	3.18	0.36	(0.06)	3.48	57.10	12.11	26.9%
		2,000	19.29	1.76	0.45	0.36	2.57	70.69	22.27	3.18	0.36	(0.06)	3.48	91.93	21.24	30.1%
		5,000	19.29	1.76	0.45	0.36	2.57	147.79	22.27	3.18	0.36	(0.06)	3.48	196.43	48.64	32.9%
		10,000	19.29	1.76	0.45	0.36	2.57	276.29	22.27	3.18	0.36	(0.06)	3.48	370.60	94.31	34.1%
		15,000	19.29	1.76	0.45	0.36	2.57	404.79	22.27	3.18	0.36	(0.06)	3.48	544.76	139.97	34.6%
GSe	**Ramara**	1,000	20.97	1.06	0.45	0.37	1.88	39.77	22.85	2.48	0.37	(0.06)	2.79	50.78	11.01	27.7%
		2,000	20.97	1.06	0.45	0.37	1.88	58.57	22.85	2.48	0.37	(0.06)	2.79	78.71	20.14	34.4%
		5,000	20.97	1.06	0.45	0.37	1.88	114.97	22.85	2.48	0.37	(0.06)	2.79	162.51	47.54	41.4%
		10,000	20.97	1.06	0.45	0.37	1.88	208.97	22.85	2.48	0.37	(0.06)	2.79	302.18	93.21	44.6%
		15,000	20.97	1.06	0.45	0.37	1.88	302.97	22.85	2.48	0.37	(0.06)	2.79	441.84	138.87	45.8%

New Rate Class: GSe

Bill Impacts of Proposed Distribution Rates include Riders

Classes		Scenario	Existing Dx Rates						New Dx Rates						$ Incr	% Incr
			SrChg	base	Rider1	Rider2	VarChg	[$/month]	SrChg	base	Rider2	Rider3	VarChg	[$/month]		
New Class	Old Class	kWh	[$/month]	[c/kWh]	[c/kWh]	[c/kWh]	[c/kWh]		[$/month]	[c/kWh]	[c/kWh]	[c/kWh]	[c/kWh]			
GSe	Red Rock	1,000	21.64	1.94	0.27	0.24	2.45	46.14	23.68	3.21	0.24	(0.06)	3.39	57.62	11.48	24.9%
		2,000	21.64	1.94	0.27	0.24	2.45	70.64	23.68	3.21	0.24	(0.06)	3.39	91.56	20.92	29.6%
		5,000	21.64	1.94	0.27	0.24	2.45	144.14	23.68	3.21	0.24	(0.06)	3.39	193.37	49.23	34.2%
		10,000	21.64	1.94	0.27	0.24	2.45	266.64	23.68	3.21	0.24	(0.06)	3.39	363.06	96.42	36.2%
		15,000	21.64	1.94	0.27	0.24	2.45	389.14	23.68	3.21	0.24	(0.06)	3.39	532.74	143.60	36.9%
GSe	Rockland	1,000	7.27	1.00	0.17	0.22	1.39	21.17	13.27	1.80	0.22	(0.06)	1.96	32.91	11.74	55.4%
		2,000	7.27	1.00	0.17	0.22	1.39	35.07	13.27	1.80	0.22	(0.06)	1.96	52.54	17.47	49.8%
		5,000	7.27	1.00	0.17	0.22	1.39	76.77	13.27	1.80	0.22	(0.06)	1.96	111.44	34.67	45.2%
		10,000	7.27	1.00	0.17	0.22	1.39	146.27	13.27	1.80	0.22	(0.06)	1.96	209.60	63.33	43.3%
		15,000	7.27	1.00	0.17	0.22	1.39	215.77	13.27	1.80	0.22	(0.06)	1.96	307.76	91.99	42.6%
GSe	Russell	1,000	19.26	2.24	0.18	0.11	2.53	44.56	22.28	3.21	0.11	(0.06)	3.26	54.91	10.35	23.2%
		2,000	19.26	2.24	0.18	0.11	2.53	69.86	22.28	3.21	0.11	(0.06)	3.26	87.55	17.69	25.3%
		5,000	19.26	2.24	0.18	0.11	2.53	145.76	22.28	3.21	0.11	(0.06)	3.26	185.46	39.70	27.2%
		10,000	19.26	2.24	0.18	0.11	2.53	272.26	22.28	3.21	0.11	(0.06)	3.26	348.65	76.39	28.1%
		15,000	19.26	2.24	0.18	0.11	2.53	398.76	22.28	3.21	0.11	(0.06)	3.26	511.84	113.08	28.4%
GSe	Schreiber	1,000	20.70	2.51	0.50	0.40	3.41	54.80	22.92	3.21	0.40	(0.06)	3.55	58.45	3.65	6.7%
		2,000	20.70	2.51	0.50	0.40	3.41	88.90	22.92	3.21	0.40	(0.06)	3.55	93.99	5.09	5.7%
		5,000	20.70	2.51	0.50	0.40	3.41	191.20	22.92	3.21	0.40	(0.06)	3.55	200.60	9.40	4.9%
		10,000	20.70	2.51	0.50	0.40	3.41	361.70	22.92	3.21	0.40	(0.06)	3.55	378.29	16.59	4.6%
		15,000	20.70	2.51	0.50	0.40	3.41	532.20	22.92	3.21	0.40	(0.06)	3.55	555.98	23.78	4.5%
GSe	Severn	1,000	22.17	1.06	0.31	0.22	1.59	38.07	24.55	2.30	0.22	(0.06)	2.46	49.18	11.11	29.2%
		2,000	22.17	1.06	0.31	0.22	1.59	53.97	24.55	2.30	0.22	(0.06)	2.46	73.81	19.84	36.8%
		5,000	22.17	1.06	0.31	0.22	1.59	101.67	24.55	2.30	0.22	(0.06)	2.46	147.71	46.04	45.3%
		10,000	22.17	1.06	0.31	0.22	1.59	181.17	24.55	2.30	0.22	(0.06)	2.46	270.88	89.71	49.5%
		15,000	22.17	1.06	0.31	0.22	1.59	260.67	24.55	2.30	0.22	(0.06)	2.46	394.04	133.37	51.2%

New Rate Class: GSe

Bill Impacts of Proposed Distribution Rates include Riders

Classes		Scenario	Existing Dx Rates						New Dx Rates						$ Incr	% Incr
			SrChg	base	Rider1	Rider2	VarChg	[$/month]	SrChg	base	Rider2	Rider3	VarChg	[$/month]		
New Class	Old Class	kWh	[$/month]	[c/kWh]	[c/kWh]	[c/kWh]	[c/kWh]		[$/month]	[c/kWh]	[c/kWh]	[c/kWh]	[c/kWh]			
GSe	**Shelburne**	1,000	20.01	0.87	0.10	0.02	0.99	29.91	23.09	1.79	0.02	(0.06)	1.75	40.62	10.71	35.8%
		2,000	20.01	0.87	0.10	0.02	0.99	39.81	23.09	1.79	0.02	(0.06)	1.75	58.15	18.34	46.1%
		5,000	20.01	0.87	0.10	0.02	0.99	69.51	23.09	1.79	0.02	(0.06)	1.75	110.75	41.24	59.3%
		10,000	20.01	0.87	0.10	0.02	0.99	119.01	23.09	1.79	0.02	(0.06)	1.75	198.42	79.41	66.7%
		15,000	20.01	0.87	0.10	0.02	0.99	168.51	23.09	1.79	0.02	(0.06)	1.75	286.08	117.57	69.8%
UGe	**Smiths Falls**	1,000	9.84	1.05	0.12	0.04	1.21	21.94	9.62	2.00	0.04	(0.06)	1.99	29.48	7.54	34.4%
		2,000	9.84	1.05	0.12	0.04	1.21	34.04	9.62	2.00	0.04	(0.06)	1.99	49.33	15.29	44.9%
		5,000	9.84	1.05	0.12	0.04	1.21	70.34	9.62	2.00	0.04	(0.06)	1.99	108.89	38.55	54.8%
		10,000	9.84	1.05	0.12	0.04	1.21	130.84	9.62	2.00	0.04	(0.06)	1.99	208.16	77.32	59.1%
		15,000	9.84	1.05	0.12	0.04	1.21	191.34	9.62	2.00	0.04	(0.06)	1.99	307.43	116.09	60.7%
GSe	**South Glengarry**	1,000	17.41	0.75	0.37	0.30	1.42	31.61	20.74	1.96	0.30	(0.06)	2.20	42.77	11.16	35.3%
		2,000	17.41	0.75	0.37	0.30	1.42	45.81	20.74	1.96	0.30	(0.06)	2.20	64.80	18.99	41.5%
		5,000	17.41	0.75	0.37	0.30	1.42	88.41	20.74	1.96	0.30	(0.06)	2.20	130.90	42.49	48.1%
		10,000	17.41	0.75	0.37	0.30	1.42	159.41	20.74	1.96	0.30	(0.06)	2.20	241.07	81.66	51.2%
		15,000	17.41	0.75	0.37	0.30	1.42	230.41	20.74	1.96	0.30	(0.06)	2.20	351.23	120.82	52.4%
GSe	**South River**	1,000	22.11	1.58	0.39	0.30	2.27	44.81	24.56	2.95	0.30	(0.06)	3.19	56.50	11.69	26.1%
		2,000	22.11	1.58	0.39	0.30	2.27	67.51	24.56	2.95	0.30	(0.06)	3.19	88.43	20.92	31.0%
		5,000	22.11	1.58	0.39	0.30	2.27	135.61	24.56	2.95	0.30	(0.06)	3.19	184.23	48.62	35.9%
		10,000	22.11	1.58	0.39	0.30	2.27	249.11	24.56	2.95	0.30	(0.06)	3.19	343.89	94.78	38.0%
		15,000	22.11	1.58	0.39	0.30	2.27	362.61	24.56	2.95	0.30	(0.06)	3.19	503.55	140.94	38.9%
GSe	**Springwater**	1,000	20.53	1.07	0.27	0.17	1.51	35.63	22.96	2.25	0.17	(0.06)	2.36	46.59	10.96	30.8%
		2,000	20.53	1.07	0.27	0.17	1.51	50.73	22.96	2.25	0.17	(0.06)	2.36	70.22	19.49	38.4%
		5,000	20.53	1.07	0.27	0.17	1.51	96.03	22.96	2.25	0.17	(0.06)	2.36	141.12	45.09	47.0%
		10,000	20.53	1.07	0.27	0.17	1.51	171.53	22.96	2.25	0.17	(0.06)	2.36	259.29	87.76	51.2%
		15,000	20.53	1.07	0.27	0.17	1.51	247.03	22.96	2.25	0.17	(0.06)	2.36	377.45	130.42	52.8%

New Rate Class: GSe

Bill Impacts of Proposed Distribution Rates include Riders

Classes		Scenario	Existing Dx Rates						New Dx Rates						$ Incr	% Incr
			SrChg	base	Rider1	Rider2	VarChg	[$/month]	SrChg	base	Rider2	Rider3	VarChg	[$/month]		
New Class	Old Class	kWh	[$/month]	[c/kWh]	[c/kWh]	[c/kWh]	[c/kWh]		[$/month]	[c/kWh]	[c/kWh]	[c/kWh]	[c/kWh]			
GSe	Stirling-Rawdon	1,000	24.12	1.30	0.21	0.09	1.60	40.12	26.06	2.47	0.09	(0.06)	2.50	51.09	10.97	27.4%
		2,000	24.12	1.30	0.21	0.09	1.60	56.12	26.06	2.47	0.09	(0.06)	2.50	76.13	20.01	35.7%
		5,000	24.12	1.30	0.21	0.09	1.60	104.12	26.06	2.47	0.09	(0.06)	2.50	151.23	47.11	45.2%
		10,000	24.12	1.30	0.21	0.09	1.60	184.12	26.06	2.47	0.09	(0.06)	2.50	276.39	92.27	50.1%
		15,000	24.12	1.30	0.21	0.09	1.60	264.12	26.06	2.47	0.09	(0.06)	2.50	401.55	137.43	52.0%
GSe	Thedford	1,000	17.83	1.06	0.36	0.31	1.73	35.13	20.63	2.30	0.31	(0.06)	2.55	46.17	11.04	31.4%
		2,000	17.83	1.06	0.36	0.31	1.73	52.43	20.63	2.30	0.31	(0.06)	2.55	71.70	19.27	36.8%
		5,000	17.83	1.06	0.36	0.31	1.73	104.33	20.63	2.30	0.31	(0.06)	2.55	148.30	43.97	42.1%
		10,000	17.83	1.06	0.36	0.31	1.73	190.83	20.63	2.30	0.31	(0.06)	2.55	275.96	85.13	44.6%
		15,000	17.83	1.06	0.36	0.31	1.73	277.33	20.63	2.30	0.31	(0.06)	2.55	403.62	126.29	45.5%
GSe	Thessalon	1,000	18.90	1.55	0.10	0.08	1.73	36.20	21.37	2.56	0.08	(0.06)	2.58	47.20	11.00	30.4%
		2,000	18.90	1.55	0.10	0.08	1.73	53.50	21.37	2.56	0.08	(0.06)	2.58	73.03	19.53	36.5%
		5,000	18.90	1.55	0.10	0.08	1.73	105.40	21.37	2.56	0.08	(0.06)	2.58	150.53	45.13	42.8%
		10,000	18.90	1.55	0.10	0.08	1.73	191.90	21.37	2.56	0.08	(0.06)	2.58	279.69	87.79	45.7%
		15,000	18.90	1.55	0.10	0.08	1.73	278.40	21.37	2.56	0.08	(0.06)	2.58	408.86	130.46	46.9%
GSe	Thorndale	1,000	14.52	1.02	0.52	0.32	1.86	33.12	18.46	2.38	0.32	(0.06)	2.64	44.89	11.77	35.6%
		2,000	14.52	1.02	0.52	0.32	1.86	51.72	18.46	2.38	0.32	(0.06)	2.64	71.33	19.61	37.9%
		5,000	14.52	1.02	0.52	0.32	1.86	107.52	18.46	2.38	0.32	(0.06)	2.64	150.63	43.11	40.1%
		10,000	14.52	1.02	0.52	0.32	1.86	200.52	18.46	2.38	0.32	(0.06)	2.64	282.79	82.27	41.0%
		15,000	14.52	1.02	0.52	0.32	1.86	293.52	18.46	2.38	0.32	(0.06)	2.64	414.95	121.43	41.4%
UGe	Thorold	1,000	22.63	1.50	0.15	0.06	1.71	39.73	19.43	2.00	0.06	(0.06)	2.01	39.48	(0.25)	-0.6%
		2,000	22.63	1.50	0.15	0.06	1.71	56.83	19.43	2.00	0.06	(0.06)	2.01	59.53	2.70	4.8%
		5,000	22.63	1.50	0.15	0.06	1.71	108.13	19.43	2.00	0.06	(0.06)	2.01	119.70	11.57	10.7%
		10,000	22.63	1.50	0.15	0.06	1.71	193.63	19.43	2.00	0.06	(0.06)	2.01	219.97	26.34	13.6%
		15,000	22.63	1.50	0.15	0.06	1.71	279.13	19.43	2.00	0.06	(0.06)	2.01	320.23	41.10	14.7%

New Rate Class: GSe

Bill Impacts of Proposed Distribution Rates include Riders

Classes		Scenario	Existing Dx Rates						New Dx Rates						$ Incr	% Incr
			SrChg	base	Rider1	Rider2	VarChg	[$/month]	SrChg	base	Rider2	Rider3	VarChg	[$/month]		
New Class	Old Class	kWh	[$/month]	[c/kWh]	[c/kWh]	[c/kWh]	[c/kWh]		[$/month]	[c/kWh]	[c/kWh]	[c/kWh]	[c/kWh]			
GSe	Tweed	1,000	8.26	0.97	0.43	0.31	1.71	25.36	14.03	2.10	0.31	(0.06)	2.35	37.56	12.20	48.1%
		2,000	8.26	0.97	0.43	0.31	1.71	42.46	14.03	2.10	0.31	(0.06)	2.35	61.09	18.63	43.9%
		5,000	8.26	0.97	0.43	0.31	1.71	93.76	14.03	2.10	0.31	(0.06)	2.35	131.69	37.93	40.5%
		10,000	8.26	0.97	0.43	0.31	1.71	179.26	14.03	2.10	0.31	(0.06)	2.35	249.35	70.09	39.1%
		15,000	8.26	0.97	0.43	0.31	1.71	264.76	14.03	2.10	0.31	(0.06)	2.35	367.02	102.26	38.6%
GSe	Wardsville	1,000	12.32	1.00	0.25	0.08	1.33	25.62	17.01	1.99	0.08	(0.06)	2.01	37.14	11.52	45.0%
		2,000	12.32	1.00	0.25	0.08	1.33	38.92	17.01	1.99	0.08	(0.06)	2.01	57.28	18.36	47.2%
		5,000	12.32	1.00	0.25	0.08	1.33	78.82	17.01	1.99	0.08	(0.06)	2.01	117.68	38.86	49.3%
		10,000	12.32	1.00	0.25	0.08	1.33	145.32	17.01	1.99	0.08	(0.06)	2.01	218.34	73.02	50.2%
		15,000	12.32	1.00	0.25	0.08	1.33	211.82	17.01	1.99	0.08	(0.06)	2.01	319.00	107.18	50.6%
GSe	Warkworth	1,000	21.31	1.52	0.46	0.35	2.33	44.61	23.76	2.95	0.35	(0.06)	3.24	56.20	11.59	26.0%
		2,000	21.31	1.52	0.46	0.35	2.33	67.91	23.76	2.95	0.35	(0.06)	3.24	88.63	20.72	30.5%
		5,000	21.31	1.52	0.46	0.35	2.33	137.81	23.76	2.95	0.35	(0.06)	3.24	185.93	48.12	34.9%
		10,000	21.31	1.52	0.46	0.35	2.33	254.31	23.76	2.95	0.35	(0.06)	3.24	348.09	93.78	36.9%
		15,000	21.31	1.52	0.46	0.35	2.33	370.81	23.76	2.95	0.35	(0.06)	3.24	510.25	139.44	37.6%
GSe	West Elgin	1,000	15.40	0.70	0.17	0.07	0.94	24.80	19.24	1.62	0.07	(0.06)	1.63	35.57	10.77	43.4%
		2,000	15.40	0.70	0.17	0.07	0.94	34.20	19.24	1.62	0.07	(0.06)	1.63	51.91	17.71	51.8%
		5,000	15.40	0.70	0.17	0.07	0.94	62.40	19.24	1.62	0.07	(0.06)	1.63	100.91	38.51	61.7%
		10,000	15.40	0.70	0.17	0.07	0.94	109.40	19.24	1.62	0.07	(0.06)	1.63	182.57	73.17	66.9%
		15,000	15.40	0.70	0.17	0.07	0.94	156.40	19.24	1.62	0.07	(0.06)	1.63	264.23	107.83	68.9%
UGe	Whitchurch Stouffville	1,000	21.85	0.93	0.11	0.04	1.08	32.65	18.62	2.00	0.04	(0.06)	1.99	38.47	5.82	17.8%
		2,000	21.85	0.93	0.11	0.04	1.08	43.45	18.62	2.00	0.04	(0.06)	1.99	58.33	14.88	34.2%
		5,000	21.85	0.93	0.11	0.04	1.08	75.85	18.62	2.00	0.04	(0.06)	1.99	117.89	42.04	55.4%
		10,000	21.85	0.93	0.11	0.04	1.08	129.85	18.62	2.00	0.04	(0.06)	1.99	217.16	87.31	67.2%
		15,000	21.85	0.93	0.11	0.04	1.08	183.85	18.62	2.00	0.04	(0.06)	1.99	316.43	132.58	72.1%

New Rate Class: GSe

Bill Impacts of Proposed Distribution Rates include Riders

Classes		Scenario	Existing Dx Rates						New Dx Rates						$ Incr	% Incr
			SrChg	base	Rider1	Rider2	VarChg	[$/month]	SrChg	base	Rider2	Rider3	VarChg	[$/month]		
New Class	Old Class	kWh	[$/month]	[c/kWh]	[c/kWh]	[c/kWh]	[c/kWh]		[$/month]	[c/kWh]	[c/kWh]	[c/kWh]	[c/kWh]			
GSe	**Wiarton**	1,000	23.78	1.89	0.19	0.09	2.17	45.48	25.15	3.10	0.09	(0.06)	3.13	56.48	11.00	24.2%
		2,000	23.78	1.89	0.19	0.09	2.17	67.18	25.15	3.10	0.09	(0.06)	3.13	87.81	20.63	30.7%
		5,000	23.78	1.89	0.19	0.09	2.17	132.28	25.15	3.10	0.09	(0.06)	3.13	181.81	49.53	37.4%
		10,000	23.78	1.89	0.19	0.09	2.17	240.78	25.15	3.10	0.09	(0.06)	3.13	338.47	97.69	40.6%
		15,000	23.78	1.89	0.19	0.09	2.17	349.28	25.15	3.10	0.09	(0.06)	3.13	495.14	145.86	41.8%
GSe	**Woodville**	1,000	16.89	1.57	0.67	0.48	2.72	44.09	19.87	3.21	0.48	(0.06)	3.63	56.21	12.12	27.5%
		2,000	16.89	1.57	0.67	0.48	2.72	71.29	19.87	3.21	0.48	(0.06)	3.63	92.54	21.25	29.8%
		5,000	16.89	1.57	0.67	0.48	2.72	152.89	19.87	3.21	0.48	(0.06)	3.63	201.56	48.67	31.8%
		10,000	16.89	1.57	0.67	0.48	2.72	288.89	19.87	3.21	0.48	(0.06)	3.63	383.24	94.35	32.7%
		15,000	16.89	1.57	0.67	0.48	2.72	424.89	19.87	3.21	0.48	(0.06)	3.63	564.93	140.04	33.0%
GSe	**Wyoming**	1,000	17.36	1.45	0.16	0.07	1.68	34.16	20.75	2.46	0.07	(0.06)	2.47	45.48	11.32	33.2%
		2,000	17.36	1.45	0.16	0.07	1.68	50.96	20.75	2.46	0.07	(0.06)	2.47	70.22	19.26	37.8%
		5,000	17.36	1.45	0.16	0.07	1.68	101.36	20.75	2.46	0.07	(0.06)	2.47	144.42	43.06	42.5%
		10,000	17.36	1.45	0.16	0.07	1.68	185.36	20.75	2.46	0.07	(0.06)	2.47	268.08	82.72	44.6%
		15,000	17.36	1.45	0.16	0.07	1.68	269.36	20.75	2.46	0.07	(0.06)	2.47	391.74	122.38	45.4%
GSe	**Terrace Bay**	1,000	41.34	1.18	0.82	-	2.00	61.34	38.76	2.67	-	(0.06)	2.61	64.89	3.55	5.8%
		2,000	41.34	1.18	0.82	-	2.00	81.34	38.76	2.67	-	(0.06)	2.61	91.02	9.68	11.9%
		5,000	41.34	1.18	0.82	-	2.00	141.34	38.76	2.67	-	(0.06)	2.61	169.42	28.08	19.9%
		10,000	41.34	1.18	0.82	-	2.00	241.34	38.76	2.67	-	(0.06)	2.61	300.08	58.74	24.3%
		15,000	41.34	1.18	0.82	-	2.00	341.34	38.76	2.67	-	(0.06)	2.61	430.75	89.41	26.2%

New Rate Class: GSd

Bill Impacts of Proposed Distribution Rates include Riders

Classes		Scenario			Existing Dx Rates						New Dx Rates						$ Incr	% Incr
					SrChg	base	Rider1	Rider2	VarChg	[$/month]	SrChg	base	Rider2	Rider3	VarChg	[$/month]		
New Class	Old Class	kWh	kW	LF	[$/month]	[$/kW]	[$/kW]	[$/kW]	[$/kW]		[$/month]	[$/kW]	[$/kW]	[$/kW]	[$/kW]			
GSd	**F1**	15,000	60	35%	28.61	7.06	0.26	0.31	7.63	486.4	56.51	9.44	0.31	(0.22)	9.53	628.5	142.1	29.2%
		43,164	133	45%	28.61	7.06	0.26	0.31	7.63	1,043.4	56.51	9.44	0.31	(0.22)	9.53	1,324.5	281.1	26.9%
with RRRP		100,000	500	28%	28.61	7.06	0.26	0.31	7.63	3,843.6	56.51	9.44	0.31	(0.22)	9.53	4,823.4	979.8	25.5%
		400,000	1000	56%	28.61	7.06	0.26	0.31	7.63	7,658.6	56.51	9.44	0.31	(0.22)	9.53	9,590.2	1,931.6	25.2%
		1,000,000	3000	46%	28.61	7.06	0.26	0.31	7.63	22,918.6	56.51	9.44	0.31	(0.22)	9.53	28,657.7	5,739.1	25.0%
		1,500,000	4000	52%	28.61	7.06	0.26	0.31	7.63	30,548.6	56.51	9.44	0.31	(0.22)	9.53	38,191.4	7,642.8	25.0%
GSd	**F1**	15,000	60	35%	60.71	7.06	0.26	0.31	7.63	518.5	56.51	9.44	0.31	(0.22)	9.53	628.5	110.0	21.2%
		43,164	133	45%	60.71	7.06	0.26	0.31	7.63	1,075.5	56.51	9.44	0.31	(0.22)	9.53	1,324.5	249.0	23.2%
no RRRP		100,000	500	28%	60.71	7.06	0.26	0.31	7.63	3,875.7	56.51	9.44	0.31	(0.22)	9.53	4,823.4	947.7	24.5%
		400,000	1000	56%	60.71	7.06	0.26	0.31	7.63	7,690.7	56.51	9.44	0.31	(0.22)	9.53	9,590.2	1,899.5	24.7%
		1,000,000	3000	46%	60.71	7.06	0.26	0.31	7.63	22,950.7	56.51	9.44	0.31	(0.22)	9.53	28,657.7	5,707.0	24.9%
		1,500,000	4000	52%	60.71	7.06	0.26	0.31	7.63	30,580.7	56.51	9.44	0.31	(0.22)	9.53	38,191.4	7,610.7	24.9%
GSd	**F3**	15,000	60	35%	30.16	10.87	0.10	0.16	11.13	698.0	51.21	9.44	0.16	(0.22)	9.38	614.2	(83.7)	-12.0%
		43,164	133	45%	30.16	10.87	0.10	0.16	11.13	1,510.5	51.21	9.44	0.16	(0.22)	9.38	1,299.2	(211.2)	-14.0%
with RRRP		100,000	500	28%	30.16	10.87	0.10	0.16	11.13	5,595.2	51.21	9.44	0.16	(0.22)	9.38	4,743.1	(852.1)	-15.2%
		400,000	1000	56%	30.16	10.87	0.10	0.16	11.13	11,160.2	51.21	9.44	0.16	(0.22)	9.38	9,434.9	(1,725.2)	-15.5%
		1,000,000	3000	46%	30.16	10.87	0.10	0.16	11.13	33,420.2	51.21	9.44	0.16	(0.22)	9.38	28,202.4	(5,217.8)	-15.6%
		1,500,000	4000	52%	30.16	10.87	0.10	0.16	11.13	44,550.2	51.21	9.44	0.16	(0.22)	9.38	37,586.1	(6,964.0)	-15.6%
GSd	**F3**	15,000	60	35%	53.91	10.87	0.10	0.16	11.13	721.7	51.21	9.44	0.16	(0.22)	9.38	614.2	(107.5)	-14.9%
		43,164	133	45%	53.91	10.87	0.10	0.16	11.13	1,534.2	51.21	9.44	0.16	(0.22)	9.38	1,299.2	(235.0)	-15.3%
no RRRP		100,000	500	28%	53.91	10.87	0.10	0.16	11.13	5,618.9	51.21	9.44	0.16	(0.22)	9.38	4,743.1	(875.8)	-15.6%
		400,000	1000	56%	53.91	10.87	0.10	0.16	11.13	11,183.9	51.21	9.44	0.16	(0.22)	9.38	9,434.9	(1,749.0)	-15.6%
		1,000,000	3000	46%	53.91	10.87	0.10	0.16	11.13	33,443.9	51.21	9.44	0.16	(0.22)	9.38	28,202.4	(5,241.5)	-15.7%
		1,500,000	4000	52%	53.91	10.87	0.10	0.16	11.13	44,573.9	51.21	9.44	0.16	(0.22)	9.38	37,586.1	(6,987.8)	-15.7%
GSd	**G1**	15,000	60	35%	36.93	9.59	0.26	0.29	10.14	645.3	38.68	9.44	0.29	(0.22)	9.51	609.5	(35.8)	-5.6%
		43,164	133	45%	36.93	9.59	0.26	0.29	10.14	1,385.6	38.68	9.44	0.29	(0.22)	9.51	1,304.0	(81.5)	-5.9%
		100,000	500	28%	36.93	9.59	0.26	0.29	10.14	5,106.9	38.68	9.44	0.29	(0.22)	9.51	4,795.5	(311.4)	-6.1%
		400,000	1000	56%	36.93	9.59	0.26	0.29	10.14	10,176.9	38.68	9.44	0.29	(0.22)	9.51	9,552.4	(624.5)	-6.1%
		1,000,000	3000	46%	36.93	9.59	0.26	0.29	10.14	30,456.9	38.68	9.44	0.29	(0.22)	9.51	28,579.9	(1,877.1)	-6.2%
		1,500,000	4000	52%	36.93	9.59	0.26	0.29	10.14	40,596.9	38.68	9.44	0.29	(0.22)	9.51	38,093.6	(2,503.3)	-6.2%

New Rate Class: GSd

Bill Impacts of Proposed Distribution Rates include Riders

Classes		Scenario			Existing Dx Rates						New Dx Rates						$ Incr	% Incr
New Class	Old Class	kWh	kW	LF	SrChg [$/month]	base [$/kW]	Rider1 [$/kW]	Rider2 [$/kW]	VarChg [$/kW]	[$/month]	SrChg [$/month]	base [$/kW]	Rider2 [$/kW]	Rider3 [$/kW]	VarChg [$/kW]	[$/month]		
GSd	**G3**	15,000	60	35%	46.78	9.91	0.08	0.15	10.14	655.2	46.00	9.44	0.15	(0.22)	9.37	608.4	(46.8)	-7.1%
		43,164	133	45%	46.78	9.91	0.08	0.15	10.14	1,395.4	46.00	9.44	0.15	(0.22)	9.37	1,292.7	(102.7)	-7.4%
		100,000	500	28%	46.78	9.91	0.08	0.15	10.14	5,116.8	46.00	9.44	0.15	(0.22)	9.37	4,732.9	(383.9)	-7.5%
		400,000	1000	56%	46.78	9.91	0.08	0.15	10.14	10,186.8	46.00	9.44	0.15	(0.22)	9.37	9,419.7	(767.1)	-7.5%
		1,000,000	3000	46%	46.78	9.91	0.08	0.15	10.14	30,466.8	46.00	9.44	0.15	(0.22)	9.37	28,167.2	(2,299.6)	-7.5%
		1,500,000	4000	52%	46.78	9.91	0.08	0.15	10.14	40,606.8	46.00	9.44	0.15	(0.22)	9.37	37,540.9	(3,065.9)	-7.6%
GSd	**T**	15,000	60	35%	261.54	8.16	0.04	0.09	8.29	758.9	207.30	9.44	0.09	(0.22)	9.31	766.1	7.2	0.9%
		43,164	133	45%	261.54	8.16	0.04	0.09	8.29	1,364.1	207.30	9.44	0.09	(0.22)	9.31	1,446.0	81.9	6.0%
		100,000	500	28%	261.54	8.16	0.04	0.09	8.29	4,406.5	207.30	9.44	0.09	(0.22)	9.31	4,864.2	457.6	10.4%
		400,000	1000	56%	261.54	8.16	0.04	0.09	8.29	8,551.5	207.30	9.44	0.09	(0.22)	9.31	9,521.0	969.5	11.3%
		1,000,000	3000	46%	261.54	8.16	0.04	0.09	8.29	25,131.5	207.30	9.44	0.09	(0.22)	9.31	28,148.5	3,016.9	12.0%
		1,500,000	4000	52%	261.54	8.16	0.04	0.09	8.29	33,421.5	207.30	9.44	0.09	(0.22)	9.31	37,462.2	4,040.7	12.1%
GSd	**Ailsa Craig**	15,000	60	35%	17.31	4.19	0.52	0.27	4.98	316.1	24.36	9.00	0.27	(0.22)	9.05	567.5	251.4	79.5%
		43,164	133	45%	17.31	4.19	0.52	0.27	4.98	679.7	24.36	9.00	0.27	(0.22)	9.05	1,228.4	548.7	80.7%
		100,000	500	28%	17.31	4.19	0.52	0.27	4.98	2,507.3	24.36	9.00	0.27	(0.22)	9.05	4,550.7	2,043.4	81.5%
		400,000	1000	56%	17.31	4.19	0.52	0.27	4.98	4,997.3	24.36	9.00	0.27	(0.22)	9.05	9,077.1	4,079.8	81.6%
		1,000,000	3000	46%	17.31	4.19	0.52	0.27	4.98	14,957.3	24.36	9.00	0.27	(0.22)	9.05	27,182.5	12,225.2	81.7%
		1,500,000	4000	52%	17.31	4.19	0.52	0.27	4.98	19,937.3	24.36	9.00	0.27	(0.22)	9.05	36,235.2	16,297.9	81.7%
GSd	**Arkona**	15,000	60	35%	3.20	1.98	1.62	0.83	4.43	269.0	13.89	9.22	0.83	(0.22)	9.84	604.1	335.1	124.6%
	no customer	43,164	133	45%	3.20	1.98	1.62	0.83	4.43	592.4	13.89	9.22	0.83	(0.22)	9.84	1,322.1	729.7	123.2%
		100,000	500	28%	3.20	1.98	1.62	0.83	4.43	2,218.2	13.89	9.22	0.83	(0.22)	9.84	4,932.0	2,713.8	122.3%
		400,000	1000	56%	3.20	1.98	1.62	0.83	4.43	4,433.2	13.89	9.22	0.83	(0.22)	9.84	9,850.2	5,417.0	122.2%
		1,000,000	3000	46%	3.20	1.98	1.62	0.83	4.43	13,293.2	13.89	9.22	0.83	(0.22)	9.84	29,522.7	16,229.5	122.1%
		1,500,000	4000	52%	3.20	1.98	1.62	0.83	4.43	17,723.2	13.89	9.22	0.83	(0.22)	9.84	39,359.0	21,635.8	122.1%
UGd	**Arnprior**	15,000	60	35%	21.38	3.70	0.50	0.20	4.40	285.4	22.95	7.33	0.20	(0.27)	7.26	458.6	173.2	60.7%
		43,164	133	45%	21.38	3.70	0.50	0.20	4.40	606.6	22.95	7.33	0.20	(0.27)	7.26	988.6	382.0	63.0%
		100,000	500	28%	21.38	3.70	0.50	0.20	4.40	2,221.4	22.95	7.33	0.20	(0.27)	7.26	3,653.1	1,431.7	64.4%
		400,000	1000	56%	21.38	3.70	0.50	0.20	4.40	4,421.4	22.95	7.33	0.20	(0.27)	7.26	7,283.2	2,861.8	64.7%
		1,000,000	3000	46%	21.38	3.70	0.50	0.20	4.40	13,221.4	22.95	7.33	0.20	(0.27)	7.26	21,803.6	8,582.2	64.9%
		1,500,000	4000	52%	21.38	3.70	0.50	0.20	4.40	17,621.4	22.95	7.33	0.20	(0.27)	7.26	29,063.8	11,442.4	64.9%

New Rate Class: GSd

Bill Impacts of Proposed Distribution Rates include Riders

Classes		Scenario			Existing Dx Rates						New Dx Rates						$ Incr	% Incr
					SrChg [$/month]	base [$/kW]	Rider1 [$/kW]	Rider2 [$/kW]	VarChg [$/kW]	[$/month]	SrChg [$/month]	base [$/kW]	Rider2 [$/kW]	Rider3 [$/kW]	VarChg [$/kW]	[$/month]		
New Class	**Old Class**	kWh	kW	LF														
GSd	**Arran-Elderslie**	15,000	60	35%	8.83	3.28	0.55	0.28	4.11	255.4	17.48	8.00	0.28	(0.22)	8.06	501.2	245.8	96.2%
		43,164	133	45%	8.83	3.28	0.55	0.28	4.11	555.5	17.48	8.00	0.28	(0.22)	8.06	1,089.8	534.4	96.2%
		100,000	500	28%	8.83	3.28	0.55	0.28	4.11	2,063.8	17.48	8.00	0.28	(0.22)	8.06	4,048.8	1,985.0	96.2%
		400,000	1000	56%	8.83	3.28	0.55	0.28	4.11	4,118.8	17.48	8.00	0.28	(0.22)	8.06	8,080.2	3,961.4	96.2%
		1,000,000	3000	46%	8.83	3.28	0.55	0.28	4.11	12,338.8	17.48	8.00	0.28	(0.22)	8.06	24,205.6	11,866.8	96.2%
		1,500,000	4000	52%	8.83	3.28	0.55	0.28	4.11	16,448.8	17.48	8.00	0.28	(0.22)	8.06	32,268.3	15,819.5	96.2%
GSd	**Artemesia**	15,000	60	35%	19.62	5.49	1.55	1.08	8.12	506.8	25.78	9.22	1.08	(0.22)	10.09	631.0	124.1	24.5%
		43,164	133	45%	19.62	5.49	1.55	1.08	8.12	1,099.6	25.78	9.22	1.08	(0.22)	10.09	1,367.3	267.7	24.3%
		100,000	500	28%	19.62	5.49	1.55	1.08	8.12	4,079.6	25.78	9.22	1.08	(0.22)	10.09	5,068.9	989.3	24.2%
		400,000	1000	56%	19.62	5.49	1.55	1.08	8.12	8,139.6	25.78	9.22	1.08	(0.22)	10.09	10,112.1	1,972.4	24.2%
		1,000,000	3000	46%	19.62	5.49	1.55	1.08	8.12	24,379.6	25.78	9.22	1.08	(0.22)	10.09	30,284.6	5,905.0	24.2%
		1,500,000	4000	52%	19.62	5.49	1.55	1.08	8.12	32,499.6	25.78	9.22	1.08	(0.22)	10.09	40,370.9	7,871.3	24.2%
GSd	**Bancroft**	15,000	60	35%	24.41	3.70	0.54	0.24	4.48	293.2	29.59	8.50	0.24	(0.22)	8.52	540.9	247.7	84.5%
		43,164	133	45%	24.41	3.70	0.54	0.24	4.48	620.3	29.59	8.50	0.24	(0.22)	8.52	1,163.1	542.9	87.5%
		100,000	500	28%	24.41	3.70	0.54	0.24	4.48	2,264.4	29.59	8.50	0.24	(0.22)	8.52	4,290.9	2,026.5	89.5%
		400,000	1000	56%	24.41	3.70	0.54	0.24	4.48	4,504.4	29.59	8.50	0.24	(0.22)	8.52	8,552.3	4,047.9	89.9%
		1,000,000	3000	46%	24.41	3.70	0.54	0.24	4.48	13,464.4	29.59	8.50	0.24	(0.22)	8.52	25,597.7	12,133.3	90.1%
		1,500,000	4000	52%	24.41	3.70	0.54	0.24	4.48	17,944.4	29.59	8.50	0.24	(0.22)	8.52	34,120.4	16,176.0	90.1%
GSd	**Bath**	15,000	60	35%	10.65	3.77	0.93	0.63	5.33	330.5	19.03	9.00	0.63	(0.22)	9.41	583.8	253.3	76.7%
		43,164	133	45%	10.65	3.77	0.93	0.63	5.33	719.5	19.03	9.00	0.63	(0.22)	9.41	1,270.9	551.4	76.6%
		100,000	500	28%	10.65	3.77	0.93	0.63	5.33	2,675.7	19.03	9.00	0.63	(0.22)	9.41	4,725.4	2,049.7	76.6%
		400,000	1000	56%	10.65	3.77	0.93	0.63	5.33	5,340.7	19.03	9.00	0.63	(0.22)	9.41	9,431.7	4,091.1	76.6%
		1,000,000	3000	46%	10.65	3.77	0.93	0.63	5.33	16,000.7	19.03	9.00	0.63	(0.22)	9.41	28,257.1	12,256.5	76.6%
		1,500,000	4000	52%	10.65	3.77	0.93	0.63	5.33	21,330.7	19.03	9.00	0.63	(0.22)	9.41	37,669.8	16,339.2	76.6%
GSd	**Blandford-Blenheim**	15,000	60	35%	23.85	3.63	0.91	0.65	5.19	335.3	28.73	8.90	0.65	(0.22)	9.33	588.7	253.4	75.6%
		43,164	133	45%	23.85	3.63	0.91	0.65	5.19	714.1	28.73	8.90	0.65	(0.22)	9.33	1,270.0	555.9	77.8%
		100,000	500	28%	23.85	3.63	0.91	0.65	5.19	2,618.9	28.73	8.90	0.65	(0.22)	9.33	4,695.1	2,076.2	79.3%
		400,000	1000	56%	23.85	3.63	0.91	0.65	5.19	5,213.9	28.73	8.90	0.65	(0.22)	9.33	9,361.4	4,147.6	79.5%
		1,000,000	3000	46%	23.85	3.63	0.91	0.65	5.19	15,593.9	28.73	8.90	0.65	(0.22)	9.33	28,026.8	12,433.0	79.7%
		1,500,000	4000	52%	23.85	3.63	0.91	0.65	5.19	20,783.9	28.73	8.90	0.65	(0.22)	9.33	37,359.5	16,575.7	79.8%

New Rate Class: GSd

Bill Impacts of Proposed Distribution Rates include Riders

Classes		Scenario			Existing Dx Rates						New Dx Rates						$ Incr	% Incr
					SrChg	base	Rider1	Rider2	VarChg	[$/month]	SrChg	base	Rider2	Rider3	VarChg	[$/month]		
New Class	Old Class	kWh	kW	LF	[$/month]	[$/kW]	[$/kW]	[$/kW]	[$/kW]		[$/month]	[$/kW]	[$/kW]	[$/kW]	[$/kW]			
GSd	Blyth	15,000	60	35%	21.63	3.37	0.82	0.64	4.83	311.4	27.28	8.50	0.64	(0.22)	8.92	562.6	251.2	80.7%
		43,164	133	45%	21.63	3.37	0.82	0.64	4.83	664.0	27.28	8.50	0.64	(0.22)	8.92	1,214.0	550.0	82.8%
		100,000	500	28%	21.63	3.37	0.82	0.64	4.83	2,436.6	27.28	8.50	0.64	(0.22)	8.92	4,488.6	2,052.0	84.2%
		400,000	1000	56%	21.63	3.37	0.82	0.64	4.83	4,851.6	27.28	8.50	0.64	(0.22)	8.92	8,950.0	4,098.4	84.5%
		1,000,000	3000	46%	21.63	3.37	0.82	0.64	4.83	14,511.6	27.28	8.50	0.64	(0.22)	8.92	26,795.4	12,283.8	84.6%
		1,500,000	4000	52%	21.63	3.37	0.82	0.64	4.83	19,341.6	27.28	8.50	0.64	(0.22)	8.92	35,718.1	16,376.5	84.7%
GSd	Bobcaygeon	15,000	60	35%	23.20	4.35	0.58	0.27	5.20	335.2	28.89	9.22	0.27	(0.22)	9.28	585.5	250.3	74.7%
		43,164	133	45%	23.20	4.35	0.58	0.27	5.20	714.8	28.89	9.22	0.27	(0.22)	9.28	1,262.6	547.8	76.6%
		100,000	500	28%	23.20	4.35	0.58	0.27	5.20	2,623.2	28.89	9.22	0.27	(0.22)	9.28	4,667.0	2,043.8	77.9%
		400,000	1000	56%	23.20	4.35	0.58	0.27	5.20	5,223.2	28.89	9.22	0.27	(0.22)	9.28	9,305.2	4,082.0	78.2%
		1,000,000	3000	46%	23.20	4.35	0.58	0.27	5.20	15,623.2	28.89	9.22	0.27	(0.22)	9.28	27,857.7	12,234.5	78.3%
		1,500,000	4000	52%	23.20	4.35	0.58	0.27	5.20	20,823.2	28.89	9.22	0.27	(0.22)	9.28	37,134.0	16,310.8	78.3%
GSd	Brighton	15,000	60	35%	22.90	4.24	0.65	0.25	5.14	331.3	27.96	9.22	0.25	(0.22)	9.26	583.3	252.0	76.1%
		43,164	133	45%	22.90	4.24	0.65	0.25	5.14	706.5	27.96	9.22	0.25	(0.22)	9.26	1,259.0	552.5	78.2%
		100,000	500	28%	22.90	4.24	0.65	0.25	5.14	2,592.9	27.96	9.22	0.25	(0.22)	9.26	4,656.1	2,063.2	79.6%
		400,000	1000	56%	22.90	4.24	0.65	0.25	5.14	5,162.9	27.96	9.22	0.25	(0.22)	9.26	9,284.2	4,121.3	79.8%
		1,000,000	3000	46%	22.90	4.24	0.65	0.25	5.14	15,442.9	27.96	9.22	0.25	(0.22)	9.26	27,796.8	12,353.9	80.0%
		1,500,000	4000	52%	22.90	4.24	0.65	0.25	5.14	20,582.9	27.96	9.22	0.25	(0.22)	9.26	37,053.1	16,470.2	80.0%
UGd	Brockville	15,000	60	35%	21.65	2.49	0.41	0.12	3.02	202.9	22.89	6.70	0.12	(0.27)	6.55	415.7	212.9	104.9%
		43,164	133	45%	21.65	2.49	0.41	0.12	3.02	423.3	22.89	6.70	0.12	(0.27)	6.55	893.7	470.3	111.1%
		100,000	500	28%	21.65	2.49	0.41	0.12	3.02	1,531.7	22.89	6.70	0.12	(0.27)	6.55	3,296.4	1,764.8	115.2%
		400,000	1000	56%	21.65	2.49	0.41	0.12	3.02	3,041.7	22.89	6.70	0.12	(0.27)	6.55	6,570.0	3,528.4	116.0%
		1,000,000	3000	46%	21.65	2.49	0.41	0.12	3.02	9,081.7	22.89	6.70	0.12	(0.27)	6.55	19,664.3	10,582.6	116.5%
		1,500,000	4000	52%	21.65	2.49	0.41	0.12	3.02	12,101.7	22.89	6.70	0.12	(0.27)	6.55	26,211.4	14,109.7	116.6%
GSd	Caledon CH	15,000	60	35%	24.21	5.73	0.45	0.27	6.45	411.2	29.64	9.22	0.27	(0.22)	9.28	586.2	175.0	42.6%
		43,164	133	45%	24.21	5.73	0.45	0.27	6.45	882.1	29.64	9.22	0.27	(0.22)	9.28	1,263.4	381.3	43.2%
		100,000	500	28%	24.21	5.73	0.45	0.27	6.45	3,249.2	29.64	9.22	0.27	(0.22)	9.28	4,667.8	1,418.6	43.7%
		400,000	1000	56%	24.21	5.73	0.45	0.27	6.45	6,474.2	29.64	9.22	0.27	(0.22)	9.28	9,305.9	2,831.7	43.7%
		1,000,000	3000	46%	24.21	5.73	0.45	0.27	6.45	19,374.2	29.64	9.22	0.27	(0.22)	9.28	27,858.5	8,484.3	43.8%
		1,500,000	4000	52%	24.21	5.73	0.45	0.27	6.45	25,824.2	29.64	9.22	0.27	(0.22)	9.28	37,134.8	11,310.6	43.8%

New Rate Class: GSd

Bill Impacts of Proposed Distribution Rates include Riders

Classes		Scenario			Existing Dx Rates						New Dx Rates						$ Incr	% Incr
					SrChg [$/month]	base [$/kW]	Rider1 [$/kW]	Rider2 [$/kW]	VarChg [$/kW]	[$/month]	SrChg [$/month]	base [$/kW]	Rider2 [$/kW]	Rider3 [$/kW]	VarChg [$/kW]	[$/month]		
New Class	Old Class	kWh	kW	LF														
GSd	Caledon OH	15,000	60	35%	25.56	5.35	0.51	0.24	6.10	391.6	30.30	9.22	0.24	(0.22)	9.25	585.1	193.5	49.4%
		43,164	133	45%	25.56	5.35	0.51	0.24	6.10	836.9	30.30	9.22	0.24	(0.22)	9.25	1,260.1	423.2	50.6%
		100,000	500	28%	25.56	5.35	0.51	0.24	6.10	3,075.6	30.30	9.22	0.24	(0.22)	9.25	4,653.4	1,577.9	51.3%
		400,000	1000	56%	25.56	5.35	0.51	0.24	6.10	6,125.6	30.30	9.22	0.24	(0.22)	9.25	9,276.6	3,151.0	51.4%
		1,000,000	3000	46%	25.56	5.35	0.51	0.24	6.10	18,325.6	30.30	9.22	0.24	(0.22)	9.25	27,769.1	9,443.6	51.5%
		1,500,000	4000	52%	25.56	5.35	0.51	0.24	6.10	24,425.6	30.30	9.22	0.24	(0.22)	9.25	37,015.4	12,589.9	51.5%
GSd	Campbellford-Seymour	15,000	60	35%	16.19	3.77	0.53	0.17	4.47	284.4	23.64	8.50	0.17	(0.22)	8.45	530.8	246.4	86.6%
		43,164	133	45%	16.19	3.77	0.53	0.17	4.47	610.7	23.64	8.50	0.17	(0.22)	8.45	1,147.8	537.1	88.0%
		100,000	500	28%	16.19	3.77	0.53	0.17	4.47	2,251.2	23.64	8.50	0.17	(0.22)	8.45	4,250.0	1,998.8	88.8%
		400,000	1000	56%	16.19	3.77	0.53	0.17	4.47	4,486.2	23.64	8.50	0.17	(0.22)	8.45	8,476.3	3,990.2	88.9%
		1,000,000	3000	46%	16.19	3.77	0.53	0.17	4.47	13,426.2	23.64	8.50	0.17	(0.22)	8.45	25,381.8	11,955.6	89.0%
		1,500,000	4000	52%	16.19	3.77	0.53	0.17	4.47	17,896.2	23.64	8.50	0.17	(0.22)	8.45	33,834.5	15,938.3	89.1%
UGd	Carleton Place	15,000	60	35%	23.65	5.31	0.42	0.22	5.95	380.7	24.39	7.33	0.22	(0.27)	7.28	461.2	80.5	21.2%
		43,164	133	45%	23.65	5.31	0.42	0.22	5.95	815.0	24.39	7.33	0.22	(0.27)	7.28	992.7	177.7	21.8%
		100,000	500	28%	23.65	5.31	0.42	0.22	5.95	2,998.7	24.39	7.33	0.22	(0.27)	7.28	3,664.5	665.8	22.2%
		400,000	1000	56%	23.65	5.31	0.42	0.22	5.95	5,973.7	24.39	7.33	0.22	(0.27)	7.28	7,304.6	1,330.9	22.3%
		1,000,000	3000	46%	23.65	5.31	0.42	0.22	5.95	17,873.7	24.39	7.33	0.22	(0.27)	7.28	21,865.0	3,991.3	22.3%
		1,500,000	4000	52%	23.65	5.31	0.42	0.22	5.95	23,823.7	24.39	7.33	0.22	(0.27)	7.28	29,145.2	5,321.6	22.3%
GSd	Cavan-Millbrook-North Monaghan	15,000	60	35%	22.28	4.67	1.06	0.81	6.54	414.7	28.12	9.22	0.81	(0.22)	9.82	617.1	202.4	48.8%
		43,164	133	45%	22.28	4.67	1.06	0.81	6.54	892.1	28.12	9.22	0.81	(0.22)	9.82	1,333.7	441.6	49.5%
		100,000	500	28%	22.28	4.67	1.06	0.81	6.54	3,292.3	28.12	9.22	0.81	(0.22)	9.82	4,936.3	1,644.0	49.9%
		400,000	1000	56%	22.28	4.67	1.06	0.81	6.54	6,562.3	28.12	9.22	0.81	(0.22)	9.82	9,844.4	3,282.1	50.0%
		1,000,000	3000	46%	22.28	4.67	1.06	0.81	6.54	19,642.3	28.12	9.22	0.81	(0.22)	9.82	29,477.0	9,834.7	50.1%
		1,500,000	4000	52%	22.28	4.67	1.06	0.81	6.54	26,182.3	28.12	9.22	0.81	(0.22)	9.82	39,293.3	13,111.0	50.1%
GSd	Centre Hastings	15,000	60	35%	18.38	3.07	0.45	0.20	3.72	241.6	25.09	7.70	0.20	(0.22)	7.68	486.1	244.5	101.2%
		43,164	133	45%	18.38	3.07	0.45	0.20	3.72	513.1	25.09	7.70	0.20	(0.22)	7.68	1,046.9	533.8	104.0%
		100,000	500	28%	18.38	3.07	0.45	0.20	3.72	1,878.4	25.09	7.70	0.20	(0.22)	7.68	3,866.4	1,988.1	105.8%
		400,000	1000	56%	18.38	3.07	0.45	0.20	3.72	3,738.4	25.09	7.70	0.20	(0.22)	7.68	7,707.8	3,969.4	106.2%
		1,000,000	3000	46%	18.38	3.07	0.45	0.20	3.72	11,178.4	25.09	7.70	0.20	(0.22)	7.68	23,073.2	11,894.8	106.4%
		1,500,000	4000	52%	18.38	3.07	0.45	0.20	3.72	14,898.4	25.09	7.70	0.20	(0.22)	7.68	30,755.9	15,857.5	106.4%

New Rate Class: GSd

Bill Impacts of Proposed Distribution Rates include Riders

Classes		Scenario			Existing Dx Rates						New Dx Rates						$ Incr	% Incr
New Class	Old Class	kWh	kW	LF	SrChg [$/month]	base [$/kW]	Rider1 [$/kW]	Rider2 [$/kW]	VarChg [$/kW]	[$/month]	SrChg [$/month]	base [$/kW]	Rider2 [$/kW]	Rider3 [$/kW]	VarChg [$/kW]	[$/month]		
GSd	**Chalk River**	15,000	60	35%	21.33	5.70	1.23	1.07	8.00	501.3	27.36	9.22	1.07	(0.22)	10.08	631.9	130.6	26.1%
		43,164	133	45%	21.33	5.70	1.23	1.07	8.00	1,085.3	27.36	9.22	1.07	(0.22)	10.08	1,367.5	282.2	26.0%
		100,000	500	28%	21.33	5.70	1.23	1.07	8.00	4,021.3	27.36	9.22	1.07	(0.22)	10.08	5,065.5	1,044.2	26.0%
		400,000	1000	56%	21.33	5.70	1.23	1.07	8.00	8,021.3	27.36	9.22	1.07	(0.22)	10.08	10,103.6	2,082.3	26.0%
		1,000,000	3000	46%	21.33	5.70	1.23	1.07	8.00	24,021.3	27.36	9.22	1.07	(0.22)	10.08	30,256.2	6,234.9	26.0%
		1,500,000	4000	52%	21.33	5.70	1.23	1.07	8.00	32,021.3	27.36	9.22	1.07	(0.22)	10.08	40,332.5	8,311.2	26.0%
GSd	**Champlain**	15,000	60	35%	20.59	2.88	0.84	0.49	4.21	273.2	26.54	8.00	0.49	(0.22)	8.27	522.9	249.7	91.4%
		43,164	133	45%	20.59	2.88	0.84	0.49	4.21	580.5	26.54	8.00	0.49	(0.22)	8.27	1,126.8	546.3	94.1%
		100,000	500	28%	20.59	2.88	0.84	0.49	4.21	2,125.6	26.54	8.00	0.49	(0.22)	8.27	4,162.9	2,037.3	95.8%
		400,000	1000	56%	20.59	2.88	0.84	0.49	4.21	4,230.6	26.54	8.00	0.49	(0.22)	8.27	8,299.2	4,068.7	96.2%
		1,000,000	3000	46%	20.59	2.88	0.84	0.49	4.21	12,650.6	26.54	8.00	0.49	(0.22)	8.27	24,844.7	12,194.1	96.4%
		1,500,000	4000	52%	20.59	2.88	0.84	0.49	4.21	16,860.6	26.54	8.00	0.49	(0.22)	8.27	33,117.4	16,256.8	96.4%
GSd	**Cobden**	15,000	60	35%	21.93	6.49	1.16	0.90	8.55	534.9	27.21	9.22	0.90	(0.22)	9.91	621.6	86.7	16.2%
		43,164	133	45%	21.93	6.49	1.16	0.90	8.55	1,159.1	27.21	9.22	0.90	(0.22)	9.91	1,344.7	185.7	16.0%
		100,000	500	28%	21.93	6.49	1.16	0.90	8.55	4,296.9	27.21	9.22	0.90	(0.22)	9.91	4,980.3	683.4	15.9%
		400,000	1000	56%	21.93	6.49	1.16	0.90	8.55	8,571.9	27.21	9.22	0.90	(0.22)	9.91	9,933.5	1,361.6	15.9%
		1,000,000	3000	46%	21.93	6.49	1.16	0.90	8.55	25,671.9	27.21	9.22	0.90	(0.22)	9.91	29,746.1	4,074.1	15.9%
		1,500,000	4000	52%	21.93	6.49	1.16	0.90	8.55	34,221.9	27.21	9.22	0.90	(0.22)	9.91	39,652.3	5,430.4	15.9%
GSd	**Deep River**	15,000	60	35%	23.94	7.18	0.46	0.46	8.10	509.9	28.70	9.22	0.46	(0.22)	9.47	596.7	86.7	17.0%
		43,164	133	45%	23.94	7.18	0.46	0.46	8.10	1,101.2	28.70	9.22	0.46	(0.22)	9.47	1,287.7	186.5	16.9%
		100,000	500	28%	23.94	7.18	0.46	0.46	8.10	4,073.9	28.70	9.22	0.46	(0.22)	9.47	4,761.8	687.9	16.9%
		400,000	1000	56%	23.94	7.18	0.46	0.46	8.10	8,123.9	28.70	9.22	0.46	(0.22)	9.47	9,495.0	1,371.0	16.9%
		1,000,000	3000	46%	23.94	7.18	0.46	0.46	8.10	24,323.9	28.70	9.22	0.46	(0.22)	9.47	28,427.6	4,103.6	16.9%
		1,500,000	4000	52%	23.94	7.18	0.46	0.46	8.10	32,423.9	28.70	9.22	0.46	(0.22)	9.47	37,893.8	5,469.9	16.9%
GSd	**Deseronto**	15,000	60	35%	10.14	3.85	0.41	0.14	4.40	274.1	19.15	8.50	0.14	(0.22)	8.42	524.5	250.4	91.3%
		43,164	133	45%	10.14	3.85	0.41	0.14	4.40	595.3	19.15	8.50	0.14	(0.22)	8.42	1,139.4	544.0	91.4%
		100,000	500	28%	10.14	3.85	0.41	0.14	4.40	2,210.1	19.15	8.50	0.14	(0.22)	8.42	4,230.5	2,020.4	91.4%
		400,000	1000	56%	10.14	3.85	0.41	0.14	4.40	4,410.1	19.15	8.50	0.14	(0.22)	8.42	8,441.9	4,031.7	91.4%
		1,000,000	3000	46%	10.14	3.85	0.41	0.14	4.40	13,210.1	19.15	8.50	0.14	(0.22)	8.42	25,287.3	12,077.1	91.4%
		1,500,000	4000	52%	10.14	3.85	0.41	0.14	4.40	17,610.1	19.15	8.50	0.14	(0.22)	8.42	33,710.0	16,099.8	91.4%

New Rate Class: GSd

Bill Impacts of Proposed Distribution Rates include Riders

Classes		Scenario			Existing Dx Rates						New Dx Rates						$ Incr	% Incr
New Class	Old Class	kWh	kW	LF	SrChg [$/month]	base [$/kW]	Rider1 [$/kW]	Rider2 [$/kW]	VarChg [$/kW]	[$/month]	SrChg [$/month]	base [$/kW]	Rider2 [$/kW]	Rider3 [$/kW]	VarChg [$/kW]	[$/month]		
UGd	**Dryden**	15,000	60	35%	19.11	3.29	0.38	0.13	3.80	247.1	21.52	7.33	0.13	(0.27)	7.19	452.9	205.8	83.3%
		43,164	133	45%	19.11	3.29	0.38	0.13	3.80	524.5	21.52	7.33	0.13	(0.27)	7.19	977.8	453.3	86.4%
		100,000	500	28%	19.11	3.29	0.38	0.13	3.80	1,919.1	21.52	7.33	0.13	(0.27)	7.19	3,616.6	1,697.5	88.5%
		400,000	1000	56%	19.11	3.29	0.38	0.13	3.80	3,819.1	21.52	7.33	0.13	(0.27)	7.19	7,211.7	3,392.6	88.8%
		1,000,000	3000	46%	19.11	3.29	0.38	0.13	3.80	11,419.1	21.52	7.33	0.13	(0.27)	7.19	21,592.1	10,173.0	89.1%
		1,500,000	4000	52%	19.11	3.29	0.38	0.13	3.80	15,219.1	21.52	7.33	0.13	(0.27)	7.19	28,782.3	13,563.2	89.1%
GSd	**Dundalk**	15,000	60	35%	23.56	5.17	0.74	0.28	6.19	395.0	28.80	9.22	0.28	(0.22)	9.29	586.0	191.0	48.4%
		43,164	133	45%	23.56	5.17	0.74	0.28	6.19	846.8	28.80	9.22	0.28	(0.22)	9.29	1,263.9	417.0	49.2%
		100,000	500	28%	23.56	5.17	0.74	0.28	6.19	3,118.6	28.80	9.22	0.28	(0.22)	9.29	4,671.9	1,553.4	49.8%
		400,000	1000	56%	23.56	5.17	0.74	0.28	6.19	6,213.6	28.80	9.22	0.28	(0.22)	9.29	9,315.1	3,101.5	49.9%
		1,000,000	3000	46%	23.56	5.17	0.74	0.28	6.19	18,593.6	28.80	9.22	0.28	(0.22)	9.29	27,887.6	9,294.1	50.0%
		1,500,000	4000	52%	23.56	5.17	0.74	0.28	6.19	24,783.6	28.80	9.22	0.28	(0.22)	9.29	37,173.9	12,390.4	50.0%
GSd	**Durham**	15,000	60	35%	24.12	4.31	0.48	0.18	4.97	322.3	29.66	9.22	0.18	(0.22)	9.19	580.8	258.5	80.2%
		43,164	133	45%	24.12	4.31	0.48	0.18	4.97	685.1	29.66	9.22	0.18	(0.22)	9.19	1,251.4	566.3	82.7%
		100,000	500	28%	24.12	4.31	0.48	0.18	4.97	2,509.1	29.66	9.22	0.18	(0.22)	9.19	4,622.8	2,113.7	84.2%
		400,000	1000	56%	24.12	4.31	0.48	0.18	4.97	4,994.1	29.66	9.22	0.18	(0.22)	9.19	9,215.9	4,221.8	84.5%
		1,000,000	3000	46%	24.12	4.31	0.48	0.18	4.97	14,934.1	29.66	9.22	0.18	(0.22)	9.19	27,588.5	12,654.4	84.7%
		1,500,000	4000	52%	24.12	4.31	0.48	0.18	4.97	19,904.1	29.66	9.22	0.18	(0.22)	9.19	36,774.8	16,870.7	84.8%
GSd	**Eganville**	15,000	60	35%	21.35	7.35	0.55	0.37	8.27	517.6	27.35	9.22	0.37	(0.22)	9.38	589.9	72.4	14.0%
		43,164	133	45%	21.35	7.35	0.55	0.37	8.27	1,121.3	27.35	9.22	0.37	(0.22)	9.38	1,274.4	153.1	13.7%
		100,000	500	28%	21.35	7.35	0.55	0.37	8.27	4,156.4	27.35	9.22	0.37	(0.22)	9.38	4,715.5	559.1	13.5%
		400,000	1000	56%	21.35	7.35	0.55	0.37	8.27	8,291.4	27.35	9.22	0.37	(0.22)	9.38	9,403.6	1,112.3	13.4%
		1,000,000	3000	46%	21.35	7.35	0.55	0.37	8.27	24,831.4	27.35	9.22	0.37	(0.22)	9.38	28,156.2	3,324.9	13.4%
		1,500,000	4000	52%	21.35	7.35	0.55	0.37	8.27	33,101.4	27.35	9.22	0.37	(0.22)	9.38	37,532.5	4,431.1	13.4%
GSd	**Erin**	15,000	60	35%	40.38	2.36	0.59	0.25	3.20	232.4	41.59	7.20	0.25	(0.22)	7.23	475.6	243.2	104.6%
		43,164	133	45%	40.38	2.36	0.59	0.25	3.20	466.0	41.59	7.20	0.25	(0.22)	7.23	1,003.5	537.6	115.4%
		100,000	500	28%	40.38	2.36	0.59	0.25	3.20	1,640.4	41.59	7.20	0.25	(0.22)	7.23	3,657.9	2,017.6	123.0%
		400,000	1000	56%	40.38	2.36	0.59	0.25	3.20	3,240.4	41.59	7.20	0.25	(0.22)	7.23	7,274.3	4,033.9	124.5%
		1,000,000	3000	46%	40.38	2.36	0.59	0.25	3.20	9,640.4	41.59	7.20	0.25	(0.22)	7.23	21,739.7	12,099.3	125.5%
		1,500,000	4000	52%	40.38	2.36	0.59	0.25	3.20	12,840.4	41.59	7.20	0.25	(0.22)	7.23	28,972.4	16,132.0	125.6%

New Rate Class: GSd

Bill Impacts of Proposed Distribution Rates include Riders

Classes		Scenario			Existing Dx Rates						New Dx Rates						$ Incr	% Incr
New Class	Old Class	kWh	kW	LF	SrChg [$/month]	base [$/kW]	Rider1 [$/kW]	Rider2 [$/kW]	VarChg [$/kW]	[$/month]	SrChg [$/month]	base [$/kW]	Rider2 [$/kW]	Rider3 [$/kW]	VarChg [$/kW]	[$/month]		
GSd	**Exeter**	15,000	60	35%	11.36	4.11	0.49	0.18	4.78	298.2	19.85	8.95	0.18	(0.22)	8.91	554.6	256.4	86.0%
		43,164	133	45%	11.36	4.11	0.49	0.18	4.78	647.1	19.85	8.95	0.18	(0.22)	8.91	1,205.2	558.1	86.3%
		100,000	500	28%	11.36	4.11	0.49	0.18	4.78	2,401.4	19.85	8.95	0.18	(0.22)	8.91	4,476.2	2,074.8	86.4%
		400,000	1000	56%	11.36	4.11	0.49	0.18	4.78	4,791.4	19.85	8.95	0.18	(0.22)	8.91	8,932.6	4,141.2	86.4%
		1,000,000	3000	46%	11.36	4.11	0.49	0.18	4.78	14,351.4	19.85	8.95	0.18	(0.22)	8.91	26,758.0	12,406.6	86.4%
		1,500,000	4000	52%	11.36	4.11	0.49	0.18	4.78	19,131.4	19.85	8.95	0.18	(0.22)	8.91	35,670.7	16,539.3	86.5%
GSd	**Fenelon Falls**	15,000	60	35%	19.81	3.02	0.47	0.24	3.73	243.6	25.74	7.75	0.24	(0.22)	7.77	492.1	248.5	102.0%
		43,164	133	45%	19.81	3.02	0.47	0.24	3.73	515.9	25.74	7.75	0.24	(0.22)	7.77	1,059.5	543.6	105.4%
		100,000	500	28%	19.81	3.02	0.47	0.24	3.73	1,884.8	25.74	7.75	0.24	(0.22)	7.77	3,912.1	2,027.3	107.6%
		400,000	1000	56%	19.81	3.02	0.47	0.24	3.73	3,749.8	25.74	7.75	0.24	(0.22)	7.77	7,798.4	4,048.6	108.0%
		1,000,000	3000	46%	19.81	3.02	0.47	0.24	3.73	11,209.8	25.74	7.75	0.24	(0.22)	7.77	23,343.8	12,134.0	108.2%
		1,500,000	4000	52%	19.81	3.02	0.47	0.24	3.73	14,939.8	25.74	7.75	0.24	(0.22)	7.77	31,116.5	16,176.7	108.3%
GSd	**Forest**	15,000	60	35%	24.91	3.74	0.50	0.20	4.44	291.3	29.46	8.50	0.20	(0.22)	8.48	538.4	247.1	84.8%
		43,164	133	45%	24.91	3.74	0.50	0.20	4.44	615.4	29.46	8.50	0.20	(0.22)	8.48	1,157.7	542.2	88.1%
		100,000	500	28%	24.91	3.74	0.50	0.20	4.44	2,244.9	29.46	8.50	0.20	(0.22)	8.48	4,270.8	2,025.9	90.2%
		400,000	1000	56%	24.91	3.74	0.50	0.20	4.44	4,464.9	29.46	8.50	0.20	(0.22)	8.48	8,512.2	4,047.3	90.6%
		1,000,000	3000	46%	24.91	3.74	0.50	0.20	4.44	13,344.9	29.46	8.50	0.20	(0.22)	8.48	25,477.6	12,132.7	90.9%
		1,500,000	4000	52%	24.91	3.74	0.50	0.20	4.44	17,784.9	29.46	8.50	0.20	(0.22)	8.48	33,960.3	16,175.4	90.9%
UGd	**GBE**	15,000	60	35%	10.77	3.64	0.49	0.19	4.32	270.0	14.61	7.33	0.19	(0.27)	7.25	449.6	179.6	66.5%
		43,164	133	45%	10.77	3.64	0.49	0.19	4.32	585.3	14.61	7.33	0.19	(0.27)	7.25	978.9	393.6	67.2%
		100,000	500	28%	10.77	3.64	0.49	0.19	4.32	2,170.8	14.61	7.33	0.19	(0.27)	7.25	3,639.7	1,468.9	67.7%
		400,000	1000	56%	10.77	3.64	0.49	0.19	4.32	4,330.8	14.61	7.33	0.19	(0.27)	7.25	7,264.8	2,934.0	67.7%
		1,000,000	3000	46%	10.77	3.64	0.49	0.19	4.32	12,970.8	14.61	7.33	0.19	(0.27)	7.25	21,765.2	8,794.4	67.8%
		1,500,000	4000	52%	10.77	3.64	0.49	0.19	4.32	17,290.8	14.61	7.33	0.19	(0.27)	7.25	29,015.4	11,724.7	67.8%
GSd	**Georgina**	15,000	60	35%	17.40	5.10	0.51	0.25	5.86	369.0	24.34	9.22	0.25	(0.22)	9.26	579.7	210.7	57.1%
		43,164	133	45%	17.40	5.10	0.51	0.25	5.86	796.8	24.34	9.22	0.25	(0.22)	9.26	1,255.4	458.6	57.6%
		100,000	500	28%	17.40	5.10	0.51	0.25	5.86	2,947.4	24.34	9.22	0.25	(0.22)	9.26	4,652.5	1,705.1	57.9%
		400,000	1000	56%	17.40	5.10	0.51	0.25	5.86	5,877.4	24.34	9.22	0.25	(0.22)	9.26	9,280.6	3,403.2	57.9%
		1,000,000	3000	46%	17.40	5.10	0.51	0.25	5.86	17,597.4	24.34	9.22	0.25	(0.22)	9.26	27,793.2	10,195.8	57.9%
		1,500,000	4000	52%	17.40	5.10	0.51	0.25	5.86	23,457.4	24.34	9.22	0.25	(0.22)	9.26	37,049.5	13,592.1	57.9%

New Rate Class: GSd

Bill Impacts of Proposed Distribution Rates include Riders

Classes		Scenario			Existing Dx Rates						New Dx Rates						$ Incr	% Incr
					SrChg [$/month]	base [$/kW]	Rider1 [$/kW]	Rider2 [$/kW]	VarChg [$/kW]	[$/month]	SrChg [$/month]	base [$/kW]	Rider2 [$/kW]	Rider3 [$/kW]	VarChg [$/kW]	[$/month]		
New Class	**Old Class**	kWh	kW	LF														
GSd	**Glencoe**	15,000	60	35%	11.37	2.55	0.69	0.44	3.68	232.2	19.85	7.40	0.44	(0.22)	7.62	477.2	245.0	105.5%
		43,164	133	45%	11.37	2.55	0.69	0.44	3.68	500.8	19.85	7.40	0.44	(0.22)	7.62	1,033.7	532.9	106.4%
		100,000	500	28%	11.37	2.55	0.69	0.44	3.68	1,851.4	19.85	7.40	0.44	(0.22)	7.62	3,831.2	1,979.8	106.9%
		400,000	1000	56%	11.37	2.55	0.69	0.44	3.68	3,691.4	19.85	7.40	0.44	(0.22)	7.62	7,642.5	3,951.2	107.0%
		1,000,000	3000	46%	11.37	2.55	0.69	0.44	3.68	11,051.4	19.85	7.40	0.44	(0.22)	7.62	22,888.0	11,836.6	107.1%
		1,500,000	4000	52%	11.37	2.55	0.69	0.44	3.68	14,731.4	19.85	7.40	0.44	(0.22)	7.62	30,510.7	15,779.3	107.1%
GSd	**Grand Bend**	15,000	60	35%	22.20	3.90	0.59	0.23	4.72	305.4	28.14	8.75	0.23	(0.22)	8.76	553.9	248.5	81.4%
		43,164	133	45%	22.20	3.90	0.59	0.23	4.72	650.0	28.14	8.75	0.23	(0.22)	8.76	1,193.6	543.6	83.6%
		100,000	500	28%	22.20	3.90	0.59	0.23	4.72	2,382.2	28.14	8.75	0.23	(0.22)	8.76	4,409.5	2,027.3	85.1%
		400,000	1000	56%	22.20	3.90	0.59	0.23	4.72	4,742.2	28.14	8.75	0.23	(0.22)	8.76	8,790.8	4,048.6	85.4%
		1,000,000	3000	46%	22.20	3.90	0.59	0.23	4.72	14,182.2	28.14	8.75	0.23	(0.22)	8.76	26,316.2	12,134.0	85.6%
		1,500,000	4000	52%	22.20	3.90	0.59	0.23	4.72	18,902.2	28.14	8.75	0.23	(0.22)	8.76	35,079.0	16,176.8	85.6%
GSd	**Hastings**	15,000	60	35%	22.89	5.32	0.74	0.29	6.35	403.9	27.97	9.22	0.29	(0.22)	9.30	585.7	181.9	45.0%
		43,164	133	45%	22.89	5.32	0.74	0.29	6.35	867.4	27.97	9.22	0.29	(0.22)	9.30	1,264.4	396.9	45.8%
		100,000	500	28%	22.89	5.32	0.74	0.29	6.35	3,197.9	27.97	9.22	0.29	(0.22)	9.30	4,676.1	1,478.2	46.2%
		400,000	1000	56%	22.89	5.32	0.74	0.29	6.35	6,372.9	27.97	9.22	0.29	(0.22)	9.30	9,324.2	2,951.4	46.3%
		1,000,000	3000	46%	22.89	5.32	0.74	0.29	6.35	19,072.9	27.97	9.22	0.29	(0.22)	9.30	27,916.8	8,843.9	46.4%
		1,500,000	4000	52%	22.89	5.32	0.74	0.29	6.35	25,422.9	27.97	9.22	0.29	(0.22)	9.30	37,213.1	11,790.2	46.4%
GSd	**Havelock**	15,000	60	35%	22.18	4.82	0.50	0.28	5.60	358.2	28.14	9.22	0.28	(0.22)	9.29	585.3	227.1	63.4%
		43,164	133	45%	22.18	4.82	0.50	0.28	5.60	767.0	28.14	9.22	0.28	(0.22)	9.29	1,263.2	496.2	64.7%
		100,000	500	28%	22.18	4.82	0.50	0.28	5.60	2,822.2	28.14	9.22	0.28	(0.22)	9.29	4,671.3	1,849.1	65.5%
		400,000	1000	56%	22.18	4.82	0.50	0.28	5.60	5,622.2	28.14	9.22	0.28	(0.22)	9.29	9,314.4	3,692.2	65.7%
		1,000,000	3000	46%	22.18	4.82	0.50	0.28	5.60	16,822.2	28.14	9.22	0.28	(0.22)	9.29	27,887.0	11,064.8	65.8%
		1,500,000	4000	52%	22.18	4.82	0.50	0.28	5.60	22,422.2	28.14	9.22	0.28	(0.22)	9.29	37,173.3	14,751.1	65.8%
GSd	**Kirkfield**	15,000	60	35%	14.69	5.92	1.95	1.34	9.21	567.3	22.02	9.22	1.34	(0.22)	10.35	642.8	75.5	13.3%
		43,164	133	45%	14.69	5.92	1.95	1.34	9.21	1,239.6	22.02	9.22	1.34	(0.22)	10.35	1,398.1	158.5	12.8%
		100,000	500	28%	14.69	5.92	1.95	1.34	9.21	4,619.7	22.02	9.22	1.34	(0.22)	10.35	5,195.2	575.5	12.5%
		400,000	1000	56%	14.69	5.92	1.95	1.34	9.21	9,224.7	22.02	9.22	1.34	(0.22)	10.35	10,368.3	1,143.6	12.4%
		1,000,000	3000	46%	14.69	5.92	1.95	1.34	9.21	27,644.7	22.02	9.22	1.34	(0.22)	10.35	31,060.9	3,416.2	12.4%
		1,500,000	4000	52%	14.69	5.92	1.95	1.34	9.21	36,854.7	22.02	9.22	1.34	(0.22)	10.35	41,407.2	4,552.5	12.4%

New Rate Class: GSd

Bill Impacts of Proposed Distribution Rates include Riders

Classes		Scenario			Existing Dx Rates						New Dx Rates						$ Incr	% Incr
New Class	Old Class	kWh	kW	LF	SrChg [$/month]	base [$/kW]	Rider1 [$/kW]	Rider2 [$/kW]	VarChg [$/kW]	[$/month]	SrChg [$/month]	base [$/kW]	Rider2 [$/kW]	Rider3 [$/kW]	VarChg [$/kW]	[$/month]		
GSd	**Lanark Highlands**	15,000	60	35%	18.43	5.26	1.99	1.32	8.57	532.6	25.08	9.22	1.32	(0.22)	10.33	644.7	112.0	21.0%
		43,164	133	45%	18.43	5.26	1.99	1.32	8.57	1,158.2	25.08	9.22	1.32	(0.22)	10.33	1,398.5	240.2	20.7%
		100,000	500	28%	18.43	5.26	1.99	1.32	8.57	4,303.4	25.08	9.22	1.32	(0.22)	10.33	5,188.2	884.8	20.6%
		400,000	1000	56%	18.43	5.26	1.99	1.32	8.57	8,588.4	25.08	9.22	1.32	(0.22)	10.33	10,351.4	1,762.9	20.5%
		1,000,000	3000	46%	18.43	5.26	1.99	1.32	8.57	25,728.4	25.08	9.22	1.32	(0.22)	10.33	31,003.9	5,275.5	20.5%
		1,500,000	4000	52%	18.43	5.26	1.99	1.32	8.57	34,298.4	25.08	9.22	1.32	(0.22)	10.33	41,330.2	7,031.8	20.5%
GSd	**Larder Lake**	15,000	60	35%	20.18	4.30	1.61	0.99	6.90	434.2	26.64	9.22	0.99	(0.22)	10.00	626.4	192.2	44.3%
		43,164	133	45%	20.18	4.30	1.61	0.99	6.90	937.9	26.64	9.22	0.99	(0.22)	10.00	1,356.1	418.3	44.6%
		100,000	500	28%	20.18	4.30	1.61	0.99	6.90	3,470.2	26.64	9.22	0.99	(0.22)	10.00	5,024.8	1,554.6	44.8%
		400,000	1000	56%	20.18	4.30	1.61	0.99	6.90	6,920.2	26.64	9.22	0.99	(0.22)	10.00	10,022.9	3,102.7	44.8%
		1,000,000	3000	46%	20.18	4.30	1.61	0.99	6.90	20,720.2	26.64	9.22	0.99	(0.22)	10.00	30,015.5	9,295.3	44.9%
		1,500,000	4000	52%	20.18	4.30	1.61	0.99	6.90	27,620.2	26.64	9.22	0.99	(0.22)	10.00	40,011.8	12,391.6	44.9%
GSd	**Latchford**	15,000	60	35%	2.88	2.44	2.06	0.48	4.98	301.7	12.97	8.80	0.48	(0.22)	9.06	556.7	255.0	84.5%
		43,164	133	45%	2.88	2.44	2.06	0.48	4.98	665.2	12.97	8.80	0.48	(0.22)	9.06	1,218.3	553.1	83.1%
		100,000	500	28%	2.88	2.44	2.06	0.48	4.98	2,492.9	12.97	8.80	0.48	(0.22)	9.06	4,544.3	2,051.4	82.3%
		400,000	1000	56%	2.88	2.44	2.06	0.48	4.98	4,982.9	12.97	8.80	0.48	(0.22)	9.06	9,075.7	4,092.8	82.1%
		1,000,000	3000	46%	2.88	2.44	2.06	0.48	4.98	14,942.9	12.97	8.80	0.48	(0.22)	9.06	27,201.1	12,258.2	82.0%
		1,500,000	4000	52%	2.88	2.44	2.06	0.48	4.98	19,922.9	12.97	8.80	0.48	(0.22)	9.06	36,263.8	16,340.9	82.0%
UGd	**Lindsay**	15,000	60	35%	23.94	4.36	0.49	0.19	5.04	326.3	24.31	7.33	0.19	(0.27)	7.25	459.3	133.0	40.8%
		43,164	133	45%	23.94	4.36	0.49	0.19	5.04	694.3	24.31	7.33	0.19	(0.27)	7.25	988.6	294.3	42.4%
		100,000	500	28%	23.94	4.36	0.49	0.19	5.04	2,543.9	24.31	7.33	0.19	(0.27)	7.25	3,649.4	1,105.5	43.5%
		400,000	1000	56%	23.94	4.36	0.49	0.19	5.04	5,063.9	24.31	7.33	0.19	(0.27)	7.25	7,274.5	2,210.6	43.7%
		1,000,000	3000	46%	23.94	4.36	0.49	0.19	5.04	15,143.9	24.31	7.33	0.19	(0.27)	7.25	21,774.9	6,631.0	43.8%
		1,500,000	4000	52%	23.94	4.36	0.49	0.19	5.04	20,183.9	24.31	7.33	0.19	(0.27)	7.25	29,025.1	8,841.2	43.8%
GSd	**Lucan Granton**	15,000	60	35%	16.99	4.61	0.53	0.30	5.44	343.4	23.44	9.22	0.30	(0.22)	9.31	581.8	238.4	69.4%
		43,164	133	45%	16.99	4.61	0.53	0.30	5.44	740.5	23.44	9.22	0.30	(0.22)	9.31	1,261.2	520.7	70.3%
		100,000	500	28%	16.99	4.61	0.53	0.30	5.44	2,737.0	23.44	9.22	0.30	(0.22)	9.31	4,676.6	1,939.6	70.9%
		400,000	1000	56%	16.99	4.61	0.53	0.30	5.44	5,457.0	23.44	9.22	0.30	(0.22)	9.31	9,329.7	3,872.7	71.0%
		1,000,000	3000	46%	16.99	4.61	0.53	0.30	5.44	16,337.0	23.44	9.22	0.30	(0.22)	9.31	27,942.3	11,605.3	71.0%
		1,500,000	4000	52%	16.99	4.61	0.53	0.30	5.44	21,777.0	23.44	9.22	0.30	(0.22)	9.31	37,248.6	15,471.6	71.0%

New Rate Class: GSd

Bill Impacts of Proposed Distribution Rates include Riders

Classes		Scenario			Existing Dx Rates						New Dx Rates						$ Incr	% Incr
					SrChg [$/month]	base [$/kW]	Rider1 [$/kW]	Rider2 [$/kW]	VarChg [$/kW]	[$/month]	SrChg [$/month]	base [$/kW]	Rider2 [$/kW]	Rider3 [$/kW]	VarChg [$/kW]	[$/month]		
New Class	**Old Class**	kWh	kW	LF														
GSd	**Malahide**	15,000	60	35%	15.99	5.42	2.57	1.32	9.31	574.6	22.69	9.22	1.32	(0.22)	10.33	642.3	67.7	11.8%
		43,164	133	45%	15.99	5.42	2.57	1.32	9.31	1,254.2	22.69	9.22	1.32	(0.22)	10.33	1,396.1	141.9	11.3%
		100,000	500	28%	15.99	5.42	2.57	1.32	9.31	4,671.0	22.69	9.22	1.32	(0.22)	10.33	5,185.8	514.8	11.0%
		400,000	1000	56%	15.99	5.42	2.57	1.32	9.31	9,326.0	22.69	9.22	1.32	(0.22)	10.33	10,349.0	1,023.0	11.0%
		1,000,000	3000	46%	15.99	5.42	2.57	1.32	9.31	27,946.0	22.69	9.22	1.32	(0.22)	10.33	31,001.5	3,055.6	10.9%
		1,500,000	4000	52%	15.99	5.42	2.57	1.32	9.31	37,256.0	22.69	9.22	1.32	(0.22)	10.33	41,327.8	4,071.8	10.9%
GSd	**Mapleton**	15,000	60	35%	21.55	5.42	1.26	0.93	7.61	478.2	27.30	9.22	0.93	(0.22)	9.94	623.5	145.3	30.4%
		43,164	133	45%	21.55	5.42	1.26	0.93	7.61	1,033.7	27.30	9.22	0.93	(0.22)	9.94	1,348.8	315.1	30.5%
		100,000	500	28%	21.55	5.42	1.26	0.93	7.61	3,826.6	27.30	9.22	0.93	(0.22)	9.94	4,995.4	1,168.9	30.5%
		400,000	1000	56%	21.55	5.42	1.26	0.93	7.61	7,631.6	27.30	9.22	0.93	(0.22)	9.94	9,963.6	2,332.0	30.6%
		1,000,000	3000	46%	21.55	5.42	1.26	0.93	7.61	22,851.6	27.30	9.22	0.93	(0.22)	9.94	29,836.2	6,984.6	30.6%
		1,500,000	4000	52%	21.55	5.42	1.26	0.93	7.61	30,461.6	27.30	9.22	0.93	(0.22)	9.94	39,772.4	9,310.9	30.6%
GSd	**Markdale**	15,000	60	35%	23.00	2.54	0.49	0.13	3.16	212.6	28.94	7.25	0.13	(0.22)	7.16	458.7	246.1	115.8%
		43,164	133	45%	23.00	2.54	0.49	0.13	3.16	443.3	28.94	7.25	0.13	(0.22)	7.16	981.6	538.3	121.4%
		100,000	500	28%	23.00	2.54	0.49	0.13	3.16	1,603.0	28.94	7.25	0.13	(0.22)	7.16	3,610.3	2,007.3	125.2%
		400,000	1000	56%	23.00	2.54	0.49	0.13	3.16	3,183.0	28.94	7.25	0.13	(0.22)	7.16	7,191.6	4,008.6	125.9%
		1,000,000	3000	46%	23.00	2.54	0.49	0.13	3.16	9,503.0	28.94	7.25	0.13	(0.22)	7.16	21,517.0	12,014.0	126.4%
		1,500,000	4000	52%	23.00	2.54	0.49	0.13	3.16	12,663.0	28.94	7.25	0.13	(0.22)	7.16	28,679.8	16,016.8	126.5%
GSd	**Marmora**	15,000	60	35%	10.02	3.33	0.49	0.16	3.98	248.8	19.18	8.00	0.16	(0.22)	7.94	495.7	246.9	99.2%
		43,164	133	45%	10.02	3.33	0.49	0.16	3.98	539.4	19.18	8.00	0.16	(0.22)	7.94	1,075.6	536.2	99.4%
		100,000	500	28%	10.02	3.33	0.49	0.16	3.98	2,000.0	19.18	8.00	0.16	(0.22)	7.94	3,990.5	1,990.5	99.5%
		400,000	1000	56%	10.02	3.33	0.49	0.16	3.98	3,990.0	19.18	8.00	0.16	(0.22)	7.94	7,961.9	3,971.9	99.5%
		1,000,000	3000	46%	10.02	3.33	0.49	0.16	3.98	11,950.0	19.18	8.00	0.16	(0.22)	7.94	23,847.3	11,897.3	99.6%
		1,500,000	4000	52%	10.02	3.33	0.49	0.16	3.98	15,930.0	19.18	8.00	0.16	(0.22)	7.94	31,790.0	15,860.0	99.6%
GSd	**McGarry**	15,000	60	35%	20.18	5.68	1.80	1.42	8.90	554.2	26.64	9.22	1.42	(0.22)	10.43	652.2	98.0	17.7%
		43,164	133	45%	20.18	5.68	1.80	1.42	8.90	1,203.9	26.64	9.22	1.42	(0.22)	10.43	1,413.3	209.5	17.4%
		100,000	500	28%	20.18	5.68	1.80	1.42	8.90	4,470.2	26.64	9.22	1.42	(0.22)	10.43	5,239.8	769.6	17.2%
		400,000	1000	56%	20.18	5.68	1.80	1.42	8.90	8,920.2	26.64	9.22	1.42	(0.22)	10.43	10,452.9	1,532.7	17.2%
		1,000,000	3000	46%	20.18	5.68	1.80	1.42	8.90	26,720.2	26.64	9.22	1.42	(0.22)	10.43	31,305.5	4,585.3	17.2%
		1,500,000	4000	52%	20.18	5.68	1.80	1.42	8.90	35,620.2	26.64	9.22	1.42	(0.22)	10.43	41,731.8	6,111.6	17.2%

New Rate Class: GSd

Bill Impacts of Proposed Distribution Rates include Riders

Classes		Scenario			Existing Dx Rates						New Dx Rates						$ Incr	% Incr
					SrChg	base	Rider1	Rider2	VarChg	[$/month]	SrChg	base	Rider2	Rider3	VarChg	[$/month]		
New Class	Old Class	kWh	kW	LF	[$/month]	[$/kW]	[$/kW]	[$/kW]	[$/kW]		[$/month]	[$/kW]	[$/kW]	[$/kW]	[$/kW]			
GSd	Meaford	15,000	60	35%	24.05	3.90	0.50	0.21	4.61	300.7	29.68	8.75	0.21	(0.22)	8.74	554.2	253.6	84.3%
		43,164	133	45%	24.05	3.90	0.50	0.21	4.61	637.2	29.68	8.75	0.21	(0.22)	8.74	1,192.5	555.3	87.1%
		100,000	500	28%	24.05	3.90	0.50	0.21	4.61	2,329.1	29.68	8.75	0.21	(0.22)	8.74	4,401.0	2,072.0	89.0%
		400,000	1000	56%	24.05	3.90	0.50	0.21	4.61	4,634.1	29.68	8.75	0.21	(0.22)	8.74	8,772.4	4,138.3	89.3%
		1,000,000	3000	46%	24.05	3.90	0.50	0.21	4.61	13,854.1	29.68	8.75	0.21	(0.22)	8.74	26,257.8	12,403.7	89.5%
		1,500,000	4000	52%	24.05	3.90	0.50	0.21	4.61	18,464.1	29.68	8.75	0.21	(0.22)	8.74	35,000.5	16,536.4	89.6%
GSd	Middlesex Centre	15,000	60	35%	17.35	3.29	1.39	0.84	5.52	348.6	24.35	9.00	0.84	(0.22)	9.62	601.7	253.2	72.6%
		43,164	133	45%	17.35	3.29	1.39	0.84	5.52	751.5	24.35	9.00	0.84	(0.22)	9.62	1,304.2	552.7	73.5%
		100,000	500	28%	17.35	3.29	1.39	0.84	5.52	2,777.4	24.35	9.00	0.84	(0.22)	9.62	4,835.7	2,058.4	74.1%
		400,000	1000	56%	17.35	3.29	1.39	0.84	5.52	5,537.4	24.35	9.00	0.84	(0.22)	9.62	9,647.1	4,109.7	74.2%
		1,000,000	3000	46%	17.35	3.29	1.39	0.84	5.52	16,577.4	24.35	9.00	0.84	(0.22)	9.62	28,892.5	12,315.1	74.3%
		1,500,000	4000	52%	17.35	3.29	1.39	0.84	5.52	22,097.4	24.35	9.00	0.84	(0.22)	9.62	38,515.2	16,417.8	74.3%
GSd	Napanee	15,000	60	35%	22.17	4.04	0.52	0.20	4.76	307.8	28.15	8.90	0.20	(0.22)	8.88	561.1	253.3	82.3%
		43,164	133	45%	22.17	4.04	0.52	0.20	4.76	655.3	28.15	8.90	0.20	(0.22)	8.88	1,209.5	554.3	84.6%
		100,000	500	28%	22.17	4.04	0.52	0.20	4.76	2,402.2	28.15	8.90	0.20	(0.22)	8.88	4,469.5	2,067.3	86.1%
		400,000	1000	56%	22.17	4.04	0.52	0.20	4.76	4,782.2	28.15	8.90	0.20	(0.22)	8.88	8,910.8	4,128.7	86.3%
		1,000,000	3000	46%	22.17	4.04	0.52	0.20	4.76	14,302.2	28.15	8.90	0.20	(0.22)	8.88	26,676.3	12,374.1	86.5%
		1,500,000	4000	52%	22.17	4.04	0.52	0.20	4.76	19,062.2	28.15	8.90	0.20	(0.22)	8.88	35,559.0	16,496.8	86.5%
GSd	Nipigon	15,000	60	35%	23.32	3.38	1.07	0.68	5.13	331.1	28.86	8.80	0.68	(0.22)	9.26	584.6	253.5	76.6%
		43,164	133	45%	23.32	3.38	1.07	0.68	5.13	705.6	28.86	8.80	0.68	(0.22)	9.26	1,260.8	555.2	78.7%
		100,000	500	28%	23.32	3.38	1.07	0.68	5.13	2,588.3	28.86	8.80	0.68	(0.22)	9.26	4,660.2	2,071.9	80.0%
		400,000	1000	56%	23.32	3.38	1.07	0.68	5.13	5,153.3	28.86	8.80	0.68	(0.22)	9.26	9,291.6	4,138.2	80.3%
		1,000,000	3000	46%	23.32	3.38	1.07	0.68	5.13	15,413.3	28.86	8.80	0.68	(0.22)	9.26	27,817.0	12,403.6	80.5%
		1,500,000	4000	52%	23.32	3.38	1.07	0.68	5.13	20,543.3	28.86	8.80	0.68	(0.22)	9.26	37,079.7	16,536.4	80.5%
GSd	North Dorchester	15,000	60	35%	15.88	2.85	1.12	0.81	4.78	302.7	22.72	8.30	0.81	(0.22)	8.89	556.3	253.6	83.8%
		43,164	133	45%	15.88	2.85	1.12	0.81	4.78	651.6	22.72	8.30	0.81	(0.22)	8.89	1,205.4	553.8	85.0%
		100,000	500	28%	15.88	2.85	1.12	0.81	4.78	2,405.9	22.72	8.30	0.81	(0.22)	8.89	4,469.1	2,063.2	85.8%
		400,000	1000	56%	15.88	2.85	1.12	0.81	4.78	4,795.9	22.72	8.30	0.81	(0.22)	8.89	8,915.4	4,119.5	85.9%
		1,000,000	3000	46%	15.88	2.85	1.12	0.81	4.78	14,355.9	22.72	8.30	0.81	(0.22)	8.89	26,700.8	12,344.9	86.0%
		1,500,000	4000	52%	15.88	2.85	1.12	0.81	4.78	19,135.9	22.72	8.30	0.81	(0.22)	8.89	35,593.5	16,457.7	86.0%

New Rate Class: GSd

Bill Impacts of Proposed Distribution Rates include Riders

Classes		Scenario			Existing Dx Rates						New Dx Rates						$ Incr	% Incr
New Class	Old Class	kWh	kW	LF	SrChg [$/month]	base [$/kW]	Rider1 [$/kW]	Rider2 [$/kW]	VarChg [$/kW]	[$/month]	SrChg [$/month]	base [$/kW]	Rider2 [$/kW]	Rider3 [$/kW]	VarChg [$/kW]	[$/month]		
GSd	**North Dundas**	15,000	60	35%	13.52	2.42	0.52	0.11	3.05	196.5	21.31	7.00	0.11	(0.22)	6.89	434.9	238.3	121.3%
		43,164	133	45%	13.52	2.42	0.52	0.11	3.05	419.2	21.31	7.00	0.11	(0.22)	6.89	938.0	518.9	123.8%
		100,000	500	28%	13.52	2.42	0.52	0.11	3.05	1,538.5	21.31	7.00	0.11	(0.22)	6.89	3,467.7	1,929.1	125.4%
		400,000	1000	56%	13.52	2.42	0.52	0.11	3.05	3,063.5	21.31	7.00	0.11	(0.22)	6.89	6,914.0	3,850.5	125.7%
		1,000,000	3000	46%	13.52	2.42	0.52	0.11	3.05	9,163.5	21.31	7.00	0.11	(0.22)	6.89	20,699.4	11,535.9	125.9%
		1,500,000	4000	52%	13.52	2.42	0.52	0.11	3.05	12,213.5	21.31	7.00	0.11	(0.22)	6.89	27,592.1	15,378.6	125.9%
GSd	**North Glengarry**	15,000	60	35%	17.72	2.82	0.69	0.39	3.90	251.7	24.26	7.70	0.39	(0.22)	7.87	496.6	244.9	97.3%
		43,164	133	45%	17.72	2.82	0.69	0.39	3.90	536.4	24.26	7.70	0.39	(0.22)	7.87	1,071.3	534.9	99.7%
		100,000	500	28%	17.72	2.82	0.69	0.39	3.90	1,967.7	24.26	7.70	0.39	(0.22)	7.87	3,960.6	1,992.9	101.3%
		400,000	1000	56%	17.72	2.82	0.69	0.39	3.90	3,917.7	24.26	7.70	0.39	(0.22)	7.87	7,897.0	3,979.2	101.6%
		1,000,000	3000	46%	17.72	2.82	0.69	0.39	3.90	11,717.7	24.26	7.70	0.39	(0.22)	7.87	23,642.4	11,924.6	101.8%
		1,500,000	4000	52%	17.72	2.82	0.69	0.39	3.90	15,617.7	24.26	7.70	0.39	(0.22)	7.87	31,515.1	15,897.4	101.8%
GSd	**North Grenville**	15,000	60	35%	20.42	5.41	0.45	0.25	6.11	387.0	26.58	9.22	0.25	(0.22)	9.26	582.0	194.9	50.4%
		43,164	133	45%	20.42	5.41	0.45	0.25	6.11	833.1	26.58	9.22	0.25	(0.22)	9.26	1,257.7	424.6	51.0%
		100,000	500	28%	20.42	5.41	0.45	0.25	6.11	3,075.4	26.58	9.22	0.25	(0.22)	9.26	4,654.7	1,579.3	51.4%
		400,000	1000	56%	20.42	5.41	0.45	0.25	6.11	6,130.4	26.58	9.22	0.25	(0.22)	9.26	9,282.9	3,152.4	51.4%
		1,000,000	3000	46%	20.42	5.41	0.45	0.25	6.11	18,350.4	26.58	9.22	0.25	(0.22)	9.26	27,795.4	9,445.0	51.5%
		1,500,000	4000	52%	20.42	5.41	0.45	0.25	6.11	24,460.4	26.58	9.22	0.25	(0.22)	9.26	37,051.7	12,591.3	51.5%
GSd	**North Perth**	15,000	60	35%	29.52	3.16	0.36	0.13	3.65	248.5	33.31	7.70	0.13	(0.22)	7.61	490.1	241.5	97.2%
		43,164	133	45%	29.52	3.16	0.36	0.13	3.65	515.0	33.31	7.70	0.13	(0.22)	7.61	1,045.8	530.8	103.1%
		100,000	500	28%	29.52	3.16	0.36	0.13	3.65	1,854.5	33.31	7.70	0.13	(0.22)	7.61	3,839.7	1,985.1	107.0%
		400,000	1000	56%	29.52	3.16	0.36	0.13	3.65	3,679.5	33.31	7.70	0.13	(0.22)	7.61	7,646.0	3,966.5	107.8%
		1,000,000	3000	46%	29.52	3.16	0.36	0.13	3.65	10,979.5	33.31	7.70	0.13	(0.22)	7.61	22,871.4	11,891.9	108.3%
		1,500,000	4000	52%	29.52	3.16	0.36	0.13	3.65	14,629.5	33.31	7.70	0.13	(0.22)	7.61	30,484.1	15,854.6	108.4%
GSd	**North Stormont**	15,000	60	35%	5.37	2.52	1.17	0.82	4.51	276.0	15.35	9.22	0.82	(0.22)	9.83	604.9	329.0	119.2%
	no customer	43,164	133	45%	5.37	2.52	1.17	0.82	4.51	605.2	15.35	9.22	0.82	(0.22)	9.83	1,322.2	717.0	118.5%
		100,000	500	28%	5.37	2.52	1.17	0.82	4.51	2,260.4	15.35	9.22	0.82	(0.22)	9.83	4,928.5	2,668.1	118.0%
		400,000	1000	56%	5.37	2.52	1.17	0.82	4.51	4,515.4	15.35	9.22	0.82	(0.22)	9.83	9,841.6	5,326.3	118.0%
		1,000,000	3000	46%	5.37	2.52	1.17	0.82	4.51	13,535.4	15.35	9.22	0.82	(0.22)	9.83	29,494.2	15,958.8	117.9%
		1,500,000	4000	52%	5.37	2.52	1.17	0.82	4.51	18,045.4	15.35	9.22	0.82	(0.22)	9.83	39,320.5	21,275.1	117.9%

New Rate Class: GSd

Bill Impacts of Proposed Distribution Rates include Riders

Classes		Scenario			Existing Dx Rates						New Dx Rates						$ Incr	% Incr
					SrChg [$/month]	base [$/kW]	Rider1 [$/kW]	Rider2 [$/kW]	VarChg [$/kW]	[$/month]	SrChg [$/month]	base [$/kW]	Rider2 [$/kW]	Rider3 [$/kW]	VarChg [$/kW]	[$/month]		
New Class	Old Class	kWh	kW	LF														
GSd	Omemee	15,000	60	35%	21.28	4.64	0.55	0.27	5.46	348.9	27.37	9.22	0.27	(0.22)	9.28	583.9	235.1	67.4%
		43,164	133	45%	21.28	4.64	0.55	0.27	5.46	747.5	27.37	9.22	0.27	(0.22)	9.28	1,261.1	513.7	68.7%
		100,000	500	28%	21.28	4.64	0.55	0.27	5.46	2,751.3	27.37	9.22	0.27	(0.22)	9.28	4,665.5	1,914.2	69.6%
		400,000	1000	56%	21.28	4.64	0.55	0.27	5.46	5,481.3	27.37	9.22	0.27	(0.22)	9.28	9,303.7	3,822.4	69.7%
		1,000,000	3000	46%	21.28	4.64	0.55	0.27	5.46	16,401.3	27.37	9.22	0.27	(0.22)	9.28	27,856.2	11,454.9	69.8%
		1,500,000	4000	52%	21.28	4.64	0.55	0.27	5.46	21,861.3	27.37	9.22	0.27	(0.22)	9.28	37,132.5	15,271.2	69.9%
UGd	Perth	15,000	60	35%	19.92	2.87	0.42	0.12	3.41	224.5	21.32	7.15	0.12	(0.27)	7.00	441.1	216.6	96.5%
		43,164	133	45%	19.92	2.87	0.42	0.12	3.41	473.5	21.32	7.15	0.12	(0.27)	7.00	951.9	478.5	101.1%
		100,000	500	28%	19.92	2.87	0.42	0.12	3.41	1,724.9	21.32	7.15	0.12	(0.27)	7.00	3,519.9	1,795.0	104.1%
		400,000	1000	56%	19.92	2.87	0.42	0.12	3.41	3,429.9	21.32	7.15	0.12	(0.27)	7.00	7,018.4	3,588.5	104.6%
		1,000,000	3000	46%	19.92	2.87	0.42	0.12	3.41	10,249.9	21.32	7.15	0.12	(0.27)	7.00	21,012.7	10,762.8	105.0%
		1,500,000	4000	52%	19.92	2.87	0.42	0.12	3.41	13,659.9	21.32	7.15	0.12	(0.27)	7.00	28,009.8	14,349.9	105.1%
GSd	Perth East	15,000	60	35%	14.65	4.08	0.52	0.27	4.87	306.9	22.03	8.95	0.27	(0.22)	9.00	562.2	255.3	83.2%
		43,164	133	45%	14.65	4.08	0.52	0.27	4.87	662.4	22.03	8.95	0.27	(0.22)	9.00	1,219.4	557.0	84.1%
		100,000	500	28%	14.65	4.08	0.52	0.27	4.87	2,449.7	22.03	8.95	0.27	(0.22)	9.00	4,523.4	2,073.7	84.7%
		400,000	1000	56%	14.65	4.08	0.52	0.27	4.87	4,884.7	22.03	8.95	0.27	(0.22)	9.00	9,024.7	4,140.1	84.8%
		1,000,000	3000	46%	14.65	4.08	0.52	0.27	4.87	14,624.7	22.03	8.95	0.27	(0.22)	9.00	27,030.1	12,405.5	84.8%
		1,500,000	4000	52%	14.65	4.08	0.52	0.27	4.87	19,494.7	22.03	8.95	0.27	(0.22)	9.00	36,032.8	16,538.2	84.8%
GSd	Prince Edward	15,000	60	35%	22.85	4.45	0.58	0.24	5.27	339.1	27.98	9.22	0.24	(0.22)	9.25	582.8	243.7	71.9%
		43,164	133	45%	22.85	4.45	0.58	0.24	5.27	723.8	27.98	9.22	0.24	(0.22)	9.25	1,257.7	534.0	73.8%
		100,000	500	28%	22.85	4.45	0.58	0.24	5.27	2,657.9	27.98	9.22	0.24	(0.22)	9.25	4,651.1	1,993.3	75.0%
		400,000	1000	56%	22.85	4.45	0.58	0.24	5.27	5,292.9	27.98	9.22	0.24	(0.22)	9.25	9,274.3	3,981.4	75.2%
		1,000,000	3000	46%	22.85	4.45	0.58	0.24	5.27	15,832.9	27.98	9.22	0.24	(0.22)	9.25	27,766.8	11,934.0	75.4%
		1,500,000	4000	52%	22.85	4.45	0.58	0.24	5.27	21,102.9	27.98	9.22	0.24	(0.22)	9.25	37,013.1	15,910.3	75.4%
UGd	Quinte West	15,000	60	35%	3.74	3.32	0.46	0.18	3.96	241.3	9.36	7.33	0.18	(0.27)	7.24	443.8	202.4	83.9%
		43,164	133	45%	3.74	3.32	0.46	0.18	3.96	530.4	9.36	7.33	0.18	(0.27)	7.24	972.3	441.9	83.3%
		100,000	500	28%	3.74	3.32	0.46	0.18	3.96	1,983.7	9.36	7.33	0.18	(0.27)	7.24	3,629.5	1,645.7	83.0%
		400,000	1000	56%	3.74	3.32	0.46	0.18	3.96	3,963.7	9.36	7.33	0.18	(0.27)	7.24	7,249.6	3,285.8	82.9%
		1,000,000	3000	46%	3.74	3.32	0.46	0.18	3.96	11,883.7	9.36	7.33	0.18	(0.27)	7.24	21,730.0	9,846.2	82.9%
		1,500,000	4000	52%	3.74	3.32	0.46	0.18	3.96	15,843.7	9.36	7.33	0.18	(0.27)	7.24	28,970.2	13,126.4	82.8%

New Rate Class: GSd

Bill Impacts of Proposed Distribution Rates include Riders

Classes		Scenario			Existing Dx Rates						New Dx Rates						$ Incr	% Incr
New Class	Old Class	kWh	kW	LF	SrChg [$/month]	base [$/kW]	Rider1 [$/kW]	Rider2 [$/kW]	VarChg [$/kW]	[$/month]	SrChg [$/month]	base [$/kW]	Rider2 [$/kW]	Rider3 [$/kW]	VarChg [$/kW]	[$/month]		
GSd	**Rainy River**	15,000	60	35%	19.29	5.59	1.44	1.14	8.17	509.5	25.87	9.22	1.14	(0.22)	10.15	634.6	125.2	24.6%
		43,164	133	45%	19.29	5.59	1.44	1.14	8.17	1,105.9	25.87	9.22	1.14	(0.22)	10.15	1,375.3	269.4	24.4%
		100,000	500	28%	19.29	5.59	1.44	1.14	8.17	4,104.3	25.87	9.22	1.14	(0.22)	10.15	5,099.0	994.7	24.2%
		400,000	1000	56%	19.29	5.59	1.44	1.14	8.17	8,189.3	25.87	9.22	1.14	(0.22)	10.15	10,172.1	1,982.9	24.2%
		1,000,000	3000	46%	19.29	5.59	1.44	1.14	8.17	24,529.3	25.87	9.22	1.14	(0.22)	10.15	30,464.7	5,935.4	24.2%
		1,500,000	4000	52%	19.29	5.59	1.44	1.14	8.17	32,699.3	25.87	9.22	1.14	(0.22)	10.15	40,611.0	7,911.7	24.2%
GSd	**Ramara**	15,000	60	35%	20.97	3.35	1.43	1.16	5.94	377.4	26.45	9.22	1.16	(0.22)	10.17	636.4	259.1	68.6%
		43,164	133	45%	20.97	3.35	1.43	1.16	5.94	811.0	26.45	9.22	1.16	(0.22)	10.17	1,378.6	567.6	70.0%
		100,000	500	28%	20.97	3.35	1.43	1.16	5.94	2,991.0	26.45	9.22	1.16	(0.22)	10.17	5,109.6	2,118.6	70.8%
		400,000	1000	56%	20.97	3.35	1.43	1.16	5.94	5,961.0	26.45	9.22	1.16	(0.22)	10.17	10,192.7	4,231.8	71.0%
		1,000,000	3000	46%	20.97	3.35	1.43	1.16	5.94	17,841.0	26.45	9.22	1.16	(0.22)	10.17	30,525.3	12,684.3	71.1%
		1,500,000	4000	52%	20.97	3.35	1.43	1.16	5.94	23,781.0	26.45	9.22	1.16	(0.22)	10.17	40,691.6	16,910.6	71.1%
GSd	**Red Rock**	15,000	60	35%	21.64	6.15	0.86	0.75	7.76	487.2	27.28	9.22	0.75	(0.22)	9.76	612.7	125.4	25.7%
		43,164	133	45%	21.64	6.15	0.86	0.75	7.76	1,053.7	27.28	9.22	0.75	(0.22)	9.76	1,324.9	271.1	25.7%
		100,000	500	28%	21.64	6.15	0.86	0.75	7.76	3,901.6	27.28	9.22	0.75	(0.22)	9.76	4,905.4	1,003.8	25.7%
		400,000	1000	56%	21.64	6.15	0.86	0.75	7.76	7,781.6	27.28	9.22	0.75	(0.22)	9.76	9,783.6	2,001.9	25.7%
		1,000,000	3000	46%	21.64	6.15	0.86	0.75	7.76	23,301.6	27.28	9.22	0.75	(0.22)	9.76	29,296.1	5,994.5	25.7%
		1,500,000	4000	52%	21.64	6.15	0.86	0.75	7.76	31,061.6	27.28	9.22	0.75	(0.22)	9.76	39,052.4	7,990.8	25.7%
GSd	**Rockland**	15,000	60	35%	7.27	2.59	0.53	0.57	3.69	228.7	16.87	7.25	0.57	(0.22)	7.60	473.0	244.4	106.9%
		43,164	133	45%	7.27	2.59	0.53	0.57	3.69	498.0	16.87	7.25	0.57	(0.22)	7.60	1,028.0	530.0	106.4%
		100,000	500	28%	7.27	2.59	0.53	0.57	3.69	1,852.3	16.87	7.25	0.57	(0.22)	7.60	3,818.2	1,966.0	106.1%
		400,000	1000	56%	7.27	2.59	0.53	0.57	3.69	3,697.3	16.87	7.25	0.57	(0.22)	7.60	7,619.6	3,922.3	106.1%
		1,000,000	3000	46%	7.27	2.59	0.53	0.57	3.69	11,077.3	16.87	7.25	0.57	(0.22)	7.60	22,825.0	11,747.7	106.1%
		1,500,000	4000	52%	7.27	2.59	0.53	0.57	3.69	14,767.3	16.87	7.25	0.57	(0.22)	7.60	30,427.7	15,660.4	106.0%
GSd	**Russell**	15,000	60	35%	19.26	7.10	0.58	0.36	8.04	501.7	25.87	9.22	0.36	(0.22)	9.37	587.8	86.2	17.2%
		43,164	133	45%	19.26	7.10	0.58	0.36	8.04	1,088.6	25.87	9.22	0.36	(0.22)	9.37	1,271.6	183.0	16.8%
		100,000	500	28%	19.26	7.10	0.58	0.36	8.04	4,039.3	25.87	9.22	0.36	(0.22)	9.37	4,709.0	669.8	16.6%
		400,000	1000	56%	19.26	7.10	0.58	0.36	8.04	8,059.3	25.87	9.22	0.36	(0.22)	9.37	9,392.2	1,332.9	16.5%
		1,000,000	3000	46%	19.26	7.10	0.58	0.36	8.04	24,139.3	25.87	9.22	0.36	(0.22)	9.37	28,124.7	3,985.5	16.5%
		1,500,000	4000	52%	19.26	7.10	0.58	0.36	8.04	32,179.3	25.87	9.22	0.36	(0.22)	9.37	37,491.0	5,311.7	16.5%

New Rate Class: GSd

Bill Impacts of Proposed Distribution Rates include Riders

Classes		Scenario			Existing Dx Rates						New Dx Rates						$ Incr	% Incr
					SrChg [$/month]	base [$/kW]	Rider1 [$/kW]	Rider2 [$/kW]	VarChg [$/kW]	[$/month]	SrChg [$/month]	base [$/kW]	Rider2 [$/kW]	Rider3 [$/kW]	VarChg [$/kW]	[$/month]		
New Class	**Old Class**	kWh	kW	LF														
GSd	**Schreiber**	15,000	60	35%	20.70	7.36	1.57	1.17	10.10	626.7	26.51	9.22	1.17	(0.22)	10.18	637.1	10.4	1.7%
		43,164	133	45%	20.70	7.36	1.57	1.17	10.10	1,364.0	26.51	9.22	1.17	(0.22)	10.18	1,380.0	16.0	1.2%
		100,000	500	28%	20.70	7.36	1.57	1.17	10.10	5,070.7	26.51	9.22	1.17	(0.22)	10.18	5,114.7	44.0	0.9%
		400,000	1000	56%	20.70	7.36	1.57	1.17	10.10	10,120.7	26.51	9.22	1.17	(0.22)	10.18	10,202.8	82.1	0.8%
		1,000,000	3000	46%	20.70	7.36	1.57	1.17	10.10	30,320.7	26.51	9.22	1.17	(0.22)	10.18	30,555.4	234.7	0.8%
		1,500,000	4000	52%	20.70	7.36	1.57	1.17	10.10	40,420.7	26.51	9.22	1.17	(0.22)	10.18	40,731.6	310.9	0.8%
GSd	**Severn**	15,000	60	35%	22.17	3.35	0.98	0.69	5.02	323.4	28.15	8.70	0.69	(0.22)	9.17	578.5	255.1	78.9%
		43,164	133	45%	22.17	3.35	0.98	0.69	5.02	689.8	28.15	8.70	0.69	(0.22)	9.17	1,248.1	558.3	80.9%
		100,000	500	28%	22.17	3.35	0.98	0.69	5.02	2,532.2	28.15	8.70	0.69	(0.22)	9.17	4,614.5	2,082.3	82.2%
		400,000	1000	56%	22.17	3.35	0.98	0.69	5.02	5,042.2	28.15	8.70	0.69	(0.22)	9.17	9,200.8	4,158.7	82.5%
		1,000,000	3000	46%	22.17	3.35	0.98	0.69	5.02	15,082.2	28.15	8.70	0.69	(0.22)	9.17	27,546.3	12,464.1	82.6%
		1,500,000	4000	52%	22.17	3.35	0.98	0.69	5.02	20,102.2	28.15	8.70	0.69	(0.22)	9.17	36,719.0	16,616.8	82.7%
GSd	**Shelburne**	15,000	60	35%	20.01	2.78	0.32	0.08	3.18	210.8	26.69	7.25	0.08	(0.22)	7.11	453.4	242.6	115.1%
		43,164	133	45%	20.01	2.78	0.32	0.08	3.18	443.0	26.69	7.25	0.08	(0.22)	7.11	972.7	529.7	119.6%
		100,000	500	28%	20.01	2.78	0.32	0.08	3.18	1,610.0	26.69	7.25	0.08	(0.22)	7.11	3,583.0	1,973.0	122.5%
		400,000	1000	56%	20.01	2.78	0.32	0.08	3.18	3,200.0	26.69	7.25	0.08	(0.22)	7.11	7,139.4	3,939.4	123.1%
		1,000,000	3000	46%	20.01	2.78	0.32	0.08	3.18	9,560.0	26.69	7.25	0.08	(0.22)	7.11	21,364.8	11,804.8	123.5%
		1,500,000	4000	52%	20.01	2.78	0.32	0.08	3.18	12,740.0	26.69	7.25	0.08	(0.22)	7.11	28,477.5	15,737.5	123.5%
UGd	**Smiths Falls**	15,000	60	35%	9.84	3.33	0.39	0.13	3.85	240.8	13.84	7.33	0.13	(0.27)	7.19	445.2	204.4	84.9%
		43,164	133	45%	9.84	3.33	0.39	0.13	3.85	521.9	13.84	7.33	0.13	(0.27)	7.19	970.1	448.2	85.9%
		100,000	500	28%	9.84	3.33	0.39	0.13	3.85	1,934.8	13.84	7.33	0.13	(0.27)	7.19	3,608.9	1,674.1	86.5%
		400,000	1000	56%	9.84	3.33	0.39	0.13	3.85	3,859.8	13.84	7.33	0.13	(0.27)	7.19	7,204.0	3,344.2	86.6%
		1,000,000	3000	46%	9.84	3.33	0.39	0.13	3.85	11,559.8	13.84	7.33	0.13	(0.27)	7.19	21,584.5	10,024.6	86.7%
		1,500,000	4000	52%	9.84	3.33	0.39	0.13	3.85	15,409.8	13.84	7.33	0.13	(0.27)	7.19	28,774.7	13,364.8	86.7%
GSd	**South Glengarry**	15,000	60	35%	17.41	2.37	1.18	0.94	4.49	286.8	24.34	7.75	0.94	(0.22)	8.47	532.7	245.9	85.7%
		43,164	133	45%	17.41	2.37	1.18	0.94	4.49	614.6	24.34	7.75	0.94	(0.22)	8.47	1,151.2	536.6	87.3%
		100,000	500	28%	17.41	2.37	1.18	0.94	4.49	2,262.4	24.34	7.75	0.94	(0.22)	8.47	4,260.7	1,998.3	88.3%
		400,000	1000	56%	17.41	2.37	1.18	0.94	4.49	4,507.4	24.34	7.75	0.94	(0.22)	8.47	8,497.0	3,989.6	88.5%
		1,000,000	3000	46%	17.41	2.37	1.18	0.94	4.49	13,487.4	24.34	7.75	0.94	(0.22)	8.47	25,442.4	11,955.0	88.6%
		1,500,000	4000	52%	17.41	2.37	1.18	0.94	4.49	17,977.4	24.34	7.75	0.94	(0.22)	8.47	33,915.1	15,937.7	88.7%

New Rate Class: GSd

Bill Impacts of Proposed Distribution Rates include Riders

Classes		Scenario			Existing Dx Rates						New Dx Rates						$ Incr	% Incr
					SrChg [$/month]	base [$/kW]	Rider1 [$/kW]	Rider2 [$/kW]	VarChg [$/kW]	[$/month]	SrChg [$/month]	base [$/kW]	Rider2 [$/kW]	Rider3 [$/kW]	VarChg [$/kW]	[$/month]		
New Class	**Old Class**	kWh	kW	LF														
GSd	**South River**	15,000	60	35%	22.11	4.87	1.22	0.92	7.01	442.7	28.16	9.22	0.92	(0.22)	9.93	623.7	181.0	40.9%
		43,164	133	45%	22.11	4.87	1.22	0.92	7.01	954.4	28.16	9.22	0.92	(0.22)	9.93	1,348.4	393.9	41.3%
		100,000	500	28%	22.11	4.87	1.22	0.92	7.01	3,527.1	28.16	9.22	0.92	(0.22)	9.93	4,991.3	1,464.2	41.5%
		400,000	1000	56%	22.11	4.87	1.22	0.92	7.01	7,032.1	28.16	9.22	0.92	(0.22)	9.93	9,954.4	2,922.3	41.6%
		1,000,000	3000	46%	22.11	4.87	1.22	0.92	7.01	21,052.1	28.16	9.22	0.92	(0.22)	9.93	29,807.0	8,754.9	41.6%
		1,500,000	4000	52%	22.11	4.87	1.22	0.92	7.01	28,062.1	28.16	9.22	0.92	(0.22)	9.93	39,733.3	11,671.2	41.6%
GSd	**Springwater**	15,000	60	35%	20.53	3.42	0.85	0.53	4.80	308.5	26.56	8.60	0.53	(0.22)	8.91	561.3	252.8	81.9%
		43,164	133	45%	20.53	3.42	0.85	0.53	4.80	658.9	26.56	8.60	0.53	(0.22)	8.91	1,211.9	553.0	83.9%
		100,000	500	28%	20.53	3.42	0.85	0.53	4.80	2,420.5	26.56	8.60	0.53	(0.22)	8.91	4,482.9	2,062.4	85.2%
		400,000	1000	56%	20.53	3.42	0.85	0.53	4.80	4,820.5	26.56	8.60	0.53	(0.22)	8.91	8,939.3	4,118.7	85.4%
		1,000,000	3000	46%	20.53	3.42	0.85	0.53	4.80	14,420.5	26.56	8.60	0.53	(0.22)	8.91	26,764.7	12,344.1	85.6%
		1,500,000	4000	52%	20.53	3.42	0.85	0.53	4.80	19,220.5	26.56	8.60	0.53	(0.22)	8.91	35,677.4	16,456.8	85.6%
GSd	**Stirling-Rawdon**	15,000	60	35%	24.12	4.11	0.67	0.30	5.08	328.9	29.66	9.22	0.30	(0.22)	9.31	588.0	259.1	78.8%
		43,164	133	45%	24.12	4.11	0.67	0.30	5.08	699.8	29.66	9.22	0.30	(0.22)	9.31	1,267.4	567.6	81.1%
		100,000	500	28%	24.12	4.11	0.67	0.30	5.08	2,564.1	29.66	9.22	0.30	(0.22)	9.31	4,682.8	2,118.7	82.6%
		400,000	1000	56%	24.12	4.11	0.67	0.30	5.08	5,104.1	29.66	9.22	0.30	(0.22)	9.31	9,335.9	4,231.8	82.9%
		1,000,000	3000	46%	24.12	4.11	0.67	0.30	5.08	15,264.1	29.66	9.22	0.30	(0.22)	9.31	27,948.5	12,684.4	83.1%
		1,500,000	4000	52%	24.12	4.11	0.67	0.30	5.08	20,344.1	29.66	9.22	0.30	(0.22)	9.31	37,254.8	16,910.7	83.1%
GSd	**Thedford**	15,000	60	35%	17.83	3.38	1.14	1.00	5.52	349.0	24.23	8.95	1.00	(0.22)	9.73	608.2	259.2	74.3%
		43,164	133	45%	17.83	3.38	1.14	1.00	5.52	752.0	24.23	8.95	1.00	(0.22)	9.73	1,318.7	566.7	75.4%
		100,000	500	28%	17.83	3.38	1.14	1.00	5.52	2,777.8	24.23	8.95	1.00	(0.22)	9.73	4,890.6	2,112.8	76.1%
		400,000	1000	56%	17.83	3.38	1.14	1.00	5.52	5,537.8	24.23	8.95	1.00	(0.22)	9.73	9,756.9	4,219.1	76.2%
		1,000,000	3000	46%	17.83	3.38	1.14	1.00	5.52	16,577.8	24.23	8.95	1.00	(0.22)	9.73	29,222.3	12,644.5	76.3%
		1,500,000	4000	52%	17.83	3.38	1.14	1.00	5.52	22,097.8	24.23	8.95	1.00	(0.22)	9.73	38,955.0	16,857.2	76.3%
GSd	**Thessalon**	15,000	60	35%	18.90	3.22	0.21	0.17	3.60	234.9	24.96	7.60	0.17	(0.22)	7.55	478.1	243.2	103.5%
		43,164	133	45%	18.90	3.22	0.21	0.17	3.60	497.7	24.96	7.60	0.17	(0.22)	7.55	1,029.5	531.8	106.8%
		100,000	500	28%	18.90	3.22	0.21	0.17	3.60	1,818.9	24.96	7.60	0.17	(0.22)	7.55	3,801.3	1,982.4	109.0%
		400,000	1000	56%	18.90	3.22	0.21	0.17	3.60	3,618.9	24.96	7.60	0.17	(0.22)	7.55	7,577.7	3,958.8	109.4%
		1,000,000	3000	46%	18.90	3.22	0.21	0.17	3.60	10,818.9	24.96	7.60	0.17	(0.22)	7.55	22,683.1	11,864.2	109.7%
		1,500,000	4000	52%	18.90	3.22	0.21	0.17	3.60	14,418.9	24.96	7.60	0.17	(0.22)	7.55	30,235.8	15,816.9	109.7%

New Rate Class: GSd

Bill Impacts of Proposed Distribution Rates include Riders

Classes		Scenario			Existing Dx Rates						New Dx Rates						$ Incr	% Incr
					SrChg [$/month]	base [$/kW]	Rider1 [$/kW]	Rider2 [$/kW]	VarChg [$/kW]	[$/month]	SrChg [$/month]	base [$/kW]	Rider2 [$/kW]	Rider3 [$/kW]	VarChg [$/kW]	[$/month]		
New Class	**Old Class**	kWh	kW	LF														
GSd	**Thorndale**	15,000	60	35%	14.52	3.25	1.67	1.03	5.95	371.5	22.06	9.22	1.03	(0.22)	10.04	624.2	252.7	68.0%
		43,164	133	45%	14.52	3.25	1.67	1.03	5.95	805.9	22.06	9.22	1.03	(0.22)	10.04	1,356.9	551.0	68.4%
		100,000	500	28%	14.52	3.25	1.67	1.03	5.95	2,989.5	22.06	9.22	1.03	(0.22)	10.04	5,040.2	2,050.7	68.6%
		400,000	1000	56%	14.52	3.25	1.67	1.03	5.95	5,964.5	22.06	9.22	1.03	(0.22)	10.04	10,058.3	4,093.8	68.6%
		1,000,000	3000	46%	14.52	3.25	1.67	1.03	5.95	17,864.5	22.06	9.22	1.03	(0.22)	10.04	30,130.9	12,266.4	68.7%
		1,500,000	4000	52%	14.52	3.25	1.67	1.03	5.95	23,814.5	22.06	9.22	1.03	(0.22)	10.04	40,167.2	16,352.7	68.7%
UGd	**Thorold**	15,000	60	35%	22.63	4.76	0.46	0.20	5.42	347.8	23.64	7.33	0.20	(0.27)	7.26	459.3	111.4	32.0%
		43,164	133	45%	22.63	4.76	0.46	0.20	5.42	743.5	23.64	7.33	0.20	(0.27)	7.26	989.2	245.8	33.1%
		100,000	500	28%	22.63	4.76	0.46	0.20	5.42	2,732.6	23.64	7.33	0.20	(0.27)	7.26	3,653.7	921.1	33.7%
		400,000	1000	56%	22.63	4.76	0.46	0.20	5.42	5,442.6	23.64	7.33	0.20	(0.27)	7.26	7,283.8	1,841.2	33.8%
		1,000,000	3000	46%	22.63	4.76	0.46	0.20	5.42	16,282.6	23.64	7.33	0.20	(0.27)	7.26	21,804.3	5,521.6	33.9%
		1,500,000	4000	52%	22.63	4.76	0.46	0.20	5.42	21,702.6	23.64	7.33	0.20	(0.27)	7.26	29,064.5	7,361.8	33.9%
GSd	**Tweed**	15,000	60	35%	8.26	3.11	1.35	0.99	5.45	335.3	17.62	8.80	0.99	(0.22)	9.57	592.0	256.7	76.6%
		43,164	133	45%	8.26	3.11	1.35	0.99	5.45	733.1	17.62	8.80	0.99	(0.22)	9.57	1,290.8	557.7	76.1%
		100,000	500	28%	8.26	3.11	1.35	0.99	5.45	2,733.3	17.62	8.80	0.99	(0.22)	9.57	4,804.0	2,070.7	75.8%
		400,000	1000	56%	8.26	3.11	1.35	0.99	5.45	5,458.3	17.62	8.80	0.99	(0.22)	9.57	9,590.3	4,132.1	75.7%
		1,000,000	3000	46%	8.26	3.11	1.35	0.99	5.45	16,358.3	17.62	8.80	0.99	(0.22)	9.57	28,735.7	12,377.5	75.7%
		1,500,000	4000	52%	8.26	3.11	1.35	0.99	5.45	21,808.3	17.62	8.80	0.99	(0.22)	9.57	38,308.4	16,500.2	75.7%
GSd	**Wardsville**	15,000	60	35%	12.32	3.16	0.81	0.26	4.23	266.1	20.61	8.20	0.26	(0.22)	8.24	515.2	249.0	93.6%
		43,164	133	45%	12.32	3.16	0.81	0.26	4.23	574.9	20.61	8.20	0.26	(0.22)	8.24	1,116.9	542.0	94.3%
		100,000	500	28%	12.32	3.16	0.81	0.26	4.23	2,127.3	20.61	8.20	0.26	(0.22)	8.24	4,142.0	2,014.6	94.7%
		400,000	1000	56%	12.32	3.16	0.81	0.26	4.23	4,242.3	20.61	8.20	0.26	(0.22)	8.24	8,263.3	4,021.0	94.8%
		1,000,000	3000	46%	12.32	3.16	0.81	0.26	4.23	12,702.3	20.61	8.20	0.26	(0.22)	8.24	24,748.7	12,046.4	94.8%
		1,500,000	4000	52%	12.32	3.16	0.81	0.26	4.23	16,932.3	20.61	8.20	0.26	(0.22)	8.24	32,991.4	16,059.1	94.8%
GSd	**Warkworth**	15,000	60	35%	21.31	4.47	1.44	1.03	6.94	437.7	27.36	9.22	1.03	(0.22)	10.04	629.5	191.8	43.8%
		43,164	133	45%	21.31	4.47	1.44	1.03	6.94	944.3	27.36	9.22	1.03	(0.22)	10.04	1,362.2	417.9	44.2%
		100,000	500	28%	21.31	4.47	1.44	1.03	6.94	3,491.3	27.36	9.22	1.03	(0.22)	10.04	5,045.5	1,554.2	44.5%
		400,000	1000	56%	21.31	4.47	1.44	1.03	6.94	6,961.3	27.36	9.22	1.03	(0.22)	10.04	10,063.6	3,102.3	44.6%
		1,000,000	3000	46%	21.31	4.47	1.44	1.03	6.94	20,841.3	27.36	9.22	1.03	(0.22)	10.04	30,136.2	9,294.9	44.6%
		1,500,000	4000	52%	21.31	4.47	1.44	1.03	6.94	27,781.3	27.36	9.22	1.03	(0.22)	10.04	40,172.5	12,391.2	44.6%

New Rate Class: GSd

Bill Impacts of Proposed Distribution Rates include Riders

Classes		Scenario			Existing Dx Rates						New Dx Rates						$ Incr	% Incr
New Class	Old Class	kWh	kW	LF	SrChg [$/month]	base [$/kW]	Rider1 [$/kW]	Rider2 [$/kW]	VarChg [$/kW]	[$/month]	SrChg [$/month]	base [$/kW]	Rider2 [$/kW]	Rider3 [$/kW]	VarChg [$/kW]	[$/month]		
GSd	**West Elgin**	15,000	60	35%	15.40	2.21	0.54	0.21	2.96	193.0	22.84	6.85	0.21	(0.22)	6.84	433.4	240.4	124.6%
		43,164	133	45%	15.40	2.21	0.54	0.21	2.96	409.1	22.84	6.85	0.21	(0.22)	6.84	932.9	523.8	128.1%
		100,000	500	28%	15.40	2.21	0.54	0.21	2.96	1,495.4	22.84	6.85	0.21	(0.22)	6.84	3,444.2	1,948.8	130.3%
		400,000	1000	56%	15.40	2.21	0.54	0.21	2.96	2,975.4	22.84	6.85	0.21	(0.22)	6.84	6,865.5	3,890.1	130.7%
		1,000,000	3000	46%	15.40	2.21	0.54	0.21	2.96	8,895.4	22.84	6.85	0.21	(0.22)	6.84	20,550.9	11,655.5	131.0%
		1,500,000	4000	52%	15.40	2.21	0.54	0.21	2.96	11,855.4	22.84	6.85	0.21	(0.22)	6.84	27,393.7	15,538.3	131.1%
UGd	**Whitchurch Stouffville**	15,000	60	35%	21.85	2.93	0.35	0.13	3.41	226.5	22.84	7.15	0.13	(0.27)	7.01	443.3	216.8	95.7%
		43,164	133	45%	21.85	2.93	0.35	0.13	3.41	475.4	22.84	7.15	0.13	(0.27)	7.01	954.8	479.4	100.8%
		100,000	500	28%	21.85	2.93	0.35	0.13	3.41	1,726.9	22.84	7.15	0.13	(0.27)	7.01	3,526.4	1,799.5	104.2%
		400,000	1000	56%	21.85	2.93	0.35	0.13	3.41	3,431.9	22.84	7.15	0.13	(0.27)	7.01	7,030.0	3,598.1	104.8%
		1,000,000	3000	46%	21.85	2.93	0.35	0.13	3.41	10,251.9	22.84	7.15	0.13	(0.27)	7.01	21,044.2	10,792.4	105.3%
		1,500,000	4000	52%	21.85	2.93	0.35	0.13	3.41	13,661.9	22.84	7.15	0.13	(0.27)	7.01	28,051.3	14,389.5	105.3%
GSd	**Wiarton**	15,000	60	35%	23.78	5.99	0.59	0.29	6.87	436.0	28.74	9.22	0.29	(0.22)	9.30	586.5	150.5	34.5%
		43,164	133	45%	23.78	5.99	0.59	0.29	6.87	937.5	28.74	9.22	0.29	(0.22)	9.30	1,265.1	327.7	35.0%
		100,000	500	28%	23.78	5.99	0.59	0.29	6.87	3,458.8	28.74	9.22	0.29	(0.22)	9.30	4,676.9	1,218.1	35.2%
		400,000	1000	56%	23.78	5.99	0.59	0.29	6.87	6,893.8	28.74	9.22	0.29	(0.22)	9.30	9,325.0	2,431.2	35.3%
		1,000,000	3000	46%	23.78	5.99	0.59	0.29	6.87	20,633.8	28.74	9.22	0.29	(0.22)	9.30	27,917.6	7,283.8	35.3%
		1,500,000	4000	52%	23.78	5.99	0.59	0.29	6.87	27,503.8	28.74	9.22	0.29	(0.22)	9.30	37,213.9	9,710.1	35.3%
GSd	**Woodville**	15,000	60	35%	16.89	4.34	2.12	1.35	7.81	485.5	23.47	9.22	1.35	(0.22)	10.36	644.8	159.4	32.8%
		43,164	133	45%	16.89	4.34	2.12	1.35	7.81	1,055.6	23.47	9.22	1.35	(0.22)	10.36	1,400.9	345.2	32.7%
		100,000	500	28%	16.89	4.34	2.12	1.35	7.81	3,921.9	23.47	9.22	1.35	(0.22)	10.36	5,201.6	1,279.7	32.6%
		400,000	1000	56%	16.89	4.34	2.12	1.35	7.81	7,826.9	23.47	9.22	1.35	(0.22)	10.36	10,379.7	2,552.9	32.6%
		1,000,000	3000	46%	16.89	4.34	2.12	1.35	7.81	23,446.9	23.47	9.22	1.35	(0.22)	10.36	31,092.3	7,645.4	32.6%
		1,500,000	4000	52%	16.89	4.34	2.12	1.35	7.81	31,256.9	23.47	9.22	1.35	(0.22)	10.36	41,448.6	10,191.7	32.6%
GSd	**Wyoming**	15,000	60	35%	17.36	4.57	0.52	0.23	5.32	336.6	24.35	9.22	0.23	(0.22)	9.24	578.5	242.0	71.9%
		43,164	133	45%	17.36	4.57	0.52	0.23	5.32	724.9	24.35	9.22	0.23	(0.22)	9.24	1,252.8	527.9	72.8%
		100,000	500	28%	17.36	4.57	0.52	0.23	5.32	2,677.4	24.35	9.22	0.23	(0.22)	9.24	4,642.5	1,965.1	73.4%
		400,000	1000	56%	17.36	4.57	0.52	0.23	5.32	5,337.4	24.35	9.22	0.23	(0.22)	9.24	9,260.6	3,923.3	73.5%
		1,000,000	3000	46%	17.36	4.57	0.52	0.23	5.32	15,977.4	24.35	9.22	0.23	(0.22)	9.24	27,733.2	11,755.8	73.6%
		1,500,000	4000	52%	17.36	4.57	0.52	0.23	5.32	21,297.4	24.35	9.22	0.23	(0.22)	9.24	36,969.5	15,672.1	73.6%

New Rate Class: GSd

Bill Impacts of Proposed Distribution Rates include Riders

Classes		Scenario			Existing Dx Rates						New Dx Rates						$ Incr	% Incr
New Class	Old Class	kWh	kW	LF	SrChg [$/month]	base [$/kW]	Rider1 [$/kW]	Rider2 [$/kW]	VarChg [$/kW]	[$/month]	SrChg [$/month]	base [$/kW]	Rider2 [$/kW]	Rider3 [$/kW]	VarChg [$/kW]	[$/month]		
GSd	Terrace Bay	15,000	60	35%	293.24	4.00	2.27	-	6.27	669.7	231.38	9.22	-	(0.22)	9.01	771.8	102.0	15.2%
		43,164	133	45%	293.24	4.00	2.27	-	6.27	1,127.8	231.38	9.22	-	(0.22)	9.01	1,429.2	301.5	26.7%
		100,000	500	28%	293.24	4.00	2.27	-	6.27	3,430.5	231.38	9.22	-	(0.22)	9.01	4,734.5	1,304.0	38.0%
		400,000	1000	56%	293.24	4.00	2.27	-	6.27	6,567.8	231.38	9.22	-	(0.22)	9.01	9,237.7	2,669.8	40.6%
		1,000,000	3000	46%	293.24	4.00	2.27	-	6.27	19,117.0	231.38	9.22	-	(0.22)	9.01	27,250.2	8,133.2	42.5%
		1,500,000	4000	52%	293.24	4.00	2.27	-	6.27	25,391.6	231.38	9.22	-	(0.22)	9.01	36,256.5	10,864.9	42.8%

New Rate Class: Gse - Unmetered

Bill Impacts of Proposed Distribution Rates include Riders

Classes		Scenario	Existing Dx Rates						New Dx Rates						$ Incr	% Incr
			SrChg	base	Rider1	Rider2	VarChg	[$/month]	SrChg	base	Rider2	Rider3	VarChg	[$/month]		
New Class	Old Class	kWh	[$/month]	[c/kWh]	[c/kWh]	[c/kWh]	[c/kWh]		[$/month]	[c/kWh]	[c/kWh]	[c/kWh]	[c/kWh]			
GSe	G1	100	22.16	3.12	0.09	0.09	3.30	25.46	22.84	5.38	0.09	(0.06)	5.41	28.25	2.79	11.0%
		250	22.16	3.12	0.09	0.09	3.30	30.41	22.84	5.38	0.09	(0.06)	5.41	36.37	5.96	19.6%
		500	22.16	3.12	0.09	0.09	3.30	38.66	22.84	5.38	0.09	(0.06)	5.41	49.90	11.24	29.1%
		750	22.16	3.12	0.09	0.09	3.30	46.91	22.84	5.38	0.09	(0.06)	5.41	63.43	16.52	35.2%
		1,000	22.16	3.12	0.09	0.09	3.30	55.16	22.84	5.38	0.09	(0.06)	5.41	76.96	21.80	39.5%
GSe	G3	100	6.29	3.07	0.02	0.05	3.14	9.43	10.81	3.60	0.05	(0.06)	3.59	14.40	4.97	52.7%
		250	6.29	3.07	0.02	0.05	3.14	14.14	10.81	3.60	0.05	(0.06)	3.59	19.79	5.65	39.9%
		500	6.29	3.07	0.02	0.05	3.14	21.99	10.81	3.60	0.05	(0.06)	3.59	28.77	6.78	30.8%
		750	6.29	3.07	0.02	0.05	3.14	29.84	10.81	3.60	0.05	(0.06)	3.59	37.75	7.91	26.5%
		1,000	6.29	3.07	0.02	0.05	3.14	37.69	10.81	3.60	0.05	(0.06)	3.59	46.74	9.05	24.0%
GSe	UG	100	0.79	2.74	0.03	0.03	2.80	3.59	6.18	3.50	0.03	(0.06)	3.47	9.65	6.06	168.9%
		250	0.79	2.74	0.03	0.03	2.80	7.79	6.18	3.50	0.03	(0.06)	3.47	14.86	7.07	90.8%
		500	0.79	2.74	0.03	0.03	2.80	14.79	6.18	3.50	0.03	(0.06)	3.47	23.55	8.76	59.2%
		750	0.79	2.74	0.03	0.03	2.80	21.79	6.18	3.50	0.03	(0.06)	3.47	32.23	10.44	47.9%
		1,000	0.79	2.74	0.03	0.03	2.80	28.79	6.18	3.50	0.03	(0.06)	3.47	40.91	12.12	42.1%
GSe	Ailsa Craig	100	8.20	1.32	0.17	0.09	1.58	9.78	12.33	2.00	0.09	(0.06)	2.03	14.36	4.58	46.8%
		250	8.20	1.32	0.17	0.09	1.58	12.15	12.33	2.00	0.09	(0.06)	2.03	17.41	5.26	43.3%
		500	8.20	1.32	0.17	0.09	1.58	16.10	12.33	2.00	0.09	(0.06)	2.03	22.49	6.39	39.7%
		750	8.20	1.32	0.17	0.09	1.58	20.05	12.33	2.00	0.09	(0.06)	2.03	27.58	7.53	37.5%
		1,000	8.20	1.32	0.17	0.09	1.58	24.00	12.33	2.00	0.09	(0.06)	2.03	32.66	8.66	36.1%
GSe	Arkona	100	1.14	0.86	0.51	0.36	1.73	2.87	7.09	2.00	0.36	(0.06)	2.30	9.40	6.53	227.4%
		250	1.14	0.86	0.51	0.36	1.73	5.47	7.09	2.00	0.36	(0.06)	2.30	12.85	7.39	135.1%
		500	1.14	0.86	0.51	0.36	1.73	9.79	7.09	2.00	0.36	(0.06)	2.30	18.61	8.82	90.1%
		750	1.14	0.86	0.51	0.36	1.73	14.12	7.09	2.00	0.36	(0.06)	2.30	24.37	10.25	72.6%
		1,000	1.14	0.86	0.51	0.36	1.73	18.44	7.09	2.00	0.36	(0.06)	2.30	30.13	11.69	63.4%

New Rate Class: Gse - Unmetered

Bill Impacts of Proposed Distribution Rates include Riders

Classes		Scenario	Existing Dx Rates						New Dx Rates						$ Incr	% Incr
			SrChg	base	Rider1	Rider2	VarChg	[$/month]	SrChg	base	Rider2	Rider3	VarChg	[$/month]		
New Class	Old Class	kWh	[$/month]	[c/kWh]	[c/kWh]	[c/kWh]	[c/kWh]		[$/month]	[c/kWh]	[c/kWh]	[c/kWh]	[c/kWh]			
GSe	Arnprior	100	10.23	1.17	0.16	0.06	1.39	11.62	13.82	2.00	0.06	(0.06)	2.00	15.82	4.20	36.2%
		250	10.23	1.17	0.16	0.06	1.39	13.71	13.82	2.00	0.06	(0.06)	2.00	18.83	5.12	37.4%
		500	10.23	1.17	0.16	0.06	1.39	17.18	13.82	2.00	0.06	(0.06)	2.00	23.84	6.66	38.7%
		750	10.23	1.17	0.16	0.06	1.39	20.66	13.82	2.00	0.06	(0.06)	2.00	28.84	8.19	39.6%
		1,000	10.23	1.17	0.16	0.06	1.39	24.13	13.82	2.00	0.06	(0.06)	2.00	33.85	9.72	40.3%
GSe	Arran-Elderslie	100	3.95	1.03	0.17	0.09	1.29	5.24	8.39	2.00	0.09	(0.06)	2.03	10.42	5.18	98.9%
		250	3.95	1.03	0.17	0.09	1.29	7.18	8.39	2.00	0.09	(0.06)	2.03	13.47	6.30	87.8%
		500	3.95	1.03	0.17	0.09	1.29	10.40	8.39	2.00	0.09	(0.06)	2.03	18.56	8.16	78.4%
		750	3.95	1.03	0.17	0.09	1.29	13.63	8.39	2.00	0.09	(0.06)	2.03	23.64	10.01	73.5%
		1,000	3.95	1.03	0.17	0.09	1.29	16.85	8.39	2.00	0.09	(0.06)	2.03	28.72	11.87	70.5%
GSe	Artemesia	100	9.34	1.74	0.49	0.34	2.57	11.91	13.04	2.00	0.34	(0.06)	2.28	15.33	3.42	28.7%
		250	9.34	1.74	0.49	0.34	2.57	15.77	13.04	2.00	0.34	(0.06)	2.28	18.75	2.99	18.9%
		500	9.34	1.74	0.49	0.34	2.57	22.19	13.04	2.00	0.34	(0.06)	2.28	24.46	2.27	10.2%
		750	9.34	1.74	0.49	0.34	2.57	28.62	13.04	2.00	0.34	(0.06)	2.28	30.17	1.55	5.4%
		1,000	9.34	1.74	0.49	0.34	2.57	35.04	13.04	2.00	0.34	(0.06)	2.28	35.88	0.84	2.4%
GSe	Bancroft	100	11.73	1.18	0.17	0.08	1.43	13.16	14.45	2.00	0.08	(0.06)	2.02	16.47	3.31	25.1%
		250	11.73	1.18	0.17	0.08	1.43	15.31	14.45	2.00	0.08	(0.06)	2.02	19.50	4.20	27.4%
		500	11.73	1.18	0.17	0.08	1.43	18.88	14.45	2.00	0.08	(0.06)	2.02	24.56	5.68	30.1%
		750	11.73	1.18	0.17	0.08	1.43	22.46	14.45	2.00	0.08	(0.06)	2.02	29.62	7.16	31.9%
		1,000	11.73	1.18	0.17	0.08	1.43	26.03	14.45	2.00	0.08	(0.06)	2.02	34.68	8.65	33.2%
GSe	Bath	100	4.86	1.47	0.29	0.24	2.00	6.86	9.16	2.00	0.24	(0.06)	2.18	11.35	4.49	65.4%
		250	4.86	1.47	0.29	0.24	2.00	9.86	9.16	2.00	0.24	(0.06)	2.18	14.62	4.76	48.3%
		500	4.86	1.47	0.29	0.24	2.00	14.86	9.16	2.00	0.24	(0.06)	2.18	20.08	5.22	35.1%
		750	4.86	1.47	0.29	0.24	2.00	19.86	9.16	2.00	0.24	(0.06)	2.18	25.54	5.68	28.6%
		1,000	4.86	1.47	0.29	0.24	2.00	24.86	9.16	2.00	0.24	(0.06)	2.18	31.00	6.14	24.7%

New Rate Class: Gse - Unmetered

Bill Impacts of Proposed Distribution Rates include Riders

Classes		Scenario	Existing Dx Rates						New Dx Rates						$ Incr	% Incr
			SrChg	base	Rider1	Rider2	VarChg	[$/month]	SrChg	base	Rider2	Rider3	VarChg	[$/month]		
New Class	Old Class	kWh	[$/month]	[c/kWh]	[c/kWh]	[c/kWh]	[c/kWh]		[$/month]	[c/kWh]	[c/kWh]	[c/kWh]	[c/kWh]			
GSe	Blandford-Blenheim	100	11.46	1.14	0.28	0.20	1.62	13.08	14.51	2.00	0.20	(0.06)	2.14	16.66	3.58	27.3%
		250	11.46	1.14	0.28	0.20	1.62	15.51	14.51	2.00	0.20	(0.06)	2.14	19.87	4.36	28.1%
		500	11.46	1.14	0.28	0.20	1.62	19.56	14.51	2.00	0.20	(0.06)	2.14	25.23	5.67	29.0%
		750	11.46	1.14	0.28	0.20	1.62	23.61	14.51	2.00	0.20	(0.06)	2.14	30.59	6.98	29.6%
		1,000	11.46	1.14	0.28	0.20	1.62	27.66	14.51	2.00	0.20	(0.06)	2.14	35.95	8.29	30.0%
GSe	Blyth	100	10.35	1.05	0.26	0.20	1.51	11.86	13.79	2.00	0.20	(0.06)	2.14	15.93	4.07	34.3%
		250	10.35	1.05	0.26	0.20	1.51	14.13	13.79	2.00	0.20	(0.06)	2.14	19.15	5.02	35.6%
		500	10.35	1.05	0.26	0.20	1.51	17.90	13.79	2.00	0.20	(0.06)	2.14	24.51	6.61	36.9%
		750	10.35	1.05	0.26	0.20	1.51	21.68	13.79	2.00	0.20	(0.06)	2.14	29.86	8.19	37.8%
		1,000	10.35	1.05	0.26	0.20	1.51	25.45	13.79	2.00	0.20	(0.06)	2.14	35.22	9.77	38.4%
GSe	Bobcaygeon	100	11.14	1.38	0.18	0.09	1.65	12.79	14.59	2.00	0.09	(0.06)	2.03	16.63	3.84	30.0%
		250	11.14	1.38	0.18	0.09	1.65	15.27	14.59	2.00	0.09	(0.06)	2.03	19.68	4.41	28.9%
		500	11.14	1.38	0.18	0.09	1.65	19.39	14.59	2.00	0.09	(0.06)	2.03	24.76	5.37	27.7%
		750	11.14	1.38	0.18	0.09	1.65	23.52	14.59	2.00	0.09	(0.06)	2.03	29.84	6.33	26.9%
		1,000	11.14	1.38	0.18	0.09	1.65	27.64	14.59	2.00	0.09	(0.06)	2.03	34.93	7.29	26.4%
GSe	Brighton	100	10.99	1.35	0.20	0.08	1.63	12.62	13.63	2.00	0.08	(0.06)	2.02	15.65	3.03	24.0%
		250	10.99	1.35	0.20	0.08	1.63	15.07	13.63	2.00	0.08	(0.06)	2.02	18.69	3.62	24.1%
		500	10.99	1.35	0.20	0.08	1.63	19.14	13.63	2.00	0.08	(0.06)	2.02	23.75	4.61	24.1%
		750	10.99	1.35	0.20	0.08	1.63	23.22	13.63	2.00	0.08	(0.06)	2.02	28.80	5.59	24.1%
		1,000	10.99	1.35	0.20	0.08	1.63	27.29	13.63	2.00	0.08	(0.06)	2.02	33.86	6.57	24.1%
GSe	Brockville	100	10.37	0.78	0.13	0.04	0.95	11.32	13.79	2.00	0.04	(0.06)	1.98	15.77	4.45	39.3%
		250	10.37	0.78	0.13	0.04	0.95	12.75	13.79	2.00	0.04	(0.06)	1.98	18.74	6.00	47.1%
		500	10.37	0.78	0.13	0.04	0.95	15.12	13.79	2.00	0.04	(0.06)	1.98	23.70	8.58	56.8%
		750	10.37	0.78	0.13	0.04	0.95	17.50	13.79	2.00	0.04	(0.06)	1.98	28.66	11.16	63.8%
		1,000	10.37	0.78	0.13	0.04	0.95	19.87	13.79	2.00	0.04	(0.06)	1.98	33.62	13.75	69.2%

New Rate Class: Gse - Unmetered

Bill Impacts of Proposed Distribution Rates include Riders

Classes		Scenario	Existing Dx Rates						New Dx Rates						$ Incr	% Incr
			SrChg	base	Rider1	Rider2	VarChg	[$/month]	SrChg	base	Rider2	Rider3	VarChg	[$/month]		
New Class	Old Class	kWh	[$/month]	[c/kWh]	[c/kWh]	[c/kWh]	[c/kWh]		[$/month]	[c/kWh]	[c/kWh]	[c/kWh]	[c/kWh]			
GSe	**Caledon CH**	100	11.63	1.80	0.14	0.08	2.02	13.65	14.47	2.00	0.08	(0.06)	2.02	16.49	2.84	20.8%
		250	11.63	1.80	0.14	0.08	2.02	16.68	14.47	2.00	0.08	(0.06)	2.02	19.53	2.85	17.1%
		500	11.63	1.80	0.14	0.08	2.02	21.73	14.47	2.00	0.08	(0.06)	2.02	24.59	2.86	13.1%
		750	11.63	1.80	0.14	0.08	2.02	26.78	14.47	2.00	0.08	(0.06)	2.02	29.64	2.86	10.7%
		1,000	11.63	1.80	0.14	0.08	2.02	31.83	14.47	2.00	0.08	(0.06)	2.02	34.70	2.87	9.0%
GSe	**Campbellford-Seymour**	100	7.63	1.19	0.17	0.05	1.41	9.04	11.47	2.00	0.05	(0.06)	1.99	13.46	4.42	48.9%
		250	7.63	1.19	0.17	0.05	1.41	11.16	11.47	2.00	0.05	(0.06)	1.99	16.45	5.30	47.5%
		500	7.63	1.19	0.17	0.05	1.41	14.68	11.47	2.00	0.05	(0.06)	1.99	21.44	6.76	46.0%
		750	7.63	1.19	0.17	0.05	1.41	18.21	11.47	2.00	0.05	(0.06)	1.99	26.42	8.21	45.1%
		1,000	7.63	1.19	0.17	0.05	1.41	21.73	11.47	2.00	0.05	(0.06)	1.99	31.40	9.67	44.5%
GSe	**Carleton Place**	100	11.36	1.68	0.13	0.07	1.88	13.24	14.54	2.00	0.07	(0.06)	2.01	16.55	3.31	25.0%
		250	11.36	1.68	0.13	0.07	1.88	16.06	14.54	2.00	0.07	(0.06)	2.01	19.57	3.51	21.9%
		500	11.36	1.68	0.13	0.07	1.88	20.76	14.54	2.00	0.07	(0.06)	2.01	24.60	3.84	18.5%
		750	11.36	1.68	0.13	0.07	1.88	25.46	14.54	2.00	0.07	(0.06)	2.01	29.64	4.18	16.4%
		1,000	11.36	1.68	0.13	0.07	1.88	30.16	14.54	2.00	0.07	(0.06)	2.01	34.67	4.51	15.0%
GSe	**Cavan-Millbrook-North Monaghan**	100	10.68	1.50	0.33	0.26	2.09	12.77	13.71	2.00	0.26	(0.06)	2.20	15.91	3.14	24.6%
		250	10.68	1.50	0.33	0.26	2.09	15.91	13.71	2.00	0.26	(0.06)	2.20	19.22	3.31	20.8%
		500	10.68	1.50	0.33	0.26	2.09	21.13	13.71	2.00	0.26	(0.06)	2.20	24.72	3.59	17.0%
		750	10.68	1.50	0.33	0.26	2.09	26.36	13.71	2.00	0.26	(0.06)	2.20	30.23	3.88	14.7%
		1,000	10.68	1.50	0.33	0.26	2.09	31.58	13.71	2.00	0.26	(0.06)	2.20	35.74	4.16	13.2%
GSe	**Centre Hastings**	100	8.73	0.97	0.14	0.06	1.17	9.90	12.20	2.00	0.06	(0.06)	2.00	14.20	4.30	43.4%
		250	8.73	0.97	0.14	0.06	1.17	11.66	12.20	2.00	0.06	(0.06)	2.00	17.20	5.55	47.6%
		500	8.73	0.97	0.14	0.06	1.17	14.58	12.20	2.00	0.06	(0.06)	2.00	22.21	7.63	52.3%
		750	8.73	0.97	0.14	0.06	1.17	17.51	12.20	2.00	0.06	(0.06)	2.00	27.22	9.71	55.5%
		1,000	8.73	0.97	0.14	0.06	1.17	20.43	12.20	2.00	0.06	(0.06)	2.00	32.23	11.80	57.7%

New Rate Class: Gse - Unmetered

Bill Impacts of Proposed Distribution Rates include Riders

Classes		Scenario	Existing Dx Rates						New Dx Rates						$ Incr	% Incr
New Class	Old Class	kWh	SrChg [$/month]	base [c/kWh]	Rider1 [c/kWh]	Rider2 [c/kWh]	VarChg [c/kWh]	[$/month]	SrChg [$/month]	base [c/kWh]	Rider2 [c/kWh]	Rider3 [c/kWh]	VarChg [c/kWh]	[$/month]		
GSe	**Chalk River**	100	10.20	1.79	0.39	0.34	2.52	12.72	13.83	2.00	0.34	(0.06)	2.28	16.11	3.39	26.7%
		250	10.20	1.79	0.39	0.34	2.52	16.50	13.83	2.00	0.34	(0.06)	2.28	19.54	3.04	18.4%
		500	10.20	1.79	0.39	0.34	2.52	22.80	13.83	2.00	0.34	(0.06)	2.28	25.24	2.44	10.7%
		750	10.20	1.79	0.39	0.34	2.52	29.10	13.83	2.00	0.34	(0.06)	2.28	30.95	1.85	6.4%
		1,000	10.20	1.79	0.39	0.34	2.52	35.40	13.83	2.00	0.34	(0.06)	2.28	36.66	1.26	3.6%
GSe	**Champlain**	100	9.83	0.91	0.26	0.15	1.32	11.15	12.92	2.00	0.15	(0.06)	2.09	15.01	3.86	34.7%
		250	9.83	0.91	0.26	0.15	1.32	13.13	12.92	2.00	0.15	(0.06)	2.09	18.15	5.02	38.3%
		500	9.83	0.91	0.26	0.15	1.32	16.43	12.92	2.00	0.15	(0.06)	2.09	23.39	6.96	42.3%
		750	9.83	0.91	0.26	0.15	1.32	19.73	12.92	2.00	0.15	(0.06)	2.09	28.62	8.89	45.1%
		1,000	9.83	0.91	0.26	0.15	1.32	23.03	12.92	2.00	0.15	(0.06)	2.09	33.85	10.82	47.0%
GSe	**Cobden**	100	10.50	2.13	0.36	0.30	2.79	13.29	13.75	2.00	0.30	(0.06)	2.24	16.00	2.71	20.4%
		250	10.50	2.13	0.36	0.30	2.79	17.48	13.75	2.00	0.30	(0.06)	2.24	19.36	1.89	10.8%
		500	10.50	2.13	0.36	0.30	2.79	24.45	13.75	2.00	0.30	(0.06)	2.24	24.97	0.52	2.1%
		750	10.50	2.13	0.36	0.30	2.79	31.43	13.75	2.00	0.30	(0.06)	2.24	30.58	(0.85)	-2.7%
		1,000	10.50	2.13	0.36	0.30	2.79	38.40	13.75	2.00	0.30	(0.06)	2.24	36.19	(2.21)	-5.8%
GSe	**Deep River**	100	11.50	2.26	0.15	0.14	2.55	14.05	14.50	2.00	0.14	(0.06)	2.08	16.59	2.54	18.0%
		250	11.50	2.26	0.15	0.14	2.55	17.88	14.50	2.00	0.14	(0.06)	2.08	19.71	1.84	10.3%
		500	11.50	2.26	0.15	0.14	2.55	24.25	14.50	2.00	0.14	(0.06)	2.08	24.92	0.67	2.8%
		750	11.50	2.26	0.15	0.14	2.55	30.63	14.50	2.00	0.14	(0.06)	2.08	30.13	(0.50)	-1.6%
		1,000	11.50	2.26	0.15	0.14	2.55	37.00	14.50	2.00	0.14	(0.06)	2.08	35.34	(1.66)	-4.5%
GSe	**Deseronto**	100	4.61	1.35	0.13	0.05	1.53	6.14	9.23	2.00	0.05	(0.06)	1.99	11.22	5.08	82.7%
		250	4.61	1.35	0.13	0.05	1.53	8.44	9.23	2.00	0.05	(0.06)	1.99	14.21	5.77	68.4%
		500	4.61	1.35	0.13	0.05	1.53	12.26	9.23	2.00	0.05	(0.06)	1.99	19.19	6.93	56.5%
		750	4.61	1.35	0.13	0.05	1.53	16.09	9.23	2.00	0.05	(0.06)	1.99	24.17	8.09	50.3%
		1,000	4.61	1.35	0.13	0.05	1.53	19.91	9.23	2.00	0.05	(0.06)	1.99	29.16	9.25	46.4%

New Rate Class: Gse - Unmetered

Bill Impacts of Proposed Distribution Rates include Riders

Classes		Scenario	Existing Dx Rates						New Dx Rates						$ Incr	% Incr
			SrChg	base	Rider1	Rider2	VarChg	[$/month]	SrChg	base	Rider2	Rider3	VarChg	[$/month]		
New Class	Old Class	kWh	[$/month]	[c/kWh]	[c/kWh]	[c/kWh]	[c/kWh]		[$/month]	[c/kWh]	[c/kWh]	[c/kWh]	[c/kWh]			
GSe	**Dryden**	100	9.09	1.03	0.12	0.04	1.19	10.28	13.11	2.00	0.04	(0.06)	1.98	15.09	4.81	46.8%
		250	9.09	1.03	0.12	0.04	1.19	12.07	13.11	2.00	0.04	(0.06)	1.98	18.06	6.00	49.7%
		500	9.09	1.03	0.12	0.04	1.19	15.04	13.11	2.00	0.04	(0.06)	1.98	23.02	7.98	53.1%
		750	9.09	1.03	0.12	0.04	1.19	18.02	13.11	2.00	0.04	(0.06)	1.98	27.98	9.96	55.3%
		1,000	9.09	1.03	0.12	0.04	1.19	20.99	13.11	2.00	0.04	(0.06)	1.98	32.94	11.95	56.9%
GSe	**Dundalk**	100	11.32	1.64	0.23	0.09	1.96	13.28	14.55	2.00	0.09	(0.06)	2.03	16.58	3.30	24.9%
		250	11.32	1.64	0.23	0.09	1.96	16.22	14.55	2.00	0.09	(0.06)	2.03	19.63	3.41	21.0%
		500	11.32	1.64	0.23	0.09	1.96	21.12	14.55	2.00	0.09	(0.06)	2.03	24.71	3.59	17.0%
		750	11.32	1.64	0.23	0.09	1.96	26.02	14.55	2.00	0.09	(0.06)	2.03	29.80	3.78	14.5%
		1,000	11.32	1.64	0.23	0.09	1.96	30.92	14.55	2.00	0.09	(0.06)	2.03	34.88	3.96	12.8%
GSe	**Durham**	100	11.59	1.37	0.15	0.06	1.58	13.17	14.48	2.00	0.06	(0.06)	2.00	16.48	3.31	25.2%
		250	11.59	1.37	0.15	0.06	1.58	15.54	14.48	2.00	0.06	(0.06)	2.00	19.49	3.95	25.4%
		500	11.59	1.37	0.15	0.06	1.58	19.49	14.48	2.00	0.06	(0.06)	2.00	24.50	5.01	25.7%
		750	11.59	1.37	0.15	0.06	1.58	23.44	14.48	2.00	0.06	(0.06)	2.00	29.50	6.06	25.9%
		1,000	11.59	1.37	0.15	0.06	1.58	27.39	14.48	2.00	0.06	(0.06)	2.00	34.51	7.12	26.0%
GSe	**Eganville**	100	10.22	2.32	0.17	0.12	2.61	12.83	13.82	2.00	0.12	(0.06)	2.06	15.89	3.06	23.8%
		250	10.22	2.32	0.17	0.12	2.61	16.75	13.82	2.00	0.12	(0.06)	2.06	18.98	2.24	13.4%
		500	10.22	2.32	0.17	0.12	2.61	23.27	13.82	2.00	0.12	(0.06)	2.06	24.14	0.87	3.7%
		750	10.22	2.32	0.17	0.12	2.61	29.80	13.82	2.00	0.12	(0.06)	2.06	29.30	(0.50)	-1.7%
		1,000	10.22	2.32	0.17	0.12	2.61	36.32	13.82	2.00	0.12	(0.06)	2.06	34.46	(1.86)	-5.1%
GSe	**Erin**	100	19.72	0.73	0.19	0.08	1.00	20.72	20.45	2.00	0.08	(0.06)	2.02	22.47	1.75	8.5%
		250	19.72	0.73	0.19	0.08	1.00	22.22	20.45	2.00	0.08	(0.06)	2.02	25.51	3.29	14.8%
		500	19.72	0.73	0.19	0.08	1.00	24.72	20.45	2.00	0.08	(0.06)	2.02	30.56	5.84	23.6%
		750	19.72	0.73	0.19	0.08	1.00	27.22	20.45	2.00	0.08	(0.06)	2.02	35.62	8.40	30.9%
		1,000	19.72	0.73	0.19	0.08	1.00	29.72	20.45	2.00	0.08	(0.06)	2.02	40.68	10.96	36.9%

New Rate Class: Gse - Unmetered

Bill Impacts of Proposed Distribution Rates include Riders

Classes		Scenario	Existing Dx Rates						New Dx Rates						$ Incr	% Incr
			SrChg	base	Rider1	Rider2	VarChg	[$/month]	SrChg	base	Rider2	Rider3	VarChg	[$/month]		
New Class	Old Class	kWh	[$/month]	[c/kWh]	[c/kWh]	[c/kWh]	[c/kWh]		[$/month]	[c/kWh]	[c/kWh]	[c/kWh]	[c/kWh]			
GSe	**Exeter**	100	5.21	1.30	0.15	0.06	1.51	6.72	10.08	2.00	0.06	(0.06)	2.00	12.08	5.36	79.7%
		250	5.21	1.30	0.15	0.06	1.51	8.99	10.08	2.00	0.06	(0.06)	2.00	15.08	6.10	67.9%
		500	5.21	1.30	0.15	0.06	1.51	12.76	10.08	2.00	0.06	(0.06)	2.00	20.09	7.33	57.5%
		750	5.21	1.30	0.15	0.06	1.51	16.54	10.08	2.00	0.06	(0.06)	2.00	25.10	8.56	51.8%
		1,000	5.21	1.30	0.15	0.06	1.51	20.31	10.08	2.00	0.06	(0.06)	2.00	30.11	9.80	48.2%
GSe	**Fenelon Falls**	100	9.43	0.95	0.15	0.08	1.18	10.61	13.02	2.00	0.08	(0.06)	2.02	15.04	4.43	41.8%
		250	9.43	0.95	0.15	0.08	1.18	12.38	13.02	2.00	0.08	(0.06)	2.02	18.08	5.70	46.0%
		500	9.43	0.95	0.15	0.08	1.18	15.33	13.02	2.00	0.08	(0.06)	2.02	23.14	7.81	50.9%
		750	9.43	0.95	0.15	0.08	1.18	18.28	13.02	2.00	0.08	(0.06)	2.02	28.19	9.91	54.2%
		1,000	9.43	0.95	0.15	0.08	1.18	21.23	13.02	2.00	0.08	(0.06)	2.02	33.25	12.02	56.6%
GSe	**Forest**	100	11.98	1.18	0.16	0.06	1.40	13.38	14.38	2.00	0.06	(0.06)	2.00	16.39	3.01	22.5%
		250	11.98	1.18	0.16	0.06	1.40	15.48	14.38	2.00	0.06	(0.06)	2.00	19.39	3.91	25.3%
		500	11.98	1.18	0.16	0.06	1.40	18.98	14.38	2.00	0.06	(0.06)	2.00	24.40	5.42	28.6%
		750	11.98	1.18	0.16	0.06	1.40	22.48	14.38	2.00	0.06	(0.06)	2.00	29.41	6.93	30.8%
		1,000	11.98	1.18	0.16	0.06	1.40	25.98	14.38	2.00	0.06	(0.06)	2.00	34.42	8.44	32.5%
GSe	**GBE**	100	4.92	1.14	0.16	0.06	1.36	6.28	9.15	2.00	0.06	(0.06)	2.00	11.15	4.87	77.6%
		250	4.92	1.14	0.16	0.06	1.36	8.32	9.15	2.00	0.06	(0.06)	2.00	14.16	5.84	70.1%
		500	4.92	1.14	0.16	0.06	1.36	11.72	9.15	2.00	0.06	(0.06)	2.00	19.16	7.44	63.5%
		750	4.92	1.14	0.16	0.06	1.36	15.12	9.15	2.00	0.06	(0.06)	2.00	24.17	9.05	59.9%
		1,000	4.92	1.14	0.16	0.06	1.36	18.52	9.15	2.00	0.06	(0.06)	2.00	29.18	10.66	57.6%
GSe	**Georgina**	100	8.24	1.62	0.16	0.08	1.86	10.10	12.32	2.00	0.08	(0.06)	2.02	14.34	4.24	42.0%
		250	8.24	1.62	0.16	0.08	1.86	12.89	12.32	2.00	0.08	(0.06)	2.02	17.38	4.49	34.8%
		500	8.24	1.62	0.16	0.08	1.86	17.54	12.32	2.00	0.08	(0.06)	2.02	22.43	4.89	27.9%
		750	8.24	1.62	0.16	0.08	1.86	22.19	12.32	2.00	0.08	(0.06)	2.02	27.49	5.30	23.9%
		1,000	8.24	1.62	0.16	0.08	1.86	26.84	12.32	2.00	0.08	(0.06)	2.02	32.55	5.71	21.3%

New Rate Class: Gse - Unmetered

Bill Impacts of Proposed Distribution Rates include Riders

Classes		Scenario	Existing Dx Rates						New Dx Rates						$ Incr	% Incr
			SrChg	base	Rider1	Rider2	VarChg	[$/month]	SrChg	base	Rider2	Rider3	VarChg	[$/month]		
New Class	Old Class	kWh	[$/month]	[c/kWh]	[c/kWh]	[c/kWh]	[c/kWh]		[$/month]	[c/kWh]	[c/kWh]	[c/kWh]	[c/kWh]			
GSe	Glencoe	100	5.21	0.81	0.22	0.14	1.17	6.38	10.08	2.00	0.14	(0.06)	2.08	12.16	5.78	90.6%
		250	5.21	0.81	0.22	0.14	1.17	8.14	10.08	2.00	0.14	(0.06)	2.08	15.28	7.15	87.9%
		500	5.21	0.81	0.22	0.14	1.17	11.06	10.08	2.00	0.14	(0.06)	2.08	20.49	9.43	85.3%
		750	5.21	0.81	0.22	0.14	1.17	13.99	10.08	2.00	0.14	(0.06)	2.08	25.70	11.71	83.8%
		1,000	5.21	0.81	0.22	0.14	1.17	16.91	10.08	2.00	0.14	(0.06)	2.08	30.91	14.00	82.8%
GSe	Grand Bend	100	10.63	1.23	0.19	0.07	1.49	12.12	13.72	2.00	0.07	(0.06)	2.01	15.73	3.61	29.8%
		250	10.63	1.23	0.19	0.07	1.49	14.36	13.72	2.00	0.07	(0.06)	2.01	18.75	4.40	30.6%
		500	10.63	1.23	0.19	0.07	1.49	18.08	13.72	2.00	0.07	(0.06)	2.01	23.79	5.71	31.6%
		750	10.63	1.23	0.19	0.07	1.49	21.81	13.72	2.00	0.07	(0.06)	2.01	28.82	7.01	32.2%
		1,000	10.63	1.23	0.19	0.07	1.49	25.53	13.72	2.00	0.07	(0.06)	2.01	33.85	8.32	32.6%
GSe	Hastings	100	10.98	1.69	0.23	0.09	2.01	12.99	13.63	2.00	0.09	(0.06)	2.03	15.67	2.68	20.6%
		250	10.98	1.69	0.23	0.09	2.01	16.01	13.63	2.00	0.09	(0.06)	2.03	18.72	2.71	16.9%
		500	10.98	1.69	0.23	0.09	2.01	21.03	13.63	2.00	0.09	(0.06)	2.03	23.80	2.77	13.2%
		750	10.98	1.69	0.23	0.09	2.01	26.06	13.63	2.00	0.09	(0.06)	2.03	28.88	2.83	10.9%
		1,000	10.98	1.69	0.23	0.09	2.01	31.08	13.63	2.00	0.09	(0.06)	2.03	33.97	2.89	9.3%
GSe	Havelock	100	10.63	1.52	0.16	0.09	1.77	12.40	13.72	2.00	0.09	(0.06)	2.03	15.75	3.35	27.0%
		250	10.63	1.52	0.16	0.09	1.77	15.06	13.72	2.00	0.09	(0.06)	2.03	18.80	3.75	24.9%
		500	10.63	1.52	0.16	0.09	1.77	19.48	13.72	2.00	0.09	(0.06)	2.03	23.89	4.41	22.6%
		750	10.63	1.52	0.16	0.09	1.77	23.91	13.72	2.00	0.09	(0.06)	2.03	28.97	5.06	21.2%
		1,000	10.63	1.52	0.16	0.09	1.77	28.33	13.72	2.00	0.09	(0.06)	2.03	34.05	5.72	20.2%
GSe	Kirkfield	100	6.88	1.95	0.61	0.44	3.00	9.88	10.66	2.00	0.44	(0.06)	2.38	13.04	3.16	32.0%
		250	6.88	1.95	0.61	0.44	3.00	14.38	10.66	2.00	0.44	(0.06)	2.38	16.62	2.24	15.5%
		500	6.88	1.95	0.61	0.44	3.00	21.88	10.66	2.00	0.44	(0.06)	2.38	22.57	0.69	3.2%
		750	6.88	1.95	0.61	0.44	3.00	29.38	10.66	2.00	0.44	(0.06)	2.38	28.53	(0.85)	-2.9%
		1,000	6.88	1.95	0.61	0.44	3.00	36.88	10.66	2.00	0.44	(0.06)	2.38	34.49	(2.39)	-6.5%

New Rate Class: Gse - Unmetered

Bill Impacts of Proposed Distribution Rates include Riders

Classes		Scenario	Existing Dx Rates						New Dx Rates						$ Incr	% Incr
New Class	Old Class	kWh	SrChg [$/month]	base [c/kWh]	Rider1 [c/kWh]	Rider2 [c/kWh]	VarChg [c/kWh]	[$/month]	SrChg [$/month]	base [c/kWh]	Rider2 [c/kWh]	Rider3 [c/kWh]	VarChg [c/kWh]	[$/month]		
GSe	Lanark Highlands	100	8.75	1.99	0.63	0.50	3.12	11.87	12.19	2.00	0.50	(0.06)	2.44	14.63	2.76	23.3%
		250	8.75	1.99	0.63	0.50	3.12	16.55	12.19	2.00	0.50	(0.06)	2.44	18.30	1.75	10.6%
		500	8.75	1.99	0.63	0.50	3.12	24.35	12.19	2.00	0.50	(0.06)	2.44	24.41	0.06	0.2%
		750	8.75	1.99	0.63	0.50	3.12	32.15	12.19	2.00	0.50	(0.06)	2.44	30.51	(1.64)	-5.1%
		1,000	8.75	1.99	0.63	0.50	3.12	39.95	12.19	2.00	0.50	(0.06)	2.44	36.62	(3.33)	-8.3%
GSe	Larder Lake	100	9.62	1.58	0.51	0.36	2.45	12.07	12.97	2.00	0.36	(0.06)	2.30	15.28	3.21	26.6%
		250	9.62	1.58	0.51	0.36	2.45	15.75	12.97	2.00	0.36	(0.06)	2.30	18.73	2.99	19.0%
		500	9.62	1.58	0.51	0.36	2.45	21.87	12.97	2.00	0.36	(0.06)	2.30	24.49	2.62	12.0%
		750	9.62	1.58	0.51	0.36	2.45	28.00	12.97	2.00	0.36	(0.06)	2.30	30.25	2.25	8.0%
		1,000	9.62	1.58	0.51	0.36	2.45	34.12	12.97	2.00	0.36	(0.06)	2.30	36.01	1.89	5.5%
GSe	Latchford	100	0.97	1.02	0.65	0.20	1.87	2.84	6.14	2.00	0.20	(0.06)	2.14	8.28	5.44	191.5%
		250	0.97	1.02	0.65	0.20	1.87	5.65	6.14	2.00	0.20	(0.06)	2.14	11.49	5.85	103.6%
		500	0.97	1.02	0.65	0.20	1.87	10.32	6.14	2.00	0.20	(0.06)	2.14	16.85	6.53	63.3%
		750	0.97	1.02	0.65	0.20	1.87	15.00	6.14	2.00	0.20	(0.06)	2.14	22.21	7.21	48.1%
		1,000	0.97	1.02	0.65	0.20	1.87	19.67	6.14	2.00	0.20	(0.06)	2.14	27.57	7.90	40.2%
GSe	Lindsay	100	11.50	1.38	0.15	0.06	1.59	13.09	14.50	2.00	0.06	(0.06)	2.00	16.51	3.42	26.1%
		250	11.50	1.38	0.15	0.06	1.59	15.48	14.50	2.00	0.06	(0.06)	2.00	19.51	4.04	26.1%
		500	11.50	1.38	0.15	0.06	1.59	19.45	14.50	2.00	0.06	(0.06)	2.00	24.52	5.07	26.1%
		750	11.50	1.38	0.15	0.06	1.59	23.43	14.50	2.00	0.06	(0.06)	2.00	29.53	6.10	26.0%
		1,000	11.50	1.38	0.15	0.06	1.59	27.40	14.50	2.00	0.06	(0.06)	2.00	34.54	7.14	26.0%
GSe	Lucan Granton	100	8.03	1.47	0.17	0.10	1.74	9.77	12.37	2.00	0.10	(0.06)	2.04	14.41	4.64	47.5%
		250	8.03	1.47	0.17	0.10	1.74	12.38	12.37	2.00	0.10	(0.06)	2.04	17.48	5.10	41.2%
		500	8.03	1.47	0.17	0.10	1.74	16.73	12.37	2.00	0.10	(0.06)	2.04	22.59	5.86	35.0%
		750	8.03	1.47	0.17	0.10	1.74	21.08	12.37	2.00	0.10	(0.06)	2.04	27.69	6.61	31.4%
		1,000	8.03	1.47	0.17	0.10	1.74	25.43	12.37	2.00	0.10	(0.06)	2.04	32.80	7.37	29.0%

New Rate Class: Gse - Unmetered

Bill Impacts of Proposed Distribution Rates include Riders

Classes		Scenario	Existing Dx Rates						New Dx Rates						$ Incr	% Incr
			SrChg	base	Rider1	Rider2	VarChg	[$/month]	SrChg	base	Rider2	Rider3	VarChg	[$/month]		
New Class	Old Class	kWh	[$/month]	[c/kWh]	[c/kWh]	[c/kWh]	[c/kWh]		[$/month]	[c/kWh]	[c/kWh]	[c/kWh]	[c/kWh]			
GSe	Malahide	100	7.45	1.98	0.81	0.49	3.28	10.73	11.52	2.00	0.49	(0.06)	2.43	13.95	3.22	30.0%
		250	7.45	1.98	0.81	0.49	3.28	15.65	11.52	2.00	0.49	(0.06)	2.43	17.60	1.95	12.4%
		500	7.45	1.98	0.81	0.49	3.28	23.85	11.52	2.00	0.49	(0.06)	2.43	23.68	(0.17)	-0.7%
		750	7.45	1.98	0.81	0.49	3.28	32.05	11.52	2.00	0.49	(0.06)	2.43	29.76	(2.29)	-7.1%
		1,000	7.45	1.98	0.81	0.49	3.28	40.25	11.52	2.00	0.49	(0.06)	2.43	35.85	(4.40)	-10.9%
GSe	Mapleton	100	10.32	1.71	0.40	0.29	2.40	12.72	13.80	2.00	0.29	(0.06)	2.23	16.03	3.31	26.0%
		250	10.32	1.71	0.40	0.29	2.40	16.32	13.80	2.00	0.29	(0.06)	2.23	19.38	3.06	18.8%
		500	10.32	1.71	0.40	0.29	2.40	22.32	13.80	2.00	0.29	(0.06)	2.23	24.96	2.64	11.8%
		750	10.32	1.71	0.40	0.29	2.40	28.32	13.80	2.00	0.29	(0.06)	2.23	30.55	2.23	7.9%
		1,000	10.32	1.71	0.40	0.29	2.40	34.32	13.80	2.00	0.29	(0.06)	2.23	36.13	1.81	5.3%
GSe	Markdale	100	11.04	0.80	0.15	0.04	0.99	12.03	14.62	2.00	0.04	(0.06)	1.98	16.60	4.57	38.0%
		250	11.04	0.80	0.15	0.04	0.99	13.52	14.62	2.00	0.04	(0.06)	1.98	19.58	6.06	44.8%
		500	11.04	0.80	0.15	0.04	0.99	15.99	14.62	2.00	0.04	(0.06)	1.98	24.53	8.54	53.4%
		750	11.04	0.80	0.15	0.04	0.99	18.47	14.62	2.00	0.04	(0.06)	1.98	29.49	11.03	59.7%
		1,000	11.04	0.80	0.15	0.04	0.99	20.94	14.62	2.00	0.04	(0.06)	1.98	34.45	13.51	64.5%
GSe	Marmora	100	4.54	1.05	0.15	0.05	1.25	5.79	9.24	2.00	0.05	(0.06)	1.99	11.24	5.45	94.1%
		250	4.54	1.05	0.15	0.05	1.25	7.67	9.24	2.00	0.05	(0.06)	1.99	14.23	6.56	85.6%
		500	4.54	1.05	0.15	0.05	1.25	10.79	9.24	2.00	0.05	(0.06)	1.99	19.21	8.42	78.0%
		750	4.54	1.05	0.15	0.05	1.25	13.92	9.24	2.00	0.05	(0.06)	1.99	24.19	10.28	73.9%
		1,000	4.54	1.05	0.15	0.05	1.25	17.04	9.24	2.00	0.05	(0.06)	1.99	29.18	12.14	71.2%
GSe	McGarry	100	9.52	2.00	0.57	0.50	3.07	12.59	13.00	2.00	0.50	(0.06)	2.44	15.44	2.85	22.6%
		250	9.52	2.00	0.57	0.50	3.07	17.20	13.00	2.00	0.50	(0.06)	2.44	19.11	1.91	11.1%
		500	9.52	2.00	0.57	0.50	3.07	24.87	13.00	2.00	0.50	(0.06)	2.44	25.21	0.34	1.4%
		750	9.52	2.00	0.57	0.50	3.07	32.55	13.00	2.00	0.50	(0.06)	2.44	31.32	(1.22)	-3.8%
		1,000	9.52	2.00	0.57	0.50	3.07	40.22	13.00	2.00	0.50	(0.06)	2.44	37.43	(2.79)	-6.9%

New Rate Class: Gse - Unmetered

Bill Impacts of Proposed Distribution Rates include Riders

Classes		Scenario	Existing Dx Rates						New Dx Rates						$ Incr	% Incr
			SrChg	base	Rider1	Rider2	VarChg	[$/month]	SrChg	base	Rider2	Rider3	VarChg	[$/month]		
New Class	Old Class	kWh	[$/month]	[c/kWh]	[c/kWh]	[c/kWh]	[c/kWh]		[$/month]	[c/kWh]	[c/kWh]	[c/kWh]	[c/kWh]			
GSe	Meaford	100	11.55	1.23	0.16	0.07	1.46	13.01	14.49	2.00	0.07	(0.06)	2.01	16.50	3.49	26.9%
		250	11.55	1.23	0.16	0.07	1.46	15.20	14.49	2.00	0.07	(0.06)	2.01	19.52	4.32	28.4%
		500	11.55	1.23	0.16	0.07	1.46	18.85	14.49	2.00	0.07	(0.06)	2.01	24.56	5.71	30.3%
		750	11.55	1.23	0.16	0.07	1.46	22.50	14.49	2.00	0.07	(0.06)	2.01	29.59	7.09	31.5%
		1,000	11.55	1.23	0.16	0.07	1.46	26.15	14.49	2.00	0.07	(0.06)	2.01	34.62	8.47	32.4%
GSe	Middlesex Centre	100	8.21	1.37	0.44	0.35	2.16	10.37	12.33	2.00	0.35	(0.06)	2.29	14.62	4.25	41.0%
		250	8.21	1.37	0.44	0.35	2.16	13.61	12.33	2.00	0.35	(0.06)	2.29	18.06	4.45	32.7%
		500	8.21	1.37	0.44	0.35	2.16	19.01	12.33	2.00	0.35	(0.06)	2.29	23.79	4.78	25.2%
		750	8.21	1.37	0.44	0.35	2.16	24.41	12.33	2.00	0.35	(0.06)	2.29	29.52	5.11	21.0%
		1,000	8.21	1.37	0.44	0.35	2.16	29.81	12.33	2.00	0.35	(0.06)	2.29	35.26	5.45	18.3%
GSe	Napanee	100	10.62	1.28	0.16	0.06	1.50	12.12	13.72	2.00	0.06	(0.06)	2.00	15.73	3.61	29.8%
		250	10.62	1.28	0.16	0.06	1.50	14.37	13.72	2.00	0.06	(0.06)	2.00	18.73	4.36	30.3%
		500	10.62	1.28	0.16	0.06	1.50	18.12	13.72	2.00	0.06	(0.06)	2.00	23.74	5.62	31.0%
		750	10.62	1.28	0.16	0.06	1.50	21.87	13.72	2.00	0.06	(0.06)	2.00	28.75	6.88	31.4%
		1,000	10.62	1.28	0.16	0.06	1.50	25.62	13.72	2.00	0.06	(0.06)	2.00	33.76	8.14	31.8%
GSe	Nipigon	100	11.19	1.05	0.34	0.21	1.60	12.79	14.58	2.00	0.21	(0.06)	2.15	16.73	3.94	30.8%
		250	11.19	1.05	0.34	0.21	1.60	15.19	14.58	2.00	0.21	(0.06)	2.15	19.96	4.77	31.4%
		500	11.19	1.05	0.34	0.21	1.60	19.19	14.58	2.00	0.21	(0.06)	2.15	25.35	6.16	32.1%
		750	11.19	1.05	0.34	0.21	1.60	23.19	14.58	2.00	0.21	(0.06)	2.15	30.73	7.54	32.5%
		1,000	11.19	1.05	0.34	0.21	1.60	27.19	14.58	2.00	0.21	(0.06)	2.15	36.11	8.92	32.8%
GSe	North Dorchester	100	7.47	0.90	0.35	0.26	1.51	8.98	11.51	2.00	0.26	(0.06)	2.20	13.71	4.73	52.7%
		250	7.47	0.90	0.35	0.26	1.51	11.25	11.51	2.00	0.26	(0.06)	2.20	17.02	5.77	51.3%
		500	7.47	0.90	0.35	0.26	1.51	15.02	11.51	2.00	0.26	(0.06)	2.20	22.53	7.51	50.0%
		750	7.47	0.90	0.35	0.26	1.51	18.80	11.51	2.00	0.26	(0.06)	2.20	28.03	9.24	49.2%
		1,000	7.47	0.90	0.35	0.26	1.51	22.57	11.51	2.00	0.26	(0.06)	2.20	33.54	10.97	48.6%

New Rate Class: Gse - Unmetered

Bill Impacts of Proposed Distribution Rates include Riders

Classes		Scenario	Existing Dx Rates						New Dx Rates						$ Incr	% Incr
			SrChg	base	Rider1	Rider2	VarChg	[$/month]	SrChg	base	Rider2	Rider3	VarChg	[$/month]		
New Class	Old Class	kWh	[$/month]	[c/kWh]	[c/kWh]	[c/kWh]	[c/kWh]		[$/month]	[c/kWh]	[c/kWh]	[c/kWh]	[c/kWh]			
GSe	**North Dundas**	100	6.29	0.83	0.16	0.04	1.03	7.32	10.81	2.00	0.04	(0.06)	1.98	12.79	5.47	74.7%
		250	6.29	0.83	0.16	0.04	1.03	8.87	10.81	2.00	0.04	(0.06)	1.98	15.76	6.90	77.8%
		500	6.29	0.83	0.16	0.04	1.03	11.44	10.81	2.00	0.04	(0.06)	1.98	20.72	9.28	81.1%
		750	6.29	0.83	0.16	0.04	1.03	14.02	10.81	2.00	0.04	(0.06)	1.98	25.68	11.66	83.2%
		1,000	6.29	0.83	0.16	0.04	1.03	16.59	10.81	2.00	0.04	(0.06)	1.98	30.64	14.05	84.7%
GSe	**North Glengarry**	100	8.40	0.90	0.21	0.12	1.23	9.63	12.28	2.00	0.12	(0.06)	2.06	14.34	4.71	48.9%
		250	8.40	0.90	0.21	0.12	1.23	11.48	12.28	2.00	0.12	(0.06)	2.06	17.44	5.96	51.9%
		500	8.40	0.90	0.21	0.12	1.23	14.55	12.28	2.00	0.12	(0.06)	2.06	22.59	8.04	55.3%
		750	8.40	0.90	0.21	0.12	1.23	17.63	12.28	2.00	0.12	(0.06)	2.06	27.75	10.13	57.5%
		1,000	8.40	0.90	0.21	0.12	1.23	20.70	12.28	2.00	0.12	(0.06)	2.06	32.91	12.21	59.0%
GSe	**North Grenville**	100	9.74	1.71	0.14	0.08	1.93	11.67	12.94	2.00	0.08	(0.06)	2.02	14.97	3.30	28.2%
		250	9.74	1.71	0.14	0.08	1.93	14.57	12.94	2.00	0.08	(0.06)	2.02	18.00	3.44	23.6%
		500	9.74	1.71	0.14	0.08	1.93	19.39	12.94	2.00	0.08	(0.06)	2.02	23.06	3.67	18.9%
		750	9.74	1.71	0.14	0.08	1.93	24.22	12.94	2.00	0.08	(0.06)	2.02	28.12	3.90	16.1%
		1,000	9.74	1.71	0.14	0.08	1.93	29.04	12.94	2.00	0.08	(0.06)	2.02	33.18	4.14	14.2%
GSe	**North Perth**	100	14.30	1.00	0.12	0.04	1.16	15.46	16.80	2.00	0.04	(0.06)	1.98	18.79	3.33	21.5%
		250	14.30	1.00	0.12	0.04	1.16	17.20	16.80	2.00	0.04	(0.06)	1.98	21.76	4.56	26.5%
		500	14.30	1.00	0.12	0.04	1.16	20.10	16.80	2.00	0.04	(0.06)	1.98	26.72	6.62	32.9%
		750	14.30	1.00	0.12	0.04	1.16	23.00	16.80	2.00	0.04	(0.06)	1.98	31.68	8.68	37.7%
		1,000	14.30	1.00	0.12	0.04	1.16	25.90	16.80	2.00	0.04	(0.06)	1.98	36.64	10.74	41.4%
GSe	**North Stormont**	100	2.22	0.78	0.37	0.26	1.41	3.63	7.82	2.00	0.26	(0.06)	2.20	10.03	6.40	176.2%
		250	2.22	0.78	0.37	0.26	1.41	5.75	7.82	2.00	0.26	(0.06)	2.20	13.33	7.59	132.0%
		500	2.22	0.78	0.37	0.26	1.41	9.27	7.82	2.00	0.26	(0.06)	2.20	18.84	9.57	103.2%
		750	2.22	0.78	0.37	0.26	1.41	12.80	7.82	2.00	0.26	(0.06)	2.20	24.35	11.55	90.3%
		1,000	2.22	0.78	0.37	0.26	1.41	16.32	7.82	2.00	0.26	(0.06)	2.20	29.86	13.54	82.9%

New Rate Class: Gse - Unmetered

Bill Impacts of Proposed Distribution Rates include Riders

Classes		Scenario	Existing Dx Rates						New Dx Rates						$ Incr	% Incr
			SrChg [$/month]	base [c/kWh]	Rider1 [c/kWh]	Rider2 [c/kWh]	VarChg [c/kWh]	[$/month]	SrChg [$/month]	base [c/kWh]	Rider2 [c/kWh]	Rider3 [c/kWh]	VarChg [c/kWh]	[$/month]		
New Class	**Old Class**	kWh														
GSe	**Omemee**	100	10.18	1.47	0.18	0.09	1.74	11.92	13.83	2.00	0.09	(0.06)	2.03	15.87	3.95	33.1%
		250	10.18	1.47	0.18	0.09	1.74	14.53	13.83	2.00	0.09	(0.06)	2.03	18.92	4.39	30.2%
		500	10.18	1.47	0.18	0.09	1.74	18.88	13.83	2.00	0.09	(0.06)	2.03	24.00	5.12	27.1%
		750	10.18	1.47	0.18	0.09	1.74	23.23	13.83	2.00	0.09	(0.06)	2.03	29.08	5.85	25.2%
		1,000	10.18	1.47	0.18	0.09	1.74	27.58	13.83	2.00	0.09	(0.06)	2.03	34.17	6.59	23.9%
GSe	**Perth**	100	9.49	0.92	0.13	0.04	1.09	10.58	13.01	2.00	0.04	(0.06)	1.98	14.99	4.41	41.7%
		250	9.49	0.92	0.13	0.04	1.09	12.22	13.01	2.00	0.04	(0.06)	1.98	17.96	5.75	47.1%
		500	9.49	0.92	0.13	0.04	1.09	14.94	13.01	2.00	0.04	(0.06)	1.98	22.92	7.98	53.4%
		750	9.49	0.92	0.13	0.04	1.09	17.67	13.01	2.00	0.04	(0.06)	1.98	27.88	10.21	57.8%
		1,000	9.49	0.92	0.13	0.04	1.09	20.39	13.01	2.00	0.04	(0.06)	1.98	32.84	12.45	61.0%
GSe	**Perth East**	100	6.86	1.29	0.16	0.09	1.54	8.40	10.66	2.00	0.09	(0.06)	2.03	12.70	4.30	51.1%
		250	6.86	1.29	0.16	0.09	1.54	10.71	10.66	2.00	0.09	(0.06)	2.03	15.75	5.04	47.0%
		500	6.86	1.29	0.16	0.09	1.54	14.56	10.66	2.00	0.09	(0.06)	2.03	20.83	6.27	43.1%
		750	6.86	1.29	0.16	0.09	1.54	18.41	10.66	2.00	0.09	(0.06)	2.03	25.91	7.50	40.8%
		1,000	6.86	1.29	0.16	0.09	1.54	22.26	10.66	2.00	0.09	(0.06)	2.03	31.00	8.74	39.2%
GSe	**Prince Edward**	100	10.96	1.42	0.18	0.08	1.68	12.64	13.64	2.00	0.08	(0.06)	2.02	15.66	3.02	23.9%
		250	10.96	1.42	0.18	0.08	1.68	15.16	13.64	2.00	0.08	(0.06)	2.02	18.70	3.54	23.3%
		500	10.96	1.42	0.18	0.08	1.68	19.36	13.64	2.00	0.08	(0.06)	2.02	23.75	4.39	22.7%
		750	10.96	1.42	0.18	0.08	1.68	23.56	13.64	2.00	0.08	(0.06)	2.02	28.81	5.25	22.3%
		1,000	10.96	1.42	0.18	0.08	1.68	27.76	13.64	2.00	0.08	(0.06)	2.02	33.87	6.11	22.0%
GSe	**Quinte West**	100	1.41	1.05	0.14	0.06	1.25	2.66	7.03	2.00	0.06	(0.06)	2.00	9.03	6.37	239.4%
		250	1.41	1.05	0.14	0.06	1.25	4.54	7.03	2.00	0.06	(0.06)	2.00	12.03	7.50	165.3%
		500	1.41	1.05	0.14	0.06	1.25	7.66	7.03	2.00	0.06	(0.06)	2.00	17.04	9.38	122.5%
		750	1.41	1.05	0.14	0.06	1.25	10.79	7.03	2.00	0.06	(0.06)	2.00	22.05	11.26	104.4%
		1,000	1.41	1.05	0.14	0.06	1.25	13.91	7.03	2.00	0.06	(0.06)	2.00	27.06	13.15	94.5%

New Rate Class: Gse - Unmetered

Bill Impacts of Proposed Distribution Rates include Riders

Classes		Scenario	Existing Dx Rates						New Dx Rates						$ Incr	% Incr
New Class	Old Class	kWh	SrChg [$/month]	base [c/kWh]	Rider1 [c/kWh]	Rider2 [c/kWh]	VarChg [c/kWh]	[$/month]	SrChg [$/month]	base [c/kWh]	Rider2 [c/kWh]	Rider3 [c/kWh]	VarChg [c/kWh]	[$/month]		
GSe	Rainy River	100	9.18	1.76	0.45	0.36	2.57	11.75	13.08	2.00	0.36	(0.06)	2.30	15.39	3.64	30.9%
		250	9.18	1.76	0.45	0.36	2.57	15.61	13.08	2.00	0.36	(0.06)	2.30	18.84	3.24	20.7%
		500	9.18	1.76	0.45	0.36	2.57	22.03	13.08	2.00	0.36	(0.06)	2.30	24.60	2.57	11.7%
		750	9.18	1.76	0.45	0.36	2.57	28.46	13.08	2.00	0.36	(0.06)	2.30	30.36	1.90	6.7%
		1,000	9.18	1.76	0.45	0.36	2.57	34.88	13.08	2.00	0.36	(0.06)	2.30	36.12	1.24	3.5%
GSe	Ramara	100	10.02	1.06	0.45	0.37	1.88	11.90	13.87	2.00	0.37	(0.06)	2.31	16.19	4.29	36.0%
		250	10.02	1.06	0.45	0.37	1.88	14.72	13.87	2.00	0.37	(0.06)	2.31	19.66	4.94	33.5%
		500	10.02	1.06	0.45	0.37	1.88	19.42	13.87	2.00	0.37	(0.06)	2.31	25.44	6.02	31.0%
		750	10.02	1.06	0.45	0.37	1.88	24.12	13.87	2.00	0.37	(0.06)	2.31	31.22	7.10	29.4%
		1,000	10.02	1.06	0.45	0.37	1.88	28.82	13.87	2.00	0.37	(0.06)	2.31	37.01	8.19	28.4%
GSe	Red Rock	100	10.36	1.94	0.27	0.24	2.45	12.81	13.79	2.00	0.24	(0.06)	2.18	15.97	3.16	24.7%
		250	10.36	1.94	0.27	0.24	2.45	16.49	13.79	2.00	0.24	(0.06)	2.18	19.25	2.76	16.7%
		500	10.36	1.94	0.27	0.24	2.45	22.61	13.79	2.00	0.24	(0.06)	2.18	24.70	2.09	9.3%
		750	10.36	1.94	0.27	0.24	2.45	28.74	13.79	2.00	0.24	(0.06)	2.18	30.16	1.43	5.0%
		1,000	10.36	1.94	0.27	0.24	2.45	34.86	13.79	2.00	0.24	(0.06)	2.18	35.62	0.76	2.2%
GSe	Rockland	100	3.16	1.00	0.17	0.22	1.39	4.55	8.59	2.00	0.22	(0.06)	2.16	10.75	6.20	136.3%
		250	3.16	1.00	0.17	0.22	1.39	6.64	8.59	2.00	0.22	(0.06)	2.16	14.00	7.36	110.9%
		500	3.16	1.00	0.17	0.22	1.39	10.11	8.59	2.00	0.22	(0.06)	2.16	19.40	9.29	91.9%
		750	3.16	1.00	0.17	0.22	1.39	13.59	8.59	2.00	0.22	(0.06)	2.16	24.81	11.23	82.6%
		1,000	3.16	1.00	0.17	0.22	1.39	17.06	8.59	2.00	0.22	(0.06)	2.16	30.22	13.16	77.1%
GSe	Russell	100	9.17	2.24	0.18	0.11	2.53	11.70	13.09	2.00	0.11	(0.06)	2.05	15.14	3.44	29.4%
		250	9.17	2.24	0.18	0.11	2.53	15.50	13.09	2.00	0.11	(0.06)	2.05	18.22	2.72	17.6%
		500	9.17	2.24	0.18	0.11	2.53	21.82	13.09	2.00	0.11	(0.06)	2.05	23.35	1.53	7.0%
		750	9.17	2.24	0.18	0.11	2.53	28.15	13.09	2.00	0.11	(0.06)	2.05	28.48	0.34	1.2%
		1,000	9.17	2.24	0.18	0.11	2.53	34.47	13.09	2.00	0.11	(0.06)	2.05	33.62	(0.85)	-2.5%

New Rate Class: Gse - Unmetered

Bill Impacts of Proposed Distribution Rates include Riders

Classes		Scenario	Existing Dx Rates						New Dx Rates						$ Incr	% Incr
			SrChg	base	Rider1	Rider2	VarChg	[$/month]	SrChg	base	Rider2	Rider3	VarChg	[$/month]		
New Class	Old Class	kWh	[$/month]	[c/kWh]	[c/kWh]	[c/kWh]	[c/kWh]		[$/month]	[c/kWh]	[c/kWh]	[c/kWh]	[c/kWh]			
GSe	**Schreiber**	100	9.88	2.51	0.50	0.40	3.41	13.29	12.91	2.00	0.40	(0.06)	2.34	15.25	1.96	14.8%
		250	9.88	2.51	0.50	0.40	3.41	18.41	12.91	2.00	0.40	(0.06)	2.34	18.77	0.36	2.0%
		500	9.88	2.51	0.50	0.40	3.41	26.93	12.91	2.00	0.40	(0.06)	2.34	24.62	(2.31)	-8.6%
		750	9.88	2.51	0.50	0.40	3.41	35.46	12.91	2.00	0.40	(0.06)	2.34	30.48	(4.97)	-14.0%
		1,000	9.88	2.51	0.50	0.40	3.41	43.98	12.91	2.00	0.40	(0.06)	2.34	36.34	(7.64)	-17.4%
GSe	**Severn**	100	10.62	1.06	0.31	0.22	1.59	12.21	13.72	2.00	0.22	(0.06)	2.16	15.89	3.68	30.1%
		250	10.62	1.06	0.31	0.22	1.59	14.60	13.72	2.00	0.22	(0.06)	2.16	19.13	4.54	31.1%
		500	10.62	1.06	0.31	0.22	1.59	18.57	13.72	2.00	0.22	(0.06)	2.16	24.54	5.97	32.1%
		750	10.62	1.06	0.31	0.22	1.59	22.55	13.72	2.00	0.22	(0.06)	2.16	29.95	7.40	32.8%
		1,000	10.62	1.06	0.31	0.22	1.59	26.52	13.72	2.00	0.22	(0.06)	2.16	35.36	8.84	33.3%
GSe	**Shelburne**	100	9.53	0.87	0.10	0.02	0.99	10.52	13.00	2.00	0.02	(0.06)	1.96	14.96	4.44	42.2%
		250	9.53	0.87	0.10	0.02	0.99	12.01	13.00	2.00	0.02	(0.06)	1.96	17.90	5.90	49.1%
		500	9.53	0.87	0.10	0.02	0.99	14.48	13.00	2.00	0.02	(0.06)	1.96	22.81	8.33	57.5%
		750	9.53	0.87	0.10	0.02	0.99	16.96	13.00	2.00	0.02	(0.06)	1.96	27.72	10.76	63.5%
		1,000	9.53	0.87	0.10	0.02	0.99	19.43	13.00	2.00	0.02	(0.06)	1.96	32.63	13.20	67.9%
GSe	**Smiths Falls**	100	4.46	1.05	0.12	0.04	1.21	5.67	9.26	2.00	0.04	(0.06)	1.98	11.25	5.58	98.3%
		250	4.46	1.05	0.12	0.04	1.21	7.49	9.26	2.00	0.04	(0.06)	1.98	14.22	6.74	90.0%
		500	4.46	1.05	0.12	0.04	1.21	10.51	9.26	2.00	0.04	(0.06)	1.98	19.18	8.67	82.5%
		750	4.46	1.05	0.12	0.04	1.21	13.54	9.26	2.00	0.04	(0.06)	1.98	24.14	10.60	78.3%
		1,000	4.46	1.05	0.12	0.04	1.21	16.56	9.26	2.00	0.04	(0.06)	1.98	29.10	12.54	75.7%
GSe	**South Glengarry**	100	8.25	0.75	0.37	0.30	1.42	9.67	12.32	2.00	0.30	(0.06)	2.24	14.56	4.89	50.6%
		250	8.25	0.75	0.37	0.30	1.42	11.80	12.32	2.00	0.30	(0.06)	2.24	17.92	6.12	51.9%
		500	8.25	0.75	0.37	0.30	1.42	15.35	12.32	2.00	0.30	(0.06)	2.24	23.53	8.18	53.3%
		750	8.25	0.75	0.37	0.30	1.42	18.90	12.32	2.00	0.30	(0.06)	2.24	29.14	10.24	54.2%
		1,000	8.25	0.75	0.37	0.30	1.42	22.45	12.32	2.00	0.30	(0.06)	2.24	34.75	12.30	54.8%

New Rate Class: Gse - Unmetered

Bill Impacts of Proposed Distribution Rates include Riders

Classes		Scenario	Existing Dx Rates						New Dx Rates						$ Incr	% Incr
			SrChg	base	Rider1	Rider2	VarChg	[$/month]	SrChg	base	Rider2	Rider3	VarChg	[$/month]		
New Class	Old Class	kWh	[$/month]	[c/kWh]	[c/kWh]	[c/kWh]	[c/kWh]		[$/month]	[c/kWh]	[c/kWh]	[c/kWh]	[c/kWh]			
GSe	South River	100	10.59	1.58	0.39	0.30	2.27	12.86	13.73	2.00	0.30	(0.06)	2.24	15.97	3.11	24.2%
		250	10.59	1.58	0.39	0.30	2.27	16.27	13.73	2.00	0.30	(0.06)	2.24	19.34	3.07	18.9%
		500	10.59	1.58	0.39	0.30	2.27	21.94	13.73	2.00	0.30	(0.06)	2.24	24.95	3.01	13.7%
		750	10.59	1.58	0.39	0.30	2.27	27.62	13.73	2.00	0.30	(0.06)	2.24	30.55	2.94	10.6%
		1,000	10.59	1.58	0.39	0.30	2.27	33.29	13.73	2.00	0.30	(0.06)	2.24	36.16	2.87	8.6%
GSe	Springwater	100	9.80	1.07	0.27	0.17	1.51	11.31	12.93	2.00	0.17	(0.06)	2.11	15.04	3.73	33.0%
		250	9.80	1.07	0.27	0.17	1.51	13.58	12.93	2.00	0.17	(0.06)	2.11	18.21	4.64	34.2%
		500	9.80	1.07	0.27	0.17	1.51	17.35	12.93	2.00	0.17	(0.06)	2.11	23.49	6.14	35.4%
		750	9.80	1.07	0.27	0.17	1.51	21.13	12.93	2.00	0.17	(0.06)	2.11	28.78	7.65	36.2%
		1,000	9.80	1.07	0.27	0.17	1.51	24.90	12.93	2.00	0.17	(0.06)	2.11	34.06	9.16	36.8%
GSe	Stirling-Rawdon	100	11.59	1.30	0.21	0.09	1.60	13.19	14.48	2.00	0.09	(0.06)	2.03	16.51	3.32	25.2%
		250	11.59	1.30	0.21	0.09	1.60	15.59	14.48	2.00	0.09	(0.06)	2.03	19.56	3.97	25.5%
		500	11.59	1.30	0.21	0.09	1.60	19.59	14.48	2.00	0.09	(0.06)	2.03	24.65	5.06	25.8%
		750	11.59	1.30	0.21	0.09	1.60	23.59	14.48	2.00	0.09	(0.06)	2.03	29.73	6.14	26.0%
		1,000	11.59	1.30	0.21	0.09	1.60	27.59	14.48	2.00	0.09	(0.06)	2.03	34.81	7.22	26.2%
GSe	Thedford	100	8.45	1.06	0.36	0.31	1.73	10.18	12.27	2.00	0.31	(0.06)	2.25	14.52	4.34	42.6%
		250	8.45	1.06	0.36	0.31	1.73	12.78	12.27	2.00	0.31	(0.06)	2.25	17.90	5.12	40.1%
		500	8.45	1.06	0.36	0.31	1.73	17.10	12.27	2.00	0.31	(0.06)	2.25	23.53	6.43	37.6%
		750	8.45	1.06	0.36	0.31	1.73	21.43	12.27	2.00	0.31	(0.06)	2.25	29.16	7.74	36.1%
		1,000	8.45	1.06	0.36	0.31	1.73	25.75	12.27	2.00	0.31	(0.06)	2.25	34.80	9.05	35.1%
GSe	Thessalon	100	8.99	1.55	0.10	0.08	1.73	10.72	12.13	2.00	0.08	(0.06)	2.02	14.15	3.43	32.0%
		250	8.99	1.55	0.10	0.08	1.73	13.32	12.13	2.00	0.08	(0.06)	2.02	17.19	3.87	29.1%
		500	8.99	1.55	0.10	0.08	1.73	17.64	12.13	2.00	0.08	(0.06)	2.02	22.25	4.61	26.1%
		750	8.99	1.55	0.10	0.08	1.73	21.97	12.13	2.00	0.08	(0.06)	2.02	27.30	5.34	24.3%
		1,000	8.99	1.55	0.10	0.08	1.73	26.29	12.13	2.00	0.08	(0.06)	2.02	32.36	6.07	23.1%

New Rate Class: Gse - Unmetered

Bill Impacts of Proposed Distribution Rates include Riders

Classes		Scenario	Existing Dx Rates						New Dx Rates						$ Incr	% Incr
			SrChg	base	Rider1	Rider2	VarChg	[$/month]	SrChg	base	Rider2	Rider3	VarChg	[$/month]		
New Class	Old Class	kWh	[$/month]	[c/kWh]	[c/kWh]	[c/kWh]	[c/kWh]		[$/month]	[c/kWh]	[c/kWh]	[c/kWh]	[c/kWh]			
GSe	Thorndale	100	6.79	1.02	0.52	0.32	1.86	8.65	10.68	2.00	0.32	(0.06)	2.26	12.94	4.29	49.6%
		250	6.79	1.02	0.52	0.32	1.86	11.44	10.68	2.00	0.32	(0.06)	2.26	16.34	4.90	42.8%
		500	6.79	1.02	0.52	0.32	1.86	16.09	10.68	2.00	0.32	(0.06)	2.26	22.00	5.91	36.7%
		750	6.79	1.02	0.52	0.32	1.86	20.74	10.68	2.00	0.32	(0.06)	2.26	27.65	6.91	33.3%
		1,000	6.79	1.02	0.52	0.32	1.86	25.39	10.68	2.00	0.32	(0.06)	2.26	33.31	7.92	31.2%
GSe	Thorold	100	10.85	1.50	0.15	0.06	1.71	12.56	13.67	2.00	0.06	(0.06)	2.00	15.67	3.11	24.7%
		250	10.85	1.50	0.15	0.06	1.71	15.13	13.67	2.00	0.06	(0.06)	2.00	18.67	3.55	23.5%
		500	10.85	1.50	0.15	0.06	1.71	19.40	13.67	2.00	0.06	(0.06)	2.00	23.68	4.28	22.1%
		750	10.85	1.50	0.15	0.06	1.71	23.68	13.67	2.00	0.06	(0.06)	2.00	28.69	5.01	21.2%
		1,000	10.85	1.50	0.15	0.06	1.71	27.95	13.67	2.00	0.06	(0.06)	2.00	33.70	5.75	20.6%
GSe	Tweed	100	3.67	0.97	0.43	0.31	1.71	5.38	8.46	2.00	0.31	(0.06)	2.25	10.71	5.33	99.1%
		250	3.67	0.97	0.43	0.31	1.71	7.95	8.46	2.00	0.31	(0.06)	2.25	14.09	6.15	77.4%
		500	3.67	0.97	0.43	0.31	1.71	12.22	8.46	2.00	0.31	(0.06)	2.25	19.73	7.51	61.4%
		750	3.67	0.97	0.43	0.31	1.71	16.50	8.46	2.00	0.31	(0.06)	2.25	25.36	8.86	53.7%
		1,000	3.67	0.97	0.43	0.31	1.71	20.77	8.46	2.00	0.31	(0.06)	2.25	30.99	10.22	49.2%
GSe	Wardsville	100	5.70	1.00	0.25	0.08	1.33	7.03	9.95	2.00	0.08	(0.06)	2.02	11.98	4.95	70.4%
		250	5.70	1.00	0.25	0.08	1.33	9.03	9.95	2.00	0.08	(0.06)	2.02	15.01	5.99	66.3%
		500	5.70	1.00	0.25	0.08	1.33	12.35	9.95	2.00	0.08	(0.06)	2.02	20.07	7.72	62.5%
		750	5.70	1.00	0.25	0.08	1.33	15.68	9.95	2.00	0.08	(0.06)	2.02	25.13	9.45	60.3%
		1,000	5.70	1.00	0.25	0.08	1.33	19.00	9.95	2.00	0.08	(0.06)	2.02	30.19	11.19	58.9%
GSe	Warkworth	100	10.20	1.52	0.46	0.35	2.33	12.53	13.83	2.00	0.35	(0.06)	2.29	16.12	3.59	28.7%
		250	10.20	1.52	0.46	0.35	2.33	16.03	13.83	2.00	0.35	(0.06)	2.29	19.56	3.54	22.1%
		500	10.20	1.52	0.46	0.35	2.33	21.85	13.83	2.00	0.35	(0.06)	2.29	25.29	3.44	15.8%
		750	10.20	1.52	0.46	0.35	2.33	27.68	13.83	2.00	0.35	(0.06)	2.29	31.03	3.35	12.1%
		1,000	10.20	1.52	0.46	0.35	2.33	33.50	13.83	2.00	0.35	(0.06)	2.29	36.76	3.26	9.7%

New Rate Class: Gse - Unmetered

Bill Impacts of Proposed Distribution Rates include Riders

Classes		Scenario	Existing Dx Rates						New Dx Rates						$ Incr	% Incr
			SrChg	base	Rider1	Rider2	VarChg	[$/month]	SrChg	base	Rider2	Rider3	VarChg	[$/month]		
New Class	Old Class	kWh	[$/month]	[c/kWh]	[c/kWh]	[c/kWh]	[c/kWh]		[$/month]	[c/kWh]	[c/kWh]	[c/kWh]	[c/kWh]			
GSe	**West Elgin**	100	7.23	0.70	0.17	0.07	0.94	8.17	11.57	2.00	0.07	(0.06)	2.01	13.58	5.41	66.3%
		250	7.23	0.70	0.17	0.07	0.94	9.58	11.57	2.00	0.07	(0.06)	2.01	16.60	7.02	73.3%
		500	7.23	0.70	0.17	0.07	0.94	11.93	11.57	2.00	0.07	(0.06)	2.01	21.64	9.71	81.4%
		750	7.23	0.70	0.17	0.07	0.94	14.28	11.57	2.00	0.07	(0.06)	2.01	26.67	12.39	86.8%
		1,000	7.23	0.70	0.17	0.07	0.94	16.63	11.57	2.00	0.07	(0.06)	2.01	31.70	15.07	90.6%
GSe	**Whitchurch Stouffville**	100	10.46	0.93	0.11	0.04	1.08	11.54	13.76	2.00	0.04	(0.06)	1.98	15.75	4.21	36.4%
		250	10.46	0.93	0.11	0.04	1.08	13.16	13.76	2.00	0.04	(0.06)	1.98	18.72	5.56	42.3%
		500	10.46	0.93	0.11	0.04	1.08	15.86	13.76	2.00	0.04	(0.06)	1.98	23.68	7.82	49.3%
		750	10.46	0.93	0.11	0.04	1.08	18.56	13.76	2.00	0.04	(0.06)	1.98	28.64	10.08	54.3%
		1,000	10.46	0.93	0.11	0.04	1.08	21.26	13.76	2.00	0.04	(0.06)	1.98	33.60	12.34	58.0%
GSe	**Wiarton**	100	11.42	1.89	0.19	0.09	2.17	13.59	14.52	2.00	0.09	(0.06)	2.03	16.56	2.97	21.8%
		250	11.42	1.89	0.19	0.09	2.17	16.85	14.52	2.00	0.09	(0.06)	2.03	19.61	2.76	16.4%
		500	11.42	1.89	0.19	0.09	2.17	22.27	14.52	2.00	0.09	(0.06)	2.03	24.69	2.42	10.9%
		750	11.42	1.89	0.19	0.09	2.17	27.70	14.52	2.00	0.09	(0.06)	2.03	29.77	2.08	7.5%
		1,000	11.42	1.89	0.19	0.09	2.17	33.12	14.52	2.00	0.09	(0.06)	2.03	34.86	1.74	5.2%
GSe	**Woodville**	100	7.98	1.57	0.67	0.48	2.72	10.70	11.38	2.00	0.48	(0.06)	2.42	13.81	3.11	29.0%
		250	7.98	1.57	0.67	0.48	2.72	14.78	11.38	2.00	0.48	(0.06)	2.42	17.44	2.66	18.0%
		500	7.98	1.57	0.67	0.48	2.72	21.58	11.38	2.00	0.48	(0.06)	2.42	23.50	1.92	8.9%
		750	7.98	1.57	0.67	0.48	2.72	28.38	11.38	2.00	0.48	(0.06)	2.42	29.56	1.18	4.1%
		1,000	7.98	1.57	0.67	0.48	2.72	35.18	11.38	2.00	0.48	(0.06)	2.42	35.62	0.44	1.2%
GSe	**Wyoming**	100	8.22	1.45	0.16	0.07	1.68	9.90	12.32	2.00	0.07	(0.06)	2.01	14.34	4.44	44.8%
		250	8.22	1.45	0.16	0.07	1.68	12.42	12.32	2.00	0.07	(0.06)	2.01	17.36	4.94	39.7%
		500	8.22	1.45	0.16	0.07	1.68	16.62	12.32	2.00	0.07	(0.06)	2.01	22.39	5.77	34.7%
		750	8.22	1.45	0.16	0.07	1.68	20.82	12.32	2.00	0.07	(0.06)	2.01	27.42	6.60	31.7%
		1,000	8.22	1.45	0.16	0.07	1.68	25.02	12.32	2.00	0.07	(0.06)	2.01	32.46	7.44	29.7%

New Rate Class: Gse - Unmetered

Bill Impacts of Proposed Distribution Rates include Riders

Classes		Scenario	Existing Dx Rates						New Dx Rates						$ Incr	% Incr
			SrChg	base	Rider1	Rider2	VarChg	[$/month]	SrChg	base	Rider2	Rider3	VarChg	[$/month]		
New Class	Old Class	kWh	[$/month]	[c/kWh]	[c/kWh]	[c/kWh]	[c/kWh]		[$/month]	[c/kWh]	[c/kWh]	[c/kWh]	[c/kWh]			
GSe	**Terrace Bay**	100	20.53	1.29	0.82	-	2.11	22.64	21.25	2.00	-	(0.06)	1.94	23.19	0.55	2.4%
		250	20.53	1.29	0.82	-	2.11	25.81	21.25	2.00	-	(0.06)	1.94	26.10	0.30	1.2%
		500	20.53	1.29	0.82	-	2.11	31.08	21.25	2.00	-	(0.06)	1.94	30.96	(0.12)	-0.4%
		750	20.53	1.29	0.82	-	2.11	36.36	21.25	2.00	-	(0.06)	1.94	35.82	(0.54)	-1.5%
		1,000	20.53	1.29	0.82	-	2.11	41.63	21.25	2.00	-	(0.06)	1.94	40.68	(0.95)	-2.3%

New Rate Class: DGen

Bill Impacts of Proposed Distribution Rates include Riders

Classes		Scenario			Existing Dx Rates						New Dx Rates						$ Incr	% Incr
					SrChg	base	Rider1	Rider2	VarChg	[$/month]	SrChg	base	Rider2	Rider3	VarChg	[$/month]		
New Class	Old Class	kWh	kW	LF	[$/month]	[$/kW]	[$/kW]	[$/kW]	[$/kW]		[$/month]	[$/kW]	[$/kW]	[$/kW]	[$/kW]			
Dgen	G3	5,000	10	69%	46.78	9.91	0.08	0.15	10.14	148.2	36.66	7.07	0.15	(0.04)	7.18	108.4	(39.8)	-26.8%
	D-billed	5,000	20	35%	46.78	9.91	0.08	0.15	10.14	249.6	36.66	7.07	0.15	(0.04)	7.18	180.2	(69.4)	-27.8%
		5,000	30	23%	46.78	9.91	0.08	0.15	10.14	351.0	36.66	7.07	0.15	(0.04)	7.18	251.9	(99.0)	-28.2%
		5,000	40	17%	46.78	9.91	0.08	0.15	10.14	452.4	36.66	7.07	0.15	(0.04)	7.18	323.7	(128.7)	-28.4%
		5,000	50	14%	46.78	9.91	0.08	0.15	10.14	553.8	36.66	7.07	0.15	(0.04)	7.18	395.4	(158.3)	-28.6%
		5,000	60	12%	46.78	9.91	0.08	0.15	10.14	655.2	36.66	7.07	0.15	(0.04)	7.18	467.2	(188.0)	-28.7%
		35,000	90	54%	46.78	9.91	0.08	0.15	10.14	956.7	36.66	7.07	0.15	(0.04)	7.18	680.6	(276.1)	-28.9%
					[$/month]	[$/kW]	[$/kW]	[$/kW]	[$/kW]									
Dgen	T	5,000	10	69%	261.54	8.16	0.04	0.09	8.29	344.4	36.66	7.07	0.09	(0.04)	7.12	107.8	(236.6)	-68.7%
	D-billed	5,000	20	35%	261.54	8.16	0.04	0.09	8.29	427.3	36.66	7.07	0.09	(0.04)	7.12	179.0	(248.4)	-58.1%
		5,000	30	23%	261.54	8.16	0.04	0.09	8.29	510.2	36.66	7.07	0.09	(0.04)	7.12	250.1	(260.1)	-51.0%
		5,000	40	17%	261.54	8.16	0.04	0.09	8.29	593.1	36.66	7.07	0.09	(0.04)	7.12	321.3	(271.8)	-45.8%
		5,000	50	14%	261.54	8.16	0.04	0.09	8.29	676.0	36.66	7.07	0.09	(0.04)	7.12	392.4	(283.6)	-41.9%
		5,000	60	12%	261.54	8.16	0.04	0.09	8.29	758.9	36.66	7.07	0.09	(0.04)	7.12	463.6	(295.3)	-38.9%
		7,700	##	5%	261.54	8.16	0.04	0.09	8.29	1,920.5	36.66	7.07	0.09	(0.04)	7.12	1,460.6	(459.9)	-23.9%
					[$/month]	[c/kWh]	[c/kWh]	[c/kWh]	[c/kWh]									
Dgen	G3	5,000	10	69%	46.78	3.07	0.02	0.05	3.14	203.8	36.66	7.07	0.15	(0.04)	7.18	108.4	(95.4)	-46.8%
	E-billed	5,000	20	35%	46.78	3.07	0.02	0.05	3.14	203.8	36.66	7.07	0.15	(0.04)	7.18	180.2	(23.6)	-11.6%
		5,000	30	23%	46.78	3.07	0.02	0.05	3.14	203.8	36.66	7.07	0.15	(0.04)	7.18	251.9	48.2	23.6%
		5,000	40	17%	46.78	3.07	0.02	0.05	3.14	203.8	36.66	7.07	0.15	(0.04)	7.18	323.7	119.9	58.8%
		5,000	50	14%	46.78	3.07	0.02	0.05	3.14	203.8	36.66	7.07	0.15	(0.04)	7.18	395.4	191.7	94.1%
		5,000	60	12%	46.78	3.07	0.02	0.05	3.14	203.8	36.66	7.07	0.15	(0.04)	7.18	467.2	263.4	129.3%
		802	8	14%	46.78	3.07	0.02	0.05	3.14	72.0	36.66	7.07	0.15	(0.04)	7.18	95.2	23.2	32.3%
					[$/month]	[c/kWh]	[c/kWh]	[c/kWh]	[c/kWh]									
Dgen	T	5,000	10	69%	261.54	2.43	0.01	0.03	2.47	385.0	36.66	7.07	0.09	(0.04)	7.12	107.8	(277.2)	-72.0%
	E-billed	5,000	20	35%	261.54	2.43	0.01	0.03	2.47	385.0	36.66	7.07	0.09	(0.04)	7.12	179.0	(206.1)	-53.5%
		5,000	30	23%	261.54	2.43	0.01	0.03	2.47	385.0	36.66	7.07	0.09	(0.04)	7.12	250.1	(134.9)	-35.0%
		5,000	40	17%	261.54	2.43	0.01	0.03	2.47	385.0	36.66	7.07	0.09	(0.04)	7.12	321.3	(63.7)	-16.6%
		5,000	50	14%	261.54	2.43	0.01	0.03	2.47	385.0	36.66	7.07	0.09	(0.04)	7.12	392.4	7.4	1.9%
		5,000	60	12%	261.54	2.43	0.01	0.03	2.47	385.0	36.66	7.07	0.09	(0.04)	7.12	463.6	78.6	20.4%
		846	26	5%	261.54	2.43	0.01	0.03	2.47	282.4	36.66	7.07	0.09	(0.04)	7.12	221.4	(61.1)	-21.6%
					[$/month]	[c/kWh]	[c/kWh]	[c/kWh]	[c/kWh]									
Dgen	Eganville	5,000	10	69%	21.35	2.32	0.17	0.12	2.61	151.9	36.66	7.07	0.37	(0.04)	7.40	110.6	(41.2)	-27.2%
	E-billed	5,000	20	35%	21.35	2.32	0.17	0.12	2.61	151.9	36.66	7.07	0.37	(0.04)	7.40	184.6	32.7	21.6%
		5,000	30	23%	21.35	2.32	0.17	0.12	2.61	151.9	36.66	7.07	0.37	(0.04)	7.40	258.5	106.7	70.3%
		5,000	40	17%	21.35	2.32	0.17	0.12	2.61	151.9	36.66	7.07	0.37	(0.04)	7.40	332.5	180.6	119.0%
		5,000	50	14%	21.35	2.32	0.17	0.12	2.61	151.9	36.66	7.07	0.37	(0.04)	7.40	406.4	254.6	167.7%
		5,000	60	12%	21.35	2.32	0.17	0.12	2.61	151.9	36.66	7.07	0.37	(0.04)	7.40	480.4	328.6	216.4%
		6	1	1%	21.35	2.32	0.17	0.12	2.61	21.5	36.66	7.07	0.37	(0.04)	7.40	45.5	24.0	111.7%

New Rate Class: GSe - Low Use Secondary

Bill Impacts of Proposed Distribution Rates include Riders

Classes		Scenario	Existing Dx Rates						New Dx Rates						$ Incr	% Incr
			SrChg	base	Rider1	Rider2	VarChg	[$/month]	SrChg	base	Rider2	Rider3	VarChg	[$/month]		
New Class	Old Class	kWh	[$/month]	[c/kWh]	[c/kWh]	[c/kWh]	[c/kWh]		[$/month]	[c/kWh]	[c/kWh]	[c/kWh]	[c/kWh]			
GSe	**F1**	50	-	2.37	0.08	0.10	2.55	1.28	6.19	3.39	0.09	(0.06)	3.42	7.90	6.63	519.9%
		75	-	2.37	0.08	0.10	2.55	1.91	6.19	3.39	0.09	(0.06)	3.42	8.76	6.85	358.0%
	F1	100	-	2.37	0.08	0.10	2.55	2.55	6.19	3.39	0.09	(0.06)	3.42	9.61	7.06	277.0%
		125	-	2.37	0.08	0.10	2.55	3.19	6.19	3.39	0.09	(0.06)	3.42	10.47	7.28	228.4%
		150	-	2.37	0.08	0.10	2.55	3.83	6.19	3.39	0.09	(0.06)	3.42	11.32	7.50	196.0%
		200	-	2.37	0.08	0.10	2.55	5.10	6.19	3.39	0.09	(0.06)	3.42	13.03	7.93	155.6%
		400	-	2.37	0.08	0.10	2.55	10.20	6.19	3.39	0.09	(0.06)	3.42	19.87	9.67	94.8%
GSe	**F3**	50	-	3.20	0.02	0.05	3.27	1.64	6.19	3.39	0.09	(0.06)	3.42	7.90	6.27	383.4%
		75	-	3.20	0.02	0.05	3.27	2.45	6.19	3.39	0.09	(0.06)	3.42	8.76	6.31	257.1%
	F3, G3	100	-	3.20	0.02	0.05	3.27	3.27	6.19	3.39	0.09	(0.06)	3.42	9.61	6.34	194.0%
		125	-	3.20	0.02	0.05	3.27	4.09	6.19	3.39	0.09	(0.06)	3.42	10.47	6.38	156.1%
		150	-	3.20	0.02	0.05	3.27	4.91	6.19	3.39	0.09	(0.06)	3.42	11.32	6.42	130.9%
		200	-	3.20	0.02	0.05	3.27	6.54	6.19	3.39	0.09	(0.06)	3.42	13.03	6.49	99.3%
		400	-	3.20	0.02	0.05	3.27	13.08	6.19	3.39	0.09	(0.06)	3.42	19.87	6.79	51.9%
GSe	**G1**	50	-	3.25	0.09	0.09	3.43	1.72	6.19	3.39	0.09	(0.06)	3.42	7.90	6.19	360.9%
		75	-	3.25	0.09	0.09	3.43	2.57	6.19	3.39	0.09	(0.06)	3.42	8.76	6.19	240.5%
	R1,R2,R3	100	-	3.25	0.09	0.09	3.43	3.43	6.19	3.39	0.09	(0.06)	3.42	9.61	6.18	180.3%
	R4,G1	125	-	3.25	0.09	0.09	3.43	4.29	6.19	3.39	0.09	(0.06)	3.42	10.47	6.18	144.2%
		150	-	3.25	0.09	0.09	3.43	5.15	6.19	3.39	0.09	(0.06)	3.42	11.32	6.18	120.1%
		200	-	3.25	0.09	0.09	3.43	6.86	6.19	3.39	0.09	(0.06)	3.42	13.03	6.17	90.0%
		400	-	3.25	0.09	0.09	3.43	13.72	6.19	3.39	0.09	(0.06)	3.42	19.87	6.15	44.8%

New Rate Class: UR

Total Bill Impacts of Proposed Distribution Rates[old RTSR+TLF]: Threshold of 600 kWhs

600.0

Classes		Scenario	May 2007 Incl Rate Riders						May 2008 Incl Rate Riders						Non-Dx Compoent				Other Reg	Commodity Bands			Existing	New	$ Incr	% Incr
			Existing Dx Rates					Existing Dx	New Dx Rates					New Dx	RTSR old	WMSC	DRC	TLF old	Old	Band 1	Band 2	Old	Total Bill	Total Bill	Total Bill	Total Bill
																				5.0	5.9					
New Class	Old Class	kWh	SrChg	base	Rider1	Rider2	VarChg	[$/month]	SrChg	base	Rider2	Rider3	VarChg	[$/month]	c/kWh	c/kWh	c/kWh		$	kWhs	kWhs	Total $	[$/month]	[$/month]	[$/month]	%
UR	**UR**	100	**14.32**	**1.83**	**0.20**	**0.05**	**2.08**	16.4	**14.00**	**2.44**	**0.05**	**(0.02)**	**2.47**	16.5	**0.94**	0.62	0.7	**1.092**	2.4	100	-	5.5	24.3	24.3	0.1	0.3%
		250	14.32	1.83	0.20	0.05	2.08	19.5	14.00	2.44	0.05	(0.02)	2.47	20.2	0.94	0.62	0.7	1.092	6.0	250	-	13.7	39.2	39.8	0.6	1.6%
		500	14.32	1.83	0.20	0.05	2.08	24.7	14.00	2.44	0.05	(0.02)	2.47	26.3	0.94	0.62	0.7	1.092	12.0	500	-	27.3	64.0	65.6	1.6	2.5%
		750	14.32	1.83	0.20	0.05	2.08	29.9	14.00	2.44	0.05	(0.02)	2.47	32.5	0.94	0.62	0.7	1.092	18.0	600	150	42.9	90.9	93.4	2.6	2.8%
		1,000	14.32	1.83	0.20	0.05	2.08	35.1	14.00	2.44	0.05	(0.02)	2.47	38.7	0.94	0.62	0.7	1.092	24.0	600	400	59.0	118.2	121.7	3.5	3.0%
		1,500	14.32	1.83	0.20	0.05	2.08	45.5	14.00	2.44	0.05	(0.02)	2.47	51.0	0.94	0.62	0.7	1.092	36.1	600	900	91.2	172.8	178.3	5.5	3.2%
		2,000	14.32	1.83	0.20	0.05	2.08	55.9	14.00	2.44	0.05	(0.02)	2.47	63.3	0.94	0.62	0.7	1.092	48.1	600	1,400	123.5	227.4	234.8	7.4	3.3%
UR	**R1**	100	**19.04**	**2.38**	**0.15**	**0.07**	**2.60**	21.6	**14.00**	**2.44**	**0.05**	**(0.02)**	**2.47**	16.5	**0.94**	0.62	0.7	**1.092**	2.4	100	-	5.5	29.5	24.3	(5.2)	-17.5%
		250	19.04	2.38	0.15	0.07	2.60	25.5	14.00	2.44	0.05	(0.02)	2.47	20.2	0.94	0.62	0.70	1.092	6.0	250	-	13.7	45.2	39.8	(5.4)	-11.9%
		500	19.04	2.38	0.15	0.07	2.60	32.0	14.00	2.44	0.05	(0.02)	2.47	26.3	0.94	0.62	0.70	1.092	12.0	500	-	27.3	71.4	65.6	(5.7)	-8.0%
		750	19.04	2.38	0.15	0.07	2.60	38.5	14.00	2.44	0.05	(0.02)	2.47	32.5	0.94	0.62	0.70	1.092	18.0	600	150	42.9	99.5	93.4	(6.0)	-6.1%
		1,000	19.04	2.38	0.15	0.07	2.60	45.0	14.00	2.44	0.05	(0.02)	2.47	38.7	0.94	0.62	0.70	1.092	24.0	600	400	59.0	128.1	121.7	(6.4)	-5.0%
		1,500	19.04	2.38	0.15	0.07	2.60	58.0	14.00	2.44	0.05	(0.02)	2.47	51.0	0.94	0.62	0.70	1.092	36.1	600	900	91.2	185.3	178.3	(7.1)	-3.8%
		2,000	19.04	2.38	0.15	0.07	2.60	71.0	14.00	2.44	0.05	(0.02)	2.47	63.3	0.94	0.62	0.70	1.092	48.1	600	1,400	123.5	242.6	234.8	(7.7)	-3.2%
UR	**R2**	100	**29.22**	**1.94**	**0.12**	**0.13**	**2.19**	31.4	**14.00**	**2.44**	**0.05**	**(0.02)**	**2.47**	16.5	**0.94**	0.62	0.7	**1.092**	2.4	100	-	5.5	39.3	24.3	(14.9)	-38.1%
		250	29.22	1.94	0.12	0.13	2.19	34.7	14.00	2.44	0.05	(0.02)	2.47	20.2	0.94	0.62	0.70	1.092	6.0	250	-	13.7	54.4	39.8	(14.5)	-26.7%
		500	29.22	1.94	0.12	0.13	2.19	40.2	14.00	2.44	0.05	(0.02)	2.47	26.3	0.94	0.62	0.70	1.092	12.0	500	-	27.3	79.5	65.6	(13.8)	-17.4%
		750	29.22	1.94	0.12	0.13	2.19	45.6	14.00	2.44	0.05	(0.02)	2.47	32.5	0.94	0.62	0.70	1.092	18.0	600	150	42.9	106.6	93.4	(13.2)	-12.3%
		1,000	29.22	1.94	0.12	0.13	2.19	51.1	14.00	2.44	0.05	(0.02)	2.47	38.7	0.94	0.62	0.70	1.092	24.0	600	400	59.0	134.2	121.7	(12.5)	-9.3%
		1,500	29.22	1.94	0.12	0.13	2.19	62.1	14.00	2.44	0.05	(0.02)	2.47	51.0	0.94	0.62	0.70	1.092	36.1	600	900	91.2	189.4	178.3	(11.1)	-5.9%
		2,000	29.22	1.94	0.12	0.13	2.19	73.0	14.00	2.44	0.05	(0.02)	2.47	63.3	0.94	0.62	0.70	1.092	48.1	600	1,400	123.5	244.5	234.8	(9.7)	-4.0%
UR	**F1**	100	**28.61**	**2.24**	**0.08**	**0.10**	**2.42**	31.0	**14.00**	**2.44**	**0.05**	**(0.02)**	**2.47**	16.5	**0.89**	0.62	0.7	**1.092**	2.3	100	-	5.5	38.8	24.3	(14.6)	-37.5%
		250	28.61	2.24	0.08	0.10	2.42	34.7	14.00	2.44	0.05	(0.02)	2.47	20.2	0.89	0.62	0.70	1.092	5.9	250	-	13.7	54.2	39.7	(14.5)	-26.8%
		500	28.61	2.24	0.08	0.10	2.42	40.7	14.00	2.44	0.05	(0.02)	2.47	26.3	0.89	0.62	0.70	1.092	11.7	500	-	27.3	79.8	65.4	(14.4)	-18.0%
		750	28.61	2.24	0.08	0.10	2.42	46.8	14.00	2.44	0.05	(0.02)	2.47	32.5	0.89	0.62	0.70	1.092	17.6	600	150	42.9	107.3	93.0	(14.3)	-13.3%
		1,000	28.61	2.24	0.08	0.10	2.42	52.8	14.00	2.44	0.05	(0.02)	2.47	38.7	0.89	0.62	0.70	1.092	23.5	600	400	59.0	135.3	121.2	(14.2)	-10.5%
		1,500	28.61	2.24	0.08	0.10	2.42	64.9	14.00	2.44	0.05	(0.02)	2.47	51.0	0.89	0.62	0.70	1.092	35.2	600	900	91.2	191.4	177.5	(13.9)	-7.3%
		2,000	28.61	2.24	0.08	0.10	2.42	77.0	14.00	2.44	0.05	(0.02)	2.47	63.3	0.89	0.62	0.70	1.092	47.0	600	1,400	123.5	247.4	233.7	(13.7)	-5.5%

New Rate Class: UR

Total Bill Impacts of Proposed Distribution Rates[old RTSR+TLF]: Threshold of 600 kWhs

Classes		Scenario	May 2007 Incl Rate Riders						May 2008 Incl Rate Riders						Non-Dx Compoent				Other Reg	Commodity Bands			Existing	New	$ Incr	% Incr
			Existing Dx Rates					Existing Dx	New Dx Rates					New Dx	RTSR old	WMSC	DRC	TLF old	Old	Band 1	Band 2	Old	Total Bill	Total Bill	Total Bill	Total Bill
																				600.0						
																				5.0	5.9					
New Class	Old Class	kWh	SrChg	base	Rider1	Rider2	VarChg	[$/month]	SrChg	base	Rider2	Rider3	VarChg	[$/month]	c/kWh	c/kWh	c/kWh		$	kWhs	kWhs	Total $	[$/month]	[$/month]	[$/month]	%
UR	**Arnprior**	100	**11.54**	**1.47**	**0.49**	**0.18**	**2.14**	13.7	**11.70**	**2.40**	**0.18**	**(0.02)**	**2.55**	14.2	**1.02**	0.62	0.7	1.055	2.4	100	-	5.3	21.4	21.9	0.6	2.6%
		250	11.54	1.47	0.49	0.18	2.14	16.9	11.70	2.40	0.18	(0.02)	2.55	18.1	1.02	0.62	0.70	1.055	6.1	250	-	13.2	36.1	37.3	1.2	3.3%
		500	11.54	1.47	0.49	0.18	2.14	22.2	11.70	2.40	0.18	(0.02)	2.55	24.4	1.02	0.62	0.70	1.055	12.1	500	-	26.4	60.7	63.0	2.2	3.6%
		750	11.54	1.47	0.49	0.18	2.14	27.6	11.70	2.40	0.18	(0.02)	2.55	30.8	1.02	0.62	0.70	1.055	18.2	600	150	41.3	87.1	90.3	3.2	3.7%
		1,000	11.54	1.47	0.49	0.18	2.14	32.9	11.70	2.40	0.18	(0.02)	2.55	37.2	1.02	0.62	0.70	1.055	24.3	600	400	56.8	114.0	118.3	4.3	3.7%
		1,500	11.54	1.47	0.49	0.18	2.14	43.6	11.70	2.40	0.18	(0.02)	2.55	50.0	1.02	0.62	0.70	1.055	36.4	600	900	87.9	168.0	174.3	6.3	3.8%
		2,000	11.54	1.47	0.49	0.18	2.14	54.3	11.70	2.40	0.18	(0.02)	2.55	62.7	1.02	0.62	0.70	1.055	48.6	600	1,400	119.0	222.0	230.3	8.4	3.8%
UR	**Brockville**	100	**12.33**	**0.93**	**0.48**	**0.16**	**1.57**	13.9	**12.50**	**2.40**	**0.16**	**(0.02)**	**2.53**	15.0	**1.02**	0.62	0.7	1.055	2.4	100	-	5.3	21.6	22.7	1.1	5.2%
		250	12.33	0.93	0.48	0.16	1.57	16.3	12.50	2.40	0.16	(0.02)	2.53	18.8	1.02	0.62	0.70	1.055	6.1	250	-	13.2	35.5	38.1	2.6	7.2%
		500	12.33	0.93	0.48	0.16	1.57	20.2	12.50	2.40	0.16	(0.02)	2.53	25.2	1.02	0.62	0.70	1.055	12.1	500	-	26.4	58.7	63.7	5.0	8.5%
		750	12.33	0.93	0.48	0.16	1.57	24.1	12.50	2.40	0.16	(0.02)	2.53	31.5	1.02	0.62	0.70	1.055	18.2	600	150	41.3	83.6	91.0	7.4	8.8%
		1,000	12.33	0.93	0.48	0.16	1.57	28.0	12.50	2.40	0.16	(0.02)	2.53	37.8	1.02	0.62	0.70	1.055	24.3	600	400	56.8	109.1	118.9	9.8	9.0%
		1,500	12.33	0.93	0.48	0.16	1.57	35.9	12.50	2.40	0.16	(0.02)	2.53	50.5	1.02	0.62	0.70	1.055	36.4	600	900	87.9	160.2	174.8	14.6	9.1%
		2,000	12.33	0.93	0.48	0.16	1.57	43.7	12.50	2.40	0.16	(0.02)	2.53	63.1	1.02	0.62	0.70	1.055	48.6	600	1,400	119.0	211.3	230.7	19.4	9.2%
UR	**Caledon OH 01**	100	**18.52**	**0.57**	**0.42**	**0.16**	**1.15**	19.7	**16.95**	**2.15**	**0.16**	**(0.02)**	**2.29**	19.2	**1.02**	0.62	0.7	1.055	2.4	100	-	5.3	27.4	26.9	(0.4)	-1.6%
		250	18.52	0.57	0.42	0.16	1.15	21.4	16.95	2.15	0.16	(0.02)	2.29	22.7	1.02	0.62	0.70	1.055	6.1	250	-	13.2	40.6	41.9	1.3	3.1%
		500	18.52	0.57	0.42	0.16	1.15	24.3	16.95	2.15	0.16	(0.02)	2.29	28.4	1.02	0.62	0.70	1.055	12.1	500	-	26.4	62.8	66.9	4.1	6.5%
		750	18.52	0.57	0.42	0.16	1.15	27.1	16.95	2.15	0.16	(0.02)	2.29	34.1	1.02	0.62	0.70	1.055	18.2	600	150	41.3	86.6	93.6	6.9	8.0%
		1,000	18.52	0.57	0.42	0.16	1.15	30.0	16.95	2.15	0.16	(0.02)	2.29	39.8	1.02	0.62	0.70	1.055	24.3	600	400	56.8	111.1	120.9	9.8	8.8%
		1,500	18.52	0.57	0.42	0.16	1.15	35.8	16.95	2.15	0.16	(0.02)	2.29	51.2	1.02	0.62	0.70	1.055	36.4	600	900	87.9	160.1	175.6	15.5	9.7%
		2,000	18.52	0.57	0.42	0.16	1.15	41.5	16.95	2.15	0.16	(0.02)	2.29	62.7	1.02	0.62	0.70	1.055	48.6	600	1,400	119.0	209.1	230.3	21.1	10.1%
UR	**Carleton Place**	100	**14.17**	**1.79**	**0.38**	**0.15**	**2.32**	16.5	**14.04**	**2.40**	**0.15**	**(0.02)**	**2.52**	16.6	**1.02**	0.62	0.7	1.055	2.4	100	-	5.3	24.2	24.3	0.1	0.3%
		250	14.17	1.79	0.38	0.15	2.32	20.0	14.04	2.40	0.15	(0.02)	2.52	20.3	1.02	0.62	0.70	1.055	6.1	250	-	13.2	39.2	39.6	0.4	0.9%
		500	14.17	1.79	0.38	0.15	2.32	25.8	14.04	2.40	0.15	(0.02)	2.52	26.6	1.02	0.62	0.70	1.055	12.1	500	-	26.4	64.3	65.2	0.9	1.4%
		750	14.17	1.79	0.38	0.15	2.32	31.6	14.04	2.40	0.15	(0.02)	2.52	32.9	1.02	0.62	0.70	1.055	18.2	600	150	41.3	91.1	92.4	1.4	1.5%
		1,000	14.17	1.79	0.38	0.15	2.32	37.4	14.04	2.40	0.15	(0.02)	2.52	39.2	1.02	0.62	0.70	1.055	24.3	600	400	56.8	118.5	120.4	1.9	1.6%
		1,500	14.17	1.79	0.38	0.15	2.32	49.0	14.04	2.40	0.15	(0.02)	2.52	51.9	1.02	0.62	0.70	1.055	36.4	600	900	87.9	173.3	176.2	2.9	1.7%
		2,000	14.17	1.79	0.38	0.15	2.32	60.6	14.04	2.40	0.15	(0.02)	2.52	64.5	1.02	0.62	0.70	1.055	48.6	600	1,400	119.0	228.2	232.1	3.9	1.7%

New Rate Class: UR

Total Bill Impacts of Proposed Distribution Rates[old RTSR+TLF]: Threshold of 600 kWhs

600.0

Classes		Scenario	May 2007 Incl Rate Riders						May 2008 Incl Rate Riders						Non-Dx Compoent				Other Reg	Commodity Bands			Existing	New	$ Incr	% Incr
			Existing Dx Rates					Existing Dx	New Dx Rates					New Dx	RTSR old	WMSC	DRC	TLF old	Old	Band 1	Band 2	Old	Total Bill	Total Bill	Total Bill	Total Bill
																				5.0	5.9					
New Class	Old Class	kWh	SrChg	base	Rider1	Rider2	VarChg	[$/month]	SrChg	base	Rider2	Rider3	VarChg	[$/month]	c/kWh	c/kWh	c/kWh		$	kWhs	kWhs	Total $	[$/month]	[$/month]	[$/month]	%
UR	**Dryden**	100	**14.28**	**1.65**	**0.43**	**0.18**	**2.26**	16.5	**14.01**	**2.40**	**0.18**	**(0.02)**	**2.55**	16.6	**1.02**	0.62	0.7	1.055	2.4	100	-	5.3	24.2	24.3	0.0	0.1%
		250	14.28	1.65	0.43	0.18	2.26	19.9	14.01	2.40	0.18	(0.02)	2.55	20.4	1.02	0.62	0.70	1.055	6.1	250	-	13.2	39.2	39.6	0.5	1.2%
		500	14.28	1.65	0.43	0.18	2.26	25.6	14.01	2.40	0.18	(0.02)	2.55	26.8	1.02	0.62	0.70	1.055	12.1	500	-	26.4	64.1	65.3	1.2	1.8%
		750	14.28	1.65	0.43	0.18	2.26	31.2	14.01	2.40	0.18	(0.02)	2.55	33.1	1.02	0.62	0.70	1.055	18.2	600	150	41.3	90.7	92.6	1.9	2.1%
		1,000	14.28	1.65	0.43	0.18	2.26	36.9	14.01	2.40	0.18	(0.02)	2.55	39.5	1.02	0.62	0.70	1.055	24.3	600	400	56.8	118.0	120.6	2.6	2.2%
		1,500	14.28	1.65	0.43	0.18	2.26	48.2	14.01	2.40	0.18	(0.02)	2.55	52.3	1.02	0.62	0.70	1.055	36.4	600	900	87.9	172.5	176.6	4.1	2.4%
		2,000	14.28	1.65	0.43	0.18	2.26	59.5	14.01	2.40	0.18	(0.02)	2.55	65.0	1.02	0.62	0.70	1.055	48.6	600	1,400	119.0	227.1	232.6	5.5	2.4%
UR	**GBE**	100	**9.68**	**0.95**	**0.46**	**0.13**	**1.54**	11.2	**10.16**	**2.35**	**0.13**	**(0.02)**	**2.46**	12.6	**1.02**	0.62	0.7	1.055	2.4	100	-	5.3	18.9	20.3	1.4	7.4%
		250	9.68	0.95	0.46	0.13	1.54	13.5	10.16	2.35	0.13	(0.02)	2.46	16.3	1.02	0.62	0.70	1.055	6.1	250	-	13.2	32.8	35.6	2.8	8.4%
		500	9.68	0.95	0.46	0.13	1.54	17.4	10.16	2.35	0.13	(0.02)	2.46	22.4	1.02	0.62	0.70	1.055	12.1	500	-	26.4	55.9	60.9	5.1	9.0%
		750	9.68	0.95	0.46	0.13	1.54	21.2	10.16	2.35	0.13	(0.02)	2.46	28.6	1.02	0.62	0.70	1.055	18.2	600	150	41.3	80.7	88.1	7.3	9.1%
		1,000	9.68	0.95	0.46	0.13	1.54	25.1	10.16	2.35	0.13	(0.02)	2.46	34.7	1.02	0.62	0.70	1.055	24.3	600	400	56.8	106.2	115.8	9.6	9.1%
		1,500	9.68	0.95	0.46	0.13	1.54	32.8	10.16	2.35	0.13	(0.02)	2.46	47.0	1.02	0.62	0.70	1.055	36.4	600	900	87.9	157.1	171.4	14.2	9.0%
		2,000	9.68	0.95	0.46	0.13	1.54	40.5	10.16	2.35	0.13	(0.02)	2.46	59.3	1.02	0.62	0.70	1.055	48.6	600	1,400	119.0	208.1	226.9	18.8	9.0%
UR	**Lindsay**	100	**15.81**	**1.01**	**0.41**	**0.14**	**1.56**	17.4	**14.63**	**2.40**	**0.14**	**(0.02)**	**2.51**	17.1	**1.02**	0.62	0.7	1.055	2.4	100	-	5.3	25.1	24.8	(0.2)	-0.9%
		250	15.81	1.01	0.41	0.14	1.56	19.7	14.63	2.40	0.14	(0.02)	2.51	20.9	1.02	0.62	0.70	1.055	6.1	250	-	13.2	39.0	40.2	1.2	3.1%
		500	15.81	1.01	0.41	0.14	1.56	23.6	14.63	2.40	0.14	(0.02)	2.51	27.2	1.02	0.62	0.70	1.055	12.1	500	-	26.4	62.1	65.7	3.6	5.8%
		750	15.81	1.01	0.41	0.14	1.56	27.5	14.63	2.40	0.14	(0.02)	2.51	33.5	1.02	0.62	0.70	1.055	18.2	600	150	41.3	87.0	92.9	5.9	6.8%
		1,000	15.81	1.01	0.41	0.14	1.56	31.4	14.63	2.40	0.14	(0.02)	2.51	39.7	1.02	0.62	0.70	1.055	24.3	600	400	56.8	112.5	120.8	8.3	7.4%
		1,500	15.81	1.01	0.41	0.14	1.56	39.2	14.63	2.40	0.14	(0.02)	2.51	52.3	1.02	0.62	0.70	1.055	36.4	600	900	87.9	163.6	176.7	13.1	8.0%
		2,000	15.81	1.01	0.41	0.14	1.56	47.0	14.63	2.40	0.14	(0.02)	2.51	64.8	1.02	0.62	0.70	1.055	48.6	600	1,400	119.0	214.6	232.5	17.8	8.3%
UR	**Perth**	100	**14.47**	**1.22**	**0.50**	**0.18**	**1.90**	16.4	**13.96**	**2.40**	**0.18**	**(0.02)**	**2.55**	16.5	**1.02**	0.62	0.7	1.055	2.4	100	-	5.3	24.1	24.2	0.1	0.6%
		250	14.47	1.22	0.50	0.18	1.90	19.2	13.96	2.40	0.18	(0.02)	2.55	20.3	1.02	0.62	0.70	1.055	6.1	250	-	13.2	38.5	39.6	1.1	2.9%
		500	14.47	1.22	0.50	0.18	1.90	24.0	13.96	2.40	0.18	(0.02)	2.55	26.7	1.02	0.62	0.70	1.055	12.1	500	-	26.4	62.5	65.2	2.7	4.4%
		750	14.47	1.22	0.50	0.18	1.90	28.7	13.96	2.40	0.18	(0.02)	2.55	33.1	1.02	0.62	0.70	1.055	18.2	600	150	41.3	88.2	92.6	4.4	5.0%
		1,000	14.47	1.22	0.50	0.18	1.90	33.5	13.96	2.40	0.18	(0.02)	2.55	39.5	1.02	0.62	0.70	1.055	24.3	600	400	56.8	114.6	120.6	6.0	5.2%
		1,500	14.47	1.22	0.50	0.18	1.90	43.0	13.96	2.40	0.18	(0.02)	2.55	52.2	1.02	0.62	0.70	1.055	36.4	600	900	87.9	167.3	176.6	9.3	5.5%
		2,000	14.47	1.22	0.50	0.18	1.90	52.5	13.96	2.40	0.18	(0.02)	2.55	65.0	1.02	0.62	0.70	1.055	48.6	600	1,400	119.0	220.1	232.6	12.5	5.7%

New Rate Class: UR

Total Bill Impacts of Proposed Distribution Rates[old RTSR+TLF]: Threshold of 600 kWhs

600.0

Classes		Scenario	May 2007 Incl Rate Riders						May 2008 Incl Rate Riders						Non-Dx Compoent				Other Reg	Commodity Bands			Existing	New	$ Incr	% Incr
			Existing Dx Rates					Existing Dx	New Dx Rates					New Dx	RTSR old	WMSC	DRC	TLF old	Old	Band 1	Band 2	Old	Total Bill	Total Bill	Total Bill	Total Bill
																				5.0	5.9					
New Class	Old Class	kWh	SrChg	base	Rider1	Rider2	VarChg	[$/month]	SrChg	base	Rider2	Rider3	VarChg	[$/month]	c/kWh	c/kWh	c/kWh		$	kWhs	kWhs	Total $	[$/month]	[$/month]	[$/month]	%
UR	**Quinte West**	100	**6.58**	**0.92**	**0.39**	**0.11**	**1.42**	8.0	**7.94**	**2.10**	**0.11**	**(0.02)**	**2.19**	10.1	**1.02**	0.62	0.7	1.055	2.4	100	-	5.3	15.7	17.8	2.1	13.5%
		250	6.58	0.92	0.39	0.11	1.42	10.1	7.94	2.10	0.11	(0.02)	2.19	13.4	1.02	0.62	0.70	1.055	6.1	250	-	13.2	29.4	32.7	3.3	11.1%
		500	6.58	0.92	0.39	0.11	1.42	13.7	7.94	2.10	0.11	(0.02)	2.19	18.9	1.02	0.62	0.70	1.055	12.1	500	-	26.4	52.2	57.4	5.2	9.9%
		750	6.58	0.92	0.39	0.11	1.42	17.2	7.94	2.10	0.11	(0.02)	2.19	24.3	1.02	0.62	0.70	1.055	18.2	600	150	41.3	76.7	83.8	7.1	9.2%
		1,000	6.58	0.92	0.39	0.11	1.42	20.8	7.94	2.10	0.11	(0.02)	2.19	29.8	1.02	0.62	0.70	1.055	24.3	600	400	56.8	101.9	110.9	9.0	8.8%
		1,500	6.58	0.92	0.39	0.11	1.42	27.9	7.94	2.10	0.11	(0.02)	2.19	40.7	1.02	0.62	0.70	1.055	36.4	600	900	87.9	152.2	165.1	12.8	8.4%
		2,000	6.58	0.92	0.39	0.11	1.42	35.0	7.94	2.10	0.11	(0.02)	2.19	51.6	1.02	0.62	0.70	1.055	48.6	600	1,400	119.0	202.6	219.3	16.7	8.2%
UR	**Smiths Falls**	100	**12.63**	**1.42**	**0.46**	**0.17**	**2.05**	14.7	**12.42**	**2.40**	**0.17**	**(0.02)**	**2.54**	15.0	**1.02**	0.62	0.7	1.055	2.4	100	-	5.3	22.4	22.7	0.3	1.3%
		250	12.63	1.42	0.46	0.17	2.05	17.8	12.42	2.40	0.17	(0.02)	2.54	18.8	1.02	0.62	0.70	1.055	6.1	250	-	13.2	37.0	38.0	1.0	2.8%
		500	12.63	1.42	0.46	0.17	2.05	22.9	12.42	2.40	0.17	(0.02)	2.54	25.1	1.02	0.62	0.70	1.055	12.1	500	-	26.4	61.4	63.6	2.2	3.7%
		750	12.63	1.42	0.46	0.17	2.05	28.0	12.42	2.40	0.17	(0.02)	2.54	31.5	1.02	0.62	0.70	1.055	18.2	600	150	41.3	87.5	91.0	3.5	4.0%
		1,000	12.63	1.42	0.46	0.17	2.05	33.1	12.42	2.40	0.17	(0.02)	2.54	37.8	1.02	0.62	0.70	1.055	24.3	600	400	56.8	114.2	118.9	4.7	4.1%
		1,500	12.63	1.42	0.46	0.17	2.05	43.4	12.42	2.40	0.17	(0.02)	2.54	50.5	1.02	0.62	0.70	1.055	36.4	600	900	87.9	167.7	174.9	7.2	4.3%
		2,000	12.63	1.42	0.46	0.17	2.05	53.6	12.42	2.40	0.17	(0.02)	2.54	63.2	1.02	0.62	0.70	1.055	48.6	600	1,400	119.0	221.2	230.9	9.6	4.3%
UR	**Thorold**	100	**13.68**	**1.47**	**0.41**	**0.14**	**2.02**	15.7	**13.16**	**2.40**	**0.14**	**(0.02)**	**2.51**	15.7	**1.02**	0.62	0.7	1.055	2.4	100	-	5.3	23.4	23.4	(0.0)	-0.1%
		250	13.68	1.47	0.41	0.14	2.02	18.7	13.16	2.40	0.14	(0.02)	2.51	19.4	1.02	0.62	0.70	1.055	6.1	250	-	13.2	38.0	38.7	0.7	1.9%
		500	13.68	1.47	0.41	0.14	2.02	23.8	13.16	2.40	0.14	(0.02)	2.51	25.7	1.02	0.62	0.70	1.055	12.1	500	-	26.4	62.3	64.2	1.9	3.1%
		750	13.68	1.47	0.41	0.14	2.02	28.8	13.16	2.40	0.14	(0.02)	2.51	32.0	1.02	0.62	0.70	1.055	18.2	600	150	41.3	88.3	91.5	3.2	3.6%
		1,000	13.68	1.47	0.41	0.14	2.02	33.9	13.16	2.40	0.14	(0.02)	2.51	38.3	1.02	0.62	0.70	1.055	24.3	600	400	56.8	115.0	119.4	4.4	3.8%
		1,500	13.68	1.47	0.41	0.14	2.02	44.0	13.16	2.40	0.14	(0.02)	2.51	50.8	1.02	0.62	0.70	1.055	36.4	600	900	87.9	168.3	175.2	6.8	4.1%
		2,000	13.68	1.47	0.41	0.14	2.02	54.1	13.16	2.40	0.14	(0.02)	2.51	63.4	1.02	0.62	0.70	1.055	48.6	600	1,400	119.0	221.7	231.0	9.3	4.2%
UR	**Whitchurch Stouffville**	100	**10.54**	**1.02**	**0.36**	**0.12**	**1.50**	12.0	**10.95**	**2.30**	**0.12**	**(0.02)**	**2.40**	13.3	**1.02**	0.62	0.7	1.055	2.4	100	-	5.3	19.7	21.0	1.3	6.6%
		250	10.54	1.02	0.36	0.12	1.50	14.3	10.95	2.30	0.12	(0.02)	2.40	16.9	1.02	0.62	0.70	1.055	6.1	250	-	13.2	33.5	36.2	2.6	7.9%
		500	10.54	1.02	0.36	0.12	1.50	18.0	10.95	2.30	0.12	(0.02)	2.40	22.9	1.02	0.62	0.70	1.055	12.1	500	-	26.4	56.5	61.4	4.9	8.6%
		750	10.54	1.02	0.36	0.12	1.50	21.8	10.95	2.30	0.12	(0.02)	2.40	28.9	1.02	0.62	0.70	1.055	18.2	600	150	41.3	81.3	88.4	7.1	8.8%
		1,000	10.54	1.02	0.36	0.12	1.50	25.5	10.95	2.30	0.12	(0.02)	2.40	34.9	1.02	0.62	0.70	1.055	24.3	600	400	56.8	106.6	116.0	9.4	8.8%
		1,500	10.54	1.02	0.36	0.12	1.50	33.0	10.95	2.30	0.12	(0.02)	2.40	46.9	1.02	0.62	0.70	1.055	36.4	600	900	87.9	157.4	171.2	13.8	8.8%
		2,000	10.54	1.02	0.36	0.12	1.50	40.5	10.95	2.30	0.12	(0.02)	2.40	58.8	1.02	0.62	0.70	1.055	48.6	600	1,400	119.0	208.2	226.5	18.3	8.8%

New Rate Class: R1

Total Bill Impacts of Proposed Distribution Rates [old RTSR+TLF]: Threshold of 600 kWhs

Classes		Scenario	May 2007 Incl Rate Riders						May 2008 Incl Rate Riders						Non-Dx Compoent				Other Reg	Commodity Bands			Existing	New	$ Incr	Incr
			Existing Dx Rates					Existing Dx	New Dx Rates					New Dx	RTSR old	WMSC	DRC	TLF old	Old	Band 1	Band 2	Old	Total Bill	Total Bill	Total Bill	Total Bill
																				600.0						
																				5.0	5.9					
New Class	Old Class	kWh	SrChg	base	Rider1	Rider2	VarChg	[$/month]	SrChg	base	Rider2	Rider3	VarChg	[$/month]	c/kWh	c/kWh	c/kWh		$	kWhs	kWhs	Total $	[$/month]	[$/month]	[$/month]	%
R1	R1	100	19.04	2.38	0.15	0.07	2.60	21.6	19.00	2.81	0.07	(0.04)	2.84	21.8	0.94	0.62	0.70	1.092	2.4	100	-	5.5	29.5	29.7	0.2	0.7%
		250	19.04	2.38	0.15	0.07	2.60	25.5	19.00	2.81	0.07	(0.04)	2.84	26.1	0.94	0.62	0.70	1.092	6.0	250	-	13.7	45.2	45.8	0.6	1.2%
		500	19.04	2.38	0.15	0.07	2.60	32.0	19.00	2.81	0.07	(0.04)	2.84	33.2	0.94	0.62	0.70	1.092	12.0	500	-	27.3	71.4	72.5	1.2	1.6%
		750	19.04	2.38	0.15	0.07	2.60	38.5	19.00	2.81	0.07	(0.04)	2.84	40.3	0.94	0.62	0.70	1.092	18.0	600	150	42.9	99.5	101.2	1.7	1.8%
		1,000	19.04	2.38	0.15	0.07	2.60	45.0	19.00	2.81	0.07	(0.04)	2.84	47.4	0.94	0.62	0.70	1.092	24.0	600	400	59.0	128.1	130.4	2.3	1.8%
		1,500	19.04	2.38	0.15	0.07	2.60	58.0	19.00	2.81	0.07	(0.04)	2.84	61.6	0.94	0.62	0.70	1.092	36.1	600	900	91.2	185.3	188.9	3.5	1.9%
		2,000	19.04	2.38	0.15	0.07	2.60	71.0	19.00	2.81	0.07	(0.04)	2.84	75.8	0.94	0.62	0.70	1.092	48.1	600	1,400	123.5	242.6	247.3	4.7	1.9%
R1	Ailsa Craig	100	10.51	0.82	0.35	0.11	1.28	11.8	12.13	1.85	0.11	(0.04)	1.92	14.1	1.02	0.62	0.70	1.0545	2.4	100	-	5.3	19.5	21.8	2.3	11.6%
		250	10.51	0.82	0.35	0.11	1.28	13.7	12.13	1.85	0.11	(0.04)	1.92	16.9	1.02	0.62	0.70	1.0545	6.1	250	-	13.2	33.0	36.2	3.2	9.8%
		500	10.51	0.82	0.35	0.11	1.28	16.9	12.13	1.85	0.11	(0.04)	1.92	21.7	1.02	0.62	0.70	1.0545	12.1	500	-	26.4	55.4	60.3	4.8	8.7%
		750	10.51	0.82	0.35	0.11	1.28	20.1	12.13	1.85	0.11	(0.04)	1.92	26.6	1.02	0.62	0.70	1.0545	18.2	600	150	41.3	79.6	86.0	6.4	8.1%
		1,000	10.51	0.82	0.35	0.11	1.28	23.3	12.13	1.85	0.11	(0.04)	1.92	31.4	1.02	0.62	0.70	1.0545	24.3	600	400	56.8	104.4	112.5	8.1	7.7%
		1,500	10.51	0.82	0.35	0.11	1.28	29.7	12.13	1.85	0.11	(0.04)	1.92	41.0	1.02	0.62	0.70	1.0545	36.4	600	900	87.9	154.1	165.3	11.3	7.3%
		2,000	10.51	0.82	0.35	0.11	1.28	36.1	12.13	1.85	0.11	(0.04)	1.92	50.6	1.02	0.62	0.70	1.0545	48.6	600	1,400	119.0	203.7	218.2	14.5	7.1%
R1	Arkona	100	5.84	0.26	0.68	0.33	1.27	7.1	8.30	1.50	0.33	(0.04)	1.79	10.1	1.02	0.62	0.70	1.0545	2.4	100	-	5.3	14.8	17.8	3.0	20.1%
		250	5.84	0.26	0.68	0.33	1.27	9.0	8.30	1.50	0.33	(0.04)	1.79	12.8	1.02	0.62	0.70	1.0545	6.1	250	-	13.2	28.3	32.0	3.8	13.3%
		500	5.84	0.26	0.68	0.33	1.27	12.2	8.30	1.50	0.33	(0.04)	1.79	17.3	1.02	0.62	0.70	1.0545	12.1	500	-	26.4	50.7	55.8	5.1	10.0%
		750	5.84	0.26	0.68	0.33	1.27	15.4	8.30	1.50	0.33	(0.04)	1.79	21.7	1.02	0.62	0.70	1.0545	18.2	600	150	41.3	74.8	81.2	6.4	8.5%
		1,000	5.84	0.26	0.68	0.33	1.27	18.5	8.30	1.50	0.33	(0.04)	1.79	26.2	1.02	0.62	0.70	1.0545	24.3	600	400	56.8	99.6	107.3	7.7	7.7%
		1,500	5.84	0.26	0.68	0.33	1.27	24.9	8.30	1.50	0.33	(0.04)	1.79	35.2	1.02	0.62	0.70	1.0545	36.4	600	900	87.9	149.3	159.6	10.3	6.9%
		2,000	5.84	0.26	0.68	0.33	1.27	31.2	8.30	1.50	0.33	(0.04)	1.79	44.2	1.02	0.62	0.70	1.0545	48.6	600	1,400	119.0	198.9	211.8	12.9	6.5%
UR	Arnprior	100	11.54	1.47	0.49	0.18	2.14	13.7	11.70	2.40	0.18	(0.02)	2.55	14.2	1.02	0.62	0.70	1.0545	2.4	100	-	5.3	21.4	21.9	0.6	2.6%
		250	11.54	1.47	0.49	0.18	2.14	16.9	11.70	2.40	0.18	(0.02)	2.55	18.1	1.02	0.62	0.70	1.0545	6.1	250	-	13.2	36.1	37.3	1.2	3.3%
		500	11.54	1.47	0.49	0.18	2.14	22.2	11.70	2.40	0.18	(0.02)	2.55	24.4	1.02	0.62	0.70	1.0545	12.1	500	-	26.4	60.7	63.0	2.2	3.6%
		750	11.54	1.47	0.49	0.18	2.14	27.6	11.70	2.40	0.18	(0.02)	2.55	30.8	1.02	0.62	0.70	1.0545	18.2	600	150	41.3	87.1	90.3	3.2	3.7%
		1,000	11.54	1.47	0.49	0.18	2.14	32.9	11.70	2.40	0.18	(0.02)	2.55	37.2	1.02	0.62	0.70	1.0545	24.3	600	400	56.8	114.0	118.3	4.3	3.7%
		1,500	11.54	1.47	0.49	0.18	2.14	43.6	11.70	2.40	0.18	(0.02)	2.55	50.0	1.02	0.62	0.70	1.0545	36.4	600	900	87.9	168.0	174.3	6.3	3.8%
		2,000	11.54	1.47	0.49	0.18	2.14	54.3	11.70	2.40	0.18	(0.02)	2.55	62.7	1.02	0.62	0.70	1.0545	48.6	600	1,400	119.0	222.0	230.3	8.4	3.8%

New Rate Class: R1

Total Bill Impacts of Proposed Distribution Rates [old RTSR+TLF]: Threshold of 600 kWhs

Classes		Scenario	May 2007 Incl Rate Riders						May 2008 Incl Rate Riders						Non-Dx Compoent				Other Reg	Commodity Bands			Existing	New	$ Incr	Incr
			Existing Dx Rates					Existing Dx	New Dx Rates					New Dx	RTSR old	WMSC	DRC	TLF old	Old	Band 1	Band 2	Old	Total Bill	Total Bill	Total Bill	Total Bill
																				600.0						
																				5.0	5.9					
New Class	Old Class	kWh	SrChg	base	Rider1	Rider2	VarChg	[$/month]	SrChg	base	Rider2	Rider3	VarChg	[$/month]	c/kWh	c/kWh	c/kWh		$	kWhs	kWhs	Total $	[$/month]	[$/month]	[$/month]	%
R1	**Arran-Elders**	100	**9.02**	**0.95**	**0.35**	**0.15**	**1.45**	10.5	**11.51**	**1.90**	**0.15**	**(0.04)**	**2.01**	13.5	**1.02**	0.62	0.70	1.0545	2.4	100	-	5.3	18.2	21.2	3.0	16.8%
		250	9.02	0.95	0.35	0.15	1.45	12.6	11.51	1.90	0.15	(0.04)	2.01	16.5	1.02	0.62	0.70	1.0545	6.1	250	-	13.2	31.9	35.8	3.9	12.2%
		500	9.02	0.95	0.35	0.15	1.45	16.3	11.51	1.90	0.15	(0.04)	2.01	21.6	1.02	0.62	0.70	1.0545	12.1	500	-	26.4	54.8	60.1	5.3	9.7%
		750	9.02	0.95	0.35	0.15	1.45	19.9	11.51	1.90	0.15	(0.04)	2.01	26.6	1.02	0.62	0.70	1.0545	18.2	600	150	41.3	79.4	86.1	6.7	8.4%
		1,000	9.02	0.95	0.35	0.15	1.45	23.5	11.51	1.90	0.15	(0.04)	2.01	31.6	1.02	0.62	0.70	1.0545	24.3	600	400	56.8	104.6	112.7	8.1	7.8%
		1,500	9.02	0.95	0.35	0.15	1.45	30.8	11.51	1.90	0.15	(0.04)	2.01	41.7	1.02	0.62	0.70	1.0545	36.4	600	900	87.9	155.1	166.1	10.9	7.0%
		2,000	9.02	0.95	0.35	0.15	1.45	38.0	11.51	1.90	0.15	(0.04)	2.01	51.8	1.02	0.62	0.70	1.0545	48.6	600	1,400	119.0	205.6	219.4	13.7	6.7%
R1	**Artemesia**	100	**12.73**	**0.93**	**0.59**	**0.34**	**1.86**	14.6	**13.58**	**2.35**	**0.34**	**(0.04)**	**2.65**	16.2	**1.02**	0.62	0.70	1.0545	2.4	100	-	5.3	22.3	23.9	1.6	7.4%
		250	12.73	0.93	0.59	0.34	1.86	17.4	13.58	2.35	0.34	(0.04)	2.65	20.2	1.02	0.62	0.70	1.0545	6.1	250	-	13.2	36.6	39.5	2.8	7.7%
		500	12.73	0.93	0.59	0.34	1.86	22.0	13.58	2.35	0.34	(0.04)	2.65	26.8	1.02	0.62	0.70	1.0545	12.1	500	-	26.4	60.5	65.4	4.8	7.9%
		750	12.73	0.93	0.59	0.34	1.86	26.7	13.58	2.35	0.34	(0.04)	2.65	33.5	1.02	0.62	0.70	1.0545	18.2	600	150	41.3	86.2	93.0	6.8	7.9%
		1,000	12.73	0.93	0.59	0.34	1.86	31.3	13.58	2.35	0.34	(0.04)	2.65	40.1	1.02	0.62	0.70	1.0545	24.3	600	400	56.8	112.4	121.2	8.8	7.8%
		1,500	12.73	0.93	0.59	0.34	1.86	40.6	13.58	2.35	0.34	(0.04)	2.65	53.4	1.02	0.62	0.70	1.0545	36.4	600	900	87.9	165.0	177.7	12.7	7.7%
		2,000	12.73	0.93	0.59	0.34	1.86	49.9	13.58	2.35	0.34	(0.04)	2.65	66.6	1.02	0.62	0.70	1.0545	48.6	600	1,400	119.0	217.5	234.3	16.7	7.7%
R1	**Bancroft**	100	**13.48**	**0.95**	**0.34**	**0.12**	**1.41**	14.9	**14.39**	**2.10**	**0.12**	**(0.04)**	**2.18**	16.6	**1.02**	0.62	0.70	1.0545	2.4	100	-	5.3	22.6	24.3	1.7	7.4%
		250	13.48	0.95	0.34	0.12	1.41	17.0	14.39	2.10	0.12	(0.04)	2.18	19.8	1.02	0.62	0.70	1.0545	6.1	250	-	13.2	36.3	39.1	2.8	7.8%
		500	13.48	0.95	0.34	0.12	1.41	20.5	14.39	2.10	0.12	(0.04)	2.18	25.3	1.02	0.62	0.70	1.0545	12.1	500	-	26.4	59.0	63.8	4.8	8.1%
		750	13.48	0.95	0.34	0.12	1.41	24.1	14.39	2.10	0.12	(0.04)	2.18	30.8	1.02	0.62	0.70	1.0545	18.2	600	150	41.3	83.5	90.2	6.7	8.0%
		1,000	13.48	0.95	0.34	0.12	1.41	27.6	14.39	2.10	0.12	(0.04)	2.18	36.2	1.02	0.62	0.70	1.0545	24.3	600	400	56.8	108.7	117.3	8.6	7.9%
		1,500	13.48	0.95	0.34	0.12	1.41	34.6	14.39	2.10	0.12	(0.04)	2.18	47.1	1.02	0.62	0.70	1.0545	36.4	600	900	87.9	159.0	171.5	12.5	7.9%
		2,000	13.48	0.95	0.34	0.12	1.41	41.7	14.39	2.10	0.12	(0.04)	2.18	58.0	1.02	0.62	0.70	1.0545	48.6	600	1,400	119.0	209.3	225.7	16.4	7.8%
R1	**Bath**	100	**13.38**	**0.86**	**0.68**	**0.38**	**1.92**	15.3	**14.42**	**2.35**	**0.38**	**(0.04)**	**2.69**	17.1	**1.02**	0.62	0.70	1.0545	2.4	100	-	5.3	23.0	24.8	1.8	7.9%
		250	13.38	0.86	0.68	0.38	1.92	18.2	14.42	2.35	0.38	(0.04)	2.69	21.1	1.02	0.62	0.70	1.0545	6.1	250	-	13.2	37.4	40.4	3.0	7.9%
		500	13.38	0.86	0.68	0.38	1.92	23.0	14.42	2.35	0.38	(0.04)	2.69	27.9	1.02	0.62	0.70	1.0545	12.1	500	-	26.4	61.5	66.4	4.9	8.0%
		750	13.38	0.86	0.68	0.38	1.92	27.8	14.42	2.35	0.38	(0.04)	2.69	34.6	1.02	0.62	0.70	1.0545	18.2	600	150	41.3	87.3	94.1	6.8	7.8%
		1,000	13.38	0.86	0.68	0.38	1.92	32.6	14.42	2.35	0.38	(0.04)	2.69	41.3	1.02	0.62	0.70	1.0545	24.3	600	400	56.8	113.7	122.5	8.8	7.7%
		1,500	13.38	0.86	0.68	0.38	1.92	42.2	14.42	2.35	0.38	(0.04)	2.69	54.8	1.02	0.62	0.70	1.0545	36.4	600	900	87.9	166.5	179.2	12.6	7.6%
		2,000	13.38	0.86	0.68	0.38	1.92	51.8	14.42	2.35	0.38	(0.04)	2.69	68.3	1.02	0.62	0.70	1.0545	48.6	600	1,400	119.0	219.4	235.9	16.5	7.5%

New Rate Class: R1

Total Bill Impacts of Proposed Distribution Rates [old RTSR+TLF]: Threshold of 600 kWhs

Classes		Scenario	May 2007 Incl Rate Riders						May 2008 Incl Rate Riders						Non-Dx Compoent				Other Reg	Commodity Bands			Existing	New	$ Incr	Incr
			Existing Dx Rates					Existing Dx	New Dx Rates					New Dx	RTSR old	WMSC	DRC	TLF old	Old	Band 1	Band 2	Old	Total Bill	Total Bill	Total Bill	Total Bill
																				600.0						
																				5.0	5.9					
New Class	Old Class	kWh	SrChg	base	Rider1	Rider2	VarChg	[$/month]	SrChg	base	Rider2	Rider3	VarChg	[$/month]	c/kWh	c/kWh	c/kWh		$	kWhs	kWhs	Total $	[$/month]	[$/month]	[$/month]	%
R1	**Blandford-Bl**	100	**11.63**	**0.90**	**0.63**	**0.33**	**1.86**	13.5	**12.85**	**2.30**	**0.33**	**(0.04)**	**2.59**	15.4	**1.02**	0.62	0.70	1.0545	2.4	100	-	5.3	21.2	23.1	2.0	9.2%
		250	11.63	0.90	0.63	0.33	1.86	16.3	12.85	2.30	0.33	(0.04)	2.59	19.3	1.02	0.62	0.70	1.0545	6.1	250	-	13.2	35.5	38.6	3.1	8.6%
		500	11.63	0.90	0.63	0.33	1.86	20.9	12.85	2.30	0.33	(0.04)	2.59	25.8	1.02	0.62	0.70	1.0545	12.1	500	-	26.4	59.4	64.3	4.9	8.2%
		750	11.63	0.90	0.63	0.33	1.86	25.6	12.85	2.30	0.33	(0.04)	2.59	32.3	1.02	0.62	0.70	1.0545	18.2	600	150	41.3	85.1	91.8	6.7	7.9%
		1,000	11.63	0.90	0.63	0.33	1.86	30.2	12.85	2.30	0.33	(0.04)	2.59	38.8	1.02	0.62	0.70	1.0545	24.3	600	400	56.8	111.3	119.9	8.6	7.7%
		1,500	11.63	0.90	0.63	0.33	1.86	39.5	12.85	2.30	0.33	(0.04)	2.59	51.7	1.02	0.62	0.70	1.0545	36.4	600	900	87.9	163.9	176.1	12.2	7.5%
		2,000	11.63	0.90	0.63	0.33	1.86	48.8	12.85	2.30	0.33	(0.04)	2.59	64.7	1.02	0.62	0.70	1.0545	48.6	600	1,400	119.0	216.4	232.3	15.9	7.3%
R1	**Blyth**	100	**7.19**	**0.91**	**0.54**	**0.27**	**1.72**	8.9	**9.96**	**2.00**	**0.27**	**(0.04)**	**2.23**	12.2	**1.02**	0.62	0.70	1.0545	2.4	100	-	5.3	16.6	19.9	3.3	19.8%
		250	7.19	0.91	0.54	0.27	1.72	11.5	9.96	2.00	0.27	(0.04)	2.23	15.5	1.02	0.62	0.70	1.0545	6.1	250	-	13.2	30.7	34.8	4.1	13.2%
		500	7.19	0.91	0.54	0.27	1.72	15.8	9.96	2.00	0.27	(0.04)	2.23	21.1	1.02	0.62	0.70	1.0545	12.1	500	-	26.4	54.3	59.6	5.3	9.8%
		750	7.19	0.91	0.54	0.27	1.72	20.1	9.96	2.00	0.27	(0.04)	2.23	26.7	1.02	0.62	0.70	1.0545	18.2	600	150	41.3	79.6	86.2	6.6	8.3%
		1,000	7.19	0.91	0.54	0.27	1.72	24.4	9.96	2.00	0.27	(0.04)	2.23	32.3	1.02	0.62	0.70	1.0545	24.3	600	400	56.8	105.5	113.4	7.9	7.5%
		1,500	7.19	0.91	0.54	0.27	1.72	33.0	9.96	2.00	0.27	(0.04)	2.23	43.5	1.02	0.62	0.70	1.0545	36.4	600	900	87.9	157.4	167.8	10.5	6.7%
		2,000	7.19	0.91	0.54	0.27	1.72	41.6	9.96	2.00	0.27	(0.04)	2.23	54.6	1.02	0.62	0.70	1.0545	48.6	600	1,400	119.0	209.2	222.2	13.0	6.2%
R1	**Bobcaygeon**	100	**14.47**	**0.97**	**0.28**	**0.10**	**1.35**	15.8	**15.14**	**2.05**	**0.10**	**(0.04)**	**2.11**	17.3	**1.02**	0.62	0.70	1.0545	2.4	100	-	5.3	23.5	25.0	1.4	6.1%
		250	14.47	0.97	0.28	0.10	1.35	17.8	15.14	2.05	0.10	(0.04)	2.11	20.4	1.02	0.62	0.70	1.0545	6.1	250	-	13.2	37.1	39.7	2.6	7.0%
		500	14.47	0.97	0.28	0.10	1.35	21.2	15.14	2.05	0.10	(0.04)	2.11	25.7	1.02	0.62	0.70	1.0545	12.1	500	-	26.4	59.7	64.2	4.5	7.5%
		750	14.47	0.97	0.28	0.10	1.35	24.6	15.14	2.05	0.10	(0.04)	2.11	31.0	1.02	0.62	0.70	1.0545	18.2	600	150	41.3	84.1	90.5	6.4	7.6%
		1,000	14.47	0.97	0.28	0.10	1.35	28.0	15.14	2.05	0.10	(0.04)	2.11	36.3	1.02	0.62	0.70	1.0545	24.3	600	400	56.8	109.1	117.4	8.3	7.6%
		1,500	14.47	0.97	0.28	0.10	1.35	34.7	15.14	2.05	0.10	(0.04)	2.11	46.8	1.02	0.62	0.70	1.0545	36.4	600	900	87.9	159.1	171.2	12.1	7.6%
		2,000	14.47	0.97	0.28	0.10	1.35	41.5	15.14	2.05	0.10	(0.04)	2.11	57.4	1.02	0.62	0.70	1.0545	48.6	600	1,400	119.0	209.1	225.0	15.9	7.6%
R1	**Brighton**	100	**11.61**	**1.07**	**0.37**	**0.11**	**1.55**	13.2	**12.86**	**2.20**	**0.11**	**(0.04)**	**2.27**	15.1	**1.02**	0.62	0.70	1.0545	2.4	100	-	5.3	20.9	22.8	2.0	9.4%
		250	11.61	1.07	0.37	0.11	1.55	15.5	12.86	2.20	0.11	(0.04)	2.27	18.5	1.02	0.62	0.70	1.0545	6.1	250	-	13.2	34.7	37.8	3.1	8.8%
		500	11.61	1.07	0.37	0.11	1.55	19.4	12.86	2.20	0.11	(0.04)	2.27	24.2	1.02	0.62	0.70	1.0545	12.1	500	-	26.4	57.9	62.7	4.9	8.4%
		750	11.61	1.07	0.37	0.11	1.55	23.2	12.86	2.20	0.11	(0.04)	2.27	29.9	1.02	0.62	0.70	1.0545	18.2	600	150	41.3	82.7	89.4	6.7	8.1%
		1,000	11.61	1.07	0.37	0.11	1.55	27.1	12.86	2.20	0.11	(0.04)	2.27	35.6	1.02	0.62	0.70	1.0545	24.3	600	400	56.8	108.2	116.7	8.5	7.8%
		1,500	11.61	1.07	0.37	0.11	1.55	34.9	12.86	2.20	0.11	(0.04)	2.27	47.0	1.02	0.62	0.70	1.0545	36.4	600	900	87.9	159.2	171.3	12.1	7.6%
		2,000	11.61	1.07	0.37	0.11	1.55	42.6	12.86	2.20	0.11	(0.04)	2.27	58.3	1.02	0.62	0.70	1.0545	48.6	600	1,400	119.0	210.2	225.9	15.7	7.5%

New Rate Class: R1

Total Bill Impacts of Proposed Distribution Rates [old RTSR+TLF]: Threshold of 600 kWhs

Classes		Scenario	May 2007 Incl Rate Riders						May 2008 Incl Rate Riders						Non-Dx Compoent				Other Reg	Commodity Bands			Existing	New	$ Incr	Incr
			Existing Dx Rates					Existing Dx	New Dx Rates					New Dx	RTSR old	WMSC	DRC	TLF old	Old	Band 1	Band 2	Old	Total Bill	Total Bill	Total Bill	Total Bill
																				600.0						
																				5.0	5.9					
New Class	Old Class	kWh	SrChg	base	Rider1	Rider2	VarChg	[$/month]	SrChg	base	Rider2	Rider3	VarChg	[$/month]	c/kWh	c/kWh	c/kWh		$	kWhs	kWhs	Total $	[$/month]	[$/month]	[$/month]	%
UR	**Brockville**	100	**12.33**	**0.93**	**0.48**	**0.16**	**1.57**	13.9	**12.50**	**2.40**	**0.16**	**(0.02)**	**2.53**	15.0	**1.02**	0.62	0.70	1.0545	2.4	100	-	5.3	21.6	22.7	1.1	5.2%
		250	12.33	0.93	0.48	0.16	1.57	16.3	12.50	2.40	0.16	(0.02)	2.53	18.8	1.02	0.62	0.70	1.0545	6.1	250	-	13.2	35.5	38.1	2.6	7.2%
		500	12.33	0.93	0.48	0.16	1.57	20.2	12.50	2.40	0.16	(0.02)	2.53	25.2	1.02	0.62	0.70	1.0545	12.1	500	-	26.4	58.7	63.7	5.0	8.5%
		750	12.33	0.93	0.48	0.16	1.57	24.1	12.50	2.40	0.16	(0.02)	2.53	31.5	1.02	0.62	0.70	1.0545	18.2	600	150	41.3	83.6	91.0	7.4	8.8%
		1,000	12.33	0.93	0.48	0.16	1.57	28.0	12.50	2.40	0.16	(0.02)	2.53	37.8	1.02	0.62	0.70	1.0545	24.3	600	400	56.8	109.1	118.9	9.8	9.0%
		1,500	12.33	0.93	0.48	0.16	1.57	35.9	12.50	2.40	0.16	(0.02)	2.53	50.5	1.02	0.62	0.70	1.0545	36.4	600	900	87.9	160.2	174.8	14.6	9.1%
		2,000	12.33	0.93	0.48	0.16	1.57	43.7	12.50	2.40	0.16	(0.02)	2.53	63.1	1.02	0.62	0.70	1.0545	48.6	600	1,400	119.0	211.3	230.7	19.4	9.2%
R1	**Caledon CH**	100	**15.19**	**1.02**	**0.28**	**0.08**	**1.38**	16.6	**15.96**	**2.10**	**0.08**	**(0.04)**	**2.14**	18.1	**1.02**	0.62	0.70	1.0545	2.4	100	-	5.3	24.3	25.8	1.5	6.3%
		250	15.19	1.02	0.28	0.08	1.38	18.6	15.96	2.10	0.08	(0.04)	2.14	21.3	1.02	0.62	0.70	1.0545	6.1	250	-	13.2	37.9	40.6	2.7	7.1%
		500	15.19	1.02	0.28	0.08	1.38	22.1	15.96	2.10	0.08	(0.04)	2.14	26.7	1.02	0.62	0.70	1.0545	12.1	500	-	26.4	60.6	65.2	4.6	7.6%
		750	15.19	1.02	0.28	0.08	1.38	25.5	15.96	2.10	0.08	(0.04)	2.14	32.0	1.02	0.62	0.70	1.0545	18.2	600	150	41.3	85.0	91.5	6.5	7.6%
		1,000	15.19	1.02	0.28	0.08	1.38	29.0	15.96	2.10	0.08	(0.04)	2.14	37.4	1.02	0.62	0.70	1.0545	24.3	600	400	56.8	110.1	118.5	8.4	7.6%
		1,500	15.19	1.02	0.28	0.08	1.38	35.9	15.96	2.10	0.08	(0.04)	2.14	48.1	1.02	0.62	0.70	1.0545	36.4	600	900	87.9	160.3	172.5	12.2	7.6%
		2,000	15.19	1.02	0.28	0.08	1.38	42.8	15.96	2.10	0.08	(0.04)	2.14	58.8	1.02	0.62	0.70	1.0545	48.6	600	1,400	119.0	210.4	226.4	16.0	7.6%
R1	**Campbellfor**	100	**12.30**	**1.07**	**0.41**	**0.12**	**1.60**	13.9	**13.69**	**2.25**	**0.12**	**(0.04)**	**2.33**	16.0	**1.02**	0.62	0.70	1.0545	2.4	100	-	5.3	21.6	23.7	2.1	9.8%
		250	12.30	1.07	0.41	0.12	1.60	16.3	13.69	2.25	0.12	(0.04)	2.33	19.5	1.02	0.62	0.70	1.0545	6.1	250	-	13.2	35.6	38.8	3.2	9.0%
		500	12.30	1.07	0.41	0.12	1.60	20.3	13.69	2.25	0.12	(0.04)	2.33	25.3	1.02	0.62	0.70	1.0545	12.1	500	-	26.4	58.8	63.9	5.0	8.6%
		750	12.30	1.07	0.41	0.12	1.60	24.3	13.69	2.25	0.12	(0.04)	2.33	31.2	1.02	0.62	0.70	1.0545	18.2	600	150	41.3	83.8	90.7	6.9	8.2%
		1,000	12.30	1.07	0.41	0.12	1.60	28.3	13.69	2.25	0.12	(0.04)	2.33	37.0	1.02	0.62	0.70	1.0545	24.3	600	400	56.8	109.4	118.1	8.7	8.0%
		1,500	12.30	1.07	0.41	0.12	1.60	36.3	13.69	2.25	0.12	(0.04)	2.33	48.7	1.02	0.62	0.70	1.0545	36.4	600	900	87.9	160.7	173.0	12.4	7.7%
		2,000	12.30	1.07	0.41	0.12	1.60	44.3	13.69	2.25	0.12	(0.04)	2.33	60.3	1.02	0.62	0.70	1.0545	48.6	600	1,400	119.0	211.9	228.0	16.0	7.6%
UR	**Carleton Pla**	100	**14.17**	**1.79**	**0.38**	**0.15**	**2.32**	16.5	**14.04**	**2.40**	**0.15**	**(0.02)**	**2.52**	16.6	**1.02**	0.62	0.70	1.0545	2.4	100	-	5.3	24.2	24.3	0.1	0.3%
		250	14.17	1.79	0.38	0.15	2.32	20.0	14.04	2.40	0.15	(0.02)	2.52	20.3	1.02	0.62	0.70	1.0545	6.1	250	-	13.2	39.2	39.6	0.4	0.9%
		500	14.17	1.79	0.38	0.15	2.32	25.8	14.04	2.40	0.15	(0.02)	2.52	26.6	1.02	0.62	0.70	1.0545	12.1	500	-	26.4	64.3	65.2	0.9	1.4%
		750	14.17	1.79	0.38	0.15	2.32	31.6	14.04	2.40	0.15	(0.02)	2.52	32.9	1.02	0.62	0.70	1.0545	18.2	600	150	41.3	91.1	92.4	1.4	1.5%
		1,000	14.17	1.79	0.38	0.15	2.32	37.4	14.04	2.40	0.15	(0.02)	2.52	39.2	1.02	0.62	0.70	1.0545	24.3	600	400	56.8	118.5	120.4	1.9	1.6%
		1,500	14.17	1.79	0.38	0.15	2.32	49.0	14.04	2.40	0.15	(0.02)	2.52	51.9	1.02	0.62	0.70	1.0545	36.4	600	900	87.9	173.3	176.2	2.9	1.7%
		2,000	14.17	1.79	0.38	0.15	2.32	60.6	14.04	2.40	0.15	(0.02)	2.52	64.5	1.02	0.62	0.70	1.0545	48.6	600	1,400	119.0	228.2	232.1	3.9	1.7%

New Rate Class: R1

Total Bill Impacts of Proposed Distribution Rates [old RTSR+TLF]: Threshold of 600 kWhs

Classes		Scenario	May 2007 Incl Rate Riders						May 2008 Incl Rate Riders						Non-Dx Compoent				Other Reg	600.0 Commodity Bands			Existing	New	$ Incr	Incr
			Existing Dx Rates					Existing Dx	New Dx Rates					New Dx	RTSR old	WMSC	DRC	TLF old	Old	Band 1 5.0	Band 2 5.9	Old	Total Bill	Total Bill	Total Bill	Total Bill
New Class	Old Class	kWh	SrChg	base	Rider1	Rider2	VarChg	[$/month]	SrChg	base	Rider2	Rider3	VarChg	[$/month]	c/kWh	c/kWh	c/kWh		$	kWhs	kWhs	Total $	[$/month]	[$/month]	[$/month]	%
R1	**Cavan-Millbr**	100	**15.01**	**1.34**	**0.68**	**0.40**	**2.42**	17.4	**16.01**	**2.71**	**0.40**	**(0.04)**	**3.08**	19.1	**1.02**	0.62	0.70	1.0545	2.4	100	-	5.3	25.1	26.8	1.7	6.6%
		250	15.01	1.34	0.68	0.40	2.42	21.1	16.01	2.71	0.40	(0.04)	3.08	23.7	1.02	0.62	0.70	1.0545	6.1	250	-	13.2	40.3	43.0	2.6	6.5%
		500	15.01	1.34	0.68	0.40	2.42	27.1	16.01	2.71	0.40	(0.04)	3.08	31.4	1.02	0.62	0.70	1.0545	12.1	500	-	26.4	65.6	69.9	4.3	6.5%
		750	15.01	1.34	0.68	0.40	2.42	33.2	16.01	2.71	0.40	(0.04)	3.08	39.1	1.02	0.62	0.70	1.0545	18.2	600	150	41.3	92.6	98.6	5.9	6.4%
		1,000	15.01	1.34	0.68	0.40	2.42	39.2	16.01	2.71	0.40	(0.04)	3.08	46.8	1.02	0.62	0.70	1.0545	24.3	600	400	56.8	120.3	127.9	7.6	6.3%
		1,500	15.01	1.34	0.68	0.40	2.42	51.3	16.01	2.71	0.40	(0.04)	3.08	62.2	1.02	0.62	0.70	1.0545	36.4	600	900	87.9	175.7	186.5	10.8	6.2%
		2,000	15.01	1.34	0.68	0.40	2.42	63.4	16.01	2.71	0.40	(0.04)	3.08	77.5	1.02	0.62	0.70	1.0545	48.6	600	1,400	119.0	231.0	245.2	14.1	6.1%
R1	**Centre Hasti**	100	**11.67**	**0.96**	**0.29**	**0.11**	**1.36**	13.0	**12.84**	**2.00**	**0.11**	**(0.04)**	**2.07**	14.9	**1.02**	0.62	0.70	1.0545	2.4	100	-	5.3	20.7	22.6	1.9	9.1%
		250	11.67	0.96	0.29	0.11	1.36	15.1	12.84	2.00	0.11	(0.04)	2.07	18.0	1.02	0.62	0.70	1.0545	6.1	250	-	13.2	34.3	37.3	3.0	8.6%
		500	11.67	0.96	0.29	0.11	1.36	18.5	12.84	2.00	0.11	(0.04)	2.07	23.2	1.02	0.62	0.70	1.0545	12.1	500	-	26.4	57.0	61.7	4.7	8.3%
		750	11.67	0.96	0.29	0.11	1.36	21.9	12.84	2.00	0.11	(0.04)	2.07	28.4	1.02	0.62	0.70	1.0545	18.2	600	150	41.3	81.4	87.9	6.5	8.0%
		1,000	11.67	0.96	0.29	0.11	1.36	25.3	12.84	2.00	0.11	(0.04)	2.07	33.6	1.02	0.62	0.70	1.0545	24.3	600	400	56.8	106.4	114.7	8.3	7.8%
		1,500	11.67	0.96	0.29	0.11	1.36	32.1	12.84	2.00	0.11	(0.04)	2.07	43.9	1.02	0.62	0.70	1.0545	36.4	600	900	87.9	156.4	168.3	11.9	7.6%
		2,000	11.67	0.96	0.29	0.11	1.36	38.9	12.84	2.00	0.11	(0.04)	2.07	54.3	1.02	0.62	0.70	1.0545	48.6	600	1,400	119.0	206.5	221.9	15.4	7.5%
R1	**Chalk River**	100	**14.03**	**1.37**	**0.61**	**0.42**	**2.40**	16.4	**15.25**	**2.71**	**0.42**	**(0.04)**	**3.10**	18.3	**1.02**	0.62	0.70	1.0545	2.4	100	-	5.3	24.1	26.1	1.9	8.0%
		250	14.03	1.37	0.61	0.42	2.40	20.0	15.25	2.71	0.42	(0.04)	3.10	23.0	1.02	0.62	0.70	1.0545	6.1	250	-	13.2	39.3	42.2	3.0	7.5%
		500	14.03	1.37	0.61	0.42	2.40	26.0	15.25	2.71	0.42	(0.04)	3.10	30.7	1.02	0.62	0.70	1.0545	12.1	500	-	26.4	64.5	69.2	4.7	7.3%
		750	14.03	1.37	0.61	0.42	2.40	32.0	15.25	2.71	0.42	(0.04)	3.10	38.5	1.02	0.62	0.70	1.0545	18.2	600	150	41.3	91.5	98.0	6.4	7.0%
		1,000	14.03	1.37	0.61	0.42	2.40	38.0	15.25	2.71	0.42	(0.04)	3.10	46.2	1.02	0.62	0.70	1.0545	24.3	600	400	56.8	119.1	127.3	8.2	6.9%
		1,500	14.03	1.37	0.61	0.42	2.40	50.0	15.25	2.71	0.42	(0.04)	3.10	61.7	1.02	0.62	0.70	1.0545	36.4	600	900	87.9	174.4	186.1	11.7	6.7%
		2,000	14.03	1.37	0.61	0.42	2.40	62.0	15.25	2.71	0.42	(0.04)	3.10	77.2	1.02	0.62	0.70	1.0545	48.6	600	1,400	119.0	229.6	244.8	15.1	6.6%
R1	**Champlain**	100	**10.36**	**0.88**	**0.45**	**0.23**	**1.56**	11.9	**12.17**	**2.00**	**0.23**	**(0.04)**	**2.19**	14.4	**1.02**	0.62	0.70	1.0545	2.4	100	-	5.3	19.6	22.1	2.4	12.4%
		250	10.36	0.88	0.45	0.23	1.56	14.3	12.17	2.00	0.23	(0.04)	2.19	17.7	1.02	0.62	0.70	1.0545	6.1	250	-	13.2	33.5	36.9	3.4	10.1%
		500	10.36	0.88	0.45	0.23	1.56	18.2	12.17	2.00	0.23	(0.04)	2.19	23.1	1.02	0.62	0.70	1.0545	12.1	500	-	26.4	56.7	61.6	5.0	8.8%
		750	10.36	0.88	0.45	0.23	1.56	22.1	12.17	2.00	0.23	(0.04)	2.19	28.6	1.02	0.62	0.70	1.0545	18.2	600	150	41.3	81.5	88.1	6.6	8.0%
		1,000	10.36	0.88	0.45	0.23	1.56	26.0	12.17	2.00	0.23	(0.04)	2.19	34.1	1.02	0.62	0.70	1.0545	24.3	600	400	56.8	107.1	115.2	8.1	7.6%
		1,500	10.36	0.88	0.45	0.23	1.56	33.8	12.17	2.00	0.23	(0.04)	2.19	45.1	1.02	0.62	0.70	1.0545	36.4	600	900	87.9	158.1	169.4	11.3	7.1%
		2,000	10.36	0.88	0.45	0.23	1.56	41.6	12.17	2.00	0.23	(0.04)	2.19	56.0	1.02	0.62	0.70	1.0545	48.6	600	1,400	119.0	209.2	223.6	14.5	6.9%

New Rate Class: R1

Total Bill Impacts of Proposed Distribution Rates [old RTSR+TLF]: Threshold of 600 kWhs

600.0

Classes		Scenario	May 2007 Incl Rate Riders						May 2008 Incl Rate Riders						Non-Dx Compoent				Other Reg	Commodity Bands			Existing	New	$ Incr	Incr
			Existing Dx Rates					Existing Dx	New Dx Rates					New Dx	RTSR old	WMSC	DRC	TLF old	Old	Band 1	Band 2	Old	Total Bill	Total Bill	Total Bill	Total Bill
																				5.0	5.9					
New Class	Old Class	kWh	SrChg	base	Rider1	Rider2	VarChg	[$/month]	SrChg	base	Rider2	Rider3	VarChg	[$/month]	c/kWh	c/kWh	c/kWh		$	kWhs	kWhs	Total $	[$/month]	[$/month]	[$/month]	%
R1	**Cobden**	100	**13.07**	**1.76**	**0.68**	**0.41**	**2.85**	15.9	**14.49**	**2.71**	**0.41**	**(0.04)**	**3.09**	17.6	**1.02**	0.62	0.70	1.0545	2.4	100	-	5.3	23.6	25.3	1.7	7.0%
		250	13.07	1.76	0.68	0.41	2.85	20.2	14.49	2.71	0.41	(0.04)	3.09	22.2	1.02	0.62	0.70	1.0545	6.1	250	-	13.2	39.4	41.5	2.0	5.1%
		500	13.07	1.76	0.68	0.41	2.85	27.3	14.49	2.71	0.41	(0.04)	3.09	29.9	1.02	0.62	0.70	1.0545	12.1	500	-	26.4	65.8	68.4	2.6	4.0%
		750	13.07	1.76	0.68	0.41	2.85	34.4	14.49	2.71	0.41	(0.04)	3.09	37.6	1.02	0.62	0.70	1.0545	18.2	600	150	41.3	93.9	97.1	3.2	3.4%
		1,000	13.07	1.76	0.68	0.41	2.85	41.6	14.49	2.71	0.41	(0.04)	3.09	45.4	1.02	0.62	0.70	1.0545	24.3	600	400	56.8	122.7	126.5	3.8	3.1%
		1,500	13.07	1.76	0.68	0.41	2.85	55.8	14.49	2.71	0.41	(0.04)	3.09	60.8	1.02	0.62	0.70	1.0545	36.4	600	900	87.9	180.2	185.2	5.0	2.8%
		2,000	13.07	1.76	0.68	0.41	2.85	70.1	14.49	2.71	0.41	(0.04)	3.09	76.2	1.02	0.62	0.70	1.0545	48.6	600	1,400	119.0	237.7	243.8	6.1	2.6%
R1	**Deep River**	100	**16.62**	**2.29**	**0.38**	**0.25**	**2.92**	19.5	**16.61**	**2.71**	**0.25**	**(0.04)**	**2.93**	19.5	**1.02**	0.62	0.70	1.0545	2.4	100	-	5.3	27.2	27.2	(0.0)	0.0%
		250	16.62	2.29	0.38	0.25	2.92	23.9	16.61	2.71	0.25	(0.04)	2.93	23.9	1.02	0.62	0.70	1.0545	6.1	250	-	13.2	43.2	43.2	0.0	0.0%
		500	16.62	2.29	0.38	0.25	2.92	31.2	16.61	2.71	0.25	(0.04)	2.93	31.2	1.02	0.62	0.70	1.0545	12.1	500	-	26.4	69.7	69.7	0.0	0.0%
		750	16.62	2.29	0.38	0.25	2.92	38.5	16.61	2.71	0.25	(0.04)	2.93	38.6	1.02	0.62	0.70	1.0545	18.2	600	150	41.3	98.0	98.0	0.0	0.0%
		1,000	16.62	2.29	0.38	0.25	2.92	45.8	16.61	2.71	0.25	(0.04)	2.93	45.9	1.02	0.62	0.70	1.0545	24.3	600	400	56.8	126.9	127.0	0.0	0.0%
		1,500	16.62	2.29	0.38	0.25	2.92	60.4	16.61	2.71	0.25	(0.04)	2.93	60.5	1.02	0.62	0.70	1.0545	36.4	600	900	87.9	184.8	184.9	0.1	0.0%
		2,000	16.62	2.29	0.38	0.25	2.92	75.0	16.61	2.71	0.25	(0.04)	2.93	75.1	1.02	0.62	0.70	1.0545	48.6	600	1,400	119.0	242.6	242.7	0.1	0.0%
R1	**Deseronto**	100	**12.89**	**1.12**	**0.37**	**0.11**	**1.60**	14.5	**13.54**	**2.30**	**0.11**	**(0.04)**	**2.37**	15.9	**1.02**	0.62	0.70	1.0545	2.4	100	-	5.3	22.2	23.6	1.4	6.4%
		250	12.89	1.12	0.37	0.11	1.60	16.9	13.54	2.30	0.11	(0.04)	2.37	19.5	1.02	0.62	0.70	1.0545	6.1	250	-	13.2	36.1	38.7	2.6	7.1%
		500	12.89	1.12	0.37	0.11	1.60	20.9	13.54	2.30	0.11	(0.04)	2.37	25.4	1.02	0.62	0.70	1.0545	12.1	500	-	26.4	59.4	63.9	4.5	7.6%
		750	12.89	1.12	0.37	0.11	1.60	24.9	13.54	2.30	0.11	(0.04)	2.37	31.3	1.02	0.62	0.70	1.0545	18.2	600	150	41.3	84.4	90.8	6.4	7.6%
		1,000	12.89	1.12	0.37	0.11	1.60	28.9	13.54	2.30	0.11	(0.04)	2.37	37.3	1.02	0.62	0.70	1.0545	24.3	600	400	56.8	110.0	118.4	8.4	7.6%
		1,500	12.89	1.12	0.37	0.11	1.60	36.9	13.54	2.30	0.11	(0.04)	2.37	49.1	1.02	0.62	0.70	1.0545	36.4	600	900	87.9	161.3	173.5	12.2	7.6%
		2,000	12.89	1.12	0.37	0.11	1.60	44.9	13.54	2.30	0.11	(0.04)	2.37	61.0	1.02	0.62	0.70	1.0545	48.6	600	1,400	119.0	212.5	228.6	16.1	7.6%
UR	**Dryden**	100	**14.28**	**1.65**	**0.43**	**0.18**	**2.26**	16.5	**14.01**	**2.40**	**0.18**	**(0.02)**	**2.55**	16.6	**1.02**	0.62	0.70	1.0545	2.4	100	-	5.3	24.2	24.3	0.0	0.1%
		250	14.28	1.65	0.43	0.18	2.26	19.9	14.01	2.40	0.18	(0.02)	2.55	20.4	1.02	0.62	0.70	1.0545	6.1	250	-	13.2	39.2	39.6	0.5	1.2%
		500	14.28	1.65	0.43	0.18	2.26	25.6	14.01	2.40	0.18	(0.02)	2.55	26.8	1.02	0.62	0.70	1.0545	12.1	500	-	26.4	64.1	65.3	1.2	1.8%
		750	14.28	1.65	0.43	0.18	2.26	31.2	14.01	2.40	0.18	(0.02)	2.55	33.1	1.02	0.62	0.70	1.0545	18.2	600	150	41.3	90.7	92.6	1.9	2.1%
		1,000	14.28	1.65	0.43	0.18	2.26	36.9	14.01	2.40	0.18	(0.02)	2.55	39.5	1.02	0.62	0.70	1.0545	24.3	600	400	56.8	118.0	120.6	2.6	2.2%
		1,500	14.28	1.65	0.43	0.18	2.26	48.2	14.01	2.40	0.18	(0.02)	2.55	52.3	1.02	0.62	0.70	1.0545	36.4	600	900	87.9	172.5	176.6	4.1	2.4%
		2,000	14.28	1.65	0.43	0.18	2.26	59.5	14.01	2.40	0.18	(0.02)	2.55	65.0	1.02	0.62	0.70	1.0545	48.6	600	1,400	119.0	227.1	232.6	5.5	2.4%

New Rate Class: R1

Total Bill Impacts of Proposed Distribution Rates [old RTSR+TLF]: Threshold of 600 kWhs

Classes		Scenario	May 2007 Incl Rate Riders						May 2008 Incl Rate Riders						Non-Dx Compoent				Other Reg	Commodity Bands			Existing	New	$ Incr	Incr
			Existing Dx Rates					Existing Dx	New Dx Rates					New Dx	RTSR old	WMSC	DRC	TLF old	Old	Band 1	Band 2	Old	Total Bill	Total Bill	Total Bill	Total Bill
																				600.0						
																				5.0	5.9					
New Class	Old Class	kWh	SrChg	base	Rider1	Rider2	VarChg	[$/month]	SrChg	base	Rider2	Rider3	VarChg	[$/month]	c/kWh	c/kWh	c/kWh		$	kWhs	kWhs	Total $	[$/month]	[$/month]	[$/month]	%
R1	**Dundalk**	100	**14.47**	**1.08**	**0.39**	**0.13**	**1.60**	16.1	**15.14**	**2.30**	**0.13**	**(0.04)**	**2.39**	17.5	**1.02**	0.62	0.70	1.0545	2.4	100	-	5.3	23.8	25.2	1.5	6.2%
		250	14.47	1.08	0.39	0.13	1.60	18.5	15.14	2.30	0.13	(0.04)	2.39	21.1	1.02	0.62	0.70	1.0545	6.1	250	-	13.2	37.7	40.4	2.7	7.0%
		500	14.47	1.08	0.39	0.13	1.60	22.5	15.14	2.30	0.13	(0.04)	2.39	27.1	1.02	0.62	0.70	1.0545	12.1	500	-	26.4	61.0	65.6	4.6	7.6%
		750	14.47	1.08	0.39	0.13	1.60	26.5	15.14	2.30	0.13	(0.04)	2.39	33.1	1.02	0.62	0.70	1.0545	18.2	600	150	41.3	86.0	92.6	6.6	7.7%
		1,000	14.47	1.08	0.39	0.13	1.60	30.5	15.14	2.30	0.13	(0.04)	2.39	39.1	1.02	0.62	0.70	1.0545	24.3	600	400	56.8	111.6	120.2	8.6	7.7%
		1,500	14.47	1.08	0.39	0.13	1.60	38.5	15.14	2.30	0.13	(0.04)	2.39	51.0	1.02	0.62	0.70	1.0545	36.4	600	900	87.9	162.8	175.4	12.6	7.7%
		2,000	14.47	1.08	0.39	0.13	1.60	46.5	15.14	2.30	0.13	(0.04)	2.39	63.0	1.02	0.62	0.70	1.0545	48.6	600	1,400	119.0	214.1	230.6	16.5	7.7%
R1	**Durham**	100	**16.35**	**1.24**	**0.46**	**0.16**	**1.86**	18.2	**16.67**	**2.60**	**0.16**	**(0.04)**	**2.72**	19.4	**1.02**	0.62	0.70	1.0545	2.4	100	-	5.3	25.9	27.1	1.2	4.6%
		250	16.35	1.24	0.46	0.16	1.86	21.0	16.67	2.60	0.16	(0.04)	2.72	23.5	1.02	0.62	0.70	1.0545	6.1	250	-	13.2	40.3	42.7	2.5	6.2%
		500	16.35	1.24	0.46	0.16	1.86	25.7	16.67	2.60	0.16	(0.04)	2.72	30.3	1.02	0.62	0.70	1.0545	12.1	500	-	26.4	64.2	68.8	4.6	7.2%
		750	16.35	1.24	0.46	0.16	1.86	30.3	16.67	2.60	0.16	(0.04)	2.72	37.1	1.02	0.62	0.70	1.0545	18.2	600	150	41.3	89.8	96.6	6.8	7.6%
		1,000	16.35	1.24	0.46	0.16	1.86	35.0	16.67	2.60	0.16	(0.04)	2.72	43.9	1.02	0.62	0.70	1.0545	24.3	600	400	56.8	116.1	125.0	9.0	7.7%
		1,500	16.35	1.24	0.46	0.16	1.86	44.3	16.67	2.60	0.16	(0.04)	2.72	57.5	1.02	0.62	0.70	1.0545	36.4	600	900	87.9	168.6	181.9	13.3	7.9%
		2,000	16.35	1.24	0.46	0.16	1.86	53.6	16.67	2.60	0.16	(0.04)	2.72	71.1	1.02	0.62	0.70	1.0545	48.6	600	1,400	119.0	221.2	238.7	17.6	7.9%
R1	**Eganville**	100	**13.86**	**1.53**	**0.29**	**0.12**	**1.94**	15.8	**14.30**	**2.71**	**0.12**	**(0.04)**	**2.80**	17.1	**1.02**	0.62	0.70	1.0545	2.4	100	-	5.3	23.5	24.8	1.3	5.5%
		250	13.86	1.53	0.29	0.12	1.94	18.7	14.30	2.71	0.12	(0.04)	2.80	21.3	1.02	0.62	0.70	1.0545	6.1	250	-	13.2	38.0	40.5	2.6	6.8%
		500	13.86	1.53	0.29	0.12	1.94	23.6	14.30	2.71	0.12	(0.04)	2.80	28.3	1.02	0.62	0.70	1.0545	12.1	500	-	26.4	62.1	66.8	4.7	7.6%
		750	13.86	1.53	0.29	0.12	1.94	28.4	14.30	2.71	0.12	(0.04)	2.80	35.3	1.02	0.62	0.70	1.0545	18.2	600	150	41.3	87.9	94.7	6.9	7.8%
		1,000	13.86	1.53	0.29	0.12	1.94	33.3	14.30	2.71	0.12	(0.04)	2.80	42.3	1.02	0.62	0.70	1.0545	24.3	600	400	56.8	114.4	123.4	9.0	7.9%
		1,500	13.86	1.53	0.29	0.12	1.94	43.0	14.30	2.71	0.12	(0.04)	2.80	56.2	1.02	0.62	0.70	1.0545	36.4	600	900	87.9	167.3	180.6	13.3	7.9%
		2,000	13.86	1.53	0.29	0.12	1.94	52.7	14.30	2.71	0.12	(0.04)	2.80	70.2	1.02	0.62	0.70	1.0545	48.6	600	1,400	119.0	220.3	237.8	17.6	8.0%
R1	**Erin**	100	**13.13**	**1.90**	**0.83**	**0.40**	**3.13**	16.3	**14.48**	**2.71**	**0.40**	**(0.04)**	**3.08**	17.6	**1.02**	0.62	0.70	1.0545	2.4	100	-	5.3	24.0	25.3	1.3	5.4%
		250	13.13	1.90	0.83	0.40	3.13	21.0	14.48	2.71	0.40	(0.04)	3.08	22.2	1.02	0.62	0.70	1.0545	6.1	250	-	13.2	40.2	41.4	1.2	3.0%
		500	13.13	1.90	0.83	0.40	3.13	28.8	14.48	2.71	0.40	(0.04)	3.08	29.9	1.02	0.62	0.70	1.0545	12.1	500	-	26.4	67.3	68.4	1.1	1.6%
		750	13.13	1.90	0.83	0.40	3.13	36.6	14.48	2.71	0.40	(0.04)	3.08	37.5	1.02	0.62	0.70	1.0545	18.2	600	150	41.3	96.1	97.0	0.9	1.0%
		1,000	13.13	1.90	0.83	0.40	3.13	44.4	14.48	2.71	0.40	(0.04)	3.08	45.2	1.02	0.62	0.70	1.0545	24.3	600	400	56.8	125.5	126.3	0.8	0.6%
		1,500	13.13	1.90	0.83	0.40	3.13	60.1	14.48	2.71	0.40	(0.04)	3.08	60.6	1.02	0.62	0.70	1.0545	36.4	600	900	87.9	184.4	185.0	0.5	0.3%
		2,000	13.13	1.90	0.83	0.40	3.13	75.7	14.48	2.71	0.40	(0.04)	3.08	76.0	1.02	0.62	0.70	1.0545	48.6	600	1,400	119.0	243.3	243.6	0.3	0.1%

New Rate Class: R1

Total Bill Impacts of Proposed Distribution Rates [old RTSR+TLF]: Threshold of 600 kWhs

Classes		Scenario	May 2007 Incl Rate Riders						May 2008 Incl Rate Riders						Non-Dx Compoent				Other Reg	Commodity Bands			Existing	New	$ Incr	Incr
			Existing Dx Rates					Existing Dx	New Dx Rates					New Dx	RTSR old	WMSC	DRC	TLF old	Old	Band 1	Band 2	Old	Total Bill	Total Bill	Total Bill	Total Bill
																				600.0						
																				5.0	5.9					
New Class	Old Class	kWh	SrChg	base	Rider1	Rider2	VarChg	[$/month]	SrChg	base	Rider2	Rider3	VarChg	[$/month]	c/kWh	c/kWh	c/kWh		$	kWhs	kWhs	Total $	[$/month]	[$/month]	[$/month]	%
R1	**Exeter**	100	**15.10**	**0.96**	**0.45**	**0.15**	**1.56**	16.7	**15.99**	**2.25**	**0.15**	**(0.04)**	**2.36**	18.3	**1.02**	0.62	0.70	1.0545	2.4	100	-	5.3	24.4	26.0	1.7	6.9%
		250	15.10	0.96	0.45	0.15	1.56	19.0	15.99	2.25	0.15	(0.04)	2.36	21.9	1.02	0.62	0.70	1.0545	6.1	250	-	13.2	38.3	41.1	2.9	7.6%
		500	15.10	0.96	0.45	0.15	1.56	22.9	15.99	2.25	0.15	(0.04)	2.36	27.8	1.02	0.62	0.70	1.0545	12.1	500	-	26.4	61.4	66.3	4.9	8.0%
		750	15.10	0.96	0.45	0.15	1.56	26.8	15.99	2.25	0.15	(0.04)	2.36	33.7	1.02	0.62	0.70	1.0545	18.2	600	150	41.3	86.3	93.2	6.9	8.0%
		1,000	15.10	0.96	0.45	0.15	1.56	30.7	15.99	2.25	0.15	(0.04)	2.36	39.6	1.02	0.62	0.70	1.0545	24.3	600	400	56.8	111.8	120.7	8.9	8.0%
		1,500	15.10	0.96	0.45	0.15	1.56	38.5	15.99	2.25	0.15	(0.04)	2.36	51.4	1.02	0.62	0.70	1.0545	36.4	600	900	87.9	162.9	175.8	12.9	7.9%
		2,000	15.10	0.96	0.45	0.15	1.56	46.3	15.99	2.25	0.15	(0.04)	2.36	63.2	1.02	0.62	0.70	1.0545	48.6	600	1,400	119.0	213.9	230.9	16.9	7.9%
R1	**Fenelon Falls**	100	**6.09**	**0.96**	**0.25**	**0.08**	**1.29**	7.4	**9.24**	**1.70**	**0.08**	**(0.04)**	**1.74**	11.0	**1.02**	0.62	0.70	1.0545	2.4	100	-	5.3	15.1	18.7	3.6	23.9%
		250	6.09	0.96	0.25	0.08	1.29	9.3	9.24	1.70	0.08	(0.04)	1.74	13.6	1.02	0.62	0.70	1.0545	6.1	250	-	13.2	28.6	32.8	4.3	15.0%
		500	6.09	0.96	0.25	0.08	1.29	12.5	9.24	1.70	0.08	(0.04)	1.74	18.0	1.02	0.62	0.70	1.0545	12.1	500	-	26.4	51.0	56.5	5.4	10.6%
		750	6.09	0.96	0.25	0.08	1.29	15.8	9.24	1.70	0.08	(0.04)	1.74	22.3	1.02	0.62	0.70	1.0545	18.2	600	150	41.3	75.2	81.8	6.5	8.7%
		1,000	6.09	0.96	0.25	0.08	1.29	19.0	9.24	1.70	0.08	(0.04)	1.74	26.7	1.02	0.62	0.70	1.0545	24.3	600	400	56.8	100.1	107.8	7.7	7.7%
		1,500	6.09	0.96	0.25	0.08	1.29	25.4	9.24	1.70	0.08	(0.04)	1.74	35.4	1.02	0.62	0.70	1.0545	36.4	600	900	87.9	149.8	159.7	9.9	6.6%
		2,000	6.09	0.96	0.25	0.08	1.29	31.9	9.24	1.70	0.08	(0.04)	1.74	44.1	1.02	0.62	0.70	1.0545	48.6	600	1,400	119.0	199.5	211.7	12.2	6.1%
R1	**Forest**	100	**15.26**	**0.95**	**0.41**	**0.15**	**1.51**	16.8	**15.95**	**2.20**	**0.15**	**(0.04)**	**2.31**	18.3	**1.02**	0.62	0.70	1.0545	2.4	100	-	5.3	24.5	26.0	1.5	6.1%
		250	15.26	0.95	0.41	0.15	1.51	19.0	15.95	2.20	0.15	(0.04)	2.31	21.7	1.02	0.62	0.70	1.0545	6.1	250	-	13.2	38.3	41.0	2.7	7.0%
		500	15.26	0.95	0.41	0.15	1.51	22.8	15.95	2.20	0.15	(0.04)	2.31	27.5	1.02	0.62	0.70	1.0545	12.1	500	-	26.4	61.3	66.0	4.7	7.7%
		750	15.26	0.95	0.41	0.15	1.51	26.6	15.95	2.20	0.15	(0.04)	2.31	33.3	1.02	0.62	0.70	1.0545	18.2	600	150	41.3	86.1	92.8	6.7	7.8%
		1,000	15.26	0.95	0.41	0.15	1.51	30.4	15.95	2.20	0.15	(0.04)	2.31	39.1	1.02	0.62	0.70	1.0545	24.3	600	400	56.8	111.5	120.2	8.7	7.8%
		1,500	15.26	0.95	0.41	0.15	1.51	37.9	15.95	2.20	0.15	(0.04)	2.31	50.6	1.02	0.62	0.70	1.0545	36.4	600	900	87.9	162.3	175.0	12.7	7.8%
		2,000	15.26	0.95	0.41	0.15	1.51	45.5	15.95	2.20	0.15	(0.04)	2.31	62.2	1.02	0.62	0.70	1.0545	48.6	600	1,400	119.0	213.1	229.8	16.7	7.9%
UR	**GBE**	100	**9.68**	**0.95**	**0.46**	**0.13**	**1.54**	11.2	**10.16**	**2.35**	**0.13**	**(0.02)**	**2.46**	12.6	**1.02**	0.62	0.70	1.0545	2.4	100	-	5.3	18.9	20.3	1.4	7.4%
		250	9.68	0.95	0.46	0.13	1.54	13.5	10.16	2.35	0.13	(0.02)	2.46	16.3	1.02	0.62	0.70	1.0545	6.1	250	-	13.2	32.8	35.6	2.8	8.4%
		500	9.68	0.95	0.46	0.13	1.54	17.4	10.16	2.35	0.13	(0.02)	2.46	22.4	1.02	0.62	0.70	1.0545	12.1	500	-	26.4	55.9	60.9	5.1	9.0%
		750	9.68	0.95	0.46	0.13	1.54	21.2	10.16	2.35	0.13	(0.02)	2.46	28.6	1.02	0.62	0.70	1.0545	18.2	600	150	41.3	80.7	88.1	7.3	9.1%
		1,000	9.68	0.95	0.46	0.13	1.54	25.1	10.16	2.35	0.13	(0.02)	2.46	34.7	1.02	0.62	0.70	1.0545	24.3	600	400	56.8	106.2	115.8	9.6	9.1%
		1,500	9.68	0.95	0.46	0.13	1.54	32.8	10.16	2.35	0.13	(0.02)	2.46	47.0	1.02	0.62	0.70	1.0545	36.4	600	900	87.9	157.1	171.4	14.2	9.0%
		2,000	9.68	0.95	0.46	0.13	1.54	40.5	10.16	2.35	0.13	(0.02)	2.46	59.3	1.02	0.62	0.70	1.0545	48.6	600	1,400	119.0	208.1	226.9	18.8	9.0%

New Rate Class: R1

Total Bill Impacts of Proposed Distribution Rates [old RTSR+TLF]: Threshold of 600 kWhs

Classes		Scenario	May 2007 Incl Rate Riders						May 2008 Incl Rate Riders						Non-Dx Compoent				Other Reg	Commodity Bands			Existing	New	$ Incr	Incr
																				600.0						
			Existing Dx Rates					Existing Dx	New Dx Rates					New Dx	RTSR old	WMSC	DRC	TLF old	Old	Band 1	Band 2	Old	Total Bill	Total Bill	Total Bill	Total Bill
																				5.0	5.9					
New Class	Old Class	kWh	SrChg	base	Rider1	Rider2	VarChg	[$/month]	SrChg	base	Rider2	Rider3	VarChg	[$/month]	c/kWh	c/kWh	c/kWh		$	kWhs	kWhs	Total $	[$/month]	[$/month]	[$/month]	%
R1	**Georgina**	100	**11.72**	**0.98**	**0.31**	**0.09**	**1.38**	13.1	**12.83**	**2.05**	**0.09**	**(0.04)**	**2.10**	14.9	**1.02**	0.62	0.70	1.0545	2.4	100	-	5.3	20.8	22.6	1.8	8.8%
		250	11.72	0.98	0.31	0.09	1.38	15.2	12.83	2.05	0.09	(0.04)	2.10	18.1	1.02	0.62	0.70	1.0545	6.1	250	-	13.2	34.4	37.3	2.9	8.5%
		500	11.72	0.98	0.31	0.09	1.38	18.6	12.83	2.05	0.09	(0.04)	2.10	23.3	1.02	0.62	0.70	1.0545	12.1	500	-	26.4	57.1	61.9	4.7	8.3%
		750	11.72	0.98	0.31	0.09	1.38	22.1	12.83	2.05	0.09	(0.04)	2.10	28.6	1.02	0.62	0.70	1.0545	18.2	600	150	41.3	81.6	88.1	6.5	8.0%
		1,000	11.72	0.98	0.31	0.09	1.38	25.5	12.83	2.05	0.09	(0.04)	2.10	33.9	1.02	0.62	0.70	1.0545	24.3	600	400	56.8	106.6	115.0	8.3	7.8%
		1,500	11.72	0.98	0.31	0.09	1.38	32.4	12.83	2.05	0.09	(0.04)	2.10	44.4	1.02	0.62	0.70	1.0545	36.4	600	900	87.9	156.8	168.7	12.0	7.6%
		2,000	11.72	0.98	0.31	0.09	1.38	39.3	12.83	2.05	0.09	(0.04)	2.10	54.9	1.02	0.62	0.70	1.0545	48.6	600	1,400	119.0	206.9	222.5	15.6	7.5%
R1	**Glencoe**	100	**12.90**	**0.77**	**0.89**	**0.43**	**2.09**	15.0	**13.54**	**2.55**	**0.43**	**(0.04)**	**2.94**	16.5	**1.02**	0.62	0.70	1.0545	2.4	100	-	5.3	22.7	24.2	1.5	6.6%
		250	12.90	0.77	0.89	0.43	2.09	18.1	13.54	2.55	0.43	(0.04)	2.94	20.9	1.02	0.62	0.70	1.0545	6.1	250	-	13.2	37.4	40.1	2.8	7.4%
		500	12.90	0.77	0.89	0.43	2.09	23.4	13.54	2.55	0.43	(0.04)	2.94	28.2	1.02	0.62	0.70	1.0545	12.1	500	-	26.4	61.9	66.8	4.9	7.9%
		750	12.90	0.77	0.89	0.43	2.09	28.6	13.54	2.55	0.43	(0.04)	2.94	35.6	1.02	0.62	0.70	1.0545	18.2	600	150	41.3	88.1	95.1	7.0	8.0%
		1,000	12.90	0.77	0.89	0.43	2.09	33.8	13.54	2.55	0.43	(0.04)	2.94	43.0	1.02	0.62	0.70	1.0545	24.3	600	400	56.8	114.9	124.1	9.2	8.0%
		1,500	12.90	0.77	0.89	0.43	2.09	44.3	13.54	2.55	0.43	(0.04)	2.94	57.7	1.02	0.62	0.70	1.0545	36.4	600	900	87.9	168.6	182.0	13.4	8.0%
		2,000	12.90	0.77	0.89	0.43	2.09	54.7	13.54	2.55	0.43	(0.04)	2.94	72.4	1.02	0.62	0.70	1.0545	48.6	600	1,400	119.0	222.3	240.0	17.7	8.0%
R1	**Grand Bend**	100	**13.58**	**0.87**	**0.42**	**0.13**	**1.42**	15.0	**14.37**	**2.10**	**0.13**	**(0.04)**	**2.19**	16.6	**1.02**	0.62	0.70	1.0545	2.4	100	-	5.3	22.7	24.3	1.6	6.9%
		250	13.58	0.87	0.42	0.13	1.42	17.1	14.37	2.10	0.13	(0.04)	2.19	19.8	1.02	0.62	0.70	1.0545	6.1	250	-	13.2	36.4	39.1	2.7	7.5%
		500	13.58	0.87	0.42	0.13	1.42	20.7	14.37	2.10	0.13	(0.04)	2.19	25.3	1.02	0.62	0.70	1.0545	12.1	500	-	26.4	59.2	63.8	4.6	7.9%
		750	13.58	0.87	0.42	0.13	1.42	24.2	14.37	2.10	0.13	(0.04)	2.19	30.8	1.02	0.62	0.70	1.0545	18.2	600	150	41.3	83.7	90.3	6.6	7.9%
		1,000	13.58	0.87	0.42	0.13	1.42	27.8	14.37	2.10	0.13	(0.04)	2.19	36.3	1.02	0.62	0.70	1.0545	24.3	600	400	56.8	108.9	117.4	8.5	7.8%
		1,500	13.58	0.87	0.42	0.13	1.42	34.9	14.37	2.10	0.13	(0.04)	2.19	47.3	1.02	0.62	0.70	1.0545	36.4	600	900	87.9	159.2	171.6	12.4	7.8%
		2,000	13.58	0.87	0.42	0.13	1.42	42.0	14.37	2.10	0.13	(0.04)	2.19	58.2	1.02	0.62	0.70	1.0545	48.6	600	1,400	119.0	209.6	225.8	16.2	7.7%
R1	**Hastings**	100	**16.44**	**1.35**	**0.37**	**0.12**	**1.84**	18.3	**16.65**	**2.65**	**0.12**	**(0.04)**	**2.73**	19.4	**1.02**	0.62	0.70	1.0545	2.4	100	-	5.3	26.0	27.1	1.1	4.2%
		250	16.44	1.35	0.37	0.12	1.84	21.0	16.65	2.65	0.12	(0.04)	2.73	23.5	1.02	0.62	0.70	1.0545	6.1	250	-	13.2	40.3	42.7	2.4	6.1%
		500	16.44	1.35	0.37	0.12	1.84	25.6	16.65	2.65	0.12	(0.04)	2.73	30.3	1.02	0.62	0.70	1.0545	12.1	500	-	26.4	64.1	68.8	4.7	7.3%
		750	16.44	1.35	0.37	0.12	1.84	30.2	16.65	2.65	0.12	(0.04)	2.73	37.1	1.02	0.62	0.70	1.0545	18.2	600	150	41.3	89.7	96.6	6.9	7.7%
		1,000	16.44	1.35	0.37	0.12	1.84	34.8	16.65	2.65	0.12	(0.04)	2.73	44.0	1.02	0.62	0.70	1.0545	24.3	600	400	56.8	115.9	125.1	9.1	7.9%
		1,500	16.44	1.35	0.37	0.12	1.84	44.0	16.65	2.65	0.12	(0.04)	2.73	57.6	1.02	0.62	0.70	1.0545	36.4	600	900	87.9	168.4	182.0	13.6	8.1%
		2,000	16.44	1.35	0.37	0.12	1.84	53.2	16.65	2.65	0.12	(0.04)	2.73	71.3	1.02	0.62	0.70	1.0545	48.6	600	1,400	119.0	220.9	238.9	18.1	8.2%

New Rate Class: R1

Total Bill Impacts of Proposed Distribution Rates [old RTSR+TLF]: Threshold of 600 kWhs

Classes		Scenario	May 2007 Incl Rate Riders						May 2008 Incl Rate Riders						Non-Dx Compoent				Other Reg	Commodity Bands			Existing	New	$ Incr	Incr
			Existing Dx Rates					Existing Dx	New Dx Rates					New Dx	RTSR old	WMSC	DRC	TLF old	Old	Band 1	Band 2	Old	Total Bill	Total Bill	Total Bill	Total Bill
																				600.0						
																				5.0	5.9					
New Class	Old Class	kWh	SrChg	base	Rider1	Rider2	VarChg	[$/month]	SrChg	base	Rider2	Rider3	VarChg	[$/month]	c/kWh	c/kWh	c/kWh		$	kWhs	kWhs	Total $	[$/month]	[$/month]	[$/month]	%
R1	**Havelock**	100	**15.17**	**1.14**	**0.32**	**0.13**	**1.59**	16.8	**15.97**	**2.30**	**0.13**	**(0.04)**	**2.39**	18.4	**1.02**	0.62	0.70	1.0545	2.4	100	-	5.3	24.5	26.1	1.6	6.5%
		250	15.17	1.14	0.32	0.13	1.59	19.1	15.97	2.30	0.13	(0.04)	2.39	21.9	1.02	0.62	0.70	1.0545	6.1	250	-	13.2	38.4	41.2	2.8	7.3%
		500	15.17	1.14	0.32	0.13	1.59	23.1	15.97	2.30	0.13	(0.04)	2.39	27.9	1.02	0.62	0.70	1.0545	12.1	500	-	26.4	61.6	66.4	4.8	7.8%
		750	15.17	1.14	0.32	0.13	1.59	27.1	15.97	2.30	0.13	(0.04)	2.39	33.9	1.02	0.62	0.70	1.0545	18.2	600	150	41.3	86.6	93.4	6.8	7.9%
		1,000	15.17	1.14	0.32	0.13	1.59	31.1	15.97	2.30	0.13	(0.04)	2.39	39.9	1.02	0.62	0.70	1.0545	24.3	600	400	56.8	112.2	121.0	8.8	7.9%
		1,500	15.17	1.14	0.32	0.13	1.59	39.0	15.97	2.30	0.13	(0.04)	2.39	51.9	1.02	0.62	0.70	1.0545	36.4	600	900	87.9	163.4	176.2	12.8	7.9%
		2,000	15.17	1.14	0.32	0.13	1.59	47.0	15.97	2.30	0.13	(0.04)	2.39	63.8	1.02	0.62	0.70	1.0545	48.6	600	1,400	119.0	214.6	231.4	16.9	7.9%
R1	**Kirkfield**	100	**5.34**	**1.00**	**0.48**	**0.26**	**1.74**	7.1	**8.43**	**2.00**	**0.26**	**(0.04)**	**2.22**	10.6	**1.02**	0.62	0.70	1.0545	2.4	100	-	5.3	14.8	18.3	3.6	24.1%
		250	5.34	1.00	0.48	0.26	1.74	9.7	8.43	2.00	0.26	(0.04)	2.22	14.0	1.02	0.62	0.70	1.0545	6.1	250	-	13.2	28.9	33.2	4.3	14.8%
		500	5.34	1.00	0.48	0.26	1.74	14.0	8.43	2.00	0.26	(0.04)	2.22	19.5	1.02	0.62	0.70	1.0545	12.1	500	-	26.4	52.5	58.0	5.5	10.5%
		750	5.34	1.00	0.48	0.26	1.74	18.4	8.43	2.00	0.26	(0.04)	2.22	25.1	1.02	0.62	0.70	1.0545	18.2	600	150	41.3	77.9	84.6	6.7	8.6%
		1,000	5.34	1.00	0.48	0.26	1.74	22.7	8.43	2.00	0.26	(0.04)	2.22	30.7	1.02	0.62	0.70	1.0545	24.3	600	400	56.8	103.8	111.8	7.9	7.6%
		1,500	5.34	1.00	0.48	0.26	1.74	31.4	8.43	2.00	0.26	(0.04)	2.22	41.8	1.02	0.62	0.70	1.0545	36.4	600	900	87.9	155.8	166.1	10.3	6.6%
		2,000	5.34	1.00	0.48	0.26	1.74	40.1	8.43	2.00	0.26	(0.04)	2.22	52.9	1.02	0.62	0.70	1.0545	48.6	600	1,400	119.0	207.8	220.5	12.7	6.1%
R1	**Lanark Highl**	100	**11.31**	**1.02**	**0.56**	**0.40**	**1.98**	13.3	**12.93**	**2.35**	**0.40**	**(0.04)**	**2.71**	15.6	**1.02**	0.62	0.70	1.0545	2.4	100	-	5.3	21.0	23.3	2.4	11.2%
		250	11.31	1.02	0.56	0.40	1.98	16.3	12.93	2.35	0.40	(0.04)	2.71	19.7	1.02	0.62	0.70	1.0545	6.1	250	-	13.2	35.5	39.0	3.5	9.7%
		500	11.31	1.02	0.56	0.40	1.98	21.2	12.93	2.35	0.40	(0.04)	2.71	26.5	1.02	0.62	0.70	1.0545	12.1	500	-	26.4	59.7	65.0	5.3	8.9%
		750	11.31	1.02	0.56	0.40	1.98	26.2	12.93	2.35	0.40	(0.04)	2.71	33.3	1.02	0.62	0.70	1.0545	18.2	600	150	41.3	85.6	92.8	7.1	8.3%
		1,000	11.31	1.02	0.56	0.40	1.98	31.1	12.93	2.35	0.40	(0.04)	2.71	40.1	1.02	0.62	0.70	1.0545	24.3	600	400	56.8	112.2	121.2	9.0	8.0%
		1,500	11.31	1.02	0.56	0.40	1.98	41.0	12.93	2.35	0.40	(0.04)	2.71	53.6	1.02	0.62	0.70	1.0545	36.4	600	900	87.9	165.4	178.0	12.6	7.6%
		2,000	11.31	1.02	0.56	0.40	1.98	50.9	12.93	2.35	0.40	(0.04)	2.71	67.2	1.02	0.62	0.70	1.0545	48.6	600	1,400	119.0	218.5	234.8	16.3	7.4%
R1	**Larder Lake**	100	**15.84**	**1.01**	**0.68**	**0.43**	**2.12**	18.0	**15.80**	**2.70**	**0.43**	**(0.04)**	**3.09**	18.9	**1.02**	0.62	0.70	1.0545	2.4	100	-	5.3	25.7	26.6	0.9	3.6%
		250	15.84	1.01	0.68	0.43	2.12	21.1	15.80	2.70	0.43	(0.04)	3.09	23.5	1.02	0.62	0.70	1.0545	6.1	250	-	13.2	40.4	42.8	2.4	5.9%
		500	15.84	1.01	0.68	0.43	2.12	26.4	15.80	2.70	0.43	(0.04)	3.09	31.3	1.02	0.62	0.70	1.0545	12.1	500	-	26.4	64.9	69.8	4.8	7.4%
		750	15.84	1.01	0.68	0.43	2.12	31.7	15.80	2.70	0.43	(0.04)	3.09	39.0	1.02	0.62	0.70	1.0545	18.2	600	150	41.3	91.2	98.5	7.3	8.0%
		1,000	15.84	1.01	0.68	0.43	2.12	37.0	15.80	2.70	0.43	(0.04)	3.09	46.7	1.02	0.62	0.70	1.0545	24.3	600	400	56.8	118.1	127.8	9.7	8.2%
		1,500	15.84	1.01	0.68	0.43	2.12	47.6	15.80	2.70	0.43	(0.04)	3.09	62.2	1.02	0.62	0.70	1.0545	36.4	600	900	87.9	172.0	186.6	14.6	8.5%
		2,000	15.84	1.01	0.68	0.43	2.12	58.2	15.80	2.70	0.43	(0.04)	3.09	77.7	1.02	0.62	0.70	1.0545	48.6	600	1,400	119.0	225.9	245.3	19.4	8.6%

New Rate Class: R1

Total Bill Impacts of Proposed Distribution Rates [old RTSR+TLF]: Threshold of 600 kWhs

Classes		Scenario	May 2007 Incl Rate Riders						May 2008 Incl Rate Riders						Non-Dx Compoent				Other Reg	Commodity Bands			Existing	New	$ Incr	Incr
																				600.0						
			Existing Dx Rates					Existing Dx	New Dx Rates					New Dx	RTSR old	WMSC	DRC	TLF old	Old	Band 1	Band 2	Old	Total Bill	Total Bill	Total Bill	Total Bill
																				5.0	5.9					
New Class	Old Class	kWh	SrChg	base	Rider1	Rider2	VarChg	[$/month]	SrChg	base	Rider2	Rider3	VarChg	[$/month]	c/kWh	c/kWh	c/kWh		$	kWhs	kWhs	Total $	[$/month]	[$/month]	[$/month]	%
R1	**Latchford**	100	**13.31**	**0.88**	**1.04**	**0.45**	**2.37**	15.7	**14.43**	**2.71**	**0.45**	**(0.04)**	**3.13**	17.6	**1.02**	0.62	0.70	1.0545	2.4	100	-	5.3	23.4	25.3	1.9	8.0%
		250	13.31	0.88	1.04	0.45	2.37	19.2	14.43	2.71	0.45	(0.04)	3.13	22.2	1.02	0.62	0.70	1.0545	6.1	250	-	13.2	38.5	41.5	3.0	7.8%
		500	13.31	0.88	1.04	0.45	2.37	25.2	14.43	2.71	0.45	(0.04)	3.13	30.1	1.02	0.62	0.70	1.0545	12.1	500	-	26.4	63.7	68.6	4.9	7.7%
		750	13.31	0.88	1.04	0.45	2.37	31.1	14.43	2.71	0.45	(0.04)	3.13	37.9	1.02	0.62	0.70	1.0545	18.2	600	150	41.3	90.6	97.4	6.8	7.5%
		1,000	13.31	0.88	1.04	0.45	2.37	37.0	14.43	2.71	0.45	(0.04)	3.13	45.7	1.02	0.62	0.70	1.0545	24.3	600	400	56.8	118.1	126.8	8.7	7.4%
		1,500	13.31	0.88	1.04	0.45	2.37	48.9	14.43	2.71	0.45	(0.04)	3.13	61.3	1.02	0.62	0.70	1.0545	36.4	600	900	87.9	173.2	185.7	12.5	7.2%
		2,000	13.31	0.88	1.04	0.45	2.37	60.7	14.43	2.71	0.45	(0.04)	3.13	77.0	1.02	0.62	0.70	1.0545	48.6	600	1,400	119.0	228.3	244.6	16.2	7.1%
UR	**Lindsay**	100	**15.81**	**1.01**	**0.41**	**0.14**	**1.56**	17.4	**14.63**	**2.40**	**0.14**	**(0.02)**	**2.51**	17.1	**1.02**	0.62	0.70	1.0545	2.4	100	-	5.3	25.1	24.8	(0.2)	-0.9%
		250	15.81	1.01	0.41	0.14	1.56	19.7	14.63	2.40	0.14	(0.02)	2.51	20.9	1.02	0.62	0.70	1.0545	6.1	250	-	13.2	39.0	40.2	1.2	3.1%
		500	15.81	1.01	0.41	0.14	1.56	23.6	14.63	2.40	0.14	(0.02)	2.51	27.2	1.02	0.62	0.70	1.0545	12.1	500	-	26.4	62.1	65.7	3.6	5.8%
		750	15.81	1.01	0.41	0.14	1.56	27.5	14.63	2.40	0.14	(0.02)	2.51	33.5	1.02	0.62	0.70	1.0545	18.2	600	150	41.3	87.0	92.9	5.9	6.8%
		1,000	15.81	1.01	0.41	0.14	1.56	31.4	14.63	2.40	0.14	(0.02)	2.51	39.7	1.02	0.62	0.70	1.0545	24.3	600	400	56.8	112.5	120.8	8.3	7.4%
		1,500	15.81	1.01	0.41	0.14	1.56	39.2	14.63	2.40	0.14	(0.02)	2.51	52.3	1.02	0.62	0.70	1.0545	36.4	600	900	87.9	163.6	176.7	13.1	8.0%
		2,000	15.81	1.01	0.41	0.14	1.56	47.0	14.63	2.40	0.14	(0.02)	2.51	64.8	1.02	0.62	0.70	1.0545	48.6	600	1,400	119.0	214.6	232.5	17.8	8.3%
R1	**Lucan Grant**	100	**11.72**	**1.42**	**0.37**	**0.17**	**1.96**	13.7	**12.83**	**2.60**	**0.17**	**(0.04)**	**2.73**	15.6	**1.02**	0.62	0.70	1.0545	2.4	100	-	5.3	21.4	23.3	1.9	8.8%
		250	11.72	1.42	0.37	0.17	1.96	16.6	12.83	2.60	0.17	(0.04)	2.73	19.7	1.02	0.62	0.70	1.0545	6.1	250	-	13.2	35.9	38.9	3.0	8.5%
		500	11.72	1.42	0.37	0.17	1.96	21.5	12.83	2.60	0.17	(0.04)	2.73	26.5	1.02	0.62	0.70	1.0545	12.1	500	-	26.4	60.0	65.0	5.0	8.3%
		750	11.72	1.42	0.37	0.17	1.96	26.4	12.83	2.60	0.17	(0.04)	2.73	33.3	1.02	0.62	0.70	1.0545	18.2	600	150	41.3	85.9	92.8	6.9	8.0%
		1,000	11.72	1.42	0.37	0.17	1.96	31.3	12.83	2.60	0.17	(0.04)	2.73	40.2	1.02	0.62	0.70	1.0545	24.3	600	400	56.8	112.4	121.3	8.8	7.9%
		1,500	11.72	1.42	0.37	0.17	1.96	41.1	12.83	2.60	0.17	(0.04)	2.73	53.8	1.02	0.62	0.70	1.0545	36.4	600	900	87.9	165.5	178.2	12.7	7.7%
		2,000	11.72	1.42	0.37	0.17	1.96	50.9	12.83	2.60	0.17	(0.04)	2.73	67.5	1.02	0.62	0.70	1.0545	48.6	600	1,400	119.0	218.5	235.1	16.6	7.6%
R1	**Malahide**	100	**11.17**	**0.87**	**0.78**	**0.34**	**1.99**	13.2	**12.97**	**2.40**	**0.34**	**(0.04)**	**2.70**	15.7	**1.02**	0.62	0.70	1.0545	2.4	100	-	5.3	20.9	23.4	2.5	12.0%
		250	11.17	0.87	0.78	0.34	1.99	16.1	12.97	2.40	0.34	(0.04)	2.70	19.7	1.02	0.62	0.70	1.0545	6.1	250	-	13.2	35.4	39.0	3.6	10.1%
		500	11.17	0.87	0.78	0.34	1.99	21.1	12.97	2.40	0.34	(0.04)	2.70	26.5	1.02	0.62	0.70	1.0545	12.1	500	-	26.4	59.6	65.0	5.4	9.0%
		750	11.17	0.87	0.78	0.34	1.99	26.1	12.97	2.40	0.34	(0.04)	2.70	33.2	1.02	0.62	0.70	1.0545	18.2	600	150	41.3	85.6	92.7	7.1	8.3%
		1,000	11.17	0.87	0.78	0.34	1.99	31.1	12.97	2.40	0.34	(0.04)	2.70	40.0	1.02	0.62	0.70	1.0545	24.3	600	400	56.8	112.2	121.1	8.9	8.0%
		1,500	11.17	0.87	0.78	0.34	1.99	41.0	12.97	2.40	0.34	(0.04)	2.70	53.5	1.02	0.62	0.70	1.0545	36.4	600	900	87.9	165.4	177.9	12.5	7.6%
		2,000	11.17	0.87	0.78	0.34	1.99	51.0	12.97	2.40	0.34	(0.04)	2.70	67.0	1.02	0.62	0.70	1.0545	48.6	600	1,400	119.0	218.6	234.6	16.1	7.3%

New Rate Class: R1

Total Bill Impacts of Proposed Distribution Rates [old RTSR+TLF]: Threshold of 600 kWhs

600.0

Classes		Scenario	May 2007 Incl Rate Riders						May 2008 Incl Rate Riders						Non-Dx Compoent				Other Reg	Commodity Bands			Existing	New	$ Incr	Incr
			Existing Dx Rates					Existing Dx	New Dx Rates					New Dx	RTSR old	WMSC	DRC	TLF old	Old	Band 1	Band 2	Old	Total Bill	Total Bill	Total Bill	Total Bill
																				5.0	5.9					
New Class	Old Class	kWh	SrChg	base	Rider1	Rider2	VarChg	[$/month]	SrChg	base	Rider2	Rider3	VarChg	[$/month]	c/kWh	c/kWh	c/kWh		$	kWhs	kWhs	Total $	[$/month]	[$/month]	[$/month]	%
R1	**Mapleton**	100	**13.47**	**0.92**	**0.65**	**0.39**	**1.96**	15.4	**14.39**	**2.40**	**0.39**	**(0.04)**	**2.75**	17.1	**1.02**	0.62	0.70	1.0545	2.4	100	-	5.3	23.1	24.8	1.7	7.4%
		250	13.47	0.92	0.65	0.39	1.96	18.4	14.39	2.40	0.39	(0.04)	2.75	21.3	1.02	0.62	0.70	1.0545	6.1	250	-	13.2	37.6	40.5	2.9	7.7%
		500	13.47	0.92	0.65	0.39	1.96	23.3	14.39	2.40	0.39	(0.04)	2.75	28.2	1.02	0.62	0.70	1.0545	12.1	500	-	26.4	61.8	66.7	4.9	7.9%
		750	13.47	0.92	0.65	0.39	1.96	28.2	14.39	2.40	0.39	(0.04)	2.75	35.0	1.02	0.62	0.70	1.0545	18.2	600	150	41.3	87.7	94.5	6.9	7.8%
		1,000	13.47	0.92	0.65	0.39	1.96	33.1	14.39	2.40	0.39	(0.04)	2.75	41.9	1.02	0.62	0.70	1.0545	24.3	600	400	56.8	114.2	123.0	8.9	7.8%
		1,500	13.47	0.92	0.65	0.39	1.96	42.9	14.39	2.40	0.39	(0.04)	2.75	55.7	1.02	0.62	0.70	1.0545	36.4	600	900	87.9	167.2	180.0	12.8	7.7%
		2,000	13.47	0.92	0.65	0.39	1.96	52.7	14.39	2.40	0.39	(0.04)	2.75	69.4	1.02	0.62	0.70	1.0545	48.6	600	1,400	119.0	220.3	237.1	16.8	7.6%
R1	**Markdale**	100	**14.30**	**0.86**	**0.44**	**0.16**	**1.46**	15.8	**15.19**	**2.10**	**0.16**	**(0.04)**	**2.22**	17.4	**1.02**	0.62	0.70	1.0545	2.4	100	-	5.3	23.5	25.1	1.6	7.0%
		250	14.30	0.86	0.44	0.16	1.46	18.0	15.19	2.10	0.16	(0.04)	2.22	20.7	1.02	0.62	0.70	1.0545	6.1	250	-	13.2	37.2	40.0	2.8	7.5%
		500	14.30	0.86	0.44	0.16	1.46	21.6	15.19	2.10	0.16	(0.04)	2.22	26.3	1.02	0.62	0.70	1.0545	12.1	500	-	26.4	60.1	64.8	4.7	7.8%
		750	14.30	0.86	0.44	0.16	1.46	25.3	15.19	2.10	0.16	(0.04)	2.22	31.9	1.02	0.62	0.70	1.0545	18.2	600	150	41.3	84.7	91.3	6.6	7.8%
		1,000	14.30	0.86	0.44	0.16	1.46	28.9	15.19	2.10	0.16	(0.04)	2.22	37.4	1.02	0.62	0.70	1.0545	24.3	600	400	56.8	110.0	118.5	8.5	7.7%
		1,500	14.30	0.86	0.44	0.16	1.46	36.2	15.19	2.10	0.16	(0.04)	2.22	48.5	1.02	0.62	0.70	1.0545	36.4	600	900	87.9	160.6	172.9	12.3	7.7%
		2,000	14.30	0.86	0.44	0.16	1.46	43.5	15.19	2.10	0.16	(0.04)	2.22	59.6	1.02	0.62	0.70	1.0545	48.6	600	1,400	119.0	211.1	227.3	16.1	7.6%
R1	**Marmora**	100	**11.59**	**0.92**	**0.33**	**0.11**	**1.36**	13.0	**12.86**	**2.00**	**0.11**	**(0.04)**	**2.07**	14.9	**1.02**	0.62	0.70	1.0545	2.4	100	-	5.3	20.7	22.6	2.0	9.6%
		250	11.59	0.92	0.33	0.11	1.36	15.0	12.86	2.00	0.11	(0.04)	2.07	18.0	1.02	0.62	0.70	1.0545	6.1	250	-	13.2	34.2	37.3	3.1	8.9%
		500	11.59	0.92	0.33	0.11	1.36	18.4	12.86	2.00	0.11	(0.04)	2.07	23.2	1.02	0.62	0.70	1.0545	12.1	500	-	26.4	56.9	61.7	4.8	8.5%
		750	11.59	0.92	0.33	0.11	1.36	21.8	12.86	2.00	0.11	(0.04)	2.07	28.4	1.02	0.62	0.70	1.0545	18.2	600	150	41.3	81.3	87.9	6.6	8.1%
		1,000	11.59	0.92	0.33	0.11	1.36	25.2	12.86	2.00	0.11	(0.04)	2.07	33.6	1.02	0.62	0.70	1.0545	24.3	600	400	56.8	106.3	114.7	8.4	7.9%
		1,500	11.59	0.92	0.33	0.11	1.36	32.0	12.86	2.00	0.11	(0.04)	2.07	44.0	1.02	0.62	0.70	1.0545	36.4	600	900	87.9	156.4	168.3	12.0	7.7%
		2,000	11.59	0.92	0.33	0.11	1.36	38.8	12.86	2.00	0.11	(0.04)	2.07	54.3	1.02	0.62	0.70	1.0545	48.6	600	1,400	119.0	206.4	221.9	15.5	7.5%
R1	**McGarry**	100	**12.85**	**0.93**	**0.71**	**0.45**	**2.09**	14.9	**13.55**	**2.50**	**0.45**	**(0.04)**	**2.91**	16.5	**1.02**	0.62	0.70	1.0545	2.4	100	-	5.3	22.6	24.2	1.5	6.7%
		250	12.85	0.93	0.71	0.45	2.09	18.1	13.55	2.50	0.45	(0.04)	2.91	20.8	1.02	0.62	0.70	1.0545	6.1	250	-	13.2	37.3	40.1	2.8	7.4%
		500	12.85	0.93	0.71	0.45	2.09	23.3	13.55	2.50	0.45	(0.04)	2.91	28.1	1.02	0.62	0.70	1.0545	12.1	500	-	26.4	61.8	66.6	4.8	7.8%
		750	12.85	0.93	0.71	0.45	2.09	28.5	13.55	2.50	0.45	(0.04)	2.91	35.4	1.02	0.62	0.70	1.0545	18.2	600	150	41.3	88.0	94.9	6.9	7.8%
		1,000	12.85	0.93	0.71	0.45	2.09	33.8	13.55	2.50	0.45	(0.04)	2.91	42.7	1.02	0.62	0.70	1.0545	24.3	600	400	56.8	114.9	123.8	8.9	7.8%
		1,500	12.85	0.93	0.71	0.45	2.09	44.2	13.55	2.50	0.45	(0.04)	2.91	57.2	1.02	0.62	0.70	1.0545	36.4	600	900	87.9	168.6	181.6	13.0	7.7%
		2,000	12.85	0.93	0.71	0.45	2.09	54.7	13.55	2.50	0.45	(0.04)	2.91	71.8	1.02	0.62	0.70	1.0545	48.6	600	1,400	119.0	222.3	239.4	17.2	7.7%

New Rate Class: R1

Total Bill Impacts of Proposed Distribution Rates [old RTSR+TLF]: Threshold of 600 kWhs

Classes		Scenario	May 2007 Incl Rate Riders						May 2008 Incl Rate Riders						Non-Dx Compoent				Other Reg	Commodity Bands			Existing	New	$ Incr	Incr
			Existing Dx Rates					Existing Dx	New Dx Rates					New Dx	RTSR old	WMSC	DRC	TLF old	Old	Band 1	Band 2	Old	Total Bill	Total Bill	Total Bill	Total Bill
																				600.0						
																				5.0	5.9					
New Class	Old Class	kWh	SrChg	base	Rider1	Rider2	VarChg	[$/month]	SrChg	base	Rider2	Rider3	VarChg	[$/month]	c/kWh	c/kWh	c/kWh		$	kWhs	kWhs	Total $	[$/month]	[$/month]	[$/month]	%
R1	**Meaford**	100	**12.75**	**0.97**	**0.40**	**0.12**	**1.49**	14.2	**13.57**	**2.20**	**0.12**	**(0.04)**	**2.28**	15.9	**1.02**	0.62	0.70	1.0545	2.4	100	-	5.3	21.9	23.6	1.6	7.4%
		250	12.75	0.97	0.40	0.12	1.49	16.5	13.57	2.20	0.12	(0.04)	2.28	19.3	1.02	0.62	0.70	1.0545	6.1	250	-	13.2	35.7	38.5	2.8	7.8%
		500	12.75	0.97	0.40	0.12	1.49	20.2	13.57	2.20	0.12	(0.04)	2.28	25.0	1.02	0.62	0.70	1.0545	12.1	500	-	26.4	58.7	63.5	4.8	8.2%
		750	12.75	0.97	0.40	0.12	1.49	23.9	13.57	2.20	0.12	(0.04)	2.28	30.7	1.02	0.62	0.70	1.0545	18.2	600	150	41.3	83.4	90.2	6.8	8.1%
		1,000	12.75	0.97	0.40	0.12	1.49	27.7	13.57	2.20	0.12	(0.04)	2.28	36.4	1.02	0.62	0.70	1.0545	24.3	600	400	56.8	108.8	117.5	8.8	8.0%
		1,500	12.75	0.97	0.40	0.12	1.49	35.1	13.57	2.20	0.12	(0.04)	2.28	47.8	1.02	0.62	0.70	1.0545	36.4	600	900	87.9	159.5	172.2	12.7	8.0%
		2,000	12.75	0.97	0.40	0.12	1.49	42.6	13.57	2.20	0.12	(0.04)	2.28	59.2	1.02	0.62	0.70	1.0545	48.6	600	1,400	119.0	210.2	226.8	16.7	7.9%
R1	**Middlesex C**	100	**14.19**	**0.78**	**0.65**	**0.40**	**1.83**	16.0	**15.21**	**2.25**	**0.40**	**(0.04)**	**2.61**	17.8	**1.02**	0.62	0.70	1.0545	2.4	100	-	5.3	23.7	25.5	1.8	7.6%
		250	14.19	0.78	0.65	0.40	1.83	18.8	15.21	2.25	0.40	(0.04)	2.61	21.7	1.02	0.62	0.70	1.0545	6.1	250	-	13.2	38.0	41.0	3.0	7.8%
		500	14.19	0.78	0.65	0.40	1.83	23.3	15.21	2.25	0.40	(0.04)	2.61	28.3	1.02	0.62	0.70	1.0545	12.1	500	-	26.4	61.8	66.8	4.9	8.0%
		750	14.19	0.78	0.65	0.40	1.83	27.9	15.21	2.25	0.40	(0.04)	2.61	34.8	1.02	0.62	0.70	1.0545	18.2	600	150	41.3	87.4	94.3	6.9	7.9%
		1,000	14.19	0.78	0.65	0.40	1.83	32.5	15.21	2.25	0.40	(0.04)	2.61	41.3	1.02	0.62	0.70	1.0545	24.3	600	400	56.8	113.6	122.5	8.9	7.8%
		1,500	14.19	0.78	0.65	0.40	1.83	41.6	15.21	2.25	0.40	(0.04)	2.61	54.4	1.02	0.62	0.70	1.0545	36.4	600	900	87.9	166.0	178.8	12.8	7.7%
		2,000	14.19	0.78	0.65	0.40	1.83	50.8	15.21	2.25	0.40	(0.04)	2.61	67.5	1.02	0.62	0.70	1.0545	48.6	600	1,400	119.0	218.4	235.1	16.7	7.6%
R1	**Napanee**	100	**14.70**	**1.02**	**0.43**	**0.14**	**1.59**	16.3	**15.09**	**2.35**	**0.14**	**(0.04)**	**2.45**	17.5	**1.02**	0.62	0.70	1.0545	2.4	100	-	5.3	24.0	25.2	1.2	5.2%
		250	14.70	1.02	0.43	0.14	1.59	18.7	15.09	2.35	0.14	(0.04)	2.45	21.2	1.02	0.62	0.70	1.0545	6.1	250	-	13.2	37.9	40.5	2.5	6.7%
		500	14.70	1.02	0.43	0.14	1.59	22.7	15.09	2.35	0.14	(0.04)	2.45	27.3	1.02	0.62	0.70	1.0545	12.1	500	-	26.4	61.2	65.9	4.7	7.7%
		750	14.70	1.02	0.43	0.14	1.59	26.6	15.09	2.35	0.14	(0.04)	2.45	33.5	1.02	0.62	0.70	1.0545	18.2	600	150	41.3	86.1	93.0	6.9	8.0%
		1,000	14.70	1.02	0.43	0.14	1.59	30.6	15.09	2.35	0.14	(0.04)	2.45	39.6	1.02	0.62	0.70	1.0545	24.3	600	400	56.8	111.7	120.7	9.0	8.1%
		1,500	14.70	1.02	0.43	0.14	1.59	38.6	15.09	2.35	0.14	(0.04)	2.45	51.9	1.02	0.62	0.70	1.0545	36.4	600	900	87.9	162.9	176.2	13.3	8.2%
		2,000	14.70	1.02	0.43	0.14	1.59	46.5	15.09	2.35	0.14	(0.04)	2.45	64.1	1.02	0.62	0.70	1.0545	48.6	600	1,400	119.0	214.1	231.8	17.6	8.2%
R1	**Nipigon**	100	**14.23**	**1.42**	**1.27**	**0.72**	**3.41**	17.6	**15.20**	**2.71**	**0.72**	**(0.04)**	**3.40**	18.6	**1.02**	0.62	0.70	1.0545	2.4	100	-	5.3	25.3	26.3	1.0	3.8%
		250	14.23	1.42	1.27	0.72	3.41	22.8	15.20	2.71	0.72	(0.04)	3.40	23.7	1.02	0.62	0.70	1.0545	6.1	250	-	13.2	42.0	42.9	0.9	2.2%
		500	14.23	1.42	1.27	0.72	3.41	31.3	15.20	2.71	0.72	(0.04)	3.40	32.2	1.02	0.62	0.70	1.0545	12.1	500	-	26.4	69.8	70.7	0.9	1.3%
		750	14.23	1.42	1.27	0.72	3.41	39.8	15.20	2.71	0.72	(0.04)	3.40	40.7	1.02	0.62	0.70	1.0545	18.2	600	150	41.3	99.3	100.2	0.9	0.9%
		1,000	14.23	1.42	1.27	0.72	3.41	48.3	15.20	2.71	0.72	(0.04)	3.40	49.2	1.02	0.62	0.70	1.0545	24.3	600	400	56.8	129.4	130.3	0.8	0.6%
		1,500	14.23	1.42	1.27	0.72	3.41	65.4	15.20	2.71	0.72	(0.04)	3.40	66.1	1.02	0.62	0.70	1.0545	36.4	600	900	87.9	189.7	190.5	0.8	0.4%
		2,000	14.23	1.42	1.27	0.72	3.41	82.4	15.20	2.71	0.72	(0.04)	3.40	83.1	1.02	0.62	0.70	1.0545	48.6	600	1,400	119.0	250.0	250.7	0.7	0.3%

New Rate Class: R1

Total Bill Impacts of Proposed Distribution Rates [old RTSR+TLF]: Threshold of 600 kWhs

600.0

Classes		Scenario	May 2007 Incl Rate Riders						May 2008 Incl Rate Riders						Non-Dx Compoent				Other Reg	Commodity Bands			Existing	New	$ Incr	Incr
			Existing Dx Rates					Existing Dx	New Dx Rates					New Dx	RTSR old	WMSC	DRC	TLF old	Old	Band 1	Band 2	Old	Total Bill	Total Bill	Total Bill	Total Bill
																				5.0	5.9					
New Class	Old Class	kWh	SrChg	base	Rider1	Rider2	VarChg	[$/month]	SrChg	base	Rider2	Rider3	VarChg	[$/month]	c/kWh	c/kWh	c/kWh		$	kWhs	kWhs	Total $	[$/month]	[$/month]	[$/month]	%
R1	**North Dorch**	100	**8.97**	**0.86**	**0.67**	**0.40**	**1.93**	10.9	**10.52**	**2.25**	**0.40**	**(0.04)**	**2.61**	13.1	**1.02**	0.62	0.70	1.0545	2.4	100	-	5.3	18.6	20.8	2.2	12.0%
		250	8.97	0.86	0.67	0.40	1.93	13.8	10.52	2.25	0.40	(0.04)	2.61	17.0	1.02	0.62	0.70	1.0545	6.1	250	-	13.2	33.0	36.3	3.3	9.8%
		500	8.97	0.86	0.67	0.40	1.93	18.6	10.52	2.25	0.40	(0.04)	2.61	23.6	1.02	0.62	0.70	1.0545	12.1	500	-	26.4	57.1	62.1	5.0	8.7%
		750	8.97	0.86	0.67	0.40	1.93	23.4	10.52	2.25	0.40	(0.04)	2.61	30.1	1.02	0.62	0.70	1.0545	18.2	600	150	41.3	82.9	89.6	6.7	8.0%
		1,000	8.97	0.86	0.67	0.40	1.93	28.3	10.52	2.25	0.40	(0.04)	2.61	36.6	1.02	0.62	0.70	1.0545	24.3	600	400	56.8	109.4	117.8	8.4	7.7%
		1,500	8.97	0.86	0.67	0.40	1.93	37.9	10.52	2.25	0.40	(0.04)	2.61	49.7	1.02	0.62	0.70	1.0545	36.4	600	900	87.9	162.3	174.1	11.8	7.3%
		2,000	8.97	0.86	0.67	0.40	1.93	47.6	10.52	2.25	0.40	(0.04)	2.61	62.8	1.02	0.62	0.70	1.0545	48.6	600	1,400	119.0	215.2	230.4	15.2	7.1%
R1	**North Dunda**	100	**11.17**	**0.97**	**0.55**	**0.14**	**1.66**	12.8	**12.97**	**2.25**	**0.14**	**(0.04)**	**2.35**	15.3	**1.02**	0.62	0.70	1.0545	2.4	100	-	5.3	20.5	23.0	2.5	12.1%
		250	11.17	0.97	0.55	0.14	1.66	15.3	12.97	2.25	0.14	(0.04)	2.35	18.8	1.02	0.62	0.70	1.0545	6.1	250	-	13.2	34.6	38.1	3.5	10.2%
		500	11.17	0.97	0.55	0.14	1.66	19.5	12.97	2.25	0.14	(0.04)	2.35	24.7	1.02	0.62	0.70	1.0545	12.1	500	-	26.4	58.0	63.2	5.3	9.1%
		750	11.17	0.97	0.55	0.14	1.66	23.6	12.97	2.25	0.14	(0.04)	2.35	30.6	1.02	0.62	0.70	1.0545	18.2	600	150	41.3	83.1	90.1	7.0	8.4%
		1,000	11.17	0.97	0.55	0.14	1.66	27.8	12.97	2.25	0.14	(0.04)	2.35	36.5	1.02	0.62	0.70	1.0545	24.3	600	400	56.8	108.9	117.6	8.7	8.0%
		1,500	11.17	0.97	0.55	0.14	1.66	36.1	12.97	2.25	0.14	(0.04)	2.35	48.3	1.02	0.62	0.70	1.0545	36.4	600	900	87.9	160.4	172.6	12.2	7.6%
		2,000	11.17	0.97	0.55	0.14	1.66	44.4	12.97	2.25	0.14	(0.04)	2.35	60.0	1.02	0.62	0.70	1.0545	48.6	600	1,400	119.0	212.0	227.6	15.7	7.4%
R1	**North Glenga**	100	**7.74**	**1.02**	**0.52**	**0.22**	**1.76**	9.5	**9.83**	**2.20**	**0.22**	**(0.04)**	**2.38**	12.2	**1.02**	0.62	0.70	1.0545	2.4	100	-	5.3	17.2	19.9	2.7	15.7%
		250	7.74	1.02	0.52	0.22	1.76	12.1	9.83	2.20	0.22	(0.04)	2.38	15.8	1.02	0.62	0.70	1.0545	6.1	250	-	13.2	31.4	35.0	3.6	11.6%
		500	7.74	1.02	0.52	0.22	1.76	16.5	9.83	2.20	0.22	(0.04)	2.38	21.7	1.02	0.62	0.70	1.0545	12.1	500	-	26.4	55.0	60.2	5.2	9.4%
		750	7.74	1.02	0.52	0.22	1.76	20.9	9.83	2.20	0.22	(0.04)	2.38	27.7	1.02	0.62	0.70	1.0545	18.2	600	150	41.3	80.4	87.2	6.8	8.4%
		1,000	7.74	1.02	0.52	0.22	1.76	25.3	9.83	2.20	0.22	(0.04)	2.38	33.7	1.02	0.62	0.70	1.0545	24.3	600	400	56.8	106.4	114.8	8.3	7.8%
		1,500	7.74	1.02	0.52	0.22	1.76	34.1	9.83	2.20	0.22	(0.04)	2.38	45.6	1.02	0.62	0.70	1.0545	36.4	600	900	87.9	158.5	169.9	11.4	7.2%
		2,000	7.74	1.02	0.52	0.22	1.76	42.9	9.83	2.20	0.22	(0.04)	2.38	57.5	1.02	0.62	0.70	1.0545	48.6	600	1,400	119.0	210.6	225.1	14.5	6.9%
R1	**North Grenvi**	100	**14.40**	**1.65**	**0.37**	**0.16**	**2.18**	16.6	**15.16**	**2.71**	**0.16**	**(0.04)**	**2.84**	18.0	**1.02**	0.62	0.70	1.0545	2.4	100	-	5.3	24.3	25.7	1.4	5.8%
		250	14.40	1.65	0.37	0.16	2.18	19.9	15.16	2.71	0.16	(0.04)	2.84	22.3	1.02	0.62	0.70	1.0545	6.1	250	-	13.2	39.1	41.5	2.4	6.1%
		500	14.40	1.65	0.37	0.16	2.18	25.3	15.16	2.71	0.16	(0.04)	2.84	29.3	1.02	0.62	0.70	1.0545	12.1	500	-	26.4	63.8	67.9	4.0	6.3%
		750	14.40	1.65	0.37	0.16	2.18	30.8	15.16	2.71	0.16	(0.04)	2.84	36.4	1.02	0.62	0.70	1.0545	18.2	600	150	41.3	90.2	95.9	5.7	6.3%
		1,000	14.40	1.65	0.37	0.16	2.18	36.2	15.16	2.71	0.16	(0.04)	2.84	43.5	1.02	0.62	0.70	1.0545	24.3	600	400	56.8	117.3	124.6	7.3	6.2%
		1,500	14.40	1.65	0.37	0.16	2.18	47.1	15.16	2.71	0.16	(0.04)	2.84	57.7	1.02	0.62	0.70	1.0545	36.4	600	900	87.9	171.5	182.1	10.6	6.2%
		2,000	14.40	1.65	0.37	0.16	2.18	58.0	15.16	2.71	0.16	(0.04)	2.84	71.9	1.02	0.62	0.70	1.0545	48.6	600	1,400	119.0	225.6	239.5	13.9	6.2%

New Rate Class: R1

Total Bill Impacts of Proposed Distribution Rates [old RTSR+TLF]: Threshold of 600 kWhs

Classes		Scenario	May 2007 Incl Rate Riders						May 2008 Incl Rate Riders						Non-Dx Compoent				Other Reg	Commodity Bands (600.0)			Existing	New	$ Incr	Incr
			Existing Dx Rates					Existing Dx	New Dx Rates					New Dx	RTSR old	WMSC	DRC	TLF old	Old	Band 1	Band 2	Old	Total Bill	Total Bill	Total Bill	Total Bill
																				5.0	5.9					
New Class	Old Class	kWh	SrChg	base	Rider1	Rider2	VarChg	[$/month]	SrChg	base	Rider2	Rider3	VarChg	[$/month]	c/kWh	c/kWh	c/kWh		$	kWhs	kWhs	Total $	[$/month]	[$/month]	[$/month]	%
R1	North Perth	100	14.73	1.05	0.47	0.16	1.68	16.4	15.08	2.40	0.16	(0.04)	2.52	17.6	1.02	0.62	0.70	1.0545	2.4	100	-	5.3	24.1	25.3	1.2	4.9%
		250	14.73	1.05	0.47	0.16	1.68	18.9	15.08	2.40	0.16	(0.04)	2.52	21.4	1.02	0.62	0.70	1.0545	6.1	250	-	13.2	38.2	40.6	2.5	6.4%
		500	14.73	1.05	0.47	0.16	1.68	23.1	15.08	2.40	0.16	(0.04)	2.52	27.7	1.02	0.62	0.70	1.0545	12.1	500	-	26.4	61.6	66.2	4.6	7.4%
		750	14.73	1.05	0.47	0.16	1.68	27.3	15.08	2.40	0.16	(0.04)	2.52	34.0	1.02	0.62	0.70	1.0545	18.2	600	150	41.3	86.8	93.5	6.7	7.7%
		1,000	14.73	1.05	0.47	0.16	1.68	31.5	15.08	2.40	0.16	(0.04)	2.52	40.3	1.02	0.62	0.70	1.0545	24.3	600	400	56.8	112.6	121.4	8.8	7.8%
		1,500	14.73	1.05	0.47	0.16	1.68	39.9	15.08	2.40	0.16	(0.04)	2.52	52.9	1.02	0.62	0.70	1.0545	36.4	600	900	87.9	164.3	177.3	13.0	7.9%
		2,000	14.73	1.05	0.47	0.16	1.68	48.3	15.08	2.40	0.16	(0.04)	2.52	65.5	1.02	0.62	0.70	1.0545	48.6	600	1,400	119.0	215.9	233.2	17.2	8.0%
R1	North Storm	100	5.42	0.92	0.62	0.36	1.90	7.3	8.41	2.10	0.36	(0.04)	2.42	10.8	1.02	0.62	0.70	1.0545	2.4	100	-	5.3	15.0	18.5	3.5	23.4%
		250	5.42	0.92	0.62	0.36	1.90	10.2	8.41	2.10	0.36	(0.04)	2.42	14.5	1.02	0.62	0.70	1.0545	6.1	250	-	13.2	29.4	33.7	4.3	14.6%
		500	5.42	0.92	0.62	0.36	1.90	14.9	8.41	2.10	0.36	(0.04)	2.42	20.5	1.02	0.62	0.70	1.0545	12.1	500	-	26.4	53.4	59.0	5.6	10.5%
		750	5.42	0.92	0.62	0.36	1.90	19.7	8.41	2.10	0.36	(0.04)	2.42	26.6	1.02	0.62	0.70	1.0545	18.2	600	150	41.3	79.2	86.1	6.9	8.7%
		1,000	5.42	0.92	0.62	0.36	1.90	24.4	8.41	2.10	0.36	(0.04)	2.42	32.6	1.02	0.62	0.70	1.0545	24.3	600	400	56.8	105.5	113.7	8.2	7.8%
		1,500	5.42	0.92	0.62	0.36	1.90	33.9	8.41	2.10	0.36	(0.04)	2.42	44.7	1.02	0.62	0.70	1.0545	36.4	600	900	87.9	158.3	169.1	10.8	6.8%
		2,000	5.42	0.92	0.62	0.36	1.90	43.4	8.41	2.10	0.36	(0.04)	2.42	56.9	1.02	0.62	0.70	1.0545	48.6	600	1,400	119.0	211.0	224.5	13.4	6.4%
R1	Omemee	100	14.99	1.50	0.36	0.14	2.00	17.0	15.01	2.71	0.14	(0.04)	2.82	17.8	1.02	0.62	0.70	1.0545	2.4	100	-	5.3	24.7	25.5	0.8	3.4%
		250	14.99	1.50	0.36	0.14	2.00	20.0	15.01	2.71	0.14	(0.04)	2.82	22.1	1.02	0.62	0.70	1.0545	6.1	250	-	13.2	39.2	41.3	2.1	5.3%
		500	14.99	1.50	0.36	0.14	2.00	25.0	15.01	2.71	0.14	(0.04)	2.82	29.1	1.02	0.62	0.70	1.0545	12.1	500	-	26.4	63.5	67.6	4.1	6.5%
		750	14.99	1.50	0.36	0.14	2.00	30.0	15.01	2.71	0.14	(0.04)	2.82	36.1	1.02	0.62	0.70	1.0545	18.2	600	150	41.3	89.5	95.6	6.1	6.9%
		1,000	14.99	1.50	0.36	0.14	2.00	35.0	15.01	2.71	0.14	(0.04)	2.82	43.2	1.02	0.62	0.70	1.0545	24.3	600	400	56.8	116.1	124.3	8.2	7.1%
		1,500	14.99	1.50	0.36	0.14	2.00	45.0	15.01	2.71	0.14	(0.04)	2.82	57.3	1.02	0.62	0.70	1.0545	36.4	600	900	87.9	169.4	181.6	12.3	7.2%
		2,000	14.99	1.50	0.36	0.14	2.00	55.0	15.01	2.71	0.14	(0.04)	2.82	71.3	1.02	0.62	0.70	1.0545	48.6	600	1,400	119.0	222.6	239.0	16.3	7.3%
UR	Perth	100	14.47	1.22	0.50	0.18	1.90	16.4	13.96	2.40	0.18	(0.02)	2.55	16.5	1.02	0.62	0.70	1.0545	2.4	100	-	5.3	24.1	24.2	0.1	0.6%
		250	14.47	1.22	0.50	0.18	1.90	19.2	13.96	2.40	0.18	(0.02)	2.55	20.3	1.02	0.62	0.70	1.0545	6.1	250	-	13.2	38.5	39.6	1.1	2.9%
		500	14.47	1.22	0.50	0.18	1.90	24.0	13.96	2.40	0.18	(0.02)	2.55	26.7	1.02	0.62	0.70	1.0545	12.1	500	-	26.4	62.5	65.2	2.7	4.4%
		750	14.47	1.22	0.50	0.18	1.90	28.7	13.96	2.40	0.18	(0.02)	2.55	33.1	1.02	0.62	0.70	1.0545	18.2	600	150	41.3	88.2	92.6	4.4	5.0%
		1,000	14.47	1.22	0.50	0.18	1.90	33.5	13.96	2.40	0.18	(0.02)	2.55	39.5	1.02	0.62	0.70	1.0545	24.3	600	400	56.8	114.6	120.6	6.0	5.2%
		1,500	14.47	1.22	0.50	0.18	1.90	43.0	13.96	2.40	0.18	(0.02)	2.55	52.2	1.02	0.62	0.70	1.0545	36.4	600	900	87.9	167.3	176.6	9.3	5.5%
		2,000	14.47	1.22	0.50	0.18	1.90	52.5	13.96	2.40	0.18	(0.02)	2.55	65.0	1.02	0.62	0.70	1.0545	48.6	600	1,400	119.0	220.1	232.6	12.5	5.7%

New Rate Class: R1

Total Bill Impacts of Proposed Distribution Rates [old RTSR+TLF]: Threshold of 600 kWhs

600.0

Classes		Scenario	May 2007 Incl Rate Riders						May 2008 Incl Rate Riders						Non-Dx Compoent				Other Reg	Commodity Bands			Existing	New	$ Incr	Incr
			Existing Dx Rates					Existing Dx	New Dx Rates					New Dx	RTSR old	WMSC	DRC	TLF old	Old	Band 1	Band 2	Old	Total Bill	Total Bill	Total Bill	Total Bill
																				5.0	5.9					
New Class	Old Class	kWh	SrChg	base	Rider1	Rider2	VarChg	[$/month]	SrChg	base	Rider2	Rider3	VarChg	[$/month]	c/kWh	c/kWh	c/kWh		$	kWhs	kWhs	Total $	[$/month]	[$/month]	[$/month]	%
R1	**Perth East**	100	**5.95**	**0.78**	**0.26**	**0.06**	**1.10**	7.1	**8.27**	**1.60**	**0.06**	**(0.04)**	**1.62**	9.9	**1.02**	0.62	0.70	1.0545	2.4	100	-	5.3	14.8	17.6	2.8	19.3%
		250	5.95	0.78	0.26	0.06	1.10	8.7	8.27	1.60	0.06	(0.04)	1.62	12.3	1.02	0.62	0.70	1.0545	6.1	250	-	13.2	28.0	31.6	3.6	13.0%
		500	5.95	0.78	0.26	0.06	1.10	11.5	8.27	1.60	0.06	(0.04)	1.62	16.4	1.02	0.62	0.70	1.0545	12.1	500	-	26.4	50.0	54.9	4.9	9.9%
		750	5.95	0.78	0.26	0.06	1.10	14.2	8.27	1.60	0.06	(0.04)	1.62	20.4	1.02	0.62	0.70	1.0545	18.2	600	150	41.3	73.7	79.9	6.2	8.5%
		1,000	5.95	0.78	0.26	0.06	1.10	17.0	8.27	1.60	0.06	(0.04)	1.62	24.5	1.02	0.62	0.70	1.0545	24.3	600	400	56.8	98.1	105.6	7.6	7.7%
		1,500	5.95	0.78	0.26	0.06	1.10	22.5	8.27	1.60	0.06	(0.04)	1.62	32.6	1.02	0.62	0.70	1.0545	36.4	600	900	87.9	146.8	157.0	10.2	6.9%
		2,000	5.95	0.78	0.26	0.06	1.10	28.0	8.27	1.60	0.06	(0.04)	1.62	40.7	1.02	0.62	0.70	1.0545	48.6	600	1,400	119.0	195.6	208.3	12.8	6.5%
R1	**Prince Edwa**	100	**14.25**	**1.05**	**0.39**	**0.13**	**1.57**	15.8	**15.20**	**2.25**	**0.13**	**(0.04)**	**2.34**	17.5	**1.02**	0.62	0.70	1.0545	2.4	100	-	5.3	23.5	25.2	1.7	7.3%
		250	14.25	1.05	0.39	0.13	1.57	18.2	15.20	2.25	0.13	(0.04)	2.34	21.1	1.02	0.62	0.70	1.0545	6.1	250	-	13.2	37.4	40.3	2.9	7.7%
		500	14.25	1.05	0.39	0.13	1.57	22.1	15.20	2.25	0.13	(0.04)	2.34	26.9	1.02	0.62	0.70	1.0545	12.1	500	-	26.4	60.6	65.4	4.8	7.9%
		750	14.25	1.05	0.39	0.13	1.57	26.0	15.20	2.25	0.13	(0.04)	2.34	32.8	1.02	0.62	0.70	1.0545	18.2	600	150	41.3	85.5	92.3	6.7	7.9%
		1,000	14.25	1.05	0.39	0.13	1.57	30.0	15.20	2.25	0.13	(0.04)	2.34	38.6	1.02	0.62	0.70	1.0545	24.3	600	400	56.8	111.1	119.7	8.7	7.8%
		1,500	14.25	1.05	0.39	0.13	1.57	37.8	15.20	2.25	0.13	(0.04)	2.34	50.3	1.02	0.62	0.70	1.0545	36.4	600	900	87.9	162.2	174.7	12.5	7.7%
		2,000	14.25	1.05	0.39	0.13	1.57	45.7	15.20	2.25	0.13	(0.04)	2.34	62.1	1.02	0.62	0.70	1.0545	48.6	600	1,400	119.0	213.3	229.7	16.4	7.7%
UR	**Quinte West**	100	**6.58**	**0.92**	**0.39**	**0.11**	**1.42**	8.0	**7.94**	**2.10**	**0.11**	**(0.02)**	**2.19**	10.1	**1.02**	0.62	0.70	1.0545	2.4	100	-	5.3	15.7	17.8	2.1	13.5%
		250	6.58	0.92	0.39	0.11	1.42	10.1	7.94	2.10	0.11	(0.02)	2.19	13.4	1.02	0.62	0.70	1.0545	6.1	250	-	13.2	29.4	32.7	3.3	11.1%
		500	6.58	0.92	0.39	0.11	1.42	13.7	7.94	2.10	0.11	(0.02)	2.19	18.9	1.02	0.62	0.70	1.0545	12.1	500	-	26.4	52.2	57.4	5.2	9.9%
		750	6.58	0.92	0.39	0.11	1.42	17.2	7.94	2.10	0.11	(0.02)	2.19	24.3	1.02	0.62	0.70	1.0545	18.2	600	150	41.3	76.7	83.8	7.1	9.2%
		1,000	6.58	0.92	0.39	0.11	1.42	20.8	7.94	2.10	0.11	(0.02)	2.19	29.8	1.02	0.62	0.70	1.0545	24.3	600	400	56.8	101.9	110.9	9.0	8.8%
		1,500	6.58	0.92	0.39	0.11	1.42	27.9	7.94	2.10	0.11	(0.02)	2.19	40.7	1.02	0.62	0.70	1.0545	36.4	600	900	87.9	152.2	165.1	12.8	8.4%
		2,000	6.58	0.92	0.39	0.11	1.42	35.0	7.94	2.10	0.11	(0.02)	2.19	51.6	1.02	0.62	0.70	1.0545	48.6	600	1,400	119.0	202.6	219.3	16.7	8.2%
R1	**Rainy River**	100	**15.04**	**1.02**	**0.75**	**0.50**	**2.27**	17.3	**16.00**	**2.65**	**0.50**	**(0.04)**	**3.11**	19.1	**1.02**	0.62	0.70	1.0545	2.4	100	-	5.3	25.0	26.8	1.8	7.2%
		250	15.04	1.02	0.75	0.50	2.27	20.7	16.00	2.65	0.50	(0.04)	3.11	23.8	1.02	0.62	0.70	1.0545	6.1	250	-	13.2	40.0	43.0	3.1	7.7%
		500	15.04	1.02	0.75	0.50	2.27	26.4	16.00	2.65	0.50	(0.04)	3.11	31.6	1.02	0.62	0.70	1.0545	12.1	500	-	26.4	64.9	70.1	5.2	8.0%
		750	15.04	1.02	0.75	0.50	2.27	32.1	16.00	2.65	0.50	(0.04)	3.11	39.3	1.02	0.62	0.70	1.0545	18.2	600	150	41.3	91.5	98.8	7.3	8.0%
		1,000	15.04	1.02	0.75	0.50	2.27	37.7	16.00	2.65	0.50	(0.04)	3.11	47.1	1.02	0.62	0.70	1.0545	24.3	600	400	56.8	118.8	128.2	9.4	7.9%
		1,500	15.04	1.02	0.75	0.50	2.27	49.1	16.00	2.65	0.50	(0.04)	3.11	62.7	1.02	0.62	0.70	1.0545	36.4	600	900	87.9	173.5	187.1	13.6	7.8%
		2,000	15.04	1.02	0.75	0.50	2.27	60.4	16.00	2.65	0.50	(0.04)	3.11	78.3	1.02	0.62	0.70	1.0545	48.6	600	1,400	119.0	228.1	245.9	17.8	7.8%

New Rate Class: R1

Total Bill Impacts of Proposed Distribution Rates [old RTSR+TLF]: Threshold of 600 kWhs

600.0

Classes		Scenario	May 2007 Incl Rate Riders						May 2008 Incl Rate Riders						Non-Dx Compoent				Other Reg	Commodity Bands			Existing	New	$ Incr	Incr
			Existing Dx Rates					Existing Dx	New Dx Rates					New Dx	RTSR old	WMSC	DRC	TLF old	Old	Band 1	Band 2	Old	Total Bill	Total Bill	Total Bill	Total Bill
																				5.0	5.9					
New Class	Old Class	kWh	SrChg	base	Rider1	Rider2	VarChg	[$/month]	SrChg	base	Rider2	Rider3	VarChg	[$/month]	c/kWh	c/kWh	c/kWh		$	kWhs	kWhs	Total $	[$/month]	[$/month]	[$/month]	%
R1	**Ramara**	100	**6.52**	**0.95**	**0.55**	**0.35**	**1.85**	8.4	**9.13**	**2.10**	**0.35**	**(0.04)**	**2.41**	11.5	**1.02**	0.62	0.70	1.0545	2.4	100	-	5.3	16.1	19.2	3.2	19.7%
		250	6.52	0.95	0.55	0.35	1.85	11.1	9.13	2.10	0.35	(0.04)	2.41	15.2	1.02	0.62	0.70	1.0545	6.1	250	-	13.2	30.4	34.4	4.0	13.2%
		500	6.52	0.95	0.55	0.35	1.85	15.8	9.13	2.10	0.35	(0.04)	2.41	21.2	1.02	0.62	0.70	1.0545	12.1	500	-	26.4	54.3	59.7	5.4	10.0%
		750	6.52	0.95	0.55	0.35	1.85	20.4	9.13	2.10	0.35	(0.04)	2.41	27.2	1.02	0.62	0.70	1.0545	18.2	600	150	41.3	79.9	86.7	6.8	8.6%
		1,000	6.52	0.95	0.55	0.35	1.85	25.0	9.13	2.10	0.35	(0.04)	2.41	33.3	1.02	0.62	0.70	1.0545	24.3	600	400	56.8	106.1	114.4	8.2	7.8%
		1,500	6.52	0.95	0.55	0.35	1.85	34.3	9.13	2.10	0.35	(0.04)	2.41	45.3	1.02	0.62	0.70	1.0545	36.4	600	900	87.9	158.6	169.7	11.1	7.0%
		2,000	6.52	0.95	0.55	0.35	1.85	43.5	9.13	2.10	0.35	(0.04)	2.41	57.4	1.02	0.62	0.70	1.0545	48.6	600	1,400	119.0	211.1	225.0	13.9	6.6%
R1	**Red Rock**	100	**15.21**	**2.07**	**0.77**	**0.54**	**3.38**	18.6	**15.96**	**2.71**	**0.54**	**(0.04)**	**3.22**	19.2	**1.02**	0.62	0.70	1.0545	2.4	100	-	5.3	26.3	26.9	0.6	2.2%
		250	15.21	2.07	0.77	0.54	3.38	23.7	15.96	2.71	0.54	(0.04)	3.22	24.0	1.02	0.62	0.70	1.0545	6.1	250	-	13.2	42.9	43.3	0.3	0.8%
		500	15.21	2.07	0.77	0.54	3.38	32.1	15.96	2.71	0.54	(0.04)	3.22	32.0	1.02	0.62	0.70	1.0545	12.1	500	-	26.4	70.6	70.5	(0.1)	-0.1%
		750	15.21	2.07	0.77	0.54	3.38	40.6	15.96	2.71	0.54	(0.04)	3.22	40.1	1.02	0.62	0.70	1.0545	18.2	600	150	41.3	100.0	99.6	(0.5)	-0.5%
		1,000	15.21	2.07	0.77	0.54	3.38	49.0	15.96	2.71	0.54	(0.04)	3.22	48.1	1.02	0.62	0.70	1.0545	24.3	600	400	56.8	130.1	129.2	(0.9)	-0.7%
		1,500	15.21	2.07	0.77	0.54	3.38	65.9	15.96	2.71	0.54	(0.04)	3.22	64.2	1.02	0.62	0.70	1.0545	36.4	600	900	87.9	190.3	188.6	(1.7)	-0.9%
		2,000	15.21	2.07	0.77	0.54	3.38	82.8	15.96	2.71	0.54	(0.04)	3.22	80.3	1.02	0.62	0.70	1.0545	48.6	600	1,400	119.0	250.4	247.9	(2.5)	-1.0%
R1	**Rockland**	100	**9.41**	**0.92**	**0.65**	**0.37**	**1.94**	11.4	**11.41**	**2.30**	**0.37**	**(0.04)**	**2.63**	14.0	**1.02**	0.62	0.70	1.0545	2.4	100	-	5.3	19.1	21.7	2.7	14.1%
		250	9.41	0.92	0.65	0.37	1.94	14.3	11.41	2.30	0.37	(0.04)	2.63	18.0	1.02	0.62	0.70	1.0545	6.1	250	-	13.2	33.5	37.2	3.7	11.1%
		500	9.41	0.92	0.65	0.37	1.94	19.1	11.41	2.30	0.37	(0.04)	2.63	24.6	1.02	0.62	0.70	1.0545	12.1	500	-	26.4	57.6	63.1	5.5	9.5%
		750	9.41	0.92	0.65	0.37	1.94	24.0	11.41	2.30	0.37	(0.04)	2.63	31.2	1.02	0.62	0.70	1.0545	18.2	600	150	41.3	83.4	90.6	7.2	8.6%
		1,000	9.41	0.92	0.65	0.37	1.94	28.8	11.41	2.30	0.37	(0.04)	2.63	37.7	1.02	0.62	0.70	1.0545	24.3	600	400	56.8	109.9	118.8	8.9	8.1%
		1,500	9.41	0.92	0.65	0.37	1.94	38.5	11.41	2.30	0.37	(0.04)	2.63	50.9	1.02	0.62	0.70	1.0545	36.4	600	900	87.9	162.9	175.3	12.4	7.6%
		2,000	9.41	0.92	0.65	0.37	1.94	48.2	11.41	2.30	0.37	(0.04)	2.63	64.1	1.02	0.62	0.70	1.0545	48.6	600	1,400	119.0	215.8	231.7	15.9	7.3%
R1	**Russell**	100	**13.11**	**1.44**	**0.28**	**0.11**	**1.83**	14.9	**14.48**	**2.50**	**0.11**	**(0.04)**	**2.57**	17.1	**1.02**	0.62	0.70	1.0545	2.4	100	-	5.3	22.6	24.8	2.1	9.3%
		250	13.11	1.44	0.28	0.11	1.83	17.7	14.48	2.50	0.11	(0.04)	2.57	20.9	1.02	0.62	0.70	1.0545	6.1	250	-	13.2	36.9	40.2	3.2	8.7%
		500	13.11	1.44	0.28	0.11	1.83	22.3	14.48	2.50	0.11	(0.04)	2.57	27.3	1.02	0.62	0.70	1.0545	12.1	500	-	26.4	60.8	65.9	5.1	8.4%
		750	13.11	1.44	0.28	0.11	1.83	26.8	14.48	2.50	0.11	(0.04)	2.57	33.8	1.02	0.62	0.70	1.0545	18.2	600	150	41.3	86.3	93.3	6.9	8.0%
		1,000	13.11	1.44	0.28	0.11	1.83	31.4	14.48	2.50	0.11	(0.04)	2.57	40.2	1.02	0.62	0.70	1.0545	24.3	600	400	56.8	112.5	121.3	8.8	7.8%
		1,500	13.11	1.44	0.28	0.11	1.83	40.6	14.48	2.50	0.11	(0.04)	2.57	53.1	1.02	0.62	0.70	1.0545	36.4	600	900	87.9	164.9	177.4	12.5	7.6%
		2,000	13.11	1.44	0.28	0.11	1.83	49.7	14.48	2.50	0.11	(0.04)	2.57	65.9	1.02	0.62	0.70	1.0545	48.6	600	1,400	119.0	217.3	233.6	16.2	7.5%

New Rate Class: R1

Total Bill Impacts of Proposed Distribution Rates [old RTSR+TLF]: Threshold of 600 kWhs

Classes		Scenario	May 2007 Incl Rate Riders						May 2008 Incl Rate Riders						Non-Dx Compoent				Other Reg	Commodity Bands			Existing	New	$ Incr	Incr
			Existing Dx Rates					Existing Dx	New Dx Rates					New Dx	RTSR old	WMSC	DRC	TLF old	Old	Band 1	Band 2	Old	Total Bill	Total Bill	Total Bill	Total Bill
																				600.0						
																				5.0	5.9					
New Class	Old Class	kWh	SrChg	base	Rider1	Rider2	VarChg	[$/month]	SrChg	base	Rider2	Rider3	VarChg	[$/month]	c/kWh	c/kWh	c/kWh		$	kWhs	kWhs	Total $	[$/month]	[$/month]	[$/month]	%
R1	Schreiber	100	**16.32**	**1.84**	**0.68**	**0.44**	**2.96**	19.3	**16.68**	**2.71**	**0.44**	**(0.04)**	**3.12**	19.8	**1.02**	0.62	0.70	1.0545	2.4	100	-	5.3	27.0	27.5	0.5	1.9%
		250	16.32	1.84	0.68	0.44	2.96	23.7	16.68	2.71	0.44	(0.04)	3.12	24.5	1.02	0.62	0.70	1.0545	6.1	250	-	13.2	43.0	43.7	0.8	1.7%
		500	16.32	1.84	0.68	0.44	2.96	31.1	16.68	2.71	0.44	(0.04)	3.12	32.3	1.02	0.62	0.70	1.0545	12.1	500	-	26.4	69.6	70.8	1.1	1.6%
		750	16.32	1.84	0.68	0.44	2.96	38.5	16.68	2.71	0.44	(0.04)	3.12	40.1	1.02	0.62	0.70	1.0545	18.2	600	150	41.3	98.0	99.5	1.5	1.6%
		1,000	16.32	1.84	0.68	0.44	2.96	45.9	16.68	2.71	0.44	(0.04)	3.12	47.8	1.02	0.62	0.70	1.0545	24.3	600	400	56.8	127.0	129.0	1.9	1.5%
		1,500	16.32	1.84	0.68	0.44	2.96	60.7	16.68	2.71	0.44	(0.04)	3.12	63.4	1.02	0.62	0.70	1.0545	36.4	600	900	87.9	185.1	187.8	2.7	1.5%
		2,000	16.32	1.84	0.68	0.44	2.96	75.5	16.68	2.71	0.44	(0.04)	3.12	79.0	1.02	0.62	0.70	1.0545	48.6	600	1,400	119.0	243.1	246.6	3.5	1.4%
R1	Severn	100	**10.60**	**0.90**	**0.59**	**0.32**	**1.81**	12.4	**12.11**	**2.25**	**0.32**	**(0.04)**	**2.53**	14.6	**1.02**	0.62	0.70	1.0545	2.4	100	-	5.3	20.1	22.3	2.2	11.1%
		250	10.60	0.90	0.59	0.32	1.81	15.1	12.11	2.25	0.32	(0.04)	2.53	18.4	1.02	0.62	0.70	1.0545	6.1	250	-	13.2	34.4	37.7	3.3	9.6%
		500	10.60	0.90	0.59	0.32	1.81	19.7	12.11	2.25	0.32	(0.04)	2.53	24.8	1.02	0.62	0.70	1.0545	12.1	500	-	26.4	58.2	63.3	5.1	8.8%
		750	10.60	0.90	0.59	0.32	1.81	24.2	12.11	2.25	0.32	(0.04)	2.53	31.1	1.02	0.62	0.70	1.0545	18.2	600	150	41.3	83.7	90.6	6.9	8.3%
		1,000	10.60	0.90	0.59	0.32	1.81	28.7	12.11	2.25	0.32	(0.04)	2.53	37.4	1.02	0.62	0.70	1.0545	24.3	600	400	56.8	109.8	118.5	8.7	8.0%
		1,500	10.60	0.90	0.59	0.32	1.81	37.8	12.11	2.25	0.32	(0.04)	2.53	50.1	1.02	0.62	0.70	1.0545	36.4	600	900	87.9	162.1	174.5	12.4	7.6%
		2,000	10.60	0.90	0.59	0.32	1.81	46.8	12.11	2.25	0.32	(0.04)	2.53	62.8	1.02	0.62	0.70	1.0545	48.6	600	1,400	119.0	214.4	230.4	16.0	7.4%
R1	Shelburne	100	**14.14**	**1.33**	**0.39**	**0.14**	**1.86**	16.0	**15.23**	**2.55**	**0.14**	**(0.04)**	**2.65**	17.9	**1.02**	0.62	0.70	1.0545	2.4	100	-	5.3	23.7	25.6	1.9	7.9%
		250	14.14	1.33	0.39	0.14	1.86	18.8	15.23	2.55	0.14	(0.04)	2.65	21.9	1.02	0.62	0.70	1.0545	6.1	250	-	13.2	38.0	41.1	3.1	8.1%
		500	14.14	1.33	0.39	0.14	1.86	23.4	15.23	2.55	0.14	(0.04)	2.65	28.5	1.02	0.62	0.70	1.0545	12.1	500	-	26.4	61.9	67.0	5.0	8.2%
		750	14.14	1.33	0.39	0.14	1.86	28.1	15.23	2.55	0.14	(0.04)	2.65	35.1	1.02	0.62	0.70	1.0545	18.2	600	150	41.3	87.6	94.6	7.0	8.0%
		1,000	14.14	1.33	0.39	0.14	1.86	32.7	15.23	2.55	0.14	(0.04)	2.65	41.8	1.02	0.62	0.70	1.0545	24.3	600	400	56.8	113.8	122.9	9.0	7.9%
		1,500	14.14	1.33	0.39	0.14	1.86	42.0	15.23	2.55	0.14	(0.04)	2.65	55.0	1.02	0.62	0.70	1.0545	36.4	600	900	87.9	166.4	179.4	13.0	7.8%
		2,000	14.14	1.33	0.39	0.14	1.86	51.3	15.23	2.55	0.14	(0.04)	2.65	68.3	1.02	0.62	0.70	1.0545	48.6	600	1,400	119.0	219.0	235.9	16.9	7.7%
UR	Smiths Falls	100	**12.63**	**1.42**	**0.46**	**0.17**	**2.05**	14.7	**12.42**	**2.40**	**0.17**	**(0.02)**	**2.54**	15.0	**1.02**	0.62	0.70	1.0545	2.4	100	-	5.3	22.4	22.7	0.3	1.3%
		250	12.63	1.42	0.46	0.17	2.05	17.8	12.42	2.40	0.17	(0.02)	2.54	18.8	1.02	0.62	0.70	1.0545	6.1	250	-	13.2	37.0	38.0	1.0	2.8%
		500	12.63	1.42	0.46	0.17	2.05	22.9	12.42	2.40	0.17	(0.02)	2.54	25.1	1.02	0.62	0.70	1.0545	12.1	500	-	26.4	61.4	63.6	2.2	3.7%
		750	12.63	1.42	0.46	0.17	2.05	28.0	12.42	2.40	0.17	(0.02)	2.54	31.5	1.02	0.62	0.70	1.0545	18.2	600	150	41.3	87.5	91.0	3.5	4.0%
		1,000	12.63	1.42	0.46	0.17	2.05	33.1	12.42	2.40	0.17	(0.02)	2.54	37.8	1.02	0.62	0.70	1.0545	24.3	600	400	56.8	114.2	118.9	4.7	4.1%
		1,500	12.63	1.42	0.46	0.17	2.05	43.4	12.42	2.40	0.17	(0.02)	2.54	50.5	1.02	0.62	0.70	1.0545	36.4	600	900	87.9	167.7	174.9	7.2	4.3%
		2,000	12.63	1.42	0.46	0.17	2.05	53.6	12.42	2.40	0.17	(0.02)	2.54	63.2	1.02	0.62	0.70	1.0545	48.6	600	1,400	119.0	221.2	230.9	9.6	4.3%

New Rate Class: R1

Total Bill Impacts of Proposed Distribution Rates [old RTSR+TLF]: Threshold of 600 kWhs

Classes		Scenario	May 2007 Incl Rate Riders						May 2008 Incl Rate Riders						Non-Dx Compoent				Other Reg	Commodity Bands			Existing	New	$ Incr	Incr
			Existing Dx Rates					Existing Dx	New Dx Rates					New Dx	RTSR old	WMSC	DRC	TLF old	Old	Band 1	Band 2	Old	Total Bill	Total Bill	Total Bill	Total Bill
																				600.0						
																				5.0	5.9					
New Class	Old Class	kWh	SrChg	base	Rider1	Rider2	VarChg	[$/month]	SrChg	base	Rider2	Rider3	VarChg	[$/month]	c/kWh	c/kWh	c/kWh		$	kWhs	kWhs	Total $	[$/month]	[$/month]	[$/month]	%
R1	**South Gleng**	100	**9.46**	**0.75**	**0.52**	**0.36**	**1.63**	11.1	**11.40**	**1.95**	**0.36**	**(0.04)**	**2.27**	13.7	**1.02**	0.62	0.70	1.0545	2.4	100	-	5.3	18.8	21.4	2.6	13.7%
		250	9.46	0.75	0.52	0.36	1.63	13.5	11.40	1.95	0.36	(0.04)	2.27	17.1	1.02	0.62	0.70	1.0545	6.1	250	-	13.2	32.8	36.3	3.5	10.8%
		500	9.46	0.75	0.52	0.36	1.63	17.6	11.40	1.95	0.36	(0.04)	2.27	22.8	1.02	0.62	0.70	1.0545	12.1	500	-	26.4	56.1	61.3	5.1	9.2%
		750	9.46	0.75	0.52	0.36	1.63	21.7	11.40	1.95	0.36	(0.04)	2.27	28.4	1.02	0.62	0.70	1.0545	18.2	600	150	41.3	81.2	87.9	6.8	8.3%
		1,000	9.46	0.75	0.52	0.36	1.63	25.8	11.40	1.95	0.36	(0.04)	2.27	34.1	1.02	0.62	0.70	1.0545	24.3	600	400	56.8	106.9	115.2	8.4	7.8%
		1,500	9.46	0.75	0.52	0.36	1.63	33.9	11.40	1.95	0.36	(0.04)	2.27	45.5	1.02	0.62	0.70	1.0545	36.4	600	900	87.9	158.3	169.9	11.6	7.3%
		2,000	9.46	0.75	0.52	0.36	1.63	42.1	11.40	1.95	0.36	(0.04)	2.27	56.9	1.02	0.62	0.70	1.0545	48.6	600	1,400	119.0	209.7	224.5	14.8	7.1%
R1	**South River**	100	**14.22**	**1.25**	**0.63**	**0.41**	**2.29**	16.5	**15.21**	**2.71**	**0.41**	**(0.04)**	**3.09**	18.3	**1.02**	0.62	0.70	1.0545	2.4	100	-	5.3	24.2	26.0	1.8	7.4%
		250	14.22	1.25	0.63	0.41	2.29	19.9	15.21	2.71	0.41	(0.04)	3.09	22.9	1.02	0.62	0.70	1.0545	6.1	250	-	13.2	39.2	42.2	3.0	7.6%
		500	14.22	1.25	0.63	0.41	2.29	25.7	15.21	2.71	0.41	(0.04)	3.09	30.6	1.02	0.62	0.70	1.0545	12.1	500	-	26.4	64.2	69.1	5.0	7.7%
		750	14.22	1.25	0.63	0.41	2.29	31.4	15.21	2.71	0.41	(0.04)	3.09	38.4	1.02	0.62	0.70	1.0545	18.2	600	150	41.3	90.9	97.8	7.0	7.7%
		1,000	14.22	1.25	0.63	0.41	2.29	37.1	15.21	2.71	0.41	(0.04)	3.09	46.1	1.02	0.62	0.70	1.0545	24.3	600	400	56.8	118.2	127.2	8.9	7.6%
		1,500	14.22	1.25	0.63	0.41	2.29	48.6	15.21	2.71	0.41	(0.04)	3.09	61.5	1.02	0.62	0.70	1.0545	36.4	600	900	87.9	172.9	185.9	12.9	7.5%
		2,000	14.22	1.25	0.63	0.41	2.29	60.0	15.21	2.71	0.41	(0.04)	3.09	76.9	1.02	0.62	0.70	1.0545	48.6	600	1,400	119.0	227.6	244.5	16.9	7.4%
R1	**Springwater**	100	**11.79**	**0.82**	**0.61**	**0.31**	**1.74**	13.5	**12.81**	**2.25**	**0.31**	**(0.04)**	**2.52**	15.3	**1.02**	0.62	0.70	1.0545	2.4	100	-	5.3	21.2	23.0	1.8	8.5%
		250	11.79	0.82	0.61	0.31	1.74	16.1	12.81	2.25	0.31	(0.04)	2.52	19.1	1.02	0.62	0.70	1.0545	6.1	250	-	13.2	35.4	38.4	3.0	8.4%
		500	11.79	0.82	0.61	0.31	1.74	20.5	12.81	2.25	0.31	(0.04)	2.52	25.4	1.02	0.62	0.70	1.0545	12.1	500	-	26.4	59.0	63.9	4.9	8.4%
		750	11.79	0.82	0.61	0.31	1.74	24.8	12.81	2.25	0.31	(0.04)	2.52	31.7	1.02	0.62	0.70	1.0545	18.2	600	150	41.3	84.3	91.2	6.9	8.2%
		1,000	11.79	0.82	0.61	0.31	1.74	29.2	12.81	2.25	0.31	(0.04)	2.52	38.0	1.02	0.62	0.70	1.0545	24.3	600	400	56.8	110.3	119.2	8.9	8.0%
		1,500	11.79	0.82	0.61	0.31	1.74	37.9	12.81	2.25	0.31	(0.04)	2.52	50.7	1.02	0.62	0.70	1.0545	36.4	600	900	87.9	162.3	175.0	12.8	7.9%
		2,000	11.79	0.82	0.61	0.31	1.74	46.6	12.81	2.25	0.31	(0.04)	2.52	63.3	1.02	0.62	0.70	1.0545	48.6	600	1,400	119.0	214.2	230.9	16.7	7.8%
R1	**Stirling-Raw**	100	**12.55**	**1.03**	**0.38**	**0.12**	**1.53**	14.1	**13.62**	**2.20**	**0.12**	**(0.04)**	**2.28**	15.9	**1.02**	0.62	0.70	1.0545	2.4	100	-	5.3	21.8	23.6	1.8	8.4%
		250	12.55	1.03	0.38	0.12	1.53	16.4	13.62	2.20	0.12	(0.04)	2.28	19.3	1.02	0.62	0.70	1.0545	6.1	250	-	13.2	35.6	38.6	3.0	8.3%
		500	12.55	1.03	0.38	0.12	1.53	20.2	13.62	2.20	0.12	(0.04)	2.28	25.0	1.02	0.62	0.70	1.0545	12.1	500	-	26.4	58.7	63.5	4.8	8.2%
		750	12.55	1.03	0.38	0.12	1.53	24.0	13.62	2.20	0.12	(0.04)	2.28	30.7	1.02	0.62	0.70	1.0545	18.2	600	150	41.3	83.5	90.2	6.7	8.0%
		1,000	12.55	1.03	0.38	0.12	1.53	27.9	13.62	2.20	0.12	(0.04)	2.28	36.5	1.02	0.62	0.70	1.0545	24.3	600	400	56.8	109.0	117.6	8.6	7.9%
		1,500	12.55	1.03	0.38	0.12	1.53	35.5	13.62	2.20	0.12	(0.04)	2.28	47.9	1.02	0.62	0.70	1.0545	36.4	600	900	87.9	159.9	172.2	12.4	7.7%
		2,000	12.55	1.03	0.38	0.12	1.53	43.2	13.62	2.20	0.12	(0.04)	2.28	59.3	1.02	0.62	0.70	1.0545	48.6	600	1,400	119.0	210.8	226.9	16.1	7.7%

New Rate Class: R1

Total Bill Impacts of Proposed Distribution Rates [old RTSR+TLF]: Threshold of 600 kWhs

Classes		Scenario	May 2007 Incl Rate Riders						May 2008 Incl Rate Riders						Non-Dx Compoent				Other Reg	Commodity Bands			Existing	New	$ Incr	Incr
			Existing Dx Rates					Existing Dx	New Dx Rates					New Dx	RTSR old	WMSC	DRC	TLF old	Old	Band 1	Band 2	Old	Total Bill	Total Bill	Total Bill	Total Bill
																				600.0						
																				5.0	5.9					
New Class	Old Class	kWh	SrChg	base	Rider1	Rider2	VarChg	[$/month]	SrChg	base	Rider2	Rider3	VarChg	[$/month]	c/kWh	c/kWh	c/kWh		$	kWhs	kWhs	Total $	[$/month]	[$/month]	[$/month]	%
R1	**Thedford**	100	**12.75**	**0.81**	**0.82**	**0.52**	**2.15**	14.9	**13.57**	**2.50**	**0.52**	**(0.04)**	**2.98**	16.6	**1.02**	0.62	0.70	1.0545	2.4	100	-	5.3	22.6	24.3	1.7	7.3%
		250	12.75	0.81	0.82	0.52	2.15	18.1	13.57	2.50	0.52	(0.04)	2.98	21.0	1.02	0.62	0.70	1.0545	6.1	250	-	13.2	37.4	40.3	2.9	7.8%
		500	12.75	0.81	0.82	0.52	2.15	23.5	13.57	2.50	0.52	(0.04)	2.98	28.5	1.02	0.62	0.70	1.0545	12.1	500	-	26.4	62.0	67.0	5.0	8.0%
		750	12.75	0.81	0.82	0.52	2.15	28.9	13.57	2.50	0.52	(0.04)	2.98	35.9	1.02	0.62	0.70	1.0545	18.2	600	150	41.3	88.4	95.4	7.1	8.0%
		1,000	12.75	0.81	0.82	0.52	2.15	34.3	13.57	2.50	0.52	(0.04)	2.98	43.4	1.02	0.62	0.70	1.0545	24.3	600	400	56.8	115.4	124.5	9.2	7.9%
		1,500	12.75	0.81	0.82	0.52	2.15	45.0	13.57	2.50	0.52	(0.04)	2.98	58.3	1.02	0.62	0.70	1.0545	36.4	600	900	87.9	169.4	182.7	13.3	7.9%
		2,000	12.75	0.81	0.82	0.52	2.15	55.8	13.57	2.50	0.52	(0.04)	2.98	73.2	1.02	0.62	0.70	1.0545	48.6	600	1,400	119.0	223.4	240.8	17.5	7.8%
R1	**Thessalon**	100	**15.56**	**1.05**	**0.28**	**0.12**	**1.45**	17.0	**15.87**	**2.20**	**0.12**	**(0.04)**	**2.28**	18.2	**1.02**	0.62	0.70	1.0545	2.4	100	-	5.3	24.7	25.9	1.1	4.6%
		250	15.56	1.05	0.28	0.12	1.45	19.2	15.87	2.20	0.12	(0.04)	2.28	21.6	1.02	0.62	0.70	1.0545	6.1	250	-	13.2	38.4	40.8	2.4	6.2%
		500	15.56	1.05	0.28	0.12	1.45	22.8	15.87	2.20	0.12	(0.04)	2.28	27.3	1.02	0.62	0.70	1.0545	12.1	500	-	26.4	61.3	65.8	4.5	7.3%
		750	15.56	1.05	0.28	0.12	1.45	26.4	15.87	2.20	0.12	(0.04)	2.28	33.0	1.02	0.62	0.70	1.0545	18.2	600	150	41.3	85.9	92.5	6.6	7.6%
		1,000	15.56	1.05	0.28	0.12	1.45	30.1	15.87	2.20	0.12	(0.04)	2.28	38.7	1.02	0.62	0.70	1.0545	24.3	600	400	56.8	111.2	119.8	8.6	7.8%
		1,500	15.56	1.05	0.28	0.12	1.45	37.3	15.87	2.20	0.12	(0.04)	2.28	50.1	1.02	0.62	0.70	1.0545	36.4	600	900	87.9	161.7	174.5	12.8	7.9%
		2,000	15.56	1.05	0.28	0.12	1.45	44.6	15.87	2.20	0.12	(0.04)	2.28	61.5	1.02	0.62	0.70	1.0545	48.6	600	1,400	119.0	212.2	229.1	17.0	8.0%
R1	**Thorndale**	100	**4.32**	**0.88**	**0.62**	**0.32**	**1.82**	6.1	**7.68**	**2.00**	**0.32**	**(0.04)**	**2.28**	10.0	**1.02**	0.62	0.70	1.0545	2.4	100	-	5.3	13.8	17.7	3.8	27.6%
		250	4.32	0.88	0.62	0.32	1.82	8.9	7.68	2.00	0.32	(0.04)	2.28	13.4	1.02	0.62	0.70	1.0545	6.1	250	-	13.2	28.1	32.6	4.5	16.1%
		500	4.32	0.88	0.62	0.32	1.82	13.4	7.68	2.00	0.32	(0.04)	2.28	19.1	1.02	0.62	0.70	1.0545	12.1	500	-	26.4	51.9	57.6	5.7	10.9%
		750	4.32	0.88	0.62	0.32	1.82	18.0	7.68	2.00	0.32	(0.04)	2.28	24.8	1.02	0.62	0.70	1.0545	18.2	600	150	41.3	77.5	84.3	6.8	8.8%
		1,000	4.32	0.88	0.62	0.32	1.82	22.5	7.68	2.00	0.32	(0.04)	2.28	30.5	1.02	0.62	0.70	1.0545	24.3	600	400	56.8	103.6	111.6	8.0	7.7%
		1,500	4.32	0.88	0.62	0.32	1.82	31.6	7.68	2.00	0.32	(0.04)	2.28	41.9	1.02	0.62	0.70	1.0545	36.4	600	900	87.9	156.0	166.3	10.3	6.6%
		2,000	4.32	0.88	0.62	0.32	1.82	40.7	7.68	2.00	0.32	(0.04)	2.28	53.3	1.02	0.62	0.70	1.0545	48.6	600	1,400	119.0	208.3	221.0	12.6	6.1%
UR	**Thorold**	100	**13.68**	**1.47**	**0.41**	**0.14**	**2.02**	15.7	**13.16**	**2.40**	**0.14**	**(0.02)**	**2.51**	15.7	**1.02**	0.62	0.70	1.0545	2.4	100	-	5.3	23.4	23.4	(0.0)	-0.1%
		250	13.68	1.47	0.41	0.14	2.02	18.7	13.16	2.40	0.14	(0.02)	2.51	19.4	1.02	0.62	0.70	1.0545	6.1	250	-	13.2	38.0	38.7	0.7	1.9%
		500	13.68	1.47	0.41	0.14	2.02	23.8	13.16	2.40	0.14	(0.02)	2.51	25.7	1.02	0.62	0.70	1.0545	12.1	500	-	26.4	62.3	64.2	1.9	3.1%
		750	13.68	1.47	0.41	0.14	2.02	28.8	13.16	2.40	0.14	(0.02)	2.51	32.0	1.02	0.62	0.70	1.0545	18.2	600	150	41.3	88.3	91.5	3.2	3.6%
		1,000	13.68	1.47	0.41	0.14	2.02	33.9	13.16	2.40	0.14	(0.02)	2.51	38.3	1.02	0.62	0.70	1.0545	24.3	600	400	56.8	115.0	119.4	4.4	3.8%
		1,500	13.68	1.47	0.41	0.14	2.02	44.0	13.16	2.40	0.14	(0.02)	2.51	50.8	1.02	0.62	0.70	1.0545	36.4	600	900	87.9	168.3	175.2	6.8	4.1%
		2,000	13.68	1.47	0.41	0.14	2.02	54.1	13.16	2.40	0.14	(0.02)	2.51	63.4	1.02	0.62	0.70	1.0545	48.6	600	1,400	119.0	221.7	231.0	9.3	4.2%

New Rate Class: R1

Total Bill Impacts of Proposed Distribution Rates [old RTSR+TLF]: Threshold of 600 kWhs

600.0

Classes		Scenario	May 2007 Incl Rate Riders						May 2008 Incl Rate Riders						Non-Dx Compoent				Other Reg	Commodity Bands			Existing	New	$ Incr	Incr
			Existing Dx Rates					Existing Dx	New Dx Rates					New Dx	RTSR old	WMSC	DRC	TLF old	Old	Band 1	Band 2	Old	Total Bill	Total Bill	Total Bill	Total Bill
																				5.0	5.9					
New Class	Old Class	kWh	SrChg	base	Rider1	Rider2	VarChg	[$/month]	SrChg	base	Rider2	Rider3	VarChg	[$/month]	c/kWh	c/kWh	c/kWh		$	kWhs	kWhs	Total $	[$/month]	[$/month]	[$/month]	%
R1	**Tweed**	100	**4.48**	**0.95**	**0.61**	**0.37**	**1.93**	6.4	**7.64**	**2.10**	**0.37**	**(0.04)**	**2.43**	10.1	**1.02**	0.62	0.70	1.0545	2.4	100	-	5.3	14.1	17.8	3.7	26.0%
		250	4.48	0.95	0.61	0.37	1.93	9.3	7.64	2.10	0.37	(0.04)	2.43	13.7	1.02	0.62	0.70	1.0545	6.1	250	-	13.2	28.6	33.0	4.4	15.5%
		500	4.48	0.95	0.61	0.37	1.93	14.1	7.64	2.10	0.37	(0.04)	2.43	19.8	1.02	0.62	0.70	1.0545	12.1	500	-	26.4	52.6	58.3	5.7	10.8%
		750	4.48	0.95	0.61	0.37	1.93	19.0	7.64	2.10	0.37	(0.04)	2.43	25.9	1.02	0.62	0.70	1.0545	18.2	600	150	41.3	78.4	85.4	6.9	8.8%
		1,000	4.48	0.95	0.61	0.37	1.93	23.8	7.64	2.10	0.37	(0.04)	2.43	32.0	1.02	0.62	0.70	1.0545	24.3	600	400	56.8	104.9	113.1	8.2	7.8%
		1,500	4.48	0.95	0.61	0.37	1.93	33.4	7.64	2.10	0.37	(0.04)	2.43	44.1	1.02	0.62	0.70	1.0545	36.4	600	900	87.9	157.8	168.5	10.7	6.8%
		2,000	4.48	0.95	0.61	0.37	1.93	43.1	7.64	2.10	0.37	(0.04)	2.43	56.3	1.02	0.62	0.70	1.0545	48.6	600	1,400	119.0	210.7	223.9	13.2	6.3%
R1	**Wardsville**	100	**9.64**	**0.97**	**0.36**	**0.10**	**1.43**	11.1	**11.35**	**2.00**	**0.10**	**(0.04)**	**2.06**	13.4	**1.02**	0.62	0.70	1.0545	2.4	100	-	5.3	18.8	21.1	2.3	12.5%
		250	9.64	0.97	0.36	0.10	1.43	13.2	11.35	2.00	0.10	(0.04)	2.06	16.5	1.02	0.62	0.70	1.0545	6.1	250	-	13.2	32.5	35.8	3.3	10.1%
		500	9.64	0.97	0.36	0.10	1.43	16.8	11.35	2.00	0.10	(0.04)	2.06	21.7	1.02	0.62	0.70	1.0545	12.1	500	-	26.4	55.3	60.2	4.9	8.8%
		750	9.64	0.97	0.36	0.10	1.43	20.4	11.35	2.00	0.10	(0.04)	2.06	26.8	1.02	0.62	0.70	1.0545	18.2	600	150	41.3	79.8	86.3	6.5	8.1%
		1,000	9.64	0.97	0.36	0.10	1.43	23.9	11.35	2.00	0.10	(0.04)	2.06	32.0	1.02	0.62	0.70	1.0545	24.3	600	400	56.8	105.0	113.1	8.0	7.7%
		1,500	9.64	0.97	0.36	0.10	1.43	31.1	11.35	2.00	0.10	(0.04)	2.06	42.3	1.02	0.62	0.70	1.0545	36.4	600	900	87.9	155.5	166.7	11.2	7.2%
		2,000	9.64	0.97	0.36	0.10	1.43	38.2	11.35	2.00	0.10	(0.04)	2.06	52.6	1.02	0.62	0.70	1.0545	48.6	600	1,400	119.0	205.9	220.2	14.4	7.0%
R1	**Warkworth**	100	**15.25**	**1.18**	**0.66**	**0.43**	**2.27**	17.5	**15.95**	**2.71**	**0.43**	**(0.04)**	**3.11**	19.1	**1.02**	0.62	0.70	1.0545	2.4	100	-	5.3	25.2	26.8	1.5	6.1%
		250	15.25	1.18	0.66	0.43	2.27	20.9	15.95	2.71	0.43	(0.04)	3.11	23.7	1.02	0.62	0.70	1.0545	6.1	250	-	13.2	40.2	43.0	2.8	6.9%
		500	15.25	1.18	0.66	0.43	2.27	26.6	15.95	2.71	0.43	(0.04)	3.11	31.5	1.02	0.62	0.70	1.0545	12.1	500	-	26.4	65.1	70.0	4.9	7.5%
		750	15.25	1.18	0.66	0.43	2.27	32.3	15.95	2.71	0.43	(0.04)	3.11	39.2	1.02	0.62	0.70	1.0545	18.2	600	150	41.3	91.8	98.7	7.0	7.6%
		1,000	15.25	1.18	0.66	0.43	2.27	38.0	15.95	2.71	0.43	(0.04)	3.11	47.0	1.02	0.62	0.70	1.0545	24.3	600	400	56.8	119.1	128.1	9.1	7.6%
		1,500	15.25	1.18	0.66	0.43	2.27	49.3	15.95	2.71	0.43	(0.04)	3.11	62.5	1.02	0.62	0.70	1.0545	36.4	600	900	87.9	173.7	186.9	13.2	7.6%
		2,000	15.25	1.18	0.66	0.43	2.27	60.7	15.95	2.71	0.43	(0.04)	3.11	78.1	1.02	0.62	0.70	1.0545	48.6	600	1,400	119.0	228.3	245.7	17.4	7.6%
R1	**West Elgin**	100	**13.30**	**1.42**	**0.63**	**0.35**	**2.40**	15.7	**14.44**	**2.71**	**0.35**	**(0.04)**	**3.03**	17.5	**1.02**	0.62	0.70	1.0545	2.4	100	-	5.3	23.4	25.2	1.8	7.5%
		250	13.30	1.42	0.63	0.35	2.40	19.3	14.44	2.71	0.35	(0.04)	3.03	22.0	1.02	0.62	0.70	1.0545	6.1	250	-	13.2	38.6	41.3	2.7	7.0%
		500	13.30	1.42	0.63	0.35	2.40	25.3	14.44	2.71	0.35	(0.04)	3.03	29.6	1.02	0.62	0.70	1.0545	12.1	500	-	26.4	63.8	68.1	4.3	6.7%
		750	13.30	1.42	0.63	0.35	2.40	31.3	14.44	2.71	0.35	(0.04)	3.03	37.1	1.02	0.62	0.70	1.0545	18.2	600	150	41.3	90.8	96.6	5.8	6.4%
		1,000	13.30	1.42	0.63	0.35	2.40	37.3	14.44	2.71	0.35	(0.04)	3.03	44.7	1.02	0.62	0.70	1.0545	24.3	600	400	56.8	118.4	125.8	7.4	6.2%
		1,500	13.30	1.42	0.63	0.35	2.40	49.3	14.44	2.71	0.35	(0.04)	3.03	59.8	1.02	0.62	0.70	1.0545	36.4	600	900	87.9	173.7	184.2	10.5	6.1%
		2,000	13.30	1.42	0.63	0.35	2.40	61.3	14.44	2.71	0.35	(0.04)	3.03	75.0	1.02	0.62	0.70	1.0545	48.6	600	1,400	119.0	228.9	242.6	13.7	6.0%

New Rate Class: R1

Total Bill Impacts of Proposed Distribution Rates [old RTSR+TLF]: Threshold of 600 kWhs

Classes		Scenario	May 2007 Incl Rate Riders						May 2008 Incl Rate Riders						Non-Dx Compoent				Other Reg	Commodity Bands			Existing	New	$ Incr	Incr
			Existing Dx Rates					Existing Dx	New Dx Rates					New Dx	RTSR old	WMSC	DRC	TLF old	Old	Band 1	Band 2	Old	Total Bill	Total Bill	Total Bill	Total Bill
																				600.0						
																				5.0	5.9					
New Class	Old Class	kWh	SrChg	base	Rider1	Rider2	VarChg	[$/month]	SrChg	base	Rider2	Rider3	VarChg	[$/month]	c/kWh	c/kWh	c/kWh		$	kWhs	kWhs	Total $	[$/month]	[$/month]	[$/month]	%
UR	**Whitchurch S**	100	**10.54**	**1.02**	**0.36**	**0.12**	**1.50**	12.0	**10.95**	**2.30**	**0.12**	**(0.02)**	**2.40**	13.3	**1.02**	0.62	0.70	1.0545	2.4	100	-	5.3	19.7	21.0	1.3	6.6%
		250	10.54	1.02	0.36	0.12	1.50	14.3	10.95	2.30	0.12	(0.02)	2.40	16.9	1.02	0.62	0.70	1.0545	6.1	250	-	13.2	33.5	36.2	2.6	7.9%
		500	10.54	1.02	0.36	0.12	1.50	18.0	10.95	2.30	0.12	(0.02)	2.40	22.9	1.02	0.62	0.70	1.0545	12.1	500	-	26.4	56.5	61.4	4.9	8.6%
		750	10.54	1.02	0.36	0.12	1.50	21.8	10.95	2.30	0.12	(0.02)	2.40	28.9	1.02	0.62	0.70	1.0545	18.2	600	150	41.3	81.3	88.4	7.1	8.8%
		1,000	10.54	1.02	0.36	0.12	1.50	25.5	10.95	2.30	0.12	(0.02)	2.40	34.9	1.02	0.62	0.70	1.0545	24.3	600	400	56.8	106.6	116.0	9.4	8.8%
		1,500	10.54	1.02	0.36	0.12	1.50	33.0	10.95	2.30	0.12	(0.02)	2.40	46.9	1.02	0.62	0.70	1.0545	36.4	600	900	87.9	157.4	171.2	13.8	8.8%
		2,000	10.54	1.02	0.36	0.12	1.50	40.5	10.95	2.30	0.12	(0.02)	2.40	58.8	1.02	0.62	0.70	1.0545	48.6	600	1,400	119.0	208.2	226.5	18.3	8.8%
R1	**Wiarton**	100	**15.83**	**1.55**	**0.37**	**0.14**	**2.06**	17.9	**15.80**	**2.71**	**0.14**	**(0.04)**	**2.82**	18.6	**1.02**	0.62	0.70	1.0545	2.4	100	-	5.3	25.6	26.3	0.7	2.8%
		250	15.83	1.55	0.37	0.14	2.06	21.0	15.80	2.71	0.14	(0.04)	2.82	22.8	1.02	0.62	0.70	1.0545	6.1	250	-	13.2	40.2	42.1	1.9	4.6%
		500	15.83	1.55	0.37	0.14	2.06	26.1	15.80	2.71	0.14	(0.04)	2.82	29.9	1.02	0.62	0.70	1.0545	12.1	500	-	26.4	64.6	68.4	3.8	5.8%
		750	15.83	1.55	0.37	0.14	2.06	31.3	15.80	2.71	0.14	(0.04)	2.82	36.9	1.02	0.62	0.70	1.0545	18.2	600	150	41.3	90.8	96.4	5.6	6.2%
		1,000	15.83	1.55	0.37	0.14	2.06	36.4	15.80	2.71	0.14	(0.04)	2.82	44.0	1.02	0.62	0.70	1.0545	24.3	600	400	56.8	117.5	125.1	7.5	6.4%
		1,500	15.83	1.55	0.37	0.14	2.06	46.7	15.80	2.71	0.14	(0.04)	2.82	58.0	1.02	0.62	0.70	1.0545	36.4	600	900	87.9	171.1	182.4	11.3	6.6%
		2,000	15.83	1.55	0.37	0.14	2.06	57.0	15.80	2.71	0.14	(0.04)	2.82	72.1	1.02	0.62	0.70	1.0545	48.6	600	1,400	119.0	224.6	239.7	15.1	6.7%
R1	**Woodville**	100	**3.78**	**0.95**	**0.51**	**0.26**	**1.72**	5.5	**6.82**	**2.00**	**0.26**	**(0.04)**	**2.22**	9.0	**1.02**	0.62	0.70	1.0545	2.4	100	-	5.3	13.2	16.7	3.5	26.8%
		250	3.78	0.95	0.51	0.26	1.72	8.1	6.82	2.00	0.26	(0.04)	2.22	12.4	1.02	0.62	0.70	1.0545	6.1	250	-	13.2	27.3	31.6	4.3	15.7%
		500	3.78	0.95	0.51	0.26	1.72	12.4	6.82	2.00	0.26	(0.04)	2.22	17.9	1.02	0.62	0.70	1.0545	12.1	500	-	26.4	50.9	56.4	5.5	10.9%
		750	3.78	0.95	0.51	0.26	1.72	16.7	6.82	2.00	0.26	(0.04)	2.22	23.5	1.02	0.62	0.70	1.0545	18.2	600	150	41.3	76.2	83.0	6.8	8.9%
		1,000	3.78	0.95	0.51	0.26	1.72	21.0	6.82	2.00	0.26	(0.04)	2.22	29.0	1.02	0.62	0.70	1.0545	24.3	600	400	56.8	102.1	110.2	8.1	7.9%
		1,500	3.78	0.95	0.51	0.26	1.72	29.6	6.82	2.00	0.26	(0.04)	2.22	40.2	1.02	0.62	0.70	1.0545	36.4	600	900	87.9	153.9	164.5	10.6	6.9%
		2,000	3.78	0.95	0.51	0.26	1.72	38.2	6.82	2.00	0.26	(0.04)	2.22	51.3	1.02	0.62	0.70	1.0545	48.6	600	1,400	119.0	205.8	218.9	13.1	6.4%
R1	**Wyoming**	100	**11.52**	**0.81**	**0.36**	**0.11**	**1.28**	12.8	**12.88**	**1.90**	**0.11**	**(0.04)**	**1.97**	14.9	**1.02**	0.62	0.70	1.0545	2.4	100	-	5.3	20.5	22.6	2.1	10.0%
		250	11.52	0.81	0.36	0.11	1.28	14.7	12.88	1.90	0.11	(0.04)	1.97	17.8	1.02	0.62	0.70	1.0545	6.1	250	-	13.2	34.0	37.1	3.1	9.1%
		500	11.52	0.81	0.36	0.11	1.28	17.9	12.88	1.90	0.11	(0.04)	1.97	22.7	1.02	0.62	0.70	1.0545	12.1	500	-	26.4	56.4	61.3	4.8	8.5%
		750	11.52	0.81	0.36	0.11	1.28	21.1	12.88	1.90	0.11	(0.04)	1.97	27.7	1.02	0.62	0.70	1.0545	18.2	600	150	41.3	80.6	87.2	6.6	8.1%
		1,000	11.52	0.81	0.36	0.11	1.28	24.3	12.88	1.90	0.11	(0.04)	1.97	32.6	1.02	0.62	0.70	1.0545	24.3	600	400	56.8	105.4	113.7	8.3	7.9%
		1,500	11.52	0.81	0.36	0.11	1.28	30.7	12.88	1.90	0.11	(0.04)	1.97	42.5	1.02	0.62	0.70	1.0545	36.4	600	900	87.9	155.1	166.8	11.8	7.6%
		2,000	11.52	0.81	0.36	0.11	1.28	37.1	12.88	1.90	0.11	(0.04)	1.97	52.3	1.02	0.62	0.70	1.0545	48.6	600	1,400	119.0	204.7	220.0	15.2	7.4%

New Rate Class: R1

Total Bill Impacts of Proposed Distribution Rates [old RTSR+TLF]: Threshold of 600 kWhs

Classes		Scenario	May 2007 Incl Rate Riders						May 2008 Incl Rate Riders						Non-Dx Compoent				Other Reg	Commodity Bands			Existing	New	$ Incr	Incr
			Existing Dx Rates					Existing Dx	New Dx Rates					New Dx	RTSR old	WMSC	DRC	TLF old	Old	Band 1	Band 2	Old	Total Bill	Total Bill	Total Bill	Total Bill
																				600.0						
																				5.0	5.9					
New Class	**Old Class**	kWh	SrChg	base	Rider1	Rider2	VarChg	[$/month]	SrChg	base	Rider2	Rider3	VarChg	[$/month]	c/kWh	c/kWh	c/kWh		$	kWhs	kWhs	Total $	[$/month]	[$/month]	[$/month]	%
R1	**Terrace Bay**	100	**20.81**	**1.45**	**0.97**	**-**	**2.42**	23.2	**19.56**	**2.71**	**-**	**(0.04)**	**2.68**	22.2	**0.51**	0.62	0.70	1.0426	1.9	100	-	5.2	30.3	29.3	(1.0)	-3.3%
		250	20.81	1.45	0.97	-	2.42	26.9	19.56	2.71	-	(0.04)	2.68	26.2	0.51	0.62	0.70	1.0426	4.7	250	-	13.0	44.6	44.0	(0.6)	-1.4%
		500	20.81	1.45	0.97	-	2.42	32.9	19.56	2.71	-	(0.04)	2.68	32.9	0.51	0.62	0.70	1.0426	9.4	500	-	26.1	68.4	68.4	0.0	0.0%
		750	20.81	1.45	0.97	-	2.42	39.0	19.56	2.71	-	(0.04)	2.68	39.6	0.51	0.62	0.70	1.0426	14.1	600	150	40.7	93.8	94.5	0.7	0.7%
		1,000	20.81	1.45	0.97	-	2.42	45.0	19.56	2.71	-	(0.04)	2.68	46.3	0.51	0.62	0.70	1.0426	18.8	600	400	56.1	119.9	121.2	1.3	1.1%
		1,500	20.81	1.45	0.97	-	2.42	57.1	19.56	2.71	-	(0.04)	2.68	59.7	0.51	0.62	0.70	1.0426	28.2	600	900	86.9	172.2	174.7	2.6	1.5%
		2,000	20.81	1.45	0.97	-	2.42	69.2	19.56	2.71	-	(0.04)	2.68	73.1	0.51	0.62	0.70	1.0426	37.6	600	1,400	117.6	224.4	228.3	3.9	1.7%

New Rate Class: R2

Total Bill Impacts of Proposed Distribution Rates [old RTSR+TLF]: Threshold of 600 kWhs

600.0

Classes		Scenario	May 2007 Incl Rate Riders						May 2008 Incl Rate Riders						Non-Dx Compoent				Other Reg	Commodity Bands			Existing	New	$ Incr	% Incr
			Existing Dx Rates					Existing Dx	New Dx Rates					New Dx	RTSR old	WMSC	DRC	TLF old	Old	Band 1	Band 2	Old	Total Bill	Total Bill	Total Bill	Total Bill
																				5.0	5.9					
New Class	Old Class	kWh	SrChg [$/cust]	base [c/kWh]	Rider1 [c/kWh]	Rider2 [c/kWh]	VarChg [c/kWh]	[$/month]	SrChg [$/cust]	base [c/kWh]	Rider2 [c/kWh]	Rider3 [c/kWh]	VarChg [c/kWh]	[$/month]	c/kWh	c/kWh	c/kWh		$	kWhs	kWhs	Total $	[$/month]	[$/month]	[$/month]	%
R2	**R2**	100	**29.22**	**1.94**	**0.12**	**0.13**	**2.19**	31.4	**27.05**	**2.68**	**0.13**	**(0.05)**	**2.76**	29.8	**0.94**	0.62	0.7	**1.092**	2.4	100	-	5.5	39.3	37.7	(1.6)	-4.1%
		250	29.22	1.94	0.12	0.13	2.19	34.7	27.05	2.68	0.13	(0.05)	2.76	33.9	0.94	0.62	0.7	1.09	6.0	250	-	13.7	54.4	53.6	(0.8)	-1.4%
			29.22	1.94	0.12	0.13	2.19	40.2	27.05	2.68	0.13	(0.05)	2.76	40.8	0.94	0.62	0.7	1.09	12.0	500	-	27.3	79.5	80.2	0.7	0.8%
		750	29.22	1.94	0.12	0.13	2.19	45.6	27.05	2.68	0.13	(0.05)	2.76	47.7	0.94	0.62	0.7	1.09	18.0	600	150	42.9	106.6	108.7	2.1	2.0%
		1,000	29.22	1.94	0.12	0.13	2.19	51.1	27.05	2.68	0.13	(0.05)	2.76	54.6	0.94	0.62	0.7	1.09	24.0	600	400	59.0	134.2	137.7	3.5	2.6%
		1,500	29.22	1.94	0.12	0.13	2.19	62.1	27.05	2.68	0.13	(0.05)	2.76	68.4	0.94	0.62	0.7	1.09	36.1	600	900	91.2	189.4	195.7	6.3	3.4%
		2,000	29.22	1.94	0.12	0.13	2.19	73.0	27.05	2.68	0.13	(0.05)	2.76	82.2	0.94	0.62	0.7	1.09	48.1	600	1,400	123.5	244.5	253.7	9.2	3.8%
R2	**F1**	100	**28.61**	**2.24**	**0.08**	**0.10**	**2.42**	31.0	**26.20**	**2.68**	**0.10**	**(0.05)**	**2.73**	28.9	**0.89**	0.62	0.7	**1.092**	2.3	100	-	5.5	38.8	36.7	(2.1)	-5.4%
		250	28.61	2.24	0.08	0.10	2.42	34.7	26.20	2.68	0.10	(0.05)	2.73	33.0	0.89	0.62	0.70	1.09	5.9	250	-	13.7	54.2	52.5	(1.6)	-3.0%
		500	28.61	2.24	0.08	0.10	2.42	40.7	26.20	2.68	0.10	(0.05)	2.73	39.8	0.89	0.62	0.70	1.09	11.7	500	-	27.3	79.8	78.9	(0.9)	-1.1%
		750	28.61	2.24	0.08	0.10	2.42	46.8	26.20	2.68	0.10	(0.05)	2.73	46.7	0.89	0.62	0.70	1.09	17.6	600	150	42.9	107.3	107.2	(0.1)	-0.1%
		1,000	28.61	2.24	0.08	0.10	2.42	52.8	26.20	2.68	0.10	(0.05)	2.73	53.5	0.89	0.62	0.70	1.09	23.5	600	400	59.0	135.3	136.0	0.7	0.5%
		1,500	28.61	2.24	0.08	0.10	2.42	64.9	26.20	2.68	0.10	(0.05)	2.73	67.1	0.89	0.62	0.70	1.09	35.2	600	900	91.2	191.4	193.6	2.2	1.2%
		2,000	28.61	2.24	0.08	0.10	2.42	77.0	26.20	2.68	0.10	(0.05)	2.73	80.8	0.89	0.62	0.70	1.09	47.0	600	1,400	123.5	247.4	251.2	3.7	1.5%
R2	**F3**	100	**30.16**	**2.89**	**0.03**	**0.04**	**2.96**	33.1	**27.81**	**2.68**	**0.04**	**(0.05)**	**2.67**	30.5	**0.84**	0.62	0.7	**1.061**	2.2	100	-	5.3	40.7	38.0	(2.6)	-6.5%
		250	30.16	2.89	0.03	0.04	2.96	37.6	27.81	2.68	0.04	(0.05)	2.67	34.5	0.84	0.62	0.70	1.06	5.6	250	-	13.3	56.4	53.4	(3.1)	-5.5%
		500	30.16	2.89	0.03	0.04	2.96	45.0	27.81	2.68	0.04	(0.05)	2.67	41.2	0.84	0.62	0.70	1.06	11.2	500	-	26.5	82.7	78.9	(3.8)	-4.6%
		750	30.16	2.89	0.03	0.04	2.96	52.4	27.81	2.68	0.04	(0.05)	2.67	47.8	0.84	0.62	0.70	1.06	16.9	600	150	41.5	110.8	106.2	(4.5)	-4.1%
		1,000	30.16	2.89	0.03	0.04	2.96	59.8	27.81	2.68	0.04	(0.05)	2.67	54.5	0.84	0.62	0.70	1.06	22.5	600	400	57.2	139.4	134.2	(5.3)	-3.8%
		1,500	30.16	2.89	0.03	0.04	2.96	74.6	27.81	2.68	0.04	(0.05)	2.67	67.8	0.84	0.62	0.70	1.06	33.7	600	900	88.5	196.8	190.1	(6.7)	-3.4%
		2,000	30.16	2.89	0.03	0.04	2.96	89.4	27.81	2.68	0.04	(0.05)	2.67	81.2	0.84	0.62	0.70	1.06	45.0	600	1,400	119.8	254.1	245.9	(8.2)	-3.2%
R2	**Caledon OH 06**	100	**34.85**	**0.50**	**0.25**	**0.11**	**0.86**	35.7	**30.64**	**2.20**	**0.11**	**(0.05)**	**2.26**	32.9	**1.02**	0.62	0.7	1.0545	2.4	100	-	5.3	43.4	40.6	(2.8)	-6.5%
		250	34.85	0.50	0.25	0.11	0.86	37.0	30.64	2.20	0.11	(0.05)	2.26	36.3	1.02	0.62	0.70	1.05	6.1	250	-	13.2	56.3	55.5	(0.7)	-1.3%
		500	34.85	0.50	0.25	0.11	0.86	39.2	30.64	2.20	0.11	(0.05)	2.26	41.9	1.02	0.62	0.70	1.05	12.1	500	-	26.4	77.7	80.5	2.8	3.6%
		750	34.85	0.50	0.25	0.11	0.86	41.3	30.64	2.20	0.11	(0.05)	2.26	47.6	1.02	0.62	0.70	1.05	18.2	600	150	41.3	100.8	107.1	6.3	6.2%
		1,000	34.85	0.50	0.25	0.11	0.86	43.5	30.64	2.20	0.11	(0.05)	2.26	53.3	1.02	0.62	0.70	1.05	24.3	600	400	56.8	124.6	134.4	9.8	7.9%
		1,500	34.85	0.50	0.25	0.11	0.86	47.8	30.64	2.20	0.11	(0.05)	2.26	64.6	1.02	0.62	0.70	1.05	36.4	600	900	87.9	172.1	188.9	16.8	9.8%
		2,000	34.85	0.50	0.25	0.11	0.86	52.1	30.64	2.20	0.11	(0.05)	2.26	75.9	1.02	0.62	0.70	1.05	48.6	600	1,400	119.0	219.7	243.5	23.8	10.8%

New Rate Class: Seasonal

Total Bill Impacts of Proposed Distribution Rates [old RTSR+TLF]: Threshold of 600 kWhs

Classes		Scenario	May 2007 Incl Rate Riders						May 2008 Incl Rate Riders						Non-Dx Compoent				Other Reg	Commodity Bands (600.0)			Existing	New	$ Incr	% Incr
			Existing Dx Rates					Existing Dx	New Dx Rates					New Dx	RTSR old	WMSC	DRC	TLF old	Old	Band 1	Band 2	Old	Total Bill	Total Bill	Total Bill	Total Bill
																				5.0	5.9					
Seasonal Residential		kWh	SrChg [$/cust]	base [c/kWh]	Rider1 [c/kWh]	Rider2 [c/kWh]	VarChg [c/kWh]	[$/month]	SrChg [$/cust]	base [c/kWh]	Rider2 [c/kWh]	Rider3 [c/kWh]	VarChg [c/kWh]	[$/month]	c/kWh	c/kWh	c/kWh		$	kWhs	kWhs	Total $	[$/month]	[$/month]	[$/month]	%
Seasonal	R3	100	**19.51**	**2.74**	**0.35**	**0.15**	**3.24**	22.8	**19.00**	**4.69**	**0.15**	**0.02**	**4.86**	23.9	**0.81**	0.62	0.7	**1.092**	2.3	100	-	5.5	30.5	31.6	1.1	3.6%
		250	19.51	2.74	0.35	0.15	3.24	27.6	19.00	4.69	0.15	0.02	4.86	31.1	0.81	0.62	0.7	1.09	5.7	250	-	13.7	46.9	50.4	3.5	7.5%
		500	19.51	2.74	0.35	0.15	3.24	35.7	19.00	4.69	0.15	0.02	4.86	43.3	0.81	0.62	0.7	1.09	11.3	500	-	27.3	74.3	81.9	7.6	10.2%
		750	19.51	2.74	0.35	0.15	3.24	43.8	19.00	4.69	0.15	0.02	4.86	55.4	0.81	0.62	0.7	1.09	17.0	600	150	42.9	103.7	115.3	11.6	11.2%
		1,000	19.51	2.74	0.35	0.15	3.24	51.9	19.00	4.69	0.15	0.02	4.86	67.6	0.81	0.62	0.7	1.09	22.6	600	400	59.0	133.6	149.2	15.7	11.7%
		1,500	19.51	2.74	0.35	0.15	3.24	68.1	19.00	4.69	0.15	0.02	4.86	91.8	0.81	0.62	0.7	1.09	33.9	600	900	91.2	193.3	217.0	23.7	12.3%
		2,000	19.51	2.74	0.35	0.15	3.24	84.3	19.00	4.69	0.15	0.02	4.86	116.1	0.81	0.62	0.7	1.09	45.2	600	1,400	123.5	253.0	284.8	31.8	12.6%
Seasonal	R4	100	**36.36**	**1.92**	**0.36**	**0.24**	**2.52**	38.9	**31.79**	**4.70**	**0.24**	**0.02**	**4.95**	36.7	**0.81**	0.62	0.7	**1.092**	2.3	100	-	5.5	46.6	44.5	(2.1)	-4.6%
		250	36.36	1.92	0.36	0.24	2.52	42.7	31.79	4.70	0.24	0.02	4.95	44.2	0.81	0.62	0.70	1.09	5.7	250	-	13.7	62.0	63.5	1.5	2.4%
		500	36.36	1.92	0.36	0.24	2.52	49.0	31.79	4.70	0.24	0.02	4.95	56.6	0.81	0.62	0.70	1.09	11.3	500	-	27.3	87.6	95.2	7.6	8.7%
		750	36.36	1.92	0.36	0.24	2.52	55.3	31.79	4.70	0.24	0.02	4.95	68.9	0.81	0.62	0.70	1.09	17.0	600	150	42.9	115.1	128.8	13.7	11.9%
		1,000	36.36	1.92	0.36	0.24	2.52	61.6	31.79	4.70	0.24	0.02	4.95	81.3	0.81	0.62	0.70	1.09	22.6	600	400	59.0	143.2	163.0	19.8	13.8%
		1,500	36.36	1.92	0.36	0.24	2.52	74.2	31.79	4.70	0.24	0.02	4.95	106.1	0.81	0.62	0.70	1.09	33.9	600	900	91.2	199.3	231.3	31.9	16.0%
		2,000	36.36	1.92	0.36	0.24	2.52	86.8	31.79	4.70	0.24	0.02	4.95	130.9	0.81	0.62	0.70	1.09	45.2	600	1,400	123.5	255.4	299.6	44.1	17.3%
Seasonal	Caledon OH 07	100	**38.78**	**1.04**	**0.43**	**0.25**	**1.72**	40.5	**33.18**	**3.20**	**0.25**	**0.02**	**3.47**	36.6	**1.02**	0.62	0.7	1.0545	2.4	100	-	5.3	48.2	44.4	(3.9)	-8.0%
		250	38.78	1.04	0.43	0.25	1.72	43.1	33.18	3.20	0.25	0.02	3.47	41.8	1.02	0.62	0.70	1.05	6.1	250	-	13.2	62.3	61.1	(1.2)	-2.0%
		500	38.78	1.04	0.43	0.25	1.72	47.4	33.18	3.20	0.25	0.02	3.47	50.5	1.02	0.62	0.70	1.05	12.1	500	-	26.4	85.9	89.0	3.1	3.7%
		750	38.78	1.04	0.43	0.25	1.72	51.7	33.18	3.20	0.25	0.02	3.47	59.2	1.02	0.62	0.70	1.05	18.2	600	150	41.3	111.2	118.7	7.5	6.8%
		1,000	38.78	1.04	0.43	0.25	1.72	56.0	33.18	3.20	0.25	0.02	3.47	67.9	1.02	0.62	0.70	1.05	24.3	600	400	56.8	137.1	149.0	11.9	8.7%
		1,500	38.78	1.04	0.43	0.25	1.72	64.6	33.18	3.20	0.25	0.02	3.47	85.2	1.02	0.62	0.70	1.05	36.4	600	900	87.9	188.9	209.5	20.6	10.9%
		2,000	38.78	1.04	0.43	0.25	1.72	73.2	33.18	3.20	0.25	0.02	3.47	102.5	1.02	0.62	0.70	1.05	48.6	600	1,400	119.0	240.8	270.1	29.3	12.2%

New Rate Class: UGe

Total Bill Impacts of Proposed Distribution Rates [old RTSR+TLF]: Threshold of 750 kWhs

Classes		Scenario	May 2007 Incl Rate Riders						May 2008 Incl Rate Riders						Non-Dx Compoent				Other Reg	Commodity Bands			Existing	New	$ Incr	% Incr
			Existing Dx Rates					Existing Dx	New Dx Rates					New Dx	RTSR old	WMSC	DRC	TLF old	Old	Band 1	Band 2	Old	Total Bill	Total Bill	Total Bill	Total Bill
																				750.0						
																				5.0	5.9					
New Class	Old Class	kWh	SrChg [$/cust]	base [c/kWh]	Rider1 [c/kWh]	Rider2 [c/kWh]	VarChg [c/kWh]	[$/month]	SrChg [$/cust]	base [c/kWh]	Rider2 [c/kWh]	Rider3 [c/kWh]	VarChg [c/kWh]	[$/month]	c/kWh	c/kWh	c/kWh		$	kWhs	kWhs	Total $	[$/month]	[$/month]	[$/month]	%
UGe	**UG**	1,000	**15.79**	**2.74**	**0.03**	**0.03**	**2.80**	43.8	**14.27**	**2.00**	**0.03**	**(0.06)**	**1.98**	34.0	**0.85**	0.62	0.7	**1.092**	23.1	750	250	57.7	124.5	114.8	(9.8)	-7.8%
		2,000	15.79	2.74	0.03	0.03	2.80	71.8	14.27	2.00	0.03	(0.06)	1.98	53.8	0.85	0.62	0.7	1.092	46.1	750	1,250	122.1	240.0	222.0	(18.0)	-7.5%
		5,000	15.79	2.74	0.03	0.03	2.80	155.8	14.27	2.00	0.03	(0.06)	1.98	113.0	0.85	0.62	0.7	1.092	115.3	750	4,250	315.4	586.4	543.7	(42.7)	-7.3%
		10,000	15.79	2.74	0.03	0.03	2.80	295.8	14.27	2.00	0.03	(0.06)	1.98	211.8	0.85	0.62	0.7	1.092	230.5	750	9,250	637.5	1,163.8	1,079.9	(84.0)	-7.2%
		15,000	15.79	2.74	0.03	0.03	2.80	435.8	14.27	2.00	0.03	(0.06)	1.98	310.6	0.85	0.62	0.7	1.092	345.8	750	14,250	959.7	1,741.2	1,616.0	(125.2)	-7.2%
UGe	**F1**	1,000	**60.71**	**2.24**	**0.08**	**0.10**	**2.42**	84.9	**14.27**	**2.00**	**0.03**	**(0.06)**	**1.98**	34.0	**0.89**	0.62	0.7	**1.092**	23.5	750	250	57.7	166.1	115.2	(50.9)	-30.6%
		2,000	60.71	2.24	0.08	0.10	2.42	109.1	14.27	2.00	0.03	(0.06)	1.98	53.8	0.89	0.62	0.70	1.092	47.0	750	1,250	122.1	278.2	222.9	(55.3)	-19.9%
		5,000	60.71	2.24	0.08	0.10	2.42	181.7	14.27	2.00	0.03	(0.06)	1.98	113.0	0.89	0.62	0.70	1.092	117.4	750	4,250	315.4	614.5	545.9	(68.7)	-11.2%
		10,000	60.71	2.24	0.08	0.10	2.42	302.7	14.27	2.00	0.03	(0.06)	1.98	211.8	0.89	0.62	0.70	1.092	234.9	750	9,250	637.5	1,175.1	1,084.2	(90.9)	-7.7%
		15,000	60.71	2.24	0.08	0.10	2.42	423.7	14.27	2.00	0.03	(0.06)	1.98	310.6	0.89	0.62	0.70	1.092	352.3	750	14,250	959.7	1,735.7	1,622.6	(113.1)	-6.5%
UGe	**G1**	1,000	**36.93**	**3.12**	**0.09**	**0.09**	**3.30**	69.9	**14.27**	**2.00**	**0.03**	**(0.06)**	**1.98**	34.0	**0.86**	0.62	0.7	**1.092**	23.2	750	250	57.7	150.8	114.9	(35.9)	-23.8%
		2,000	36.93	3.12	0.09	0.09	3.30	102.9	14.27	2.00	0.03	(0.06)	1.98	53.8	0.86	0.62	0.70	1.092	46.3	750	1,250	122.1	271.4	222.2	(49.1)	-18.1%
		5,000	36.93	3.12	0.09	0.09	3.30	201.9	14.27	2.00	0.03	(0.06)	1.98	113.0	0.86	0.62	0.70	1.092	115.8	750	4,250	315.4	633.1	544.2	(88.9)	-14.0%
		10,000	36.93	3.12	0.09	0.09	3.30	366.9	14.27	2.00	0.03	(0.06)	1.98	211.8	0.86	0.62	0.70	1.092	231.6	750	9,250	637.5	1,236.1	1,081.0	(155.1)	-12.5%
		15,000	36.93	3.12	0.09	0.09	3.30	531.9	14.27	2.00	0.03	(0.06)	1.98	310.6	0.86	0.62	0.70	1.092	347.4	750	14,250	959.7	1,839.0	1,617.7	(221.3)	-12.0%
UGe	**G3**	1,000	**46.78**	**3.07**	**0.02**	**0.05**	**3.14**	78.2	**14.27**	**2.00**	**0.03**	**(0.06)**	**1.98**	34.0	**0.85**	0.62	0.7	**1.061**	22.6	750	250	55.8	156.6	112.5	(44.2)	-28.2%
		2,000	46.78	3.07	0.02	0.05	3.14	109.6	14.27	2.00	0.03	(0.06)	1.98	53.8	0.85	0.62	0.70	1.061	45.2	750	1,250	118.4	273.2	217.4	(55.8)	-20.4%
		5,000	46.78	3.07	0.02	0.05	3.14	203.8	14.27	2.00	0.03	(0.06)	1.98	113.0	0.85	0.62	0.70	1.061	113.0	750	4,250	306.2	623.0	532.3	(90.7)	-14.6%
		10,000	46.78	3.07	0.02	0.05	3.14	360.8	14.27	2.00	0.03	(0.06)	1.98	211.8	0.85	0.62	0.70	1.061	226.0	750	9,250	619.2	1,206.0	1,057.0	(149.0)	-12.4%
		15,000	46.78	3.07	0.02	0.05	3.14	517.8	14.27	2.00	0.03	(0.06)	1.98	310.6	0.85	0.62	0.70	1.061	339.0	750	14,250	932.2	1,789.0	1,581.8	(207.2)	-11.6%

New Rate Class: UGe

Total Bill Impacts of Proposed Distribution Rates [old RTSR+TLF]: Threshold of 750 kWhs

750.0

Classes: New Class	Classes: Old Class	Scenario: kWh	May 2007 Incl Rate Riders – Existing Dx Rates: SrChg [$/cust]	base [c/kWh]	Rider1 [c/kWh]	Rider2 [c/kWh]	VarChg [c/kWh]	Existing Dx [$/month]	May 2008 Incl Rate Riders – New Dx Rates: SrChg [$/cust]	base [c/kWh]	Rider2 [c/kWh]	Rider3 [c/kWh]	VarChg [c/kWh]	New Dx [$/month]	Non-Dx Compoent: RTSR old c/kWh	WMSC c/kWh	DRC c/kWh	TLF old	Other Reg Old $	Commodity Bands: Band 1 (5.0) kWhs	Band 2 (5.9) kWhs	Old Total $	Existing Total Bill [$/month]	New Total Bill [$/month]	$ Incr Total Bill [$/month]	% Incr Total Bill %
UGe	**Arnprior**	1,000	**21.38**	**1.17**	**0.16**	**0.06**	**1.39**	35.3	**18.74**	**2.00**	**0.06**	**(0.06)**	**2.01**	38.8	**0.93**	0.62	0.7	1.0545	23.3	750	250	55.5	114.1	117.6	3.5	3.1%
		2,000	21.38	1.17	0.16	0.06	1.39	49.2	18.74	2.00	0.06	(0.06)	2.01	58.8	0.93	0.62	0.70	1.05	46.7	750	1,250	117.7	213.6	223.2	9.7	4.5%
		5,000	21.38	1.17	0.16	0.06	1.39	90.9	18.74	2.00	0.06	(0.06)	2.01	119.0	0.93	0.62	0.70	1.05	116.7	750	4,250	304.3	511.9	540.1	28.1	5.5%
		10,000	21.38	1.17	0.16	0.06	1.39	160.4	18.74	2.00	0.06	(0.06)	2.01	219.3	0.93	0.62	0.70	1.05	233.4	750	9,250	615.4	1,009.2	1,068.1	58.9	5.8%
		15,000	21.38	1.17	0.16	0.06	1.39	229.9	18.74	2.00	0.06	(0.06)	2.01	319.5	0.93	0.62	0.70	1.05	350.2	750	14,250	926.5	1,506.5	1,596.2	89.7	6.0%
UGe	**Brockville**	1,000	**21.65**	**0.78**	**0.13**	**0.04**	**0.95**	31.2	**18.67**	**2.00**	**0.04**	**(0.06)**	**1.99**	38.5	**0.93**	0.62	0.7	1.0545	23.3	750	250	55.5	110.0	117.3	7.4	6.7%
		2,000	21.65	0.78	0.13	0.04	0.95	40.7	18.67	2.00	0.04	(0.06)	1.99	58.4	0.93	0.62	0.70	1.05	46.7	750	1,250	117.7	205.0	222.7	17.7	8.6%
		5,000	21.65	0.78	0.13	0.04	0.95	69.2	18.67	2.00	0.04	(0.06)	1.99	117.9	0.93	0.62	0.70	1.05	116.7	750	4,250	304.3	490.2	539.0	48.8	10.0%
		10,000	21.65	0.78	0.13	0.04	0.95	116.7	18.67	2.00	0.04	(0.06)	1.99	217.2	0.93	0.62	0.70	1.05	233.4	750	9,250	615.4	965.5	1,066.1	100.6	10.4%
		15,000	21.65	0.78	0.13	0.04	0.95	164.2	18.67	2.00	0.04	(0.06)	1.99	316.5	0.93	0.62	0.70	1.05	350.2	750	14,250	926.5	1,440.8	1,593.1	152.3	10.6%
UGe	**Carleton Place**	1,000	**23.65**	**1.68**	**0.13**	**0.07**	**1.88**	42.5	**20.17**	**2.00**	**0.07**	**(0.06)**	**2.02**	40.3	**0.93**	0.62	0.7	1.0545	23.3	750	250	55.5	121.3	119.1	(2.1)	-1.8%
		2,000	23.65	1.68	0.13	0.07	1.88	61.3	20.17	2.00	0.07	(0.06)	2.02	60.5	0.93	0.62	0.70	1.05	46.7	750	1,250	117.7	225.6	224.8	(0.8)	-0.3%
		5,000	23.65	1.68	0.13	0.07	1.88	117.7	20.17	2.00	0.07	(0.06)	2.02	120.9	0.93	0.62	0.70	1.05	116.7	750	4,250	304.3	538.7	542.0	3.3	0.6%
		10,000	23.65	1.68	0.13	0.07	1.88	211.7	20.17	2.00	0.07	(0.06)	2.02	221.7	0.93	0.62	0.70	1.05	233.4	750	9,250	615.4	1,060.5	1,070.6	10.1	0.9%
		15,000	23.65	1.68	0.13	0.07	1.88	305.7	20.17	2.00	0.07	(0.06)	2.02	322.5	0.93	0.62	0.70	1.05	350.2	750	14,250	926.5	1,582.3	1,599.1	16.8	1.1%
UGe	**Dryden**	1,000	**19.11**	**1.03**	**0.12**	**0.04**	**1.19**	31.0	**17.31**	**2.00**	**0.04**	**(0.06)**	**1.99**	37.2	**0.93**	0.62	0.7	1.0545	23.3	750	250	55.5	109.8	116.0	6.1	5.6%
		2,000	19.11	1.03	0.12	0.04	1.19	42.9	17.31	2.00	0.04	(0.06)	1.99	57.0	0.93	0.62	0.70	1.05	46.7	750	1,250	117.7	207.3	221.4	14.1	6.8%
		5,000	19.11	1.03	0.12	0.04	1.19	78.6	17.31	2.00	0.04	(0.06)	1.99	116.6	0.93	0.62	0.70	1.05	116.7	750	4,250	304.3	499.7	537.6	38.0	7.6%
		10,000	19.11	1.03	0.12	0.04	1.19	138.1	17.31	2.00	0.04	(0.06)	1.99	215.8	0.93	0.62	0.70	1.05	233.4	750	9,250	615.4	987.0	1,064.7	77.7	7.9%
		15,000	19.11	1.03	0.12	0.04	1.19	197.6	17.31	2.00	0.04	(0.06)	1.99	315.1	0.93	0.62	0.70	1.05	350.2	750	14,250	926.5	1,474.3	1,591.8	117.5	8.0%

New Rate Class: UGe

Total Bill Impacts of Proposed Distribution Rates [old RTSR+TLF]: Threshold of 750 kWhs

Classes		Scenario	May 2007 Incl Rate Riders						May 2008 Incl Rate Riders						Non-Dx Compoent				Other Reg	Commodity Bands			Existing	New	$ Incr	% Incr
			Existing Dx Rates					Existing Dx	New Dx Rates					New Dx	RTSR old	WMSC	DRC	TLF old	Old	Band 1	Band 2	Old	Total Bill	Total Bill	Total Bill	Total Bill
																				750.0 / 5.0	5.9					
New Class	Old Class	kWh	SrChg [$/cust]	base [c/kWh]	Rider1 [c/kWh]	Rider2 [c/kWh]	VarChg [c/kWh]	[$/month]	SrChg [$/cust]	base [c/kWh]	Rider2 [c/kWh]	Rider3 [c/kWh]	VarChg [c/kWh]	[$/month]	c/kWh	c/kWh	c/kWh		$	kWhs	kWhs	Total $	[$/month]	[$/month]	[$/month]	%
UGe	**GBE**	1,000	**10.77**	**1.14**	**0.16**	**0.06**	**1.36**	24.4	**10.39**	**2.00**	**0.06**	**(0.06)**	**2.01**	30.4	**0.93**	0.62	0.7	1.0545	23.3	750	250	55.5	103.2	109.3	6.1	5.9%
		2,000	10.77	1.14	0.16	0.06	1.36	38.0	10.39	2.00	0.06	(0.06)	2.01	50.5	0.93	0.62	0.70	1.05	46.7	750	1,250	117.7	202.3	214.9	12.5	6.2%
		5,000	10.77	1.14	0.16	0.06	1.36	78.8	10.39	2.00	0.06	(0.06)	2.01	110.7	0.93	0.62	0.70	1.05	116.7	750	4,250	304.3	499.8	531.7	31.9	6.4%
		10,000	10.77	1.14	0.16	0.06	1.36	146.8	10.39	2.00	0.06	(0.06)	2.01	210.9	0.93	0.62	0.70	1.05	233.4	750	9,250	615.4	995.6	1,059.8	64.2	6.4%
		15,000	10.77	1.14	0.16	0.06	1.36	214.8	10.39	2.00	0.06	(0.06)	2.01	311.2	0.93	0.62	0.70	1.05	350.2	750	14,250	926.5	1,491.4	1,587.9	96.4	6.5%
UGe	**Lindsay**	1,000	**23.94**	**1.38**	**0.15**	**0.06**	**1.59**	39.8	**20.10**	**2.00**	**0.06**	**(0.06)**	**2.01**	40.2	**0.93**	0.62	0.7	1.0545	23.3	750	250	55.5	118.7	119.0	0.3	0.3%
		2,000	23.94	1.38	0.15	0.06	1.59	55.7	20.10	2.00	0.06	(0.06)	2.01	60.2	0.93	0.62	0.70	1.05	46.7	750	1,250	117.7	220.1	224.6	4.5	2.0%
		5,000	23.94	1.38	0.15	0.06	1.59	103.4	20.10	2.00	0.06	(0.06)	2.01	120.4	0.93	0.62	0.70	1.05	116.7	750	4,250	304.3	524.5	541.4	16.9	3.2%
		10,000	23.94	1.38	0.15	0.06	1.59	182.9	20.10	2.00	0.06	(0.06)	2.01	220.6	0.93	0.62	0.70	1.05	233.4	750	9,250	615.4	1,031.8	1,069.5	37.7	3.7%
		15,000	23.94	1.38	0.15	0.06	1.59	262.4	20.10	2.00	0.06	(0.06)	2.01	320.9	0.93	0.62	0.70	1.05	350.2	750	14,250	926.5	1,539.1	1,597.6	58.5	3.8%
UGe	**Perth**	1,000	**19.92**	**0.92**	**0.13**	**0.04**	**1.09**	30.8	**17.10**	**2.00**	**0.04**	**(0.06)**	**1.99**	37.0	**0.93**	0.62	0.7	1.0545	23.3	750	250	55.5	109.6	115.8	6.1	5.6%
		2,000	19.92	0.92	0.13	0.04	1.09	41.7	17.10	2.00	0.04	(0.06)	1.99	56.8	0.93	0.62	0.70	1.05	46.7	750	1,250	117.7	206.1	221.2	15.1	7.3%
		5,000	19.92	0.92	0.13	0.04	1.09	74.4	17.10	2.00	0.04	(0.06)	1.99	116.4	0.93	0.62	0.70	1.05	116.7	750	4,250	304.3	495.5	537.4	42.0	8.5%
		10,000	19.92	0.92	0.13	0.04	1.09	128.9	17.10	2.00	0.04	(0.06)	1.99	215.6	0.93	0.62	0.70	1.05	233.4	750	9,250	615.4	977.8	1,064.5	86.7	8.9%
		15,000	19.92	0.92	0.13	0.04	1.09	183.4	17.10	2.00	0.04	(0.06)	1.99	314.9	0.93	0.62	0.70	1.05	350.2	750	14,250	926.5	1,460.1	1,591.6	131.5	9.0%
UGe	**Quinte West**	1,000	**3.74**	**1.05**	**0.14**	**0.06**	**1.25**	16.2	**5.15**	**2.00**	**0.06**	**(0.06)**	**2.01**	25.2	**0.93**	0.62	0.7	1.0545	23.3	750	250	55.5	95.1	104.0	9.0	9.4%
		2,000	3.74	1.05	0.14	0.06	1.25	28.7	5.15	2.00	0.06	(0.06)	2.01	45.3	0.93	0.62	0.70	1.05	46.7	750	1,250	117.7	193.1	209.6	16.5	8.6%
		5,000	3.74	1.05	0.14	0.06	1.25	66.2	5.15	2.00	0.06	(0.06)	2.01	105.4	0.93	0.62	0.70	1.05	116.7	750	4,250	304.3	487.3	526.5	39.2	8.0%
		10,000	3.74	1.05	0.14	0.06	1.25	128.7	5.15	2.00	0.06	(0.06)	2.01	205.7	0.93	0.62	0.70	1.05	233.4	750	9,250	615.4	977.6	1,054.5	76.9	7.9%
		15,000	3.74	1.05	0.14	0.06	1.25	191.2	5.15	2.00	0.06	(0.06)	2.01	306.0	0.93	0.62	0.70	1.05	350.2	750	14,250	926.5	1,467.9	1,582.6	114.7	7.8%

New Rate Class: UGe

Total Bill Impacts of Proposed Distribution Rates [old RTSR+TLF]: Threshold of 750 kWhs

Classes		Scenario	May 2007 Incl Rate Riders						May 2008 Incl Rate Riders						Non-Dx Compoent				Other Reg	Commodity Bands			Existing	New	$ Incr	% Incr
			Existing Dx Rates					Existing Dx	New Dx Rates					New Dx	RTSR old	WMSC	DRC	TLF old	Old	Band 1	Band 2	Old	Total Bill	Total Bill	Total Bill	Total Bill
																				750.0						
																				5.0	5.9					
New Class	Old Class	kWh	SrChg [$/cust]	base [c/kWh]	Rider1 [c/kWh]	Rider2 [c/kWh]	VarChg [c/kWh]	[$/month]	SrChg [$/cust]	base [c/kWh]	Rider2 [c/kWh]	Rider3 [c/kWh]	VarChg [c/kWh]	[$/month]	c/kWh	c/kWh	c/kWh		$	kWhs	kWhs	Total $	[$/month]	[$/month]	[$/month]	%
UGe	**Smiths Falls**	1,000	**9.84**	**1.05**	**0.12**	**0.04**	**1.21**	21.9	**9.62**	**2.00**	**0.04**	**(0.06)**	**1.99**	29.5	**0.93**	0.62	0.7	1.0545	23.3	750	250	55.5	100.8	108.3	7.5	7.5%
		2,000	9.84	1.05	0.12	0.04	1.21	34.0	9.62	2.00	0.04	(0.06)	1.99	49.3	0.93	0.62	0.70	1.05	46.7	750	1,250	117.7	198.4	213.7	15.3	7.7%
		5,000	9.84	1.05	0.12	0.04	1.21	70.3	9.62	2.00	0.04	(0.06)	1.99	108.9	0.93	0.62	0.70	1.05	116.7	750	4,250	304.3	491.4	529.9	38.6	7.8%
		10,000	9.84	1.05	0.12	0.04	1.21	130.8	9.62	2.00	0.04	(0.06)	1.99	208.2	0.93	0.62	0.70	1.05	233.4	750	9,250	615.4	979.7	1,057.0	77.3	7.9%
		15,000	9.84	1.05	0.12	0.04	1.21	191.3	9.62	2.00	0.04	(0.06)	1.99	307.4	0.93	0.62	0.70	1.05	350.2	750	14,250	926.5	1,468.0	1,584.1	116.1	7.9%
UGe	**Thorold**	1,000	**22.63**	**1.50**	**0.15**	**0.06**	**1.71**	39.7	**19.43**	**2.00**	**0.06**	**(0.06)**	**2.01**	39.5	**0.93**	0.62	0.7	1.0545	23.3	750	250	55.5	118.5	118.3	(0.3)	-0.2%
		2,000	22.63	1.50	0.15	0.06	1.71	56.8	19.43	2.00	0.06	(0.06)	2.01	59.5	0.93	0.62	0.70	1.05	46.7	750	1,250	117.7	221.2	223.9	2.7	1.2%
		5,000	22.63	1.50	0.15	0.06	1.71	108.1	19.43	2.00	0.06	(0.06)	2.01	119.7	0.93	0.62	0.70	1.05	116.7	750	4,250	304.3	529.2	540.7	11.6	2.2%
		10,000	22.63	1.50	0.15	0.06	1.71	193.6	19.43	2.00	0.06	(0.06)	2.01	220.0	0.93	0.62	0.70	1.05	233.4	750	9,250	615.4	1,042.5	1,068.8	26.3	2.5%
		15,000	22.63	1.50	0.15	0.06	1.71	279.1	19.43	2.00	0.06	(0.06)	2.01	320.2	0.93	0.62	0.70	1.05	350.2	750	14,250	926.5	1,555.8	1,596.9	41.1	2.6%
UGe	**Whitchurch Stouffville**	1,000	**21.85**	**0.93**	**0.11**	**0.04**	**1.08**	32.7	**18.62**	**2.00**	**0.04**	**(0.06)**	**1.99**	38.5	**0.93**	0.62	0.7	1.0545	23.3	750	250	55.5	111.5	117.3	5.8	5.2%
		2,000	21.85	0.93	0.11	0.04	1.08	43.5	18.62	2.00	0.04	(0.06)	1.99	58.3	0.93	0.62	0.70	1.05	46.7	750	1,250	117.7	207.8	222.7	14.9	7.2%
		5,000	21.85	0.93	0.11	0.04	1.08	75.9	18.62	2.00	0.04	(0.06)	1.99	117.9	0.93	0.62	0.70	1.05	116.7	750	4,250	304.3	496.9	538.9	42.0	8.5%
		10,000	21.85	0.93	0.11	0.04	1.08	129.9	18.62	2.00	0.04	(0.06)	1.99	217.2	0.93	0.62	0.70	1.05	233.4	750	9,250	615.4	978.7	1,066.0	87.3	8.9%
		15,000	21.85	0.93	0.11	0.04	1.08	183.9	18.62	2.00	0.04	(0.06)	1.99	316.4	0.93	0.62	0.70	1.05	350.2	750	14,250	926.5	1,460.5	1,593.1	132.6	9.1%

New Rate Class: UGd

Total Bill Impacts of Proposed Distribution Rates [old RTSR+TLF]: Threshold of 750 kWhs

Classes		Scenario			May 2007 Incl Rate Riders						May 2008 Incl Rate Riders						Non-Dx Compoent				Other Reg	Commodity Bands			Existing	New	$ Incr	% Incr
					Existing Dx Rates					Existing Dx	New Dx Rates					New Dx	RTSR old	WMSC	DRC	TLF old	Old	Band 1	Band 2	Old	Total Bill	Total Bill	Total Bill	Total Bill
																						-	5.2					
New Class	Old Class	kWh	kW	LF	SrChg [$/cust]	base [$/kW]	Rider1 [$/kW]	Rider2 [$/kW]	VarChg [$/kW]	[$/month]	SrChg [$/cust]	base [$/kW]	Rider2 [$/kW]	Rider3 [$/kW]	VarChg [$/kW]	[$/month]	$/kW	c/kWh	c/kWh		$	kWhs	kWhs	Total $	[$/month]	[$/month]	[$/month]	%
UGd	**UG**	15,000	60	35%	**15.79**	**8.44**	**0.10**	**0.11**	**8.65**	534.8	**18.49**	**7.42**	**0.11**	**(0.27)**	**7.26**	454.2	**2.58**	0.62	0.7	**1.092**	375.7	-	15,000	851.8	1,762.3	1,681.7	(80.6)	-4.6%
		43,164	133	45%	15.79	8.44	0.10	0.11	8.65	1,166.2	18.49	7.42	0.11	(0.27)	7.26	984.3	2.58	0.62	0.7	1.092	969.4	-	43,164	2,451.0	4,586.6	4,404.7	(181.9)	-4.0%
		100,000	500	28%	15.79	8.44	0.10	0.11	8.65	4,340.8	18.49	7.42	0.11	(0.27)	7.26	3,649.3	2.58	0.62	0.7	1.092	2,786.8	-	100,000	5,678.4	12,806.0	12,114.6	(691.4)	-5.4%
		400,000	1000	56%	15.79	8.44	0.10	0.11	8.65	8,665.8	18.49	7.42	0.11	(0.27)	7.26	7,280.2	2.58	0.62	0.7	1.092	8,327.7	-	400,000	22,713.6	39,707.1	38,321.5	(1,385.6)	-3.5%
		1,000,000	3000	46%	15.79	8.44	0.10	0.11	8.65	25,965.8	18.49	7.42	0.11	(0.27)	7.26	21,803.6	2.58	0.62	0.7	1.092	22,229.0	-	1,000,000	56,784.0	104,978.8	100,816.6	(4,162.2)	-4.0%
		1,500,000	4000	52%	15.79	8.44	0.10	0.11	8.65	34,615.8	18.49	7.42	0.11	(0.27)	7.26	29,065.3	2.58	0.62	0.7	1.092	31,933.8	-	1,500,000	85,176.0	151,725.6	146,175.1	(5,550.5)	-3.7%
UGd	**G1**	15,000	60	35%	**36.93**	**9.59**	**0.26**	**0.29**	**10.14**	645.3	**18.49**	**7.42**	**0.11**	**(0.27)**	**7.26**	454.2	**2.62**	0.62	0.7	**1.092**	378.2	-	15,000	851.8	1,875.2	1,684.1	(191.1)	-10.2%
		43,164	133	45%	36.93	9.59	0.26	0.29	10.14	1,385.6	18.49	7.42	0.11	(0.27)	7.26	984.3	2.62	0.62	0.70	1.092	974.8	-	43,164	2,451.0	4,811.3	4,410.1	(401.3)	-8.3%
		100,000	500	28%	36.93	9.59	0.26	0.29	10.14	5,106.9	18.49	7.42	0.11	(0.27)	7.26	3,649.3	2.62	0.62	0.70	1.092	2,807.0	-	100,000	5,678.4	13,592.3	12,134.8	(1,457.6)	-10.7%
		400,000	1000	56%	36.93	9.59	0.26	0.29	10.14	10,176.9	18.49	7.42	0.11	(0.27)	7.26	7,280.2	2.62	0.62	0.70	1.092	8,368.1	-	400,000	22,713.6	41,258.6	38,361.9	(2,896.7)	-7.0%
		1,000,000	3000	46%	36.93	9.59	0.26	0.29	10.14	30,456.9	18.49	7.42	0.11	(0.27)	7.26	21,803.6	2.62	0.62	0.70	1.092	22,350.2	-	1,000,000	56,784.0	109,591.2	100,937.8	(8,653.3)	-7.9%
		1,500,000	4000	52%	36.93	9.59	0.26	0.29	10.14	40,596.9	18.49	7.42	0.11	(0.27)	7.26	29,065.3	2.62	0.62	0.70	1.092	32,095.4	-	1,500,000	85,176.0	157,868.3	146,336.7	(11,531.6)	-7.3%
UGd	**G3**	15,000	60	35%	**46.78**	**9.91**	**0.08**	**0.15**	**10.14**	655.2	**18.49**	**7.42**	**0.11**	**(0.27)**	**7.26**	454.2	**2.75**	0.62	0.7	**1.061**	378.9	-	15,000	827.6	1,861.6	1,660.6	(201.0)	-10.8%
		43,164	133	45%	46.78	9.91	0.08	0.15	10.14	1,395.4	18.49	7.42	0.11	(0.27)	7.26	984.3	2.75	0.62	0.70	1.061	974.4	-	43,164	2,381.4	4,751.3	4,340.2	(411.1)	-8.7%
		100,000	500	28%	46.78	9.91	0.08	0.15	10.14	5,116.8	18.49	7.42	0.11	(0.27)	7.26	3,649.3	2.75	0.62	0.70	1.061	2,817.8	-	100,000	5,517.2	13,451.7	11,984.3	(1,467.4)	-10.9%
		400,000	1000	56%	46.78	9.91	0.08	0.15	10.14	10,186.8	18.49	7.42	0.11	(0.27)	7.26	7,280.2	2.75	0.62	0.70	1.061	8,351.2	-	400,000	22,068.8	40,606.7	37,700.1	(2,906.6)	-7.2%
		1,000,000	3000	46%	46.78	9.91	0.08	0.15	10.14	30,466.8	18.49	7.42	0.11	(0.27)	7.26	21,803.6	2.75	0.62	0.70	1.061	22,337.8	-	1,000,000	55,172.0	107,976.6	99,313.4	(8,663.2)	-8.0%
		1,500,000	4000	52%	46.78	9.91	0.08	0.15	10.14	40,606.8	18.49	7.42	0.11	(0.27)	7.26	29,065.3	2.75	0.62	0.70	1.061	32,046.8	-	1,500,000	82,758.0	155,411.6	143,870.1	(11,541.5)	-7.4%
UGd	**Arnprior**	15,000	60	35%	**21.38**	**3.70**	**0.50**	**0.20**	**4.40**	285.4	**22.95**	**7.33**	**0.20**	**(0.27)**	**7.26**	458.6	**3.54**	0.62	0.7	1.0545	426.9	-	15,000	822.5	1,534.8	1,708.0	173.2	11.3%
		43,164	133	45%	21.38	3.70	0.50	0.20	4.40	606.6	22.95	7.33	0.20	(0.27)	7.26	988.6	3.54	0.62	0.70	1.05	1,080.5	-	43,164	2,366.9	4,054.0	4,436.0	382.0	9.4%
		100,000	500	28%	21.38	3.70	0.50	0.20	4.40	2,221.4	22.95	7.33	0.20	(0.27)	7.26	3,653.1	3.54	0.62	0.70	1.05	3,219.2	-	100,000	5,483.4	10,924.0	12,355.7	1,431.7	13.1%
		400,000	1000	56%	21.38	3.70	0.50	0.20	4.40	4,421.4	22.95	7.33	0.20	(0.27)	7.26	7,283.2	3.54	0.62	0.70	1.05	9,146.0	-	400,000	21,933.6	35,501.0	38,362.7	2,861.8	8.1%
		1,000,000	3000	46%	21.38	3.70	0.50	0.20	4.40	13,221.4	22.95	7.33	0.20	(0.27)	7.26	21,803.6	3.54	0.62	0.70	1.05	24,730.4	-	1,000,000	54,834.0	92,785.7	101,367.9	8,582.2	9.2%
		1,500,000	4000	52%	21.38	3.70	0.50	0.20	4.40	17,621.4	22.95	7.33	0.20	(0.27)	7.26	29,063.8	3.54	0.62	0.70	1.05	35,230.1	-	1,500,000	82,251.0	135,102.5	146,544.9	11,442.4	8.5%

New Rate Class: UGd

Total Bill Impacts of Proposed Distribution Rates [old RTSR+TLF]: Threshold of 750 kWhs

Classes		Scenario			May 2007 Incl Rate Riders						May 2008 Incl Rate Riders						Non-Dx Compoent				Other Reg	Commodity Bands			Existing	New	$ Incr	% Incr
					Existing Dx Rates					Existing Dx	New Dx Rates					New Dx	RTSR old	WMSC	DRC	TLF old	Old	Band 1	Band 2	Old	Total Bill	Total Bill	Total Bill	Total Bill
																						-	5.2					
New Class	Old Class	kWh	kW	LF	SrChg [$/cust]	base [$/kW]	Rider1 [$/kW]	Rider2 [$/kW]	VarChg [$/kW]	[$/month]	SrChg [$/cust]	base [$/kW]	Rider2 [$/kW]	Rider3 [$/kW]	VarChg [$/kW]	[$/month]	$/kW	c/kWh	c/kWh		$	kWhs	kWhs	Total $	[$/month]	[$/month]	[$/month]	%
UGd	Brockville	15,000	60	35%	21.65	2.49	0.41	0.12	3.02	202.9	22.89	6.70	0.12	(0.27)	6.55	415.7	3.54	0.62	0.7	1.0545	426.9	-	15,000	822.5	1,452.3	1,665.1	212.9	14.7%
		43,164	133	45%	21.65	2.49	0.41	0.12	3.02	423.3	22.89	6.70	0.12	(0.27)	6.55	893.7	3.54	0.62	0.70	1.05	1,080.5	-	43,164	2,366.9	3,870.7	4,341.1	470.3	12.2%
		100,000	500	28%	21.65	2.49	0.41	0.12	3.02	1,531.7	22.89	6.70	0.12	(0.27)	6.55	3,296.4	3.54	0.62	0.70	1.05	3,219.2	-	100,000	5,483.4	10,234.3	11,999.0	1,764.8	17.2%
		400,000	1000	56%	21.65	2.49	0.41	0.12	3.02	3,041.7	22.89	6.70	0.12	(0.27)	6.55	6,570.0	3.54	0.62	0.70	1.05	9,146.0	-	400,000	21,933.6	34,121.2	37,649.6	3,528.4	10.3%
		1,000,000	3000	46%	21.65	2.49	0.41	0.12	3.02	9,081.7	22.89	6.70	0.12	(0.27)	6.55	19,664.3	3.54	0.62	0.70	1.05	24,730.4	-	1,000,000	54,834.0	88,646.0	99,228.6	10,582.6	11.9%
		1,500,000	4000	52%	21.65	2.49	0.41	0.12	3.02	12,101.7	22.89	6.70	0.12	(0.27)	6.55	26,211.4	3.54	0.62	0.70	1.05	35,230.1	-	1,500,000	82,251.0	129,582.8	143,692.5	14,109.7	10.9%
UGd	Carleton Plac	15,000	60	35%	23.65	5.31	0.42	0.22	5.95	380.7	24.39	7.33	0.22	(0.27)	7.28	461.2	3.54	0.62	0.7	1.0545	426.9	-	15,000	822.5	1,630.1	1,710.6	80.5	4.9%
		43,164	133	45%	23.65	5.31	0.42	0.22	5.95	815.0	24.39	7.33	0.22	(0.27)	7.28	992.7	3.54	0.62	0.70	1.05	1,080.5	-	43,164	2,366.9	4,262.4	4,440.1	177.7	4.2%
		100,000	500	28%	23.65	5.31	0.42	0.22	5.95	2,998.7	24.39	7.33	0.22	(0.27)	7.28	3,664.5	3.54	0.62	0.70	1.05	3,219.2	-	100,000	5,483.4	11,701.3	12,367.1	665.8	5.7%
		400,000	1000	56%	23.65	5.31	0.42	0.22	5.95	5,973.7	24.39	7.33	0.22	(0.27)	7.28	7,304.6	3.54	0.62	0.70	1.05	9,146.0	-	400,000	21,933.6	37,053.2	38,384.2	1,330.9	3.6%
		1,000,000	3000	46%	23.65	5.31	0.42	0.22	5.95	17,873.7	24.39	7.33	0.22	(0.27)	7.28	21,865.0	3.54	0.62	0.70	1.05	24,730.4	-	1,000,000	54,834.0	97,438.0	101,429.4	3,991.3	4.1%
		1,500,000	4000	52%	23.65	5.31	0.42	0.22	5.95	23,823.7	24.39	7.33	0.22	(0.27)	7.28	29,145.2	3.54	0.62	0.70	1.05	35,230.1	-	1,500,000	82,251.0	141,304.8	146,626.3	5,321.6	3.8%
UGd	Dryden	15,000	60	35%	19.11	3.29	0.38	0.13	3.80	247.1	21.52	7.33	0.13	(0.27)	7.19	452.9	3.54	0.62	0.7	1.0545	426.9	-	15,000	822.5	1,496.5	1,702.4	205.8	13.8%
		43,164	133	45%	19.11	3.29	0.38	0.13	3.80	524.5	21.52	7.33	0.13	(0.27)	7.19	977.8	3.54	0.62	0.70	1.05	1,080.5	-	43,164	2,366.9	3,971.9	4,425.2	453.3	11.4%
		100,000	500	28%	19.11	3.29	0.38	0.13	3.80	1,919.1	21.52	7.33	0.13	(0.27)	7.19	3,616.6	3.54	0.62	0.70	1.05	3,219.2	-	100,000	5,483.4	10,621.7	12,319.2	1,697.5	16.0%
		400,000	1000	56%	19.11	3.29	0.38	0.13	3.80	3,819.1	21.52	7.33	0.13	(0.27)	7.19	7,211.7	3.54	0.62	0.70	1.05	9,146.0	-	400,000	21,933.6	34,898.7	38,291.3	3,392.6	9.7%
		1,000,000	3000	46%	19.11	3.29	0.38	0.13	3.80	11,419.1	21.52	7.33	0.13	(0.27)	7.19	21,592.1	3.54	0.62	0.70	1.05	24,730.4	-	1,000,000	54,834.0	90,983.5	101,156.5	10,173.0	11.2%
		1,500,000	4000	52%	19.11	3.29	0.38	0.13	3.80	15,219.1	21.52	7.33	0.13	(0.27)	7.19	28,782.3	3.54	0.62	0.70	1.05	35,230.1	-	1,500,000	82,251.0	132,700.2	146,263.5	13,563.2	10.2%
UGd	GBE	15,000	60	35%	10.77	3.64	0.49	0.19	4.32	270.0	14.61	7.33	0.19	(0.27)	7.25	449.6	3.54	0.62	0.7	1.0545	426.9	-	15,000	822.5	1,519.4	1,699.0	179.6	11.8%
		43,164	133	45%	10.77	3.64	0.49	0.19	4.32	585.3	14.61	7.33	0.19	(0.27)	7.25	978.9	3.54	0.62	0.70	1.05	1,080.5	-	43,164	2,366.9	4,032.7	4,426.3	393.6	9.8%
		100,000	500	28%	10.77	3.64	0.49	0.19	4.32	2,170.8	14.61	7.33	0.19	(0.27)	7.25	3,639.7	3.54	0.62	0.70	1.05	3,219.2	-	100,000	5,483.4	10,873.4	12,342.3	1,468.9	13.5%
		400,000	1000	56%	10.77	3.64	0.49	0.19	4.32	4,330.8	14.61	7.33	0.19	(0.27)	7.25	7,264.8	3.54	0.62	0.70	1.05	9,146.0	-	400,000	21,933.6	35,410.4	38,344.4	2,934.0	8.3%
		1,000,000	3000	46%	10.77	3.64	0.49	0.19	4.32	12,970.8	14.61	7.33	0.19	(0.27)	7.25	21,765.2	3.54	0.62	0.70	1.05	24,730.4	-	1,000,000	54,834.0	92,535.1	101,329.6	8,794.4	9.5%
		1,500,000	4000	52%	10.77	3.64	0.49	0.19	4.32	17,290.8	14.61	7.33	0.19	(0.27)	7.25	29,015.4	3.54	0.62	0.70	1.05	35,230.1	-	1,500,000	82,251.0	134,771.9	146,496.6	11,724.7	8.7%

New Rate Class: UGd

Total Bill Impacts of Proposed Distribution Rates [old RTSR+TLF]: Threshold of 750 kWhs

Classes		Scenario			May 2007 Incl Rate Riders						May 2008 Incl Rate Riders						Non-Dx Compoent				Other Reg	Commodity Bands			Existing	New	$ Incr	% Incr
					Existing Dx Rates					Existing Dx	New Dx Rates					New Dx	RTSR old	WMSC	DRC	TLF old	Old	Band 1	Band 2	Old	Total Bill	Total Bill	Total Bill	Total Bill
																						-	5.2					
New Class	Old Class	kWh	kW	LF	SrChg [$/cust]	base [$/kW]	Rider1 [$/kW]	Rider2 [$/kW]	VarChg [$/kW]	[$/month]	SrChg [$/cust]	base [$/kW]	Rider2 [$/kW]	Rider3 [$/kW]	VarChg [$/kW]	[$/month]	$/kW	c/kWh	c/kWh		$	kWhs	kWhs	Total $	[$/month]	[$/month]	[$/month]	%
UGd	**Lindsay**	15,000	60	35%	**23.94**	**4.36**	**0.49**	**0.19**	**5.04**	326.3	**24.31**	**7.33**	**0.19**	**(0.27)**	**7.25**	459.3	**3.54**	0.62	0.7	1.0545	426.9	-	15,000	822.5	1,575.8	1,708.8	133.0	8.4%
		43,164	133	45%	23.94	4.36	0.49	0.19	5.04	694.3	24.31	7.33	0.19	(0.27)	7.25	988.6	3.54	0.62	0.70	1.05	1,080.5	-	43,164	2,366.9	4,141.7	4,436.0	294.3	7.1%
		100,000	500	28%	23.94	4.36	0.49	0.19	5.04	2,543.9	24.31	7.33	0.19	(0.27)	7.25	3,649.4	3.54	0.62	0.70	1.05	3,219.2	-	100,000	5,483.4	11,246.5	12,352.0	1,105.5	9.8%
		400,000	1000	56%	23.94	4.36	0.49	0.19	5.04	5,063.9	24.31	7.33	0.19	(0.27)	7.25	7,274.5	3.54	0.62	0.70	1.05	9,146.0	-	400,000	21,933.6	36,143.5	38,354.1	2,210.6	6.1%
		1,000,000	3000	46%	23.94	4.36	0.49	0.19	5.04	15,143.9	24.31	7.33	0.19	(0.27)	7.25	21,774.9	3.54	0.62	0.70	1.05	24,730.4	-	1,000,000	54,834.0	94,708.3	101,339.3	6,631.0	7.0%
		1,500,000	4000	52%	23.94	4.36	0.49	0.19	5.04	20,183.9	24.31	7.33	0.19	(0.27)	7.25	29,025.1	3.54	0.62	0.70	1.05	35,230.1	-	1,500,000	82,251.0	137,665.1	146,506.3	8,841.2	6.4%
UGd	**Perth**	15,000	60	35%	**19.92**	**2.87**	**0.42**	**0.12**	**3.41**	224.5	**21.32**	**7.15**	**0.12**	**(0.27)**	**7.00**	441.1	**3.54**	0.62	0.7	1.0545	426.9	-	15,000	822.5	1,473.9	1,690.6	216.6	14.7%
		43,164	133	45%	19.92	2.87	0.42	0.12	3.41	473.5	21.32	7.15	0.12	(0.27)	7.00	951.9	3.54	0.62	0.70	1.05	1,080.5	-	43,164	2,366.9	3,920.9	4,399.3	478.5	12.2%
		100,000	500	28%	19.92	2.87	0.42	0.12	3.41	1,724.9	21.32	7.15	0.12	(0.27)	7.00	3,519.9	3.54	0.62	0.70	1.05	3,219.2	-	100,000	5,483.4	10,427.5	12,222.5	1,795.0	17.2%
		400,000	1000	56%	19.92	2.87	0.42	0.12	3.41	3,429.9	21.32	7.15	0.12	(0.27)	7.00	7,018.4	3.54	0.62	0.70	1.05	9,146.0	-	400,000	21,933.6	34,509.5	38,098.0	3,588.5	10.4%
		1,000,000	3000	46%	19.92	2.87	0.42	0.12	3.41	10,249.9	21.32	7.15	0.12	(0.27)	7.00	21,012.7	3.54	0.62	0.70	1.05	24,730.4	-	1,000,000	54,834.0	89,814.3	100,577.1	10,762.8	12.0%
		1,500,000	4000	52%	19.92	2.87	0.42	0.12	3.41	13,659.9	21.32	7.15	0.12	(0.27)	7.00	28,009.8	3.54	0.62	0.70	1.05	35,230.1	-	1,500,000	82,251.0	131,141.1	145,491.0	14,349.9	10.9%
UGd	**Quinte West**	15,000	60	35%	**3.74**	**3.32**	**0.46**	**0.18**	**3.96**	241.3	**9.36**	**7.33**	**0.18**	**(0.27)**	**7.24**	443.8	**3.54**	0.62	0.7	1.0545	426.9	-	15,000	822.5	1,490.8	1,693.2	202.4	13.6%
		43,164	133	45%	3.74	3.32	0.46	0.18	3.96	530.4	9.36	7.33	0.18	(0.27)	7.24	972.3	3.54	0.62	0.70	1.05	1,080.5	-	43,164	2,366.9	3,977.8	4,419.7	441.9	11.1%
		100,000	500	28%	3.74	3.32	0.46	0.18	3.96	1,983.7	9.36	7.33	0.18	(0.27)	7.24	3,629.5	3.54	0.62	0.70	1.05	3,219.2	-	100,000	5,483.4	10,686.3	12,332.1	1,645.7	15.4%
		400,000	1000	56%	3.74	3.32	0.46	0.18	3.96	3,963.7	9.36	7.33	0.18	(0.27)	7.24	7,249.6	3.54	0.62	0.70	1.05	9,146.0	-	400,000	21,933.6	35,043.3	38,329.1	3,285.8	9.4%
		1,000,000	3000	46%	3.74	3.32	0.46	0.18	3.96	11,883.7	9.36	7.33	0.18	(0.27)	7.24	21,730.0	3.54	0.62	0.70	1.05	24,730.4	-	1,000,000	54,834.0	91,448.1	101,294.3	9,846.2	10.8%
		1,500,000	4000	52%	3.74	3.32	0.46	0.18	3.96	15,843.7	9.36	7.33	0.18	(0.27)	7.24	28,970.2	3.54	0.62	0.70	1.05	35,230.1	-	1,500,000	82,251.0	133,324.9	146,451.3	13,126.4	9.8%
UGd	**Smiths Falls**	15,000	60	35%	**9.84**	**3.33**	**0.39**	**0.13**	**3.85**	240.8	**13.84**	**7.33**	**0.13**	**(0.27)**	**7.19**	445.2	**3.54**	0.62	0.7	1.0545	426.9	-	15,000	822.5	1,490.3	1,694.7	204.4	13.7%
		43,164	133	45%	9.84	3.33	0.39	0.13	3.85	521.9	13.84	7.33	0.13	(0.27)	7.19	970.1	3.54	0.62	0.70	1.05	1,080.5	-	43,164	2,366.9	3,969.3	4,417.5	448.2	11.3%
		100,000	500	28%	9.84	3.33	0.39	0.13	3.85	1,934.8	13.84	7.33	0.13	(0.27)	7.19	3,608.9	3.54	0.62	0.70	1.05	3,219.2	-	100,000	5,483.4	10,637.4	12,311.5	1,674.1	15.7%
		400,000	1000	56%	9.84	3.33	0.39	0.13	3.85	3,859.8	13.84	7.33	0.13	(0.27)	7.19	7,204.0	3.54	0.62	0.70	1.05	9,146.0	-	400,000	21,933.6	34,939.4	38,283.6	3,344.2	9.6%
		1,000,000	3000	46%	9.84	3.33	0.39	0.13	3.85	11,559.8	13.84	7.33	0.13	(0.27)	7.19	21,584.5	3.54	0.62	0.70	1.05	24,730.4	-	1,000,000	54,834.0	91,124.2	101,148.8	10,024.6	11.0%
		1,500,000	4000	52%	9.84	3.33	0.39	0.13	3.85	15,409.8	13.84	7.33	0.13	(0.27)	7.19	28,774.7	3.54	0.62	0.70	1.05	35,230.1	-	1,500,000	82,251.0	132,891.0	146,255.8	13,364.8	10.1%

New Rate Class: UGd

Total Bill Impacts of Proposed Distribution Rates [old RTSR+TLF]: Threshold of 750 kWhs

Classes		Scenario			May 2007 Incl Rate Riders						May 2008 Incl Rate Riders						Non-Dx Compoent				Other Reg	Commodity Bands			Existing	New	$ Incr	% Incr
					Existing Dx Rates					Existing Dx	New Dx Rates					New Dx	RTSR old	WMSC	DRC	TLF old	Old	Band 1	Band 2	Old	Total Bill	Total Bill	Total Bill	Total Bill
																						-	5.2					
New Class	Old Class	kWh	kW	LF	SrChg [$/cust]	base [$/kW]	Rider1 [$/kW]	Rider2 [$/kW]	VarChg [$/kW]	[$/month]	SrChg [$/cust]	base [$/kW]	Rider2 [$/kW]	Rider3 [$/kW]	VarChg [$/kW]	[$/month]	$/kW	c/kWh	c/kWh		$	kWhs	kWhs	Total $	[$/month]	[$/month]	[$/month]	%
UGd	**Thorold**	15,000	60	35%	**22.63**	**4.76**	**0.46**	**0.20**	**5.42**	347.8	**23.64**	**7.33**	**0.20**	**(0.27)**	**7.26**	459.3	**3.54**	0.62	0.7	1.0545	426.9	-	15,000	822.5	1,597.3	1,708.7	111.4	7.0%
		43,164	133	45%	22.63	4.76	0.46	0.20	5.42	743.5	23.64	7.33	0.20	(0.27)	7.26	989.2	3.54	0.62	0.70	1.05	1,080.5	-	43,164	2,366.9	4,190.9	4,436.7	245.8	5.9%
		100,000	500	28%	22.63	4.76	0.46	0.20	5.42	2,732.6	23.64	7.33	0.20	(0.27)	7.26	3,653.7	3.54	0.62	0.70	1.05	3,219.2	-	100,000	5,483.4	11,435.2	12,356.3	921.1	8.1%
		400,000	1000	56%	22.63	4.76	0.46	0.20	5.42	5,442.6	23.64	7.33	0.20	(0.27)	7.26	7,283.8	3.54	0.62	0.70	1.05	9,146.0	-	400,000	21,933.6	36,522.2	38,363.4	1,841.2	5.0%
		1,000,000	3000	46%	22.63	4.76	0.46	0.20	5.42	16,282.6	23.64	7.33	0.20	(0.27)	7.26	21,804.3	3.54	0.62	0.70	1.05	24,730.4	-	1,000,000	54,834.0	95,847.0	101,368.6	5,521.6	5.8%
		1,500,000	4000	52%	22.63	4.76	0.46	0.20	5.42	21,702.6	23.64	7.33	0.20	(0.27)	7.26	29,064.5	3.54	0.62	0.70	1.05	35,230.1	-	1,500,000	82,251.0	139,183.8	146,545.6	7,361.8	5.3%
UGd	**Whitchurch S**	15,000	60	35%	**21.85**	**2.93**	**0.35**	**0.13**	**3.41**	226.5	**22.84**	**7.15**	**0.13**	**(0.27)**	**7.01**	443.3	**3.54**	0.62	0.7	1.0545	426.9	-	15,000	822.5	1,475.9	1,692.7	216.8	14.7%
		43,164	133	45%	21.85	2.93	0.35	0.13	3.41	475.4	22.84	7.15	0.13	(0.27)	7.01	954.8	3.54	0.62	0.70	1.05	1,080.5	-	43,164	2,366.9	3,922.8	4,402.2	479.4	12.2%
		100,000	500	28%	21.85	2.93	0.35	0.13	3.41	1,726.9	22.84	7.15	0.13	(0.27)	7.01	3,526.4	3.54	0.62	0.70	1.05	3,219.2	-	100,000	5,483.4	10,429.5	12,229.0	1,799.5	17.3%
		400,000	1000	56%	21.85	2.93	0.35	0.13	3.41	3,431.9	22.84	7.15	0.13	(0.27)	7.01	7,030.0	3.54	0.62	0.70	1.05	9,146.0	-	400,000	21,933.6	34,511.4	38,109.5	3,598.1	10.4%
		1,000,000	3000	46%	21.85	2.93	0.35	0.13	3.41	10,251.9	22.84	7.15	0.13	(0.27)	7.01	21,044.2	3.54	0.62	0.70	1.05	24,730.4	-	1,000,000	54,834.0	89,816.2	100,608.6	10,792.4	12.0%
		1,500,000	4000	52%	21.85	2.93	0.35	0.13	3.41	13,661.9	22.84	7.15	0.13	(0.27)	7.01	28,051.3	3.54	0.62	0.70	1.05	35,230.1	-	1,500,000	82,251.0	131,143.0	145,532.5	14,389.5	11.0%

New Rate Class: GSe - Metered

Total Bill Impacts of Proposed Distribution Rates [ol RTSR+TLF]: Threshold of 750 kWhs

750.0

Classes		Scenario	May 2007 Incl Rate Riders						May 2008 Incl Rate Riders						Non-Dx Compoent				Other Reg	Commodity Bands			Existing	New	$ Incr	% Incr
			Existing Dx Rates					Existing Dx	New Dx Rates					New Dx	RTSR old	WMSC	DRC	TLF old	Old	Band 1	Band 2	Old	Total Bill	Total Bill	Total Bill	Total Bill
																				5.0	5.9					
New Class	Old Class	kWh	SrChg [$/cust]	base [c/kWh]	Rider1 [c/kWh]	Rider2 [c/kWh]	VarChg [c/kWh]	[$/month]	SrChg [$/cust]	base [c/kWh]	Rider2 [c/kWh]	Rider3 [c/kWh]	VarChg [c/kWh]	[$/month]	c/kWh	c/kWh	c/kWh		$	kWhs	kWhs	Total $	[$/month]	[$/month]	[$/month]	%
GSe	**F1**	1,000	**60.71**	**2.24**	**0.08**	**0.10**	**2.42**	84.9	**52.91**	**3.38**	**0.10**	**(0.06)**	**3.42**	87.1	**0.89**	0.62	0.7	**1.092**	23.5	750	250	57.7	166.1	168.3	2.2	1.3%
		2,000	60.71	2.24	0.08	0.10	2.42	109.1	52.91	3.38	0.10	(0.06)	3.42	121.3	0.89	0.62	0.7	1.092	47.0	750	1,250	122.1	278.2	290.4	12.2	4.4%
		5,000	60.71	2.24	0.08	0.10	2.42	181.7	52.91	3.38	0.10	(0.06)	3.42	223.9	0.89	0.62	0.7	1.092	117.4	750	4,250	315.4	614.5	656.8	42.2	6.9%
		10,000	60.71	2.24	0.08	0.10	2.42	302.7	52.91	3.38	0.10	(0.06)	3.42	394.9	0.89	0.62	0.7	1.092	234.9	750	9,250	637.5	1,175.1	1,267.4	92.2	7.8%
		15,000	60.71	2.24	0.08	0.10	2.42	423.7	52.91	3.38	0.10	(0.06)	3.42	565.9	0.89	0.62	0.7	1.092	352.3	750	14,250	959.7	1,735.7	1,877.9	142.2	8.2%
GSe	**F3**	1,000	**53.91**	**2.89**	**0.03**	**0.04**	**2.96**	83.5	**47.61**	**3.38**	**0.04**	**(0.06)**	**3.36**	81.2	**0.84**	0.62	0.7	**1.061**	22.5	750	250	55.8	161.8	159.6	(2.3)	-1.4%
		2,000	53.91	2.89	0.03	0.04	2.96	113.1	47.61	3.38	0.04	(0.06)	3.36	114.8	0.84	0.62	0.70	1.061	45.0	750	1,250	118.4	276.5	278.2	1.7	0.6%
		5,000	53.91	2.89	0.03	0.04	2.96	201.9	47.61	3.38	0.04	(0.06)	3.36	215.6	0.84	0.62	0.70	1.061	112.5	750	4,250	306.2	620.6	634.3	13.7	2.2%
		10,000	53.91	2.89	0.03	0.04	2.96	349.9	47.61	3.38	0.04	(0.06)	3.36	383.6	0.84	0.62	0.70	1.061	224.9	750	9,250	619.2	1,194.1	1,227.8	33.7	2.8%
		15,000	53.91	2.89	0.03	0.04	2.96	497.9	47.61	3.38	0.04	(0.06)	3.36	551.6	0.84	0.62	0.70	1.061	337.4	750	14,250	932.2	1,767.5	1,821.2	53.7	3.0%
GSe	**G1**	1,000	**36.93**	**3.12**	**0.09**	**0.09**	**3.30**	69.9	**35.09**	**3.38**	**0.09**	**(0.06)**	**3.41**	69.2	**0.86**	0.62	0.7	**1.092**	23.2	750	250	57.7	150.8	150.0	(0.7)	-0.5%
		2,000	36.93	3.12	0.09	0.09	3.30	102.9	35.09	3.38	0.09	(0.06)	3.41	103.3	0.86	0.62	0.70	1.092	46.3	750	1,250	122.1	271.4	271.7	0.4	0.1%
		5,000	36.93	3.12	0.09	0.09	3.30	201.9	35.09	3.38	0.09	(0.06)	3.41	205.6	0.86	0.62	0.70	1.092	115.8	750	4,250	315.4	633.1	636.8	3.7	0.6%
		10,000	36.93	3.12	0.09	0.09	3.30	366.9	35.09	3.38	0.09	(0.06)	3.41	376.1	0.86	0.62	0.70	1.092	231.6	750	9,250	637.5	1,236.1	1,245.2	9.2	0.7%
		15,000	36.93	3.12	0.09	0.09	3.30	531.9	35.09	3.38	0.09	(0.06)	3.41	546.6	0.86	0.62	0.70	1.092	347.4	750	14,250	959.7	1,839.0	1,853.7	14.7	0.8%
GSe	**G3**	1,000	**46.78**	**3.07**	**0.02**	**0.05**	**3.14**	78.2	**42.40**	**3.38**	**0.05**	**(0.06)**	**3.37**	76.1	**0.85**	0.62	0.7	**1.061**	22.6	750	250	55.8	156.6	154.6	(2.1)	-1.3%
		2,000	46.78	3.07	0.02	0.05	3.14	109.6	42.40	3.38	0.05	(0.06)	3.37	109.8	0.85	0.62	0.70	1.061	45.2	750	1,250	118.4	273.2	273.4	0.2	0.1%
		5,000	46.78	3.07	0.02	0.05	3.14	203.8	42.40	3.38	0.05	(0.06)	3.37	210.9	0.85	0.62	0.70	1.061	113.0	750	4,250	306.2	623.0	630.1	7.1	1.1%
		10,000	46.78	3.07	0.02	0.05	3.14	360.8	42.40	3.38	0.05	(0.06)	3.37	379.4	0.85	0.62	0.70	1.061	226.0	750	9,250	619.2	1,206.0	1,224.6	18.6	1.5%
		15,000	46.78	3.07	0.02	0.05	3.14	517.8	42.40	3.38	0.05	(0.06)	3.37	547.9	0.85	0.62	0.70	1.061	339.0	750	14,250	932.2	1,789.0	1,819.1	30.1	1.7%
GSe	**T**	1,000	**261.54**	**2.43**	**0.01**	**0.03**	**2.47**	286.2	**203.71**	**3.38**	**0.03**	**(0.06)**	**3.35**	237.2	**0.84**	0.62	0.7	**1.061**	22.5	750	250	55.8	364.6	315.5	(49.0)	-13.4%
		2,000	261.54	2.43	0.01	0.03	2.47	310.9	203.71	3.38	0.03	(0.06)	3.35	270.7	0.84	0.62	0.70	1.061	45.0	750	1,250	118.4	474.4	434.1	(40.2)	-8.5%
		5,000	261.54	2.43	0.01	0.03	2.47	385.0	203.71	3.38	0.03	(0.06)	3.35	371.2	0.84	0.62	0.70	1.061	112.5	750	4,250	306.2	803.7	789.9	(13.8)	-1.7%
		10,000	261.54	2.43	0.01	0.03	2.47	508.5	203.71	3.38	0.03	(0.06)	3.35	538.7	0.84	0.62	0.70	1.061	224.9	750	9,250	619.2	1,352.7	1,382.9	30.2	2.2%
		15,000	261.54	2.43	0.01	0.03	2.47	632.0	203.71	3.38	0.03	(0.06)	3.35	706.2	0.84	0.62	0.70	1.061	337.4	750	14,250	932.2	1,901.6	1,975.8	74.2	3.9%

New Rate Class: GSe - Metered

Total Bill Impacts of Proposed Distribution Rates [ol RTSR+TLF]: Threshold of 750 kWhs

Classes		Scenario	May 2007 Incl Rate Riders						May 2008 Incl Rate Riders						Non-Dx Compoent				Other Reg	Commodity Bands			Existing	New	$ Incr	% Incr
			Existing Dx Rates					Existing Dx	New Dx Rates					New Dx	RTSR old	WMSC	DRC	TLF old	Old	Band 1	Band 2	Old	Total Bill	Total Bill	Total Bill	Total Bill
																				750.0						
																				5.0	5.9					
New Class	Old Class	kWh	SrChg [$/cust]	base [c/kWh]	Rider1 [c/kWh]	Rider2 [c/kWh]	VarChg [c/kWh]	[$/month]	SrChg [$/cust]	base [c/kWh]	Rider2 [c/kWh]	Rider3 [c/kWh]	VarChg [c/kWh]	[$/month]	c/kWh	c/kWh	c/kWh		$	kWhs	kWhs	Total $	[$/month]	[$/month]	[$/month]	%
GSe	**Ailsa Craig**	1,000	**17.31**	**1.32**	**0.17**	**0.09**	**1.58**	33.1	**20.76**	**2.34**	**0.09**	**(0.06)**	**2.37**	44.5	**0.93**	0.62	0.7	1.0545	23.3	750	250	55.5	111.9	123.3	11.4	10.2%
		2,000	17.31	1.32	0.17	0.09	1.58	48.9	20.76	2.34	0.09	(0.06)	2.37	68.2	0.93	0.62	0.70	1.05	46.7	750	1,250	117.7	213.3	232.6	19.3	9.1%
		5,000	17.31	1.32	0.17	0.09	1.58	96.3	20.76	2.34	0.09	(0.06)	2.37	139.4	0.93	0.62	0.70	1.05	116.7	750	4,250	304.3	517.4	560.5	43.1	8.3%
		10,000	17.31	1.32	0.17	0.09	1.58	175.3	20.76	2.34	0.09	(0.06)	2.37	258.1	0.93	0.62	0.70	1.05	233.4	750	9,250	615.4	1,024.2	1,106.9	82.8	8.1%
		15,000	17.31	1.32	0.17	0.09	1.58	254.3	20.76	2.34	0.09	(0.06)	2.37	376.8	0.93	0.62	0.70	1.05	350.2	750	14,250	926.5	1,531.0	1,653.4	122.4	8.0%
GSe	**Arkona**	1,000	**3.20**	**0.86**	**0.51**	**0.36**	**1.73**	20.5	**10.29**	**1.98**	**0.36**	**(0.06)**	**2.28**	33.1	**0.93**	0.62	0.7	1.0545	23.3	750	250	55.5	99.3	111.9	12.6	12.7%
		2,000	3.20	0.86	0.51	0.36	1.73	37.8	10.29	1.98	0.36	(0.06)	2.28	56.0	0.93	0.62	0.70	1.05	46.7	750	1,250	117.7	202.2	220.3	18.2	9.0%
		5,000	3.20	0.86	0.51	0.36	1.73	89.7	10.29	1.98	0.36	(0.06)	2.28	124.5	0.93	0.62	0.70	1.05	116.7	750	4,250	304.3	510.8	545.5	34.8	6.8%
		10,000	3.20	0.86	0.51	0.36	1.73	176.2	10.29	1.98	0.36	(0.06)	2.28	238.6	0.93	0.62	0.70	1.05	233.4	750	9,250	615.4	1,025.1	1,087.5	62.4	6.1%
		15,000	3.20	0.86	0.51	0.36	1.73	262.7	10.29	1.98	0.36	(0.06)	2.28	352.8	0.93	0.62	0.70	1.05	350.2	750	14,250	926.5	1,539.4	1,629.4	90.1	5.9%
UGe	**Arnprior**	1,000	**21.38**	**1.17**	**0.16**	**0.06**	**1.39**	35.3	**18.74**	**2.00**	**0.06**	**(0.06)**	**2.01**	38.8	**0.93**	0.62	0.7	1.0545	23.3	750	250	55.5	114.1	117.6	3.5	3.1%
		2,000	21.38	1.17	0.16	0.06	1.39	49.2	18.74	2.00	0.06	(0.06)	2.01	58.8	0.93	0.62	0.70	1.05	46.7	750	1,250	117.7	213.6	223.2	9.7	4.5%
		5,000	21.38	1.17	0.16	0.06	1.39	90.9	18.74	2.00	0.06	(0.06)	2.01	119.0	0.93	0.62	0.70	1.05	116.7	750	4,250	304.3	511.9	540.1	28.1	5.5%
		10,000	21.38	1.17	0.16	0.06	1.39	160.4	18.74	2.00	0.06	(0.06)	2.01	219.3	0.93	0.62	0.70	1.05	233.4	750	9,250	615.4	1,009.2	1,068.1	58.9	5.8%
		15,000	21.38	1.17	0.16	0.06	1.39	229.9	18.74	2.00	0.06	(0.06)	2.01	319.5	0.93	0.62	0.70	1.05	350.2	750	14,250	926.5	1,506.5	1,596.2	89.7	6.0%
GSe	**Arran-Elderslie**	1,000	**8.83**	**1.03**	**0.17**	**0.09**	**1.29**	21.7	**13.88**	**1.90**	**0.09**	**(0.06)**	**1.93**	33.2	**0.93**	0.62	0.7	1.0545	23.3	750	250	55.5	100.5	112.0	11.5	11.4%
		2,000	8.83	1.03	0.17	0.09	1.29	34.6	13.88	1.90	0.09	(0.06)	1.93	52.5	0.93	0.62	0.70	1.05	46.7	750	1,250	117.7	199.0	216.9	17.9	9.0%
		5,000	8.83	1.03	0.17	0.09	1.29	73.3	13.88	1.90	0.09	(0.06)	1.93	110.5	0.93	0.62	0.70	1.05	116.7	750	4,250	304.3	494.4	531.6	37.2	7.5%
		10,000	8.83	1.03	0.17	0.09	1.29	137.8	13.88	1.90	0.09	(0.06)	1.93	207.2	0.93	0.62	0.70	1.05	233.4	750	9,250	615.4	986.7	1,056.1	69.4	7.0%
		15,000	8.83	1.03	0.17	0.09	1.29	202.3	13.88	1.90	0.09	(0.06)	1.93	303.9	0.93	0.62	0.70	1.05	350.2	750	14,250	926.5	1,479.0	1,580.5	101.5	6.9%
GSe	**Artemesia**	1,000	**19.62**	**1.74**	**0.49**	**0.34**	**2.57**	45.3	**22.19**	**3.21**	**0.34**	**(0.06)**	**3.49**	57.1	**0.93**	0.62	0.7	1.0545	23.3	750	250	55.5	124.1	135.9	11.8	9.5%
		2,000	19.62	1.74	0.49	0.34	2.57	71.0	22.19	3.21	0.34	(0.06)	3.49	92.1	0.93	0.62	0.70	1.05	46.7	750	1,250	117.7	235.4	256.4	21.0	8.9%
		5,000	19.62	1.74	0.49	0.34	2.57	148.1	22.19	3.21	0.34	(0.06)	3.49	196.9	0.93	0.62	0.70	1.05	116.7	750	4,250	304.3	569.2	617.9	48.8	8.6%
		10,000	19.62	1.74	0.49	0.34	2.57	276.6	22.19	3.21	0.34	(0.06)	3.49	371.6	0.93	0.62	0.70	1.05	233.4	750	9,250	615.4	1,125.5	1,220.4	94.9	8.4%
		15,000	19.62	1.74	0.49	0.34	2.57	405.1	22.19	3.21	0.34	(0.06)	3.49	546.2	0.93	0.62	0.70	1.05	350.2	750	14,250	926.5	1,681.8	1,822.9	141.1	8.4%

New Rate Class: GSe - Metered

Total Bill Impacts of Proposed Distribution Rates [ol RTSR+TLF]: Threshold of 750 kWhs

Classes		Scenario	May 2007 Incl Rate Riders						May 2008 Incl Rate Riders						Non-Dx Compoent				Other Reg	Commodity Bands			Existing	New	$ Incr	% Incr
			Existing Dx Rates					Existing Dx	New Dx Rates					New Dx	RTSR old	WMSC	DRC	TLF old	Old	Band 1	Band 2	Old	Total Bill	Total Bill	Total Bill	Total Bill
																				750.0						
																				5.0	5.9					
New Class	Old Class	kWh	SrChg [$/cust]	base [c/kWh]	Rider1 [c/kWh]	Rider2 [c/kWh]	VarChg [c/kWh]	[$/month]	SrChg [$/cust]	base [c/kWh]	Rider2 [c/kWh]	Rider3 [c/kWh]	VarChg [c/kWh]	[$/month]	c/kWh	c/kWh	c/kWh		$	kWhs	kWhs	Total $	[$/month]	[$/month]	[$/month]	%
GSe	**Bancroft**	1,000	**24.41**	**1.18**	**0.17**	**0.08**	**1.43**	38.7	**25.99**	**2.30**	**0.08**	**(0.06)**	**2.32**	49.2	**0.93**	0.62	0.7	1.0545	23.3	750	250	55.5	117.5	128.0	10.5	8.9%
		2,000	24.41	1.18	0.17	0.08	1.43	53.0	25.99	2.30	0.08	(0.06)	2.32	72.5	0.93	0.62	0.70	1.05	46.7	750	1,250	117.7	217.4	236.8	19.4	8.9%
		5,000	24.41	1.18	0.17	0.08	1.43	95.9	25.99	2.30	0.08	(0.06)	2.32	142.2	0.93	0.62	0.70	1.05	116.7	750	4,250	304.3	517.0	563.2	46.2	8.9%
		10,000	24.41	1.18	0.17	0.08	1.43	167.4	25.99	2.30	0.08	(0.06)	2.32	258.3	0.93	0.62	0.70	1.05	233.4	750	9,250	615.4	1,016.3	1,107.2	90.9	8.9%
		15,000	24.41	1.18	0.17	0.08	1.43	238.9	25.99	2.30	0.08	(0.06)	2.32	374.5	0.93	0.62	0.70	1.05	350.2	750	14,250	926.5	1,515.6	1,651.1	135.6	8.9%
GSe	**Bath**	1,000	**10.65**	**1.47**	**0.29**	**0.24**	**2.00**	30.7	**15.43**	**2.55**	**0.24**	**(0.06)**	**2.73**	42.8	**0.93**	0.62	0.7	1.0545	23.3	750	250	55.5	109.5	121.6	12.1	11.1%
		2,000	10.65	1.47	0.29	0.24	2.00	50.7	15.43	2.55	0.24	(0.06)	2.73	70.1	0.93	0.62	0.70	1.05	46.7	750	1,250	117.7	215.0	234.5	19.4	9.0%
		5,000	10.65	1.47	0.29	0.24	2.00	110.7	15.43	2.55	0.24	(0.06)	2.73	152.1	0.93	0.62	0.70	1.05	116.7	750	4,250	304.3	531.7	573.1	41.4	7.8%
		10,000	10.65	1.47	0.29	0.24	2.00	210.7	15.43	2.55	0.24	(0.06)	2.73	288.8	0.93	0.62	0.70	1.05	233.4	750	9,250	615.4	1,059.5	1,137.6	78.1	7.4%
		15,000	10.65	1.47	0.29	0.24	2.00	310.7	15.43	2.55	0.24	(0.06)	2.73	425.4	0.93	0.62	0.70	1.05	350.2	750	14,250	926.5	1,587.3	1,702.1	114.8	7.2%
GSe	**Blandford-Bler**	1,000	**23.85**	**1.14**	**0.28**	**0.20**	**1.62**	40.1	**25.13**	**2.40**	**0.20**	**(0.06)**	**2.54**	50.6	**0.93**	0.62	0.7	1.0545	23.3	750	250	55.5	118.9	129.4	10.5	8.8%
		2,000	23.85	1.14	0.28	0.20	1.62	56.3	25.13	2.40	0.20	(0.06)	2.54	76.0	0.93	0.62	0.70	1.05	46.7	750	1,250	117.7	220.6	240.4	19.7	8.9%
		5,000	23.85	1.14	0.28	0.20	1.62	104.9	25.13	2.40	0.20	(0.06)	2.54	152.3	0.93	0.62	0.70	1.05	116.7	750	4,250	304.3	525.9	573.3	47.4	9.0%
		10,000	23.85	1.14	0.28	0.20	1.62	185.9	25.13	2.40	0.20	(0.06)	2.54	279.5	0.93	0.62	0.70	1.05	233.4	750	9,250	615.4	1,034.7	1,128.3	93.6	9.0%
		15,000	23.85	1.14	0.28	0.20	1.62	266.9	25.13	2.40	0.20	(0.06)	2.54	406.6	0.93	0.62	0.70	1.05	350.2	750	14,250	926.5	1,543.5	1,683.3	139.8	9.1%
GSe	**Blyth**	1,000	**21.63**	**1.05**	**0.26**	**0.20**	**1.51**	36.7	**23.68**	**2.20**	**0.20**	**(0.06)**	**2.34**	47.1	**0.93**	0.62	0.7	1.0545	23.3	750	250	55.5	115.5	125.9	10.4	9.0%
		2,000	21.63	1.05	0.26	0.20	1.51	51.8	23.68	2.20	0.20	(0.06)	2.34	70.5	0.93	0.62	0.70	1.05	46.7	750	1,250	117.7	216.2	234.9	18.7	8.7%
		5,000	21.63	1.05	0.26	0.20	1.51	97.1	23.68	2.20	0.20	(0.06)	2.34	140.8	0.93	0.62	0.70	1.05	116.7	750	4,250	304.3	518.2	561.9	43.7	8.4%
		10,000	21.63	1.05	0.26	0.20	1.51	172.6	23.68	2.20	0.20	(0.06)	2.34	258.0	0.93	0.62	0.70	1.05	233.4	750	9,250	615.4	1,021.5	1,106.9	85.4	8.4%
		15,000	21.63	1.05	0.26	0.20	1.51	248.1	23.68	2.20	0.20	(0.06)	2.34	375.2	0.93	0.62	0.70	1.05	350.2	750	14,250	926.5	1,524.8	1,651.8	127.0	8.3%
GSe	**Bobcaygeon**	1,000	**23.20**	**1.38**	**0.18**	**0.09**	**1.65**	39.7	**25.29**	**2.50**	**0.09**	**(0.06)**	**2.53**	50.6	**0.93**	0.62	0.7	1.0545	23.3	750	250	55.5	118.5	129.4	10.9	9.2%
		2,000	23.20	1.38	0.18	0.09	1.65	56.2	25.29	2.50	0.09	(0.06)	2.53	76.0	0.93	0.62	0.70	1.05	46.7	750	1,250	117.7	220.6	240.3	19.8	9.0%
		5,000	23.20	1.38	0.18	0.09	1.65	105.7	25.29	2.50	0.09	(0.06)	2.53	152.0	0.93	0.62	0.70	1.05	116.7	750	4,250	304.3	526.8	573.0	46.3	8.8%
		10,000	23.20	1.38	0.18	0.09	1.65	188.2	25.29	2.50	0.09	(0.06)	2.53	278.6	0.93	0.62	0.70	1.05	233.4	750	9,250	615.4	1,037.1	1,127.5	90.4	8.7%
		15,000	23.20	1.38	0.18	0.09	1.65	270.7	25.29	2.50	0.09	(0.06)	2.53	405.3	0.93	0.62	0.70	1.05	350.2	750	14,250	926.5	1,547.4	1,681.9	134.6	8.7%

New Rate Class: GSe - Metered

Total Bill Impacts of Proposed Distribution Rates [ol RTSR+TLF]: Threshold of 750 kWhs

750.0

Classes		Scenario	May 2007 Incl Rate Riders						May 2008 Incl Rate Riders						Non-Dx Compoent				Other Reg	Commodity Bands			Existing	New	$ Incr	% Incr
			Existing Dx Rates					Existing Dx	New Dx Rates					New Dx	RTSR old	WMSC	DRC	TLF old	Old	Band 1	Band 2	Old	Total Bill	Total Bill	Total Bill	Total Bill
																				5.0	5.9					
New Class	Old Class	kWh	SrChg [$/cust]	base [c/kWh]	Rider1 [c/kWh]	Rider2 [c/kWh]	VarChg [c/kWh]	[$/month]	SrChg [$/cust]	base [c/kWh]	Rider2 [c/kWh]	Rider3 [c/kWh]	VarChg [c/kWh]	[$/month]	c/kWh	c/kWh	c/kWh		$	kWhs	kWhs	Total $	[$/month]	[$/month]	[$/month]	%
GSe	**Brighton**	1,000	**22.90**	**1.35**	**0.20**	**0.08**	**1.63**	39.2	**24.37**	**2.50**	**0.08**	**(0.06)**	**2.52**	49.6	**0.93**	0.62	0.7	1.0545	23.3	750	250	55.5	118.0	128.4	10.4	8.8%
		2,000	22.90	1.35	0.20	0.08	1.63	55.5	24.37	2.50	0.08	(0.06)	2.52	74.8	0.93	0.62	0.70	1.05	46.7	750	1,250	117.7	219.9	239.2	19.3	8.8%
		5,000	22.90	1.35	0.20	0.08	1.63	104.4	24.37	2.50	0.08	(0.06)	2.52	150.5	0.93	0.62	0.70	1.05	116.7	750	4,250	304.3	525.5	571.6	46.1	8.8%
		10,000	22.90	1.35	0.20	0.08	1.63	185.9	24.37	2.50	0.08	(0.06)	2.52	276.7	0.93	0.62	0.70	1.05	233.4	750	9,250	615.4	1,034.8	1,125.5	90.8	8.8%
		15,000	22.90	1.35	0.20	0.08	1.63	267.4	24.37	2.50	0.08	(0.06)	2.52	402.9	0.93	0.62	0.70	1.05	350.2	750	14,250	926.5	1,544.1	1,679.5	135.5	8.8%
UGe	**Brockville**	1,000	**21.65**	**0.78**	**0.13**	**0.04**	**0.95**	31.2	**18.67**	**2.00**	**0.04**	**(0.06)**	**1.99**	38.5	**0.93**	0.62	0.7	1.0545	23.3	750	250	55.5	110.0	117.3	7.4	6.7%
		2,000	21.65	0.78	0.13	0.04	0.95	40.7	18.67	2.00	0.04	(0.06)	1.99	58.4	0.93	0.62	0.70	1.05	46.7	750	1,250	117.7	205.0	222.7	17.7	8.6%
		5,000	21.65	0.78	0.13	0.04	0.95	69.2	18.67	2.00	0.04	(0.06)	1.99	117.9	0.93	0.62	0.70	1.05	116.7	750	4,250	304.3	490.2	539.0	48.8	10.0%
		10,000	21.65	0.78	0.13	0.04	0.95	116.7	18.67	2.00	0.04	(0.06)	1.99	217.2	0.93	0.62	0.70	1.05	233.4	750	9,250	615.4	965.5	1,066.1	100.6	10.4%
		15,000	21.65	0.78	0.13	0.04	0.95	164.2	18.67	2.00	0.04	(0.06)	1.99	316.5	0.93	0.62	0.70	1.05	350.2	750	14,250	926.5	1,440.8	1,593.1	152.3	10.6%
GSe	**Caledon CH**	1,000	**24.21**	**1.80**	**0.14**	**0.08**	**2.02**	44.4	**26.04**	**2.90**	**0.08**	**(0.06)**	**2.92**	55.3	**0.93**	0.62	0.7	1.0545	23.3	750	250	55.5	123.2	134.1	10.9	8.8%
		2,000	24.21	1.80	0.14	0.08	2.02	64.6	26.04	2.90	0.08	(0.06)	2.92	84.5	0.93	0.62	0.70	1.05	46.7	750	1,250	117.7	229.0	248.9	19.9	8.7%
		5,000	24.21	1.80	0.14	0.08	2.02	125.2	26.04	2.90	0.08	(0.06)	2.92	172.2	0.93	0.62	0.70	1.05	116.7	750	4,250	304.3	546.3	593.3	47.0	8.6%
		10,000	24.21	1.80	0.14	0.08	2.02	226.2	26.04	2.90	0.08	(0.06)	2.92	318.4	0.93	0.62	0.70	1.05	233.4	750	9,250	615.4	1,075.1	1,167.2	92.2	8.6%
		15,000	24.21	1.80	0.14	0.08	2.02	327.2	26.04	2.90	0.08	(0.06)	2.92	464.5	0.93	0.62	0.70	1.05	350.2	750	14,250	926.5	1,603.9	1,741.2	137.3	8.6%
GSe	**Caledon OH**	1,000	**25.56**	**1.70**	**0.16**	**0.07**	**1.93**	44.9	**26.70**	**2.90**	**0.07**	**(0.06)**	**2.91**	55.8	**0.93**	0.62	0.7	1.0545	23.3	750	250	55.5	123.7	134.6	11.0	8.9%
		2,000	25.56	1.70	0.16	0.07	1.93	64.2	26.70	2.90	0.07	(0.06)	2.91	85.0	0.93	0.62	0.70	1.05	46.7	750	1,250	117.7	228.5	249.3	20.8	9.1%
		5,000	25.56	1.70	0.16	0.07	1.93	122.1	26.70	2.90	0.07	(0.06)	2.91	172.4	0.93	0.62	0.70	1.05	116.7	750	4,250	304.3	543.1	593.4	50.3	9.3%
		10,000	25.56	1.70	0.16	0.07	1.93	218.6	26.70	2.90	0.07	(0.06)	2.91	318.0	0.93	0.62	0.70	1.05	233.4	750	9,250	615.4	1,067.4	1,166.9	99.5	9.3%
		15,000	25.56	1.70	0.16	0.07	1.93	315.1	26.70	2.90	0.07	(0.06)	2.91	463.7	0.93	0.62	0.70	1.05	350.2	750	14,250	926.5	1,591.7	1,740.3	148.6	9.3%
GSe	**Campbellford-!**	1,000	**16.19**	**1.19**	**0.17**	**0.05**	**1.41**	30.3	**20.04**	**2.15**	**0.05**	**(0.06)**	**2.14**	41.5	**0.93**	0.62	0.7	1.0545	23.3	750	250	55.5	109.1	120.3	11.2	10.3%
		2,000	16.19	1.19	0.17	0.05	1.41	44.4	20.04	2.15	0.05	(0.06)	2.14	62.9	0.93	0.62	0.70	1.05	46.7	750	1,250	117.7	208.8	227.3	18.5	8.9%
		5,000	16.19	1.19	0.17	0.05	1.41	86.7	20.04	2.15	0.05	(0.06)	2.14	127.2	0.93	0.62	0.70	1.05	116.7	750	4,250	304.3	507.7	548.3	40.5	8.0%
		10,000	16.19	1.19	0.17	0.05	1.41	157.2	20.04	2.15	0.05	(0.06)	2.14	234.4	0.93	0.62	0.70	1.05	233.4	750	9,250	615.4	1,006.0	1,083.2	77.2	7.7%
		15,000	16.19	1.19	0.17	0.05	1.41	227.7	20.04	2.15	0.05	(0.06)	2.14	341.5	0.93	0.62	0.70	1.05	350.2	750	14,250	926.5	1,504.3	1,618.2	113.8	7.6%

New Rate Class: GSe - Metered

Total Bill Impacts of Proposed Distribution Rates [ol RTSR+TLF]: Threshold of 750 kWhs

750.0

Classes		Scenario	May 2007 Incl Rate Riders						May 2008 Incl Rate Riders						Non-Dx Compoent				Other Reg	Commodity Bands			Existing	New	$ Incr	% Incr
			Existing Dx Rates					Existing Dx	New Dx Rates					New Dx	RTSR old	WMSC	DRC	TLF old	Old	Band 1	Band 2	Old	Total Bill	Total Bill	Total Bill	Total Bill
																				5.0	5.9					
New Class	Old Class	kWh	SrChg [$/cust]	base [c/kWh]	Rider1 [c/kWh]	Rider2 [c/kWh]	VarChg [c/kWh]	[$/month]	SrChg [$/cust]	base [c/kWh]	Rider2 [c/kWh]	Rider3 [c/kWh]	VarChg [c/kWh]	[$/month]	c/kWh	c/kWh	c/kWh		$	kWhs	kWhs	Total $	[$/month]	[$/month]	[$/month]	%
UGe	**Carleton Place**	1,000	**23.65**	**1.68**	**0.13**	**0.07**	**1.88**	42.5	**20.17**	**2.00**	**0.07**	**(0.06)**	**2.02**	40.3	**0.93**	0.62	0.7	1.0545	23.3	750	250	55.5	121.3	119.1	(2.1)	-1.8%
		2,000	23.65	1.68	0.13	0.07	1.88	61.3	20.17	2.00	0.07	(0.06)	2.02	60.5	0.93	0.62	0.70	1.05	46.7	750	1,250	117.7	225.6	224.8	(0.8)	-0.3%
		5,000	23.65	1.68	0.13	0.07	1.88	117.7	20.17	2.00	0.07	(0.06)	2.02	120.9	0.93	0.62	0.70	1.05	116.7	750	4,250	304.3	538.7	542.0	3.3	0.6%
		10,000	23.65	1.68	0.13	0.07	1.88	211.7	20.17	2.00	0.07	(0.06)	2.02	221.7	0.93	0.62	0.70	1.05	233.4	750	9,250	615.4	1,060.5	1,070.6	10.1	0.9%
		15,000	23.65	1.68	0.13	0.07	1.88	305.7	20.17	2.00	0.07	(0.06)	2.02	322.5	0.93	0.62	0.70	1.05	350.2	750	14,250	926.5	1,582.3	1,599.1	16.8	1.1%
GSe	**Cavan-Millbroc**	1,000	**22.28**	**1.50**	**0.33**	**0.26**	**2.09**	43.2	**24.52**	**2.80**	**0.26**	**(0.06)**	**3.00**	54.6	**0.93**	0.62	0.7	1.0545	23.3	750	250	55.5	122.0	133.4	11.4	9.3%
		2,000	22.28	1.50	0.33	0.26	2.09	64.1	24.52	2.80	0.26	(0.06)	3.00	84.6	0.93	0.62	0.70	1.05	46.7	750	1,250	117.7	228.5	249.0	20.5	9.0%
		5,000	22.28	1.50	0.33	0.26	2.09	126.8	24.52	2.80	0.26	(0.06)	3.00	174.7	0.93	0.62	0.70	1.05	116.7	750	4,250	304.3	547.8	595.7	47.9	8.7%
		10,000	22.28	1.50	0.33	0.26	2.09	231.3	24.52	2.80	0.26	(0.06)	3.00	324.8	0.93	0.62	0.70	1.05	233.4	750	9,250	615.4	1,080.1	1,173.7	93.6	8.7%
		15,000	22.28	1.50	0.33	0.26	2.09	335.8	24.52	2.80	0.26	(0.06)	3.00	475.0	0.93	0.62	0.70	1.05	350.2	750	14,250	926.5	1,612.4	1,751.7	139.2	8.6%
GSe	**Centre Hasting**	1,000	**18.38**	**0.97**	**0.14**	**0.06**	**1.17**	30.1	**21.50**	**1.94**	**0.06**	**(0.06)**	**1.94**	40.9	**0.93**	0.62	0.7	1.0545	23.3	750	250	55.5	108.9	119.7	10.8	10.0%
		2,000	18.38	0.97	0.14	0.06	1.17	41.8	21.50	1.94	0.06	(0.06)	1.94	60.4	0.93	0.62	0.70	1.05	46.7	750	1,250	117.7	206.2	224.7	18.6	9.0%
		5,000	18.38	0.97	0.14	0.06	1.17	76.9	21.50	1.94	0.06	(0.06)	1.94	118.7	0.93	0.62	0.70	1.05	116.7	750	4,250	304.3	497.9	539.7	41.8	8.4%
		10,000	18.38	0.97	0.14	0.06	1.17	135.4	21.50	1.94	0.06	(0.06)	1.94	215.8	0.93	0.62	0.70	1.05	233.4	750	9,250	615.4	984.2	1,064.7	80.4	8.2%
		15,000	18.38	0.97	0.14	0.06	1.17	193.9	21.50	1.94	0.06	(0.06)	1.94	313.0	0.93	0.62	0.70	1.05	350.2	750	14,250	926.5	1,470.5	1,589.6	119.1	8.1%
GSe	**Chalk River**	1,000	**21.33**	**1.79**	**0.39**	**0.34**	**2.52**	46.5	**23.76**	**3.18**	**0.34**	**(0.06)**	**3.46**	58.4	**0.93**	0.62	0.7	1.0545	23.3	750	250	55.5	125.3	137.2	11.9	9.5%
		2,000	21.33	1.79	0.39	0.34	2.52	71.7	23.76	3.18	0.34	(0.06)	3.46	93.0	0.93	0.62	0.70	1.05	46.7	750	1,250	117.7	236.1	257.4	21.3	9.0%
		5,000	21.33	1.79	0.39	0.34	2.52	147.3	23.76	3.18	0.34	(0.06)	3.46	196.9	0.93	0.62	0.70	1.05	116.7	750	4,250	304.3	568.4	618.0	49.6	8.7%
		10,000	21.33	1.79	0.39	0.34	2.52	273.3	23.76	3.18	0.34	(0.06)	3.46	370.1	0.93	0.62	0.70	1.05	233.4	750	9,250	615.4	1,122.2	1,218.9	96.8	8.6%
		15,000	21.33	1.79	0.39	0.34	2.52	399.3	23.76	3.18	0.34	(0.06)	3.46	543.2	0.93	0.62	0.70	1.05	350.2	750	14,250	926.5	1,676.0	1,819.9	143.9	8.6%
GSe	**Champlain**	1,000	**20.59**	**0.91**	**0.26**	**0.15**	**1.32**	33.8	**22.94**	**2.05**	**0.15**	**(0.06)**	**2.14**	44.4	**0.93**	0.62	0.7	1.0545	23.3	750	250	55.5	112.6	123.2	10.6	9.4%
		2,000	20.59	0.91	0.26	0.15	1.32	47.0	22.94	2.05	0.15	(0.06)	2.14	65.8	0.93	0.62	0.70	1.05	46.7	750	1,250	117.7	211.4	230.2	18.8	8.9%
		5,000	20.59	0.91	0.26	0.15	1.32	86.6	22.94	2.05	0.15	(0.06)	2.14	130.1	0.93	0.62	0.70	1.05	116.7	750	4,250	304.3	507.6	551.2	43.5	8.6%
		10,000	20.59	0.91	0.26	0.15	1.32	152.6	22.94	2.05	0.15	(0.06)	2.14	237.3	0.93	0.62	0.70	1.05	233.4	750	9,250	615.4	1,001.4	1,086.1	84.7	8.5%
		15,000	20.59	0.91	0.26	0.15	1.32	218.6	22.94	2.05	0.15	(0.06)	2.14	344.4	0.93	0.62	0.70	1.05	350.2	750	14,250	926.5	1,495.2	1,621.1	125.8	8.4%

New Rate Class: GSe - Metered

Total Bill Impacts of Proposed Distribution Rates [ol RTSR+TLF]: Threshold of 750 kWhs

Classes		Scenario	May 2007 Incl Rate Riders						May 2008 Incl Rate Riders						Non-Dx Compoent				Other Reg	Commodity Bands 750.0			Existing	New	$ Incr	% Incr
			Existing Dx Rates					Existing Dx	New Dx Rates					New Dx	RTSR old	WMSC	DRC	TLF old	Old	Band 1	Band 2	Old	Total Bill	Total Bill	Total Bill	Total Bill
																				5.0	5.9					
New Class	Old Class	kWh	SrChg [$/cust]	base [c/kWh]	Rider1 [c/kWh]	Rider2 [c/kWh]	VarChg [c/kWh]	[$/month]	SrChg [$/cust]	base [c/kWh]	Rider2 [c/kWh]	Rider3 [c/kWh]	VarChg [c/kWh]	[$/month]	c/kWh	c/kWh	c/kWh		$	kWhs	kWhs	Total $	[$/month]	[$/month]	[$/month]	%
GSe	**Cobden**	1,000	**21.93**	**2.13**	**0.36**	**0.30**	**2.79**	49.8	**23.61**	**3.21**	**0.30**	**(0.06)**	**3.45**	58.1	**0.93**	0.62	0.7	1.0545	23.3	750	250	55.5	128.6	137.0	8.3	6.5%
		2,000	21.93	2.13	0.36	0.30	2.79	77.7	23.61	3.21	0.30	(0.06)	3.45	92.7	0.93	0.62	0.70	1.05	46.7	750	1,250	117.7	242.1	257.1	15.0	6.2%
		5,000	21.93	2.13	0.36	0.30	2.79	161.4	23.61	3.21	0.30	(0.06)	3.45	196.3	0.93	0.62	0.70	1.05	116.7	750	4,250	304.3	582.5	617.3	34.9	6.0%
		10,000	21.93	2.13	0.36	0.30	2.79	300.9	23.61	3.21	0.30	(0.06)	3.45	369.0	0.93	0.62	0.70	1.05	233.4	750	9,250	615.4	1,149.8	1,217.8	68.1	5.9%
		15,000	21.93	2.13	0.36	0.30	2.79	440.4	23.61	3.21	0.30	(0.06)	3.45	541.7	0.93	0.62	0.70	1.05	350.2	750	14,250	926.5	1,717.1	1,818.3	101.2	5.9%
GSe	**Deep River**	1,000	**23.94**	**2.26**	**0.15**	**0.14**	**2.55**	49.4	**25.11**	**3.21**	**0.14**	**(0.06)**	**3.29**	58.0	**0.93**	0.62	0.7	1.0545	23.3	750	250	55.5	128.3	136.9	8.6	6.7%
		2,000	23.94	2.26	0.15	0.14	2.55	74.9	25.11	3.21	0.14	(0.06)	3.29	91.0	0.93	0.62	0.70	1.05	46.7	750	1,250	117.7	239.3	255.4	16.0	6.7%
		5,000	23.94	2.26	0.15	0.14	2.55	151.4	25.11	3.21	0.14	(0.06)	3.29	189.8	0.93	0.62	0.70	1.05	116.7	750	4,250	304.3	572.5	610.8	38.4	6.7%
		10,000	23.94	2.26	0.15	0.14	2.55	278.9	25.11	3.21	0.14	(0.06)	3.29	354.5	0.93	0.62	0.70	1.05	233.4	750	9,250	615.4	1,127.8	1,203.3	75.5	6.7%
		15,000	23.94	2.26	0.15	0.14	2.55	406.4	25.11	3.21	0.14	(0.06)	3.29	519.2	0.93	0.62	0.70	1.05	350.2	750	14,250	926.5	1,683.1	1,795.8	112.7	6.7%
GSe	**Deseronto**	1,000	**10.14**	**1.35**	**0.13**	**0.05**	**1.53**	25.4	**15.56**	**2.18**	**0.05**	**(0.06)**	**2.17**	37.3	**0.93**	0.62	0.7	1.0545	23.3	750	250	55.5	104.3	116.1	11.8	11.4%
		2,000	10.14	1.35	0.13	0.05	1.53	40.7	15.56	2.18	0.05	(0.06)	2.17	59.0	0.93	0.62	0.70	1.05	46.7	750	1,250	117.7	205.1	223.4	18.3	8.9%
		5,000	10.14	1.35	0.13	0.05	1.53	86.6	15.56	2.18	0.05	(0.06)	2.17	124.2	0.93	0.62	0.70	1.05	116.7	750	4,250	304.3	507.7	545.3	37.6	7.4%
		10,000	10.14	1.35	0.13	0.05	1.53	163.1	15.56	2.18	0.05	(0.06)	2.17	232.9	0.93	0.62	0.70	1.05	233.4	750	9,250	615.4	1,012.0	1,081.7	69.7	6.9%
		15,000	10.14	1.35	0.13	0.05	1.53	239.6	15.56	2.18	0.05	(0.06)	2.17	341.5	0.93	0.62	0.70	1.05	350.2	750	14,250	926.5	1,516.3	1,618.2	101.9	6.7%
UGe	**Dryden**	1,000	**19.11**	**1.03**	**0.12**	**0.04**	**1.19**	31.0	**17.31**	**2.00**	**0.04**	**(0.06)**	**1.99**	37.2	**0.93**	0.62	0.7	1.0545	23.3	750	250	55.5	109.8	116.0	6.1	5.6%
		2,000	19.11	1.03	0.12	0.04	1.19	42.9	17.31	2.00	0.04	(0.06)	1.99	57.0	0.93	0.62	0.70	1.05	46.7	750	1,250	117.7	207.3	221.4	14.1	6.8%
		5,000	19.11	1.03	0.12	0.04	1.19	78.6	17.31	2.00	0.04	(0.06)	1.99	116.6	0.93	0.62	0.70	1.05	116.7	750	4,250	304.3	499.7	537.6	38.0	7.6%
		10,000	19.11	1.03	0.12	0.04	1.19	138.1	17.31	2.00	0.04	(0.06)	1.99	215.8	0.93	0.62	0.70	1.05	233.4	750	9,250	615.4	987.0	1,064.7	77.7	7.9%
		15,000	19.11	1.03	0.12	0.04	1.19	197.6	17.31	2.00	0.04	(0.06)	1.99	315.1	0.93	0.62	0.70	1.05	350.2	750	14,250	926.5	1,474.3	1,591.8	117.5	8.0%
GSe	**Dundalk**	1,000	**23.56**	**1.64**	**0.23**	**0.09**	**1.96**	43.2	**25.20**	**2.85**	**0.09**	**(0.06)**	**2.88**	54.0	**0.93**	0.62	0.7	1.0545	23.3	750	250	55.5	122.0	132.8	10.9	8.9%
		2,000	23.56	1.64	0.23	0.09	1.96	62.8	25.20	2.85	0.09	(0.06)	2.88	82.9	0.93	0.62	0.70	1.05	46.7	750	1,250	117.7	227.1	247.2	20.1	8.9%
		5,000	23.56	1.64	0.23	0.09	1.96	121.6	25.20	2.85	0.09	(0.06)	2.88	169.4	0.93	0.62	0.70	1.05	116.7	750	4,250	304.3	542.6	590.4	47.8	8.8%
		10,000	23.56	1.64	0.23	0.09	1.96	219.6	25.20	2.85	0.09	(0.06)	2.88	313.5	0.93	0.62	0.70	1.05	233.4	750	9,250	615.4	1,068.4	1,162.4	94.0	8.8%
		15,000	23.56	1.64	0.23	0.09	1.96	317.6	25.20	2.85	0.09	(0.06)	2.88	457.7	0.93	0.62	0.70	1.05	350.2	750	14,250	926.5	1,594.2	1,734.3	140.1	8.8%

New Rate Class: GSe - Metered

Total Bill Impacts of Proposed Distribution Rates [ol RTSR+TLF]: Threshold of 750 kWhs

750.0

Classes		Scenario	May 2007 Incl Rate Riders						May 2008 Incl Rate Riders						Non-Dx Compoent				Other Reg	Commodity Bands			Existing	New	$ Incr	% Incr
			Existing Dx Rates					Existing Dx	New Dx Rates					New Dx	RTSR old	WMSC	DRC	TLF old	Old	Band 1	Band 2	Old	Total Bill	Total Bill	Total Bill	Total Bill
																				5.0	5.9					
New Class	Old Class	kWh	SrChg [$/cust]	base [c/kWh]	Rider1 [c/kWh]	Rider2 [c/kWh]	VarChg [c/kWh]	[$/month]	SrChg [$/cust]	base [c/kWh]	Rider2 [c/kWh]	Rider3 [c/kWh]	VarChg [c/kWh]	[$/month]	c/kWh	c/kWh	c/kWh		$	kWhs	kWhs	Total $	[$/month]	[$/month]	[$/month]	%
GSe	**Durham**	1,000	**24.12**	**1.37**	**0.15**	**0.06**	**1.58**	39.9	**26.06**	**2.48**	**0.06**	**(0.06)**	**2.48**	50.9	**0.93**	0.62	0.7	1.0545	23.3	750	250	55.5	118.7	129.7	11.0	9.2%
		2,000	24.12	1.37	0.15	0.06	1.58	55.7	26.06	2.48	0.06	(0.06)	2.48	75.7	0.93	0.62	0.70	1.05	46.7	750	1,250	117.7	220.1	240.1	20.0	9.1%
		5,000	24.12	1.37	0.15	0.06	1.58	103.1	26.06	2.48	0.06	(0.06)	2.48	150.2	0.93	0.62	0.70	1.05	116.7	750	4,250	304.3	524.2	571.3	47.1	9.0%
		10,000	24.12	1.37	0.15	0.06	1.58	182.1	26.06	2.48	0.06	(0.06)	2.48	274.4	0.93	0.62	0.70	1.05	233.4	750	9,250	615.4	1,031.0	1,123.2	92.3	8.9%
		15,000	24.12	1.37	0.15	0.06	1.58	261.1	26.06	2.48	0.06	(0.06)	2.48	398.6	0.93	0.62	0.70	1.05	350.2	750	14,250	926.5	1,537.8	1,675.2	137.4	8.9%
GSe	**Eganville**	1,000	**21.35**	**2.32**	**0.17**	**0.12**	**2.61**	47.5	**23.75**	**3.21**	**0.12**	**(0.06)**	**3.27**	56.5	**0.93**	0.62	0.7	1.0545	23.3	750	250	55.5	126.3	135.3	9.0	7.2%
		2,000	21.35	2.32	0.17	0.12	2.61	73.6	23.75	3.21	0.12	(0.06)	3.27	89.2	0.93	0.62	0.70	1.05	46.7	750	1,250	117.7	237.9	253.6	15.7	6.6%
		5,000	21.35	2.32	0.17	0.12	2.61	151.9	23.75	3.21	0.12	(0.06)	3.27	187.4	0.93	0.62	0.70	1.05	116.7	750	4,250	304.3	572.9	608.5	35.6	6.2%
		10,000	21.35	2.32	0.17	0.12	2.61	282.4	23.75	3.21	0.12	(0.06)	3.27	351.1	0.93	0.62	0.70	1.05	233.4	750	9,250	615.4	1,131.2	1,200.0	68.8	6.1%
		15,000	21.35	2.32	0.17	0.12	2.61	412.9	23.75	3.21	0.12	(0.06)	3.27	514.8	0.93	0.62	0.70	1.05	350.2	750	14,250	926.5	1,689.5	1,791.5	102.0	6.0%
GSe	**Erin**	1,000	**40.38**	**0.73**	**0.19**	**0.08**	**1.00**	50.4	**38.00**	**2.10**	**0.08**	**(0.06)**	**2.12**	59.2	**0.93**	0.62	0.7	1.0545	23.3	750	250	55.5	129.2	138.0	8.8	6.9%
		2,000	40.38	0.73	0.19	0.08	1.00	60.4	38.00	2.10	0.08	(0.06)	2.12	80.5	0.93	0.62	0.70	1.05	46.7	750	1,250	117.7	224.8	244.8	20.1	8.9%
		5,000	40.38	0.73	0.19	0.08	1.00	90.4	38.00	2.10	0.08	(0.06)	2.12	144.2	0.93	0.62	0.70	1.05	116.7	750	4,250	304.3	511.4	565.2	53.8	10.5%
		10,000	40.38	0.73	0.19	0.08	1.00	140.4	38.00	2.10	0.08	(0.06)	2.12	250.3	0.93	0.62	0.70	1.05	233.4	750	9,250	615.4	989.2	1,099.2	109.9	11.1%
		15,000	40.38	0.73	0.19	0.08	1.00	190.4	38.00	2.10	0.08	(0.06)	2.12	356.5	0.93	0.62	0.70	1.05	350.2	750	14,250	926.5	1,467.0	1,633.1	166.1	11.3%
GSe	**Exeter**	1,000	**11.36**	**1.30**	**0.15**	**0.06**	**1.51**	26.5	**16.25**	**2.18**	**0.06**	**(0.06)**	**2.18**	38.1	**0.93**	0.62	0.7	1.0545	23.3	750	250	55.5	105.3	116.9	11.6	11.0%
		2,000	11.36	1.30	0.15	0.06	1.51	41.6	16.25	2.18	0.06	(0.06)	2.18	59.9	0.93	0.62	0.70	1.05	46.7	750	1,250	117.7	205.9	224.3	18.4	8.9%
		5,000	11.36	1.30	0.15	0.06	1.51	86.9	16.25	2.18	0.06	(0.06)	2.18	125.4	0.93	0.62	0.70	1.05	116.7	750	4,250	304.3	507.9	546.5	38.6	7.6%
		10,000	11.36	1.30	0.15	0.06	1.51	162.4	16.25	2.18	0.06	(0.06)	2.18	234.6	0.93	0.62	0.70	1.05	233.4	750	9,250	615.4	1,011.2	1,083.4	72.2	7.1%
		15,000	11.36	1.30	0.15	0.06	1.51	237.9	16.25	2.18	0.06	(0.06)	2.18	343.7	0.93	0.62	0.70	1.05	350.2	750	14,250	926.5	1,514.5	1,620.4	105.9	7.0%
GSe	**Fenelon Falls**	1,000	**19.81**	**0.95**	**0.15**	**0.08**	**1.18**	31.6	**22.14**	**1.98**	**0.08**	**(0.06)**	**2.00**	42.2	**0.93**	0.62	0.7	1.0545	23.3	750	250	55.5	110.4	121.0	10.6	9.6%
		2,000	19.81	0.95	0.15	0.08	1.18	43.4	22.14	1.98	0.08	(0.06)	2.00	62.2	0.93	0.62	0.70	1.05	46.7	750	1,250	117.7	207.8	226.6	18.8	9.0%
		5,000	19.81	0.95	0.15	0.08	1.18	78.8	22.14	1.98	0.08	(0.06)	2.00	122.3	0.93	0.62	0.70	1.05	116.7	750	4,250	304.3	499.9	543.4	43.5	8.7%
		10,000	19.81	0.95	0.15	0.08	1.18	137.8	22.14	1.98	0.08	(0.06)	2.00	222.5	0.93	0.62	0.70	1.05	233.4	750	9,250	615.4	986.7	1,071.3	84.7	8.6%
		15,000	19.81	0.95	0.15	0.08	1.18	196.8	22.14	1.98	0.08	(0.06)	2.00	322.6	0.93	0.62	0.70	1.05	350.2	750	14,250	926.5	1,473.5	1,599.3	125.8	8.5%

New Rate Class: GSe - Metered

Total Bill Impacts of Proposed Distribution Rates [ol RTSR+TLF]: Threshold of 750 kWhs

Classes		Scenario	May 2007 Incl Rate Riders						May 2008 Incl Rate Riders						Non-Dx Compoent				Other Reg	Commodity Bands			Existing	New	$ Incr	% Incr
			Existing Dx Rates					Existing Dx	New Dx Rates					New Dx	RTSR old	WMSC	DRC	TLF old	Old	Band 1	Band 2	Old	Total Bill	Total Bill	Total Bill	Total Bill
																				750.0						
																				5.0	5.9					
New Class	Old Class	kWh	SrChg [$/cust]	base [c/kWh]	Rider1 [c/kWh]	Rider2 [c/kWh]	VarChg [c/kWh]	[$/month]	SrChg [$/cust]	base [c/kWh]	Rider2 [c/kWh]	Rider3 [c/kWh]	VarChg [c/kWh]	[$/month]	c/kWh	c/kWh	c/kWh		$	kWhs	kWhs	Total $	[$/month]	[$/month]	[$/month]	%
GSe	**Forest**	1,000	**24.91**	**1.18**	**0.16**	**0.06**	**1.40**	38.9	**25.86**	**2.32**	**0.06**	**(0.06)**	**2.32**	49.1	**0.93**	0.62	0.7	1.0545	23.3	750	250	55.5	117.7	127.9	10.2	8.7%
		2,000	24.91	1.18	0.16	0.06	1.40	52.9	25.86	2.32	0.06	(0.06)	2.32	72.3	0.93	0.62	0.70	1.05	46.7	750	1,250	117.7	217.3	236.7	19.4	8.9%
		5,000	24.91	1.18	0.16	0.06	1.40	94.9	25.86	2.32	0.06	(0.06)	2.32	142.0	0.93	0.62	0.70	1.05	116.7	750	4,250	304.3	516.0	563.1	47.1	9.1%
		10,000	24.91	1.18	0.16	0.06	1.40	164.9	25.86	2.32	0.06	(0.06)	2.32	258.2	0.93	0.62	0.70	1.05	233.4	750	9,250	615.4	1,013.8	1,107.0	93.3	9.2%
		15,000	24.91	1.18	0.16	0.06	1.40	234.9	25.86	2.32	0.06	(0.06)	2.32	374.4	0.93	0.62	0.70	1.05	350.2	750	14,250	926.5	1,511.6	1,651.0	139.4	9.2%
UGe	**GBE**	1,000	**10.77**	**1.14**	**0.16**	**0.06**	**1.36**	24.4	**10.39**	**2.00**	**0.06**	**(0.06)**	**2.01**	30.4	**0.93**	0.62	0.7	1.0545	23.3	750	250	55.5	103.2	109.3	6.1	5.9%
		2,000	10.77	1.14	0.16	0.06	1.36	38.0	10.39	2.00	0.06	(0.06)	2.01	50.5	0.93	0.62	0.70	1.05	46.7	750	1,250	117.7	202.3	214.9	12.5	6.2%
		5,000	10.77	1.14	0.16	0.06	1.36	78.8	10.39	2.00	0.06	(0.06)	2.01	110.7	0.93	0.62	0.70	1.05	116.7	750	4,250	304.3	499.8	531.7	31.9	6.4%
		10,000	10.77	1.14	0.16	0.06	1.36	146.8	10.39	2.00	0.06	(0.06)	2.01	210.9	0.93	0.62	0.70	1.05	233.4	750	9,250	615.4	995.6	1,059.8	64.2	6.4%
		15,000	10.77	1.14	0.16	0.06	1.36	214.8	10.39	2.00	0.06	(0.06)	2.01	311.2	0.93	0.62	0.70	1.05	350.2	750	14,250	926.5	1,491.4	1,587.9	96.4	6.5%
GSe	**Georgina**	1,000	**17.40**	**1.62**	**0.16**	**0.08**	**1.86**	36.0	**20.74**	**2.65**	**0.08**	**(0.06)**	**2.67**	47.5	**0.93**	0.62	0.7	1.0545	23.3	750	250	55.5	114.8	126.3	11.5	10.0%
		2,000	17.40	1.62	0.16	0.08	1.86	54.6	20.74	2.65	0.08	(0.06)	2.67	74.2	0.93	0.62	0.70	1.05	46.7	750	1,250	117.7	219.0	238.6	19.6	9.0%
		5,000	17.40	1.62	0.16	0.08	1.86	110.4	20.74	2.65	0.08	(0.06)	2.67	154.4	0.93	0.62	0.70	1.05	116.7	750	4,250	304.3	531.5	575.5	44.0	8.3%
		10,000	17.40	1.62	0.16	0.08	1.86	203.4	20.74	2.65	0.08	(0.06)	2.67	288.1	0.93	0.62	0.70	1.05	233.4	750	9,250	615.4	1,052.3	1,136.9	84.7	8.0%
		15,000	17.40	1.62	0.16	0.08	1.86	296.4	20.74	2.65	0.08	(0.06)	2.67	421.7	0.93	0.62	0.70	1.05	350.2	750	14,250	926.5	1,573.1	1,698.4	125.3	8.0%
GSe	**Glencoe**	1,000	**11.37**	**0.81**	**0.22**	**0.14**	**1.17**	23.1	**16.25**	**1.74**	**0.14**	**(0.06)**	**1.82**	34.5	**0.93**	0.62	0.7	1.0545	23.3	750	250	55.5	101.9	113.3	11.4	11.2%
		2,000	11.37	0.81	0.22	0.14	1.17	34.8	16.25	1.74	0.14	(0.06)	1.82	52.7	0.93	0.62	0.70	1.05	46.7	750	1,250	117.7	199.1	217.1	17.9	9.0%
		5,000	11.37	0.81	0.22	0.14	1.17	69.9	16.25	1.74	0.14	(0.06)	1.82	107.4	0.93	0.62	0.70	1.05	116.7	750	4,250	304.3	490.9	528.5	37.5	7.6%
		10,000	11.37	0.81	0.22	0.14	1.17	128.4	16.25	1.74	0.14	(0.06)	1.82	198.6	0.93	0.62	0.70	1.05	233.4	750	9,250	615.4	977.2	1,047.4	70.2	7.2%
		15,000	11.37	0.81	0.22	0.14	1.17	186.9	16.25	1.74	0.14	(0.06)	1.82	289.7	0.93	0.62	0.70	1.05	350.2	750	14,250	926.5	1,463.5	1,566.4	102.9	7.0%
GSe	**Grand Bend**	1,000	**22.20**	**1.23**	**0.19**	**0.07**	**1.49**	37.1	**24.54**	**2.34**	**0.07**	**(0.06)**	**2.35**	48.1	**0.93**	0.62	0.7	1.0545	23.3	750	250	55.5	115.9	126.9	11.0	9.5%
		2,000	22.20	1.23	0.19	0.07	1.49	52.0	24.54	2.34	0.07	(0.06)	2.35	71.6	0.93	0.62	0.70	1.05	46.7	750	1,250	117.7	216.4	236.0	19.6	9.1%
		5,000	22.20	1.23	0.19	0.07	1.49	96.7	24.54	2.34	0.07	(0.06)	2.35	142.2	0.93	0.62	0.70	1.05	116.7	750	4,250	304.3	517.8	563.3	45.5	8.8%
		10,000	22.20	1.23	0.19	0.07	1.49	171.2	24.54	2.34	0.07	(0.06)	2.35	259.9	0.93	0.62	0.70	1.05	233.4	750	9,250	615.4	1,020.1	1,108.7	88.7	8.7%
		15,000	22.20	1.23	0.19	0.07	1.49	245.7	24.54	2.34	0.07	(0.06)	2.35	377.5	0.93	0.62	0.70	1.05	350.2	750	14,250	926.5	1,522.4	1,654.2	131.8	8.7%

New Rate Class: GSe - Metered

Total Bill Impacts of Proposed Distribution Rates [ol RTSR+TLF]: Threshold of 750 kWhs

Classes		Scenario	May 2007 Incl Rate Riders						May 2008 Incl Rate Riders						Non-Dx Compoent				Other Reg	Commodity Bands			Existing	New	$ Incr	% Incr
			Existing Dx Rates					Existing Dx	New Dx Rates					New Dx	RTSR old	WMSC	DRC	TLF old	Old	Band 1	Band 2	Old	Total Bill	Total Bill	Total Bill	Total Bill
																				750.0						
																				5.0	5.9					
New Class	Old Class	kWh	SrChg [$/cust]	base [c/kWh]	Rider1 [c/kWh]	Rider2 [c/kWh]	VarChg [c/kWh]	[$/month]	SrChg [$/cust]	base [c/kWh]	Rider2 [c/kWh]	Rider3 [c/kWh]	VarChg [c/kWh]	[$/month]	c/kWh	c/kWh	c/kWh		$	kWhs	kWhs	Total $	[$/month]	[$/month]	[$/month]	%
GSe	**Hastings**	1,000	**22.89**	**1.69**	**0.23**	**0.09**	**2.01**	43.0	**24.37**	**2.93**	**0.09**	**(0.06)**	**2.96**	54.0	**0.93**	0.62	0.7	1.0545	23.3	750	250	55.5	121.8	132.8	11.0	9.0%
		2,000	22.89	1.69	0.23	0.09	2.01	63.1	24.37	2.93	0.09	(0.06)	2.96	83.6	0.93	0.62	0.70	1.05	46.7	750	1,250	117.7	227.5	248.0	20.5	9.0%
		5,000	22.89	1.69	0.23	0.09	2.01	123.4	24.37	2.93	0.09	(0.06)	2.96	172.5	0.93	0.62	0.70	1.05	116.7	750	4,250	304.3	544.4	593.6	49.1	9.0%
		10,000	22.89	1.69	0.23	0.09	2.01	223.9	24.37	2.93	0.09	(0.06)	2.96	320.7	0.93	0.62	0.70	1.05	233.4	750	9,250	615.4	1,072.7	1,169.5	96.8	9.0%
		15,000	22.89	1.69	0.23	0.09	2.01	324.4	24.37	2.93	0.09	(0.06)	2.96	468.9	0.93	0.62	0.70	1.05	350.2	750	14,250	926.5	1,601.0	1,745.5	144.5	9.0%
GSe	**Havelock**	1,000	**22.18**	**1.52**	**0.16**	**0.09**	**1.77**	39.9	**24.55**	**2.60**	**0.09**	**(0.06)**	**2.63**	50.9	**0.93**	0.62	0.7	1.0545	23.3	750	250	55.5	118.7	129.7	11.0	9.3%
		2,000	22.18	1.52	0.16	0.09	1.77	57.6	24.55	2.60	0.09	(0.06)	2.63	77.2	0.93	0.62	0.70	1.05	46.7	750	1,250	117.7	222.0	241.6	19.6	8.8%
		5,000	22.18	1.52	0.16	0.09	1.77	110.7	24.55	2.60	0.09	(0.06)	2.63	156.2	0.93	0.62	0.70	1.05	116.7	750	4,250	304.3	531.7	577.3	45.5	8.6%
		10,000	22.18	1.52	0.16	0.09	1.77	199.2	24.55	2.60	0.09	(0.06)	2.63	287.9	0.93	0.62	0.70	1.05	233.4	750	9,250	615.4	1,048.0	1,136.7	88.7	8.5%
		15,000	22.18	1.52	0.16	0.09	1.77	287.7	24.55	2.60	0.09	(0.06)	2.63	419.5	0.93	0.62	0.70	1.05	350.2	750	14,250	926.5	1,564.3	1,696.2	131.9	8.4%
GSe	**Kirkfield**	1,000	**14.69**	**1.95**	**0.61**	**0.44**	**3.00**	44.7	**18.42**	**3.21**	**0.44**	**(0.06)**	**3.59**	54.4	**0.93**	0.62	0.7	1.0545	23.3	750	250	55.5	123.5	133.2	9.7	7.8%
		2,000	14.69	1.95	0.61	0.44	3.00	74.7	18.42	3.21	0.44	(0.06)	3.59	90.3	0.93	0.62	0.70	1.05	46.7	750	1,250	117.7	239.1	254.7	15.6	6.5%
		5,000	14.69	1.95	0.61	0.44	3.00	164.7	18.42	3.21	0.44	(0.06)	3.59	198.1	0.93	0.62	0.70	1.05	116.7	750	4,250	304.3	585.7	619.2	33.4	5.7%
		10,000	14.69	1.95	0.61	0.44	3.00	314.7	18.42	3.21	0.44	(0.06)	3.59	377.8	0.93	0.62	0.70	1.05	233.4	750	9,250	615.4	1,163.5	1,226.6	63.1	5.4%
		15,000	14.69	1.95	0.61	0.44	3.00	464.7	18.42	3.21	0.44	(0.06)	3.59	557.5	0.93	0.62	0.70	1.05	350.2	750	14,250	926.5	1,741.3	1,834.1	92.8	5.3%
GSe	**Lanark Highlar**	1,000	**18.43**	**1.99**	**0.63**	**0.50**	**3.12**	49.6	**21.48**	**3.21**	**0.50**	**(0.06)**	**3.65**	58.0	**0.93**	0.62	0.7	1.0545	23.3	750	250	55.5	128.4	136.8	8.4	6.5%
		2,000	18.43	1.99	0.63	0.50	3.12	80.8	21.48	3.21	0.50	(0.06)	3.65	94.6	0.93	0.62	0.70	1.05	46.7	750	1,250	117.7	245.2	258.9	13.7	5.6%
		5,000	18.43	1.99	0.63	0.50	3.12	174.4	21.48	3.21	0.50	(0.06)	3.65	204.2	0.93	0.62	0.70	1.05	116.7	750	4,250	304.3	595.5	625.2	29.7	5.0%
		10,000	18.43	1.99	0.63	0.50	3.12	330.4	21.48	3.21	0.50	(0.06)	3.65	386.9	0.93	0.62	0.70	1.05	233.4	750	9,250	615.4	1,179.3	1,235.7	56.4	4.8%
		15,000	18.43	1.99	0.63	0.50	3.12	486.4	21.48	3.21	0.50	(0.06)	3.65	569.5	0.93	0.62	0.70	1.05	350.2	750	14,250	926.5	1,763.1	1,846.2	83.1	4.7%
GSe	**Larder Lake**	1,000	**20.18**	**1.58**	**0.51**	**0.36**	**2.45**	44.7	**23.05**	**3.05**	**0.36**	**(0.06)**	**3.35**	56.6	**0.93**	0.62	0.7	1.0545	23.3	750	250	55.5	123.5	135.4	11.9	9.6%
		2,000	20.18	1.58	0.51	0.36	2.45	69.2	23.05	3.05	0.36	(0.06)	3.35	90.1	0.93	0.62	0.70	1.05	46.7	750	1,250	117.7	233.6	254.5	20.9	9.0%
		5,000	20.18	1.58	0.51	0.36	2.45	142.7	23.05	3.05	0.36	(0.06)	3.35	190.7	0.93	0.62	0.70	1.05	116.7	750	4,250	304.3	563.7	611.8	48.0	8.5%
		10,000	20.18	1.58	0.51	0.36	2.45	265.2	23.05	3.05	0.36	(0.06)	3.35	358.4	0.93	0.62	0.70	1.05	233.4	750	9,250	615.4	1,114.0	1,207.2	93.2	8.4%
		15,000	20.18	1.58	0.51	0.36	2.45	387.7	23.05	3.05	0.36	(0.06)	3.35	526.0	0.93	0.62	0.70	1.05	350.2	750	14,250	926.5	1,664.3	1,802.7	138.4	8.3%

New Rate Class: GSe - Metered

Total Bill Impacts of Proposed Distribution Rates [ol RTSR+TLF]: Threshold of 750 kWhs

750.0

Classes		Scenario	May 2007 Incl Rate Riders						May 2008 Incl Rate Riders						Non-Dx Compoent				Other Reg	Commodity Bands			Existing	New	$ Incr	% Incr
			Existing Dx Rates					Existing Dx	New Dx Rates					New Dx	RTSR old	WMSC	DRC	TLF old	Old	Band 1	Band 2	Old	Total Bill	Total Bill	Total Bill	Total Bill
																				5.0	5.9					
New Class	Old Class	kWh	SrChg [$/cust]	base [c/kWh]	Rider1 [c/kWh]	Rider2 [c/kWh]	VarChg [c/kWh]	[$/month]	SrChg [$/cust]	base [c/kWh]	Rider2 [c/kWh]	Rider3 [c/kWh]	VarChg [c/kWh]	[$/month]	c/kWh	c/kWh	c/kWh		$	kWhs	kWhs	Total $	[$/month]	[$/month]	[$/month]	%
GSe	Latchford	1,000	**2.88**	**1.02**	**0.65**	**0.20**	**1.87**	21.6	**9.37**	**2.32**	**0.20**	**(0.06)**	**2.46**	34.0	**0.93**	0.62	0.7	1.0545	23.3	750	250	55.5	100.4	112.8	12.4	12.4%
		2,000	2.88	1.02	0.65	0.20	1.87	40.3	9.37	2.32	0.20	(0.06)	2.46	58.6	0.93	0.62	0.70	1.05	46.7	750	1,250	117.7	204.7	223.0	18.4	9.0%
		5,000	2.88	1.02	0.65	0.20	1.87	96.4	9.37	2.32	0.20	(0.06)	2.46	132.5	0.93	0.62	0.70	1.05	116.7	750	4,250	304.3	517.4	553.6	36.2	7.0%
		10,000	2.88	1.02	0.65	0.20	1.87	189.9	9.37	2.32	0.20	(0.06)	2.46	255.7	0.93	0.62	0.70	1.05	233.4	750	9,250	615.4	1,038.7	1,104.6	65.8	6.3%
		15,000	2.88	1.02	0.65	0.20	1.87	283.4	9.37	2.32	0.20	(0.06)	2.46	378.9	0.93	0.62	0.70	1.05	350.2	750	14,250	926.5	1,560.0	1,655.5	95.5	6.1%
UGe	Lindsay	1,000	**23.94**	**1.38**	**0.15**	**0.06**	**1.59**	39.8	**20.10**	**2.00**	**0.06**	**(0.06)**	**2.01**	40.2	**0.93**	0.62	0.7	1.0545	23.3	750	250	55.5	118.7	119.0	0.3	0.3%
		2,000	23.94	1.38	0.15	0.06	1.59	55.7	20.10	2.00	0.06	(0.06)	2.01	60.2	0.93	0.62	0.70	1.05	46.7	750	1,250	117.7	220.1	224.6	4.5	2.0%
		5,000	23.94	1.38	0.15	0.06	1.59	103.4	20.10	2.00	0.06	(0.06)	2.01	120.4	0.93	0.62	0.70	1.05	116.7	750	4,250	304.3	524.5	541.4	16.9	3.2%
		10,000	23.94	1.38	0.15	0.06	1.59	182.9	20.10	2.00	0.06	(0.06)	2.01	220.6	0.93	0.62	0.70	1.05	233.4	750	9,250	615.4	1,031.8	1,069.5	37.7	3.7%
		15,000	23.94	1.38	0.15	0.06	1.59	262.4	20.10	2.00	0.06	(0.06)	2.01	320.9	0.93	0.62	0.70	1.05	350.2	750	14,250	926.5	1,539.1	1,597.6	58.5	3.8%
GSe	Lucan Granton	1,000	**16.99**	**1.47**	**0.17**	**0.10**	**1.74**	34.4	**19.84**	**2.53**	**0.10**	**(0.06)**	**2.57**	45.6	**0.93**	0.62	0.7	1.0545	23.3	750	250	55.5	113.2	124.4	11.2	9.9%
		2,000	16.99	1.47	0.17	0.10	1.74	51.8	19.84	2.53	0.10	(0.06)	2.57	71.3	0.93	0.62	0.70	1.05	46.7	750	1,250	117.7	216.2	235.7	19.5	9.0%
		5,000	16.99	1.47	0.17	0.10	1.74	104.0	19.84	2.53	0.10	(0.06)	2.57	148.5	0.93	0.62	0.70	1.05	116.7	750	4,250	304.3	525.0	569.6	44.5	8.5%
		10,000	16.99	1.47	0.17	0.10	1.74	191.0	19.84	2.53	0.10	(0.06)	2.57	277.2	0.93	0.62	0.70	1.05	233.4	750	9,250	615.4	1,039.8	1,126.0	86.2	8.3%
		15,000	16.99	1.47	0.17	0.10	1.74	278.0	19.84	2.53	0.10	(0.06)	2.57	405.8	0.93	0.62	0.70	1.05	350.2	750	14,250	926.5	1,554.6	1,682.5	127.8	8.2%
GSe	Malahide	1,000	**15.84**	**1.98**	**0.81**	**0.49**	**3.28**	48.6	**19.13**	**3.21**	**0.49**	**(0.06)**	**3.64**	55.6	**0.93**	0.62	0.7	1.0545	23.3	750	250	55.5	127.5	134.4	6.9	5.4%
		2,000	15.84	1.98	0.81	0.49	3.28	81.4	19.13	3.21	0.49	(0.06)	3.64	92.0	0.93	0.62	0.70	1.05	46.7	750	1,250	117.7	245.8	256.4	10.6	4.3%
		5,000	15.84	1.98	0.81	0.49	3.28	179.8	19.13	3.21	0.49	(0.06)	3.64	201.3	0.93	0.62	0.70	1.05	116.7	750	4,250	304.3	600.9	622.4	21.5	3.6%
		10,000	15.84	1.98	0.81	0.49	3.28	343.8	19.13	3.21	0.49	(0.06)	3.64	383.5	0.93	0.62	0.70	1.05	233.4	750	9,250	615.4	1,192.7	1,232.4	39.7	3.3%
		15,000	15.84	1.98	0.81	0.49	3.28	507.8	19.13	3.21	0.49	(0.06)	3.64	565.7	0.93	0.62	0.70	1.05	350.2	750	14,250	926.5	1,784.5	1,842.3	57.9	3.2%
GSe	Mapleton	1,000	**21.55**	**1.71**	**0.40**	**0.29**	**2.40**	45.6	**23.70**	**3.11**	**0.29**	**(0.06)**	**3.34**	57.1	**0.93**	0.62	0.7	1.0545	23.3	750	250	55.5	124.4	135.9	11.6	9.3%
		2,000	21.55	1.71	0.40	0.29	2.40	69.6	23.70	3.11	0.29	(0.06)	3.34	90.6	0.93	0.62	0.70	1.05	46.7	750	1,250	117.7	233.9	254.9	21.0	9.0%
		5,000	21.55	1.71	0.40	0.29	2.40	141.6	23.70	3.11	0.29	(0.06)	3.34	190.9	0.93	0.62	0.70	1.05	116.7	750	4,250	304.3	562.6	611.9	49.3	8.8%
		10,000	21.55	1.71	0.40	0.29	2.40	261.6	23.70	3.11	0.29	(0.06)	3.34	358.0	0.93	0.62	0.70	1.05	233.4	750	9,250	615.4	1,110.4	1,206.9	96.5	8.7%
		15,000	21.55	1.71	0.40	0.29	2.40	381.6	23.70	3.11	0.29	(0.06)	3.34	525.2	0.93	0.62	0.70	1.05	350.2	750	14,250	926.5	1,658.2	1,801.8	143.6	8.7%

New Rate Class: GSe - Metered

Total Bill Impacts of Proposed Distribution Rates [ol RTSR+TLF]: Threshold of 750 kWhs

Classes		Scenario	May 2007 Incl Rate Riders						May 2008 Incl Rate Riders						Non-Dx Compoent				Other Reg	Commodity Bands			Existing	New	$ Incr	% Incr
			Existing Dx Rates					Existing Dx	New Dx Rates					New Dx	RTSR old	WMSC	DRC	TLF old	Old	Band 1	Band 2	Old	Total Bill	Total Bill	Total Bill	Total Bill
																				750.0						
																				5.0	5.9					
New Class	Old Class	kWh	SrChg [$/cust]	base [c/kWh]	Rider1 [c/kWh]	Rider2 [c/kWh]	VarChg [c/kWh]	[$/month]	SrChg [$/cust]	base [c/kWh]	Rider2 [c/kWh]	Rider3 [c/kWh]	VarChg [c/kWh]	[$/month]	c/kWh	c/kWh	c/kWh		$	kWhs	kWhs	Total $	[$/month]	[$/month]	[$/month]	%
GSe	Markdale	1,000	**23.00**	**0.80**	**0.15**	**0.04**	**0.99**	32.9	**25.34**	**1.82**	**0.04**	**(0.06)**	**1.80**	43.4	**0.93**	0.62	0.7	1.0545	23.3	750	250	55.5	111.7	122.2	10.5	9.4%
		2,000	23.00	0.80	0.15	0.04	0.99	42.8	25.34	1.82	0.04	(0.06)	1.80	61.4	0.93	0.62	0.70	1.05	46.7	750	1,250	117.7	207.2	225.8	18.6	9.0%
		5,000	23.00	0.80	0.15	0.04	0.99	72.5	25.34	1.82	0.04	(0.06)	1.80	115.5	0.93	0.62	0.70	1.05	116.7	750	4,250	304.3	493.6	536.6	43.0	8.7%
		10,000	23.00	0.80	0.15	0.04	0.99	122.0	25.34	1.82	0.04	(0.06)	1.80	205.7	0.93	0.62	0.70	1.05	233.4	750	9,250	615.4	970.9	1,054.5	83.7	8.6%
		15,000	23.00	0.80	0.15	0.04	0.99	171.5	25.34	1.82	0.04	(0.06)	1.80	295.8	0.93	0.62	0.70	1.05	350.2	750	14,250	926.5	1,448.2	1,572.5	124.3	8.6%
GSe	Marmora	1,000	**10.02**	**1.05**	**0.15**	**0.05**	**1.25**	22.5	**15.59**	**1.88**	**0.05**	**(0.06)**	**1.87**	34.3	**0.93**	0.62	0.7	1.0545	23.3	750	250	55.5	101.3	113.1	11.8	11.6%
		2,000	10.02	1.05	0.15	0.05	1.25	35.0	15.59	1.88	0.05	(0.06)	1.87	53.1	0.93	0.62	0.70	1.05	46.7	750	1,250	117.7	199.4	217.4	18.0	9.0%
		5,000	10.02	1.05	0.15	0.05	1.25	72.5	15.59	1.88	0.05	(0.06)	1.87	109.3	0.93	0.62	0.70	1.05	116.7	750	4,250	304.3	493.6	530.3	36.7	7.4%
		10,000	10.02	1.05	0.15	0.05	1.25	135.0	15.59	1.88	0.05	(0.06)	1.87	202.9	0.93	0.62	0.70	1.05	233.4	750	9,250	615.4	983.9	1,051.8	67.9	6.9%
		15,000	10.02	1.05	0.15	0.05	1.25	197.5	15.59	1.88	0.05	(0.06)	1.87	296.6	0.93	0.62	0.70	1.05	350.2	750	14,250	926.5	1,474.2	1,573.2	99.1	6.7%
GSe	McGarry	1,000	**19.99**	**2.00**	**0.57**	**0.50**	**3.07**	50.7	**22.09**	**3.21**	**0.50**	**(0.06)**	**3.65**	58.6	**0.93**	0.62	0.7	1.0545	23.3	750	250	55.5	129.5	137.4	7.9	6.1%
		2,000	19.99	2.00	0.57	0.50	3.07	81.4	22.09	3.21	0.50	(0.06)	3.65	95.2	0.93	0.62	0.70	1.05	46.7	750	1,250	117.7	245.8	259.5	13.8	5.6%
		5,000	19.99	2.00	0.57	0.50	3.07	173.5	22.09	3.21	0.50	(0.06)	3.65	204.8	0.93	0.62	0.70	1.05	116.7	750	4,250	304.3	594.5	625.8	31.3	5.3%
		10,000	19.99	2.00	0.57	0.50	3.07	327.0	22.09	3.21	0.50	(0.06)	3.65	387.5	0.93	0.62	0.70	1.05	233.4	750	9,250	615.4	1,175.8	1,236.3	60.5	5.1%
		15,000	19.99	2.00	0.57	0.50	3.07	480.5	22.09	3.21	0.50	(0.06)	3.65	570.2	0.93	0.62	0.70	1.05	350.2	750	14,250	926.5	1,757.1	1,846.8	89.7	5.1%
GSe	Meaford	1,000	**24.05**	**1.23**	**0.16**	**0.07**	**1.46**	38.7	**26.08**	**2.32**	**0.07**	**(0.06)**	**2.33**	49.4	**0.93**	0.62	0.7	1.0545	23.3	750	250	55.5	117.5	128.2	10.8	9.2%
		2,000	24.05	1.23	0.16	0.07	1.46	53.3	26.08	2.32	0.07	(0.06)	2.33	72.7	0.93	0.62	0.70	1.05	46.7	750	1,250	117.7	217.6	237.1	19.5	9.0%
		5,000	24.05	1.23	0.16	0.07	1.46	97.1	26.08	2.32	0.07	(0.06)	2.33	142.7	0.93	0.62	0.70	1.05	116.7	750	4,250	304.3	518.1	563.8	45.7	8.8%
		10,000	24.05	1.23	0.16	0.07	1.46	170.1	26.08	2.32	0.07	(0.06)	2.33	259.4	0.93	0.62	0.70	1.05	233.4	750	9,250	615.4	1,018.9	1,108.3	89.4	8.8%
		15,000	24.05	1.23	0.16	0.07	1.46	243.1	26.08	2.32	0.07	(0.06)	2.33	376.1	0.93	0.62	0.70	1.05	350.2	750	14,250	926.5	1,519.7	1,652.7	133.0	8.8%
GSe	Middlesex Cen	1,000	**17.35**	**1.37**	**0.44**	**0.35**	**2.16**	39.0	**20.75**	**2.70**	**0.35**	**(0.06)**	**2.99**	50.7	**0.93**	0.62	0.7	1.0545	23.3	750	250	55.5	117.8	129.5	11.7	10.0%
		2,000	17.35	1.37	0.44	0.35	2.16	60.6	20.75	2.70	0.35	(0.06)	2.99	80.6	0.93	0.62	0.70	1.05	46.7	750	1,250	117.7	224.9	245.0	20.1	8.9%
		5,000	17.35	1.37	0.44	0.35	2.16	125.4	20.75	2.70	0.35	(0.06)	2.99	170.4	0.93	0.62	0.70	1.05	116.7	750	4,250	304.3	546.4	591.5	45.1	8.2%
		10,000	17.35	1.37	0.44	0.35	2.16	233.4	20.75	2.70	0.35	(0.06)	2.99	320.1	0.93	0.62	0.70	1.05	233.4	750	9,250	615.4	1,082.2	1,168.9	86.7	8.0%
		15,000	17.35	1.37	0.44	0.35	2.16	341.4	20.75	2.70	0.35	(0.06)	2.99	469.7	0.93	0.62	0.70	1.05	350.2	750	14,250	926.5	1,618.0	1,746.4	128.4	7.9%

New Rate Class: GSe - Metered

Total Bill Impacts of Proposed Distribution Rates [ol RTSR+TLF]: Threshold of 750 kWhs

750.0

Classes: New Class	Classes: Old Class	Scenario: kWh	May 2007 Incl Rate Riders, Existing Dx Rates: SrChg	base	Rider1	Rider2	VarChg	Existing Dx	May 2008 Incl Rate Riders, New Dx Rates: SrChg	base	Rider2	Rider3	VarChg	New Dx	Non-Dx Compoent: RTSR old	WMSC	DRC	TLF old	Other Reg Old	Commodity Bands: Band 1 (5.0)	Band 2 (5.9)	Old Total $	Existing Total Bill	New Total Bill	$ Incr Total Bill	% Incr Total Bill
			[$/cust]	[c/kWh]	[c/kWh]	[c/kWh]	[c/kWh]	[$/month]	[$/cust]	[c/kWh]	[c/kWh]	[c/kWh]	[c/kWh]	[$/month]	c/kWh	c/kWh	c/kWh		$	kWhs	kWhs	Total $	[$/month]	[$/month]	[$/month]	%
GSe	**Napanee**	1,000	**22.17**	**1.28**	**0.16**	**0.06**	**1.50**	37.2	**24.55**	**2.35**	**0.06**	**(0.06)**	**2.35**	48.1	**0.93**	0.62	0.7	1.0545	23.3	750	250	55.5	116.0	126.9	10.9	9.4%
		2,000	22.17	1.28	0.16	0.06	1.50	52.2	24.55	2.35	0.06	(0.06)	2.35	71.6	0.93	0.62	0.70	1.05	46.7	750	1,250	117.7	216.5	236.0	19.4	9.0%
		5,000	22.17	1.28	0.16	0.06	1.50	97.2	24.55	2.35	0.06	(0.06)	2.35	142.2	0.93	0.62	0.70	1.05	116.7	750	4,250	304.3	518.2	563.3	45.0	8.7%
		10,000	22.17	1.28	0.16	0.06	1.50	172.2	24.55	2.35	0.06	(0.06)	2.35	259.9	0.93	0.62	0.70	1.05	233.4	750	9,250	615.4	1,021.0	1,108.7	87.7	8.6%
		15,000	22.17	1.28	0.16	0.06	1.50	247.2	24.55	2.35	0.06	(0.06)	2.35	377.5	0.93	0.62	0.70	1.05	350.2	750	14,250	926.5	1,523.8	1,654.2	130.4	8.6%
GSe	**Nipigon**	1,000	**23.32**	**1.05**	**0.34**	**0.21**	**1.60**	39.3	**25.26**	**2.34**	**0.21**	**(0.06)**	**2.49**	50.2	**0.93**	0.62	0.7	1.0545	23.3	750	250	55.5	118.1	129.0	10.9	9.2%
		2,000	23.32	1.05	0.34	0.21	1.60	55.3	25.26	2.34	0.21	(0.06)	2.49	75.1	0.93	0.62	0.70	1.05	46.7	750	1,250	117.7	219.7	239.5	19.8	9.0%
		5,000	23.32	1.05	0.34	0.21	1.60	103.3	25.26	2.34	0.21	(0.06)	2.49	149.9	0.93	0.62	0.70	1.05	116.7	750	4,250	304.3	524.4	571.0	46.6	8.9%
		10,000	23.32	1.05	0.34	0.21	1.60	183.3	25.26	2.34	0.21	(0.06)	2.49	274.6	0.93	0.62	0.70	1.05	233.4	750	9,250	615.4	1,032.2	1,123.4	91.3	8.8%
		15,000	23.32	1.05	0.34	0.21	1.60	263.3	25.26	2.34	0.21	(0.06)	2.49	399.3	0.93	0.62	0.70	1.05	350.2	750	14,250	926.5	1,540.0	1,675.9	135.9	8.8%
GSe	**North Dorches**	1,000	**15.88**	**0.90**	**0.35**	**0.26**	**1.51**	31.0	**19.12**	**2.08**	**0.26**	**(0.06)**	**2.28**	42.0	**0.93**	0.62	0.7	1.0545	23.3	750	250	55.5	109.8	120.8	11.0	10.0%
		2,000	15.88	0.90	0.35	0.26	1.51	46.1	19.12	2.08	0.26	(0.06)	2.28	64.8	0.93	0.62	0.70	1.05	46.7	750	1,250	117.7	210.5	229.2	18.7	8.9%
		5,000	15.88	0.90	0.35	0.26	1.51	91.4	19.12	2.08	0.26	(0.06)	2.28	133.3	0.93	0.62	0.70	1.05	116.7	750	4,250	304.3	512.4	554.3	41.9	8.2%
		10,000	15.88	0.90	0.35	0.26	1.51	166.9	19.12	2.08	0.26	(0.06)	2.28	247.4	0.93	0.62	0.70	1.05	233.4	750	9,250	615.4	1,015.7	1,096.3	80.6	7.9%
		15,000	15.88	0.90	0.35	0.26	1.51	242.4	19.12	2.08	0.26	(0.06)	2.28	361.6	0.93	0.62	0.70	1.05	350.2	750	14,250	926.5	1,519.0	1,638.3	119.2	7.8%
GSe	**North Dundas**	1,000	**13.52**	**0.83**	**0.16**	**0.04**	**1.03**	23.8	**17.71**	**1.72**	**0.04**	**(0.06)**	**1.70**	34.7	**0.93**	0.62	0.7	1.0545	23.3	750	250	55.5	102.6	113.6	10.9	10.6%
		2,000	13.52	0.83	0.16	0.04	1.03	34.1	17.71	1.72	0.04	(0.06)	1.70	51.8	0.93	0.62	0.70	1.05	46.7	750	1,250	117.7	198.5	216.1	17.7	8.9%
		5,000	13.52	0.83	0.16	0.04	1.03	65.0	17.71	1.72	0.04	(0.06)	1.70	102.9	0.93	0.62	0.70	1.05	116.7	750	4,250	304.3	486.1	523.9	37.9	7.8%
		10,000	13.52	0.83	0.16	0.04	1.03	116.5	17.71	1.72	0.04	(0.06)	1.70	188.0	0.93	0.62	0.70	1.05	233.4	750	9,250	615.4	965.4	1,036.9	71.5	7.4%
		15,000	13.52	0.83	0.16	0.04	1.03	168.0	17.71	1.72	0.04	(0.06)	1.70	273.2	0.93	0.62	0.70	1.05	350.2	750	14,250	926.5	1,444.7	1,549.9	105.2	7.3%
GSe	**North Glengarı**	1,000	**17.72**	**0.90**	**0.21**	**0.12**	**1.23**	30.0	**20.66**	**1.95**	**0.12**	**(0.06)**	**2.01**	40.8	**0.93**	0.62	0.7	1.0545	23.3	750	250	55.5	108.8	119.6	10.8	9.9%
		2,000	17.72	0.90	0.21	0.12	1.23	42.3	20.66	1.95	0.12	(0.06)	2.01	60.9	0.93	0.62	0.70	1.05	46.7	750	1,250	117.7	206.7	225.3	18.6	9.0%
		5,000	17.72	0.90	0.21	0.12	1.23	79.2	20.66	1.95	0.12	(0.06)	2.01	121.3	0.93	0.62	0.70	1.05	116.7	750	4,250	304.3	500.3	542.4	42.1	8.4%
		10,000	17.72	0.90	0.21	0.12	1.23	140.7	20.66	1.95	0.12	(0.06)	2.01	222.0	0.93	0.62	0.70	1.05	233.4	750	9,250	615.4	989.6	1,070.8	81.3	8.2%
		15,000	17.72	0.90	0.21	0.12	1.23	202.2	20.66	1.95	0.12	(0.06)	2.01	322.7	0.93	0.62	0.70	1.05	350.2	750	14,250	926.5	1,478.9	1,599.3	120.4	8.1%

New Rate Class: GSe - Metered

Total Bill Impacts of Proposed Distribution Rates [ol RTSR+TLF]: Threshold of 750 kWhs

750.0

Classes		Scenario	May 2007 Incl Rate Riders						May 2008 Incl Rate Riders						Non-Dx Compoent				Other Reg	Commodity Bands			Existing	New	$ Incr	% Incr
			Existing Dx Rates					Existing Dx	New Dx Rates					New Dx	RTSR old	WMSC	DRC	TLF old	Old	Band 1	Band 2	Old	Total Bill	Total Bill	Total Bill	Total Bill
																				5.0	5.9					
New Class	Old Class	kWh	SrChg [$/cust]	base [c/kWh]	Rider1 [c/kWh]	Rider2 [c/kWh]	VarChg [c/kWh]	[$/month]	SrChg [$/cust]	base [c/kWh]	Rider2 [c/kWh]	Rider3 [c/kWh]	VarChg [c/kWh]	[$/month]	c/kWh	c/kWh	c/kWh		$	kWhs	kWhs	Total $	[$/month]	[$/month]	[$/month]	%
GSe	**North Grenville**	1,000	**20.42**	**1.71**	**0.14**	**0.08**	**1.93**	39.7	**22.99**	**2.79**	**0.08**	**(0.06)**	**2.81**	51.1	**0.93**	0.62	0.7	1.0545	23.3	750	250	55.5	118.5	129.9	11.4	9.6%
		2,000	20.42	1.71	0.14	0.08	1.93	59.0	22.99	2.79	0.08	(0.06)	2.81	79.3	0.93	0.62	0.70	1.05	46.7	750	1,250	117.7	223.4	243.6	20.2	9.1%
		5,000	20.42	1.71	0.14	0.08	1.93	116.9	22.99	2.79	0.08	(0.06)	2.81	163.7	0.93	0.62	0.70	1.05	116.7	750	4,250	304.3	538.0	584.7	46.7	8.7%
		10,000	20.42	1.71	0.14	0.08	1.93	213.4	22.99	2.79	0.08	(0.06)	2.81	304.3	0.93	0.62	0.70	1.05	233.4	750	9,250	615.4	1,062.3	1,153.2	90.9	8.6%
		15,000	20.42	1.71	0.14	0.08	1.93	309.9	22.99	2.79	0.08	(0.06)	2.81	445.0	0.93	0.62	0.70	1.05	350.2	750	14,250	926.5	1,586.6	1,721.6	135.1	8.5%
GSe	**North Perth**	1,000	**29.52**	**1.00**	**0.12**	**0.04**	**1.16**	41.1	**29.71**	**2.15**	**0.04**	**(0.06)**	**2.13**	51.0	**0.93**	0.62	0.7	1.0545	23.3	750	250	55.5	119.9	129.9	9.9	8.3%
		2,000	29.52	1.00	0.12	0.04	1.16	52.7	29.71	2.15	0.04	(0.06)	2.13	72.4	0.93	0.62	0.70	1.05	46.7	750	1,250	117.7	217.1	236.7	19.7	9.1%
		5,000	29.52	1.00	0.12	0.04	1.16	87.5	29.71	2.15	0.04	(0.06)	2.13	136.4	0.93	0.62	0.70	1.05	116.7	750	4,250	304.3	508.6	557.4	48.9	9.6%
		10,000	29.52	1.00	0.12	0.04	1.16	145.5	29.71	2.15	0.04	(0.06)	2.13	243.0	0.93	0.62	0.70	1.05	233.4	750	9,250	615.4	994.4	1,091.9	97.5	9.8%
		15,000	29.52	1.00	0.12	0.04	1.16	203.5	29.71	2.15	0.04	(0.06)	2.13	349.7	0.93	0.62	0.70	1.05	350.2	750	14,250	926.5	1,480.2	1,626.4	146.2	9.9%
GSe	**North Stormon**	1,000	**5.37**	**0.78**	**0.37**	**0.26**	**1.41**	19.5	**11.75**	**1.78**	**0.26**	**(0.06)**	**1.98**	31.6	**0.93**	0.62	0.7	1.0545	23.3	750	250	55.5	98.3	110.4	12.1	12.3%
		2,000	5.37	0.78	0.37	0.26	1.41	33.6	11.75	1.78	0.26	(0.06)	1.98	51.4	0.93	0.62	0.70	1.05	46.7	750	1,250	117.7	197.9	215.8	17.8	9.0%
		5,000	5.37	0.78	0.37	0.26	1.41	75.9	11.75	1.78	0.26	(0.06)	1.98	110.9	0.93	0.62	0.70	1.05	116.7	750	4,250	304.3	496.9	532.0	35.0	7.1%
		10,000	5.37	0.78	0.37	0.26	1.41	146.4	11.75	1.78	0.26	(0.06)	1.98	210.1	0.93	0.62	0.70	1.05	233.4	750	9,250	615.4	995.2	1,058.9	63.7	6.4%
		15,000	5.37	0.78	0.37	0.26	1.41	216.9	11.75	1.78	0.26	(0.06)	1.98	309.2	0.93	0.62	0.70	1.05	350.2	750	14,250	926.5	1,493.5	1,585.9	92.4	6.2%
GSe	**Omemee**	1,000	**21.28**	**1.47**	**0.18**	**0.09**	**1.74**	38.7	**23.77**	**2.55**	**0.09**	**(0.06)**	**2.58**	49.6	**0.93**	0.62	0.7	1.0545	23.3	750	250	55.5	117.5	128.4	10.9	9.3%
		2,000	21.28	1.47	0.18	0.09	1.74	56.1	23.77	2.55	0.09	(0.06)	2.58	75.4	0.93	0.62	0.70	1.05	46.7	750	1,250	117.7	220.5	239.8	19.4	8.8%
		5,000	21.28	1.47	0.18	0.09	1.74	108.3	23.77	2.55	0.09	(0.06)	2.58	152.9	0.93	0.62	0.70	1.05	116.7	750	4,250	304.3	529.3	574.0	44.7	8.4%
		10,000	21.28	1.47	0.18	0.09	1.74	195.3	23.77	2.55	0.09	(0.06)	2.58	282.1	0.93	0.62	0.70	1.05	233.4	750	9,250	615.4	1,044.1	1,131.0	86.8	8.3%
		15,000	21.28	1.47	0.18	0.09	1.74	282.3	23.77	2.55	0.09	(0.06)	2.58	411.3	0.93	0.62	0.70	1.05	350.2	750	14,250	926.5	1,558.9	1,687.9	129.0	8.3%
UGe	**Perth**	1,000	**19.92**	**0.92**	**0.13**	**0.04**	**1.09**	30.8	**17.10**	**2.00**	**0.04**	**(0.06)**	**1.99**	37.0	**0.93**	0.62	0.7	1.0545	23.3	750	250	55.5	109.6	115.8	6.1	5.6%
		2,000	19.92	0.92	0.13	0.04	1.09	41.7	17.10	2.00	0.04	(0.06)	1.99	56.8	0.93	0.62	0.70	1.05	46.7	750	1,250	117.7	206.1	221.2	15.1	7.3%
		5,000	19.92	0.92	0.13	0.04	1.09	74.4	17.10	2.00	0.04	(0.06)	1.99	116.4	0.93	0.62	0.70	1.05	116.7	750	4,250	304.3	495.5	537.4	42.0	8.5%
		10,000	19.92	0.92	0.13	0.04	1.09	128.9	17.10	2.00	0.04	(0.06)	1.99	215.6	0.93	0.62	0.70	1.05	233.4	750	9,250	615.4	977.8	1,064.5	86.7	8.9%
		15,000	19.92	0.92	0.13	0.04	1.09	183.4	17.10	2.00	0.04	(0.06)	1.99	314.9	0.93	0.62	0.70	1.05	350.2	750	14,250	926.5	1,460.1	1,591.6	131.5	9.0%

New Rate Class: GSe - Metered

Total Bill Impacts of Proposed Distribution Rates [ol RTSR+TLF]: Threshold of 750 kWhs

Classes		Scenario	May 2007 Incl Rate Riders						May 2008 Incl Rate Riders						Non-Dx Compoent				Other Reg	Commodity Bands (750.0)			Existing	New	$ Incr	% Incr
			Existing Dx Rates					Existing Dx	New Dx Rates					New Dx	RTSR old	WMSC	DRC	TLF old	Old	Band 1 (5.0)	Band 2 (5.9)	Old	Total Bill	Total Bill	Total Bill	Total Bill
New Class	Old Class	kWh	SrChg [$/cust]	base [c/kWh]	Rider1 [c/kWh]	Rider2 [c/kWh]	VarChg [c/kWh]	[$/month]	SrChg [$/cust]	base [c/kWh]	Rider2 [c/kWh]	Rider3 [c/kWh]	VarChg [c/kWh]	[$/month]	c/kWh	c/kWh	c/kWh		$	kWhs	kWhs	Total $	[$/month]	[$/month]	[$/month]	%
GSe	**Perth East**	1,000	**14.65**	**1.29**	**0.16**	**0.09**	**1.54**	30.1	**18.43**	**2.25**	**0.09**	**(0.06)**	**2.28**	41.3	**0.93**	0.62	0.7	1.0545	23.3	750	250	55.5	108.9	120.1	11.2	10.3%
		2,000	14.65	1.29	0.16	0.09	1.54	45.5	18.43	2.25	0.09	(0.06)	2.28	64.1	0.93	0.62	0.70	1.05	46.7	750	1,250	117.7	209.8	228.5	18.6	8.9%
		5,000	14.65	1.29	0.16	0.09	1.54	91.7	18.43	2.25	0.09	(0.06)	2.28	132.6	0.93	0.62	0.70	1.05	116.7	750	4,250	304.3	512.7	553.6	40.9	8.0%
		10,000	14.65	1.29	0.16	0.09	1.54	168.7	18.43	2.25	0.09	(0.06)	2.28	246.8	0.93	0.62	0.70	1.05	233.4	750	9,250	615.4	1,017.5	1,095.6	78.1	7.7%
		15,000	14.65	1.29	0.16	0.09	1.54	245.7	18.43	2.25	0.09	(0.06)	2.28	360.9	0.93	0.62	0.70	1.05	350.2	750	14,250	926.5	1,522.3	1,637.6	115.3	7.6%
GSe	**Prince Edward**	1,000	**22.85**	**1.42**	**0.18**	**0.08**	**1.68**	39.7	**24.38**	**2.57**	**0.08**	**(0.06)**	**2.59**	50.3	**0.93**	0.62	0.7	1.0545	23.3	750	250	55.5	118.5	129.1	10.7	9.0%
		2,000	22.85	1.42	0.18	0.08	1.68	56.5	24.38	2.57	0.08	(0.06)	2.59	76.2	0.93	0.62	0.70	1.05	46.7	750	1,250	117.7	220.8	240.6	19.8	9.0%
		5,000	22.85	1.42	0.18	0.08	1.68	106.9	24.38	2.57	0.08	(0.06)	2.59	154.0	0.93	0.62	0.70	1.05	116.7	750	4,250	304.3	527.9	575.1	47.2	8.9%
		10,000	22.85	1.42	0.18	0.08	1.68	190.9	24.38	2.57	0.08	(0.06)	2.59	283.7	0.93	0.62	0.70	1.05	233.4	750	9,250	615.4	1,039.7	1,132.6	92.9	8.9%
		15,000	22.85	1.42	0.18	0.08	1.68	274.9	24.38	2.57	0.08	(0.06)	2.59	413.4	0.93	0.62	0.70	1.05	350.2	750	14,250	926.5	1,551.5	1,690.0	138.5	8.9%
UGe	**Quinte West**	1,000	**3.74**	**1.05**	**0.14**	**0.06**	**1.25**	16.2	**5.15**	**2.00**	**0.06**	**(0.06)**	**2.01**	25.2	**0.93**	0.62	0.7	1.0545	23.3	750	250	55.5	95.1	104.0	9.0	9.4%
		2,000	3.74	1.05	0.14	0.06	1.25	28.7	5.15	2.00	0.06	(0.06)	2.01	45.3	0.93	0.62	0.70	1.05	46.7	750	1,250	117.7	193.1	209.6	16.5	8.6%
		5,000	3.74	1.05	0.14	0.06	1.25	66.2	5.15	2.00	0.06	(0.06)	2.01	105.4	0.93	0.62	0.70	1.05	116.7	750	4,250	304.3	487.3	526.5	39.2	8.0%
		10,000	3.74	1.05	0.14	0.06	1.25	128.7	5.15	2.00	0.06	(0.06)	2.01	205.7	0.93	0.62	0.70	1.05	233.4	750	9,250	615.4	977.6	1,054.5	76.9	7.9%
		15,000	3.74	1.05	0.14	0.06	1.25	191.2	5.15	2.00	0.06	(0.06)	2.01	306.0	0.93	0.62	0.70	1.05	350.2	750	14,250	926.5	1,467.9	1,582.6	114.7	7.8%
GSe	**Rainy River**	1,000	**19.29**	**1.76**	**0.45**	**0.36**	**2.57**	45.0	**22.27**	**3.18**	**0.36**	**(0.06)**	**3.48**	57.1	**0.93**	0.62	0.7	1.0545	23.3	750	250	55.5	123.8	135.9	12.1	9.8%
		2,000	19.29	1.76	0.45	0.36	2.57	70.7	22.27	3.18	0.36	(0.06)	3.48	91.9	0.93	0.62	0.70	1.05	46.7	750	1,250	117.7	235.1	256.3	21.2	9.0%
		5,000	19.29	1.76	0.45	0.36	2.57	147.8	22.27	3.18	0.36	(0.06)	3.48	196.4	0.93	0.62	0.70	1.05	116.7	750	4,250	304.3	568.8	617.5	48.6	8.6%
		10,000	19.29	1.76	0.45	0.36	2.57	276.3	22.27	3.18	0.36	(0.06)	3.48	370.6	0.93	0.62	0.70	1.05	233.4	750	9,250	615.4	1,125.1	1,219.4	94.3	8.4%
		15,000	19.29	1.76	0.45	0.36	2.57	404.8	22.27	3.18	0.36	(0.06)	3.48	544.8	0.93	0.62	0.70	1.05	350.2	750	14,250	926.5	1,681.4	1,821.4	140.0	8.3%
GSe	**Ramara**	1,000	**20.97**	**1.06**	**0.45**	**0.37**	**1.88**	39.8	**22.85**	**2.48**	**0.37**	**(0.06)**	**2.79**	50.8	**0.93**	0.62	0.7	1.0545	23.3	750	250	55.5	118.6	129.6	11.0	9.3%
		2,000	20.97	1.06	0.45	0.37	1.88	58.6	22.85	2.48	0.37	(0.06)	2.79	78.7	0.93	0.62	0.70	1.05	46.7	750	1,250	117.7	222.9	243.1	20.1	9.0%
		5,000	20.97	1.06	0.45	0.37	1.88	115.0	22.85	2.48	0.37	(0.06)	2.79	162.5	0.93	0.62	0.70	1.05	116.7	750	4,250	304.3	536.0	583.6	47.5	8.9%
		10,000	20.97	1.06	0.45	0.37	1.88	209.0	22.85	2.48	0.37	(0.06)	2.79	302.2	0.93	0.62	0.70	1.05	233.4	750	9,250	615.4	1,057.8	1,151.0	93.2	8.8%
		15,000	20.97	1.06	0.45	0.37	1.88	303.0	22.85	2.48	0.37	(0.06)	2.79	441.8	0.93	0.62	0.70	1.05	350.2	750	14,250	926.5	1,579.6	1,718.5	138.9	8.8%

New Rate Class: GSe - Metered

Total Bill Impacts of Proposed Distribution Rates [ol RTSR+TLF]: Threshold of 750 kWhs

750.0

Classes		Scenario	May 2007 Incl Rate Riders						May 2008 Incl Rate Riders						Non-Dx Compoent				Other Reg	Commodity Bands			Existing	New	$ Incr	% Incr
			Existing Dx Rates					Existing Dx	New Dx Rates					New Dx	RTSR old	WMSC	DRC	TLF old	Old	Band 1	Band 2	Old	Total Bill	Total Bill	Total Bill	Total Bill
																				5.0	5.9					
New Class	Old Class	kWh	SrChg [$/cust]	base [c/kWh]	Rider1 [c/kWh]	Rider2 [c/kWh]	VarChg [c/kWh]	[$/month]	SrChg [$/cust]	base [c/kWh]	Rider2 [c/kWh]	Rider3 [c/kWh]	VarChg [c/kWh]	[$/month]	c/kWh	c/kWh	c/kWh		$	kWhs	kWhs	Total $	[$/month]	[$/month]	[$/month]	%
GSe	Red Rock	1,000	**21.64**	**1.94**	**0.27**	**0.24**	**2.45**	46.1	**23.68**	**3.21**	**0.24**	**(0.06)**	**3.39**	57.6	**0.93**	0.62	0.7	1.0545	23.3	750	250	55.5	125.0	136.4	11.5	9.2%
		2,000	21.64	1.94	0.27	0.24	2.45	70.6	23.68	3.21	0.24	(0.06)	3.39	91.6	0.93	0.62	0.70	1.05	46.7	750	1,250	117.7	235.0	255.9	20.9	8.9%
		5,000	21.64	1.94	0.27	0.24	2.45	144.1	23.68	3.21	0.24	(0.06)	3.39	193.4	0.93	0.62	0.70	1.05	116.7	750	4,250	304.3	565.2	614.4	49.2	8.7%
		10,000	21.64	1.94	0.27	0.24	2.45	266.6	23.68	3.21	0.24	(0.06)	3.39	363.1	0.93	0.62	0.70	1.05	233.4	750	9,250	615.4	1,115.5	1,211.9	96.4	8.6%
		15,000	21.64	1.94	0.27	0.24	2.45	389.1	23.68	3.21	0.24	(0.06)	3.39	532.7	0.93	0.62	0.70	1.05	350.2	750	14,250	926.5	1,665.8	1,809.4	143.6	8.6%
GSe	Rockland	1,000	**7.27**	**1.00**	**0.17**	**0.22**	**1.39**	21.2	**13.27**	**1.80**	**0.22**	**(0.06)**	**1.96**	32.9	**0.93**	0.62	0.7	1.0545	23.3	750	250	55.5	100.0	111.7	11.7	11.7%
		2,000	7.27	1.00	0.17	0.22	1.39	35.1	13.27	1.80	0.22	(0.06)	1.96	52.5	0.93	0.62	0.70	1.05	46.7	750	1,250	117.7	199.4	216.9	17.5	8.8%
		5,000	7.27	1.00	0.17	0.22	1.39	76.8	13.27	1.80	0.22	(0.06)	1.96	111.4	0.93	0.62	0.70	1.05	116.7	750	4,250	304.3	497.8	532.5	34.7	7.0%
		10,000	7.27	1.00	0.17	0.22	1.39	146.3	13.27	1.80	0.22	(0.06)	1.96	209.6	0.93	0.62	0.70	1.05	233.4	750	9,250	615.4	995.1	1,058.5	63.3	6.4%
		15,000	7.27	1.00	0.17	0.22	1.39	215.8	13.27	1.80	0.22	(0.06)	1.96	307.8	0.93	0.62	0.70	1.05	350.2	750	14,250	926.5	1,492.4	1,584.4	92.0	6.2%
GSe	Russell	1,000	**19.26**	**2.24**	**0.18**	**0.11**	**2.53**	44.6	**22.28**	**3.21**	**0.11**	**(0.06)**	**3.26**	54.9	**0.93**	0.62	0.7	1.0545	23.3	750	250	55.5	123.4	133.7	10.4	8.4%
		2,000	19.26	2.24	0.18	0.11	2.53	69.9	22.28	3.21	0.11	(0.06)	3.26	87.6	0.93	0.62	0.70	1.05	46.7	750	1,250	117.7	234.2	251.9	17.7	7.6%
		5,000	19.26	2.24	0.18	0.11	2.53	145.8	22.28	3.21	0.11	(0.06)	3.26	185.5	0.93	0.62	0.70	1.05	116.7	750	4,250	304.3	566.8	606.5	39.7	7.0%
		10,000	19.26	2.24	0.18	0.11	2.53	272.3	22.28	3.21	0.11	(0.06)	3.26	348.7	0.93	0.62	0.70	1.05	233.4	750	9,250	615.4	1,121.1	1,197.5	76.4	6.8%
		15,000	19.26	2.24	0.18	0.11	2.53	398.8	22.28	3.21	0.11	(0.06)	3.26	511.8	0.93	0.62	0.70	1.05	350.2	750	14,250	926.5	1,675.4	1,788.5	113.1	6.7%
GSe	Schreiber	1,000	**20.70**	**2.51**	**0.50**	**0.40**	**3.41**	54.8	**22.92**	**3.21**	**0.40**	**(0.06)**	**3.55**	58.5	**0.93**	0.62	0.7	1.0545	23.3	750	250	55.5	133.6	137.3	3.7	2.7%
		2,000	20.70	2.51	0.50	0.40	3.41	88.9	22.92	3.21	0.40	(0.06)	3.55	94.0	0.93	0.62	0.70	1.05	46.7	750	1,250	117.7	253.3	258.4	5.1	2.0%
		5,000	20.70	2.51	0.50	0.40	3.41	191.2	22.92	3.21	0.40	(0.06)	3.55	200.6	0.93	0.62	0.70	1.05	116.7	750	4,250	304.3	612.3	621.7	9.4	1.5%
		10,000	20.70	2.51	0.50	0.40	3.41	361.7	22.92	3.21	0.40	(0.06)	3.55	378.3	0.93	0.62	0.70	1.05	233.4	750	9,250	615.4	1,210.6	1,227.1	16.6	1.4%
		15,000	20.70	2.51	0.50	0.40	3.41	532.2	22.92	3.21	0.40	(0.06)	3.55	556.0	0.93	0.62	0.70	1.05	350.2	750	14,250	926.5	1,808.9	1,832.6	23.8	1.3%
GSe	Severn	1,000	**22.17**	**1.06**	**0.31**	**0.22**	**1.59**	38.1	**24.55**	**2.30**	**0.22**	**(0.06)**	**2.46**	49.2	**0.93**	0.62	0.7	1.0545	23.3	750	250	55.5	116.9	128.0	11.1	9.5%
		2,000	22.17	1.06	0.31	0.22	1.59	54.0	24.55	2.30	0.22	(0.06)	2.46	73.8	0.93	0.62	0.70	1.05	46.7	750	1,250	117.7	218.3	238.2	19.8	9.1%
		5,000	22.17	1.06	0.31	0.22	1.59	101.7	24.55	2.30	0.22	(0.06)	2.46	147.7	0.93	0.62	0.70	1.05	116.7	750	4,250	304.3	522.7	568.8	46.0	8.8%
		10,000	22.17	1.06	0.31	0.22	1.59	181.2	24.55	2.30	0.22	(0.06)	2.46	270.9	0.93	0.62	0.70	1.05	233.4	750	9,250	615.4	1,030.0	1,119.7	89.7	8.7%
		15,000	22.17	1.06	0.31	0.22	1.59	260.7	24.55	2.30	0.22	(0.06)	2.46	394.0	0.93	0.62	0.70	1.05	350.2	750	14,250	926.5	1,537.3	1,670.7	133.4	8.7%

New Rate Class: GSe - Metered

Total Bill Impacts of Proposed Distribution Rates [ol RTSR+TLF]: Threshold of 750 kWhs

Classes		Scenario	May 2007 Incl Rate Riders						May 2008 Incl Rate Riders						Non-Dx Compoent				Other Reg	Commodity Bands (750.0)			Existing	New	$ Incr	% Incr
			Existing Dx Rates					Existing Dx	New Dx Rates					New Dx	RTSR old	WMSC	DRC	TLF old	Old	Band 1	Band 2	Old	Total Bill	Total Bill	Total Bill	Total Bill
																				5.0	5.9					
New Class	Old Class	kWh	SrChg [$/cust]	base [c/kWh]	Rider1 [c/kWh]	Rider2 [c/kWh]	VarChg [c/kWh]	[$/month]	SrChg [$/cust]	base [c/kWh]	Rider2 [c/kWh]	Rider3 [c/kWh]	VarChg [c/kWh]	[$/month]	c/kWh	c/kWh	c/kWh		$	kWhs	kWhs	Total $	[$/month]	[$/month]	[$/month]	%
GSe	Shelburne	1,000	**20.01**	**0.87**	**0.10**	**0.02**	**0.99**	29.9	**23.09**	**1.79**	**0.02**	**(0.06)**	**1.75**	40.6	**0.93**	0.62	0.7	1.0545	23.3	750	250	55.5	108.7	119.4	10.7	9.9%
		2,000	20.01	0.87	0.10	0.02	0.99	39.8	23.09	1.79	0.02	(0.06)	1.75	58.2	0.93	0.62	0.70	1.05	46.7	750	1,250	117.7	204.2	222.5	18.3	9.0%
		5,000	20.01	0.87	0.10	0.02	0.99	69.5	23.09	1.79	0.02	(0.06)	1.75	110.8	0.93	0.62	0.70	1.05	116.7	750	4,250	304.3	490.6	531.8	41.2	8.4%
		10,000	20.01	0.87	0.10	0.02	0.99	119.0	23.09	1.79	0.02	(0.06)	1.75	198.4	0.93	0.62	0.70	1.05	233.4	750	9,250	615.4	967.9	1,047.3	79.4	8.2%
		15,000	20.01	0.87	0.10	0.02	0.99	168.5	23.09	1.79	0.02	(0.06)	1.75	286.1	0.93	0.62	0.70	1.05	350.2	750	14,250	926.5	1,445.2	1,562.7	117.6	8.1%
UGe	Smiths Falls	1,000	**9.84**	**1.05**	**0.12**	**0.04**	**1.21**	21.9	**9.62**	**2.00**	**0.04**	**(0.06)**	**1.99**	29.5	**0.93**	0.62	0.7	1.0545	23.3	750	250	55.5	100.8	108.3	7.5	7.5%
		2,000	9.84	1.05	0.12	0.04	1.21	34.0	9.62	2.00	0.04	(0.06)	1.99	49.3	0.93	0.62	0.70	1.05	46.7	750	1,250	117.7	198.4	213.7	15.3	7.7%
		5,000	9.84	1.05	0.12	0.04	1.21	70.3	9.62	2.00	0.04	(0.06)	1.99	108.9	0.93	0.62	0.70	1.05	116.7	750	4,250	304.3	491.4	529.9	38.6	7.8%
		10,000	9.84	1.05	0.12	0.04	1.21	130.8	9.62	2.00	0.04	(0.06)	1.99	208.2	0.93	0.62	0.70	1.05	233.4	750	9,250	615.4	979.7	1,057.0	77.3	7.9%
		15,000	9.84	1.05	0.12	0.04	1.21	191.3	9.62	2.00	0.04	(0.06)	1.99	307.4	0.93	0.62	0.70	1.05	350.2	750	14,250	926.5	1,468.0	1,584.1	116.1	7.9%
GSe	South Glengar	1,000	**17.41**	**0.75**	**0.37**	**0.30**	**1.42**	31.6	**20.74**	**1.96**	**0.30**	**(0.06)**	**2.20**	42.8	**0.93**	0.62	0.7	1.0545	23.3	750	250	55.5	110.4	121.6	11.2	10.1%
		2,000	17.41	0.75	0.37	0.30	1.42	45.8	20.74	1.96	0.30	(0.06)	2.20	64.8	0.93	0.62	0.70	1.05	46.7	750	1,250	117.7	210.2	229.2	19.0	9.0%
		5,000	17.41	0.75	0.37	0.30	1.42	88.4	20.74	1.96	0.30	(0.06)	2.20	130.9	0.93	0.62	0.70	1.05	116.7	750	4,250	304.3	509.5	552.0	42.5	8.3%
		10,000	17.41	0.75	0.37	0.30	1.42	159.4	20.74	1.96	0.30	(0.06)	2.20	241.1	0.93	0.62	0.70	1.05	233.4	750	9,250	615.4	1,008.3	1,089.9	81.7	8.1%
		15,000	17.41	0.75	0.37	0.30	1.42	230.4	20.74	1.96	0.30	(0.06)	2.20	351.2	0.93	0.62	0.70	1.05	350.2	750	14,250	926.5	1,507.1	1,627.9	120.8	8.0%
GSe	South River	1,000	**22.11**	**1.58**	**0.39**	**0.30**	**2.27**	44.8	**24.56**	**2.95**	**0.30**	**(0.06)**	**3.19**	56.5	**0.93**	0.62	0.7	1.0545	23.3	750	250	55.5	123.6	135.3	11.7	9.5%
		2,000	22.11	1.58	0.39	0.30	2.27	67.5	24.56	2.95	0.30	(0.06)	3.19	88.4	0.93	0.62	0.70	1.05	46.7	750	1,250	117.7	231.9	252.8	20.9	9.0%
		5,000	22.11	1.58	0.39	0.30	2.27	135.6	24.56	2.95	0.30	(0.06)	3.19	184.2	0.93	0.62	0.70	1.05	116.7	750	4,250	304.3	556.7	605.3	48.6	8.7%
		10,000	22.11	1.58	0.39	0.30	2.27	249.1	24.56	2.95	0.30	(0.06)	3.19	343.9	0.93	0.62	0.70	1.05	233.4	750	9,250	615.4	1,098.0	1,192.7	94.8	8.6%
		15,000	22.11	1.58	0.39	0.30	2.27	362.6	24.56	2.95	0.30	(0.06)	3.19	503.6	0.93	0.62	0.70	1.05	350.2	750	14,250	926.5	1,639.3	1,780.2	140.9	8.6%
GSe	Springwater	1,000	**20.53**	**1.07**	**0.27**	**0.17**	**1.51**	35.6	**22.96**	**2.25**	**0.17**	**(0.06)**	**2.36**	46.6	**0.93**	0.62	0.7	1.0545	23.3	750	250	55.5	114.4	125.4	11.0	9.6%
		2,000	20.53	1.07	0.27	0.17	1.51	50.7	22.96	2.25	0.17	(0.06)	2.36	70.2	0.93	0.62	0.70	1.05	46.7	750	1,250	117.7	215.1	234.6	19.5	9.1%
		5,000	20.53	1.07	0.27	0.17	1.51	96.0	22.96	2.25	0.17	(0.06)	2.36	141.1	0.93	0.62	0.70	1.05	116.7	750	4,250	304.3	517.1	562.2	45.1	8.7%
		10,000	20.53	1.07	0.27	0.17	1.51	171.5	22.96	2.25	0.17	(0.06)	2.36	259.3	0.93	0.62	0.70	1.05	233.4	750	9,250	615.4	1,020.4	1,108.1	87.8	8.6%
		15,000	20.53	1.07	0.27	0.17	1.51	247.0	22.96	2.25	0.17	(0.06)	2.36	377.4	0.93	0.62	0.70	1.05	350.2	750	14,250	926.5	1,523.7	1,654.1	130.4	8.6%

New Rate Class: GSe - Metered

Total Bill Impacts of Proposed Distribution Rates [ol RTSR+TLF]: Threshold of 750 kWhs

Classes		Scenario	May 2007 Incl Rate Riders						May 2008 Incl Rate Riders						Non-Dx Compoent				Other Reg	Commodity Bands			Existing	New	$ Incr	% Incr
			Existing Dx Rates					Existing Dx	New Dx Rates					New Dx	RTSR old	WMSC	DRC	TLF old	Old	Band 1	Band 2	Old	Total Bill	Total Bill	Total Bill	Total Bill
																				750.0						
																				5.0	5.9					
New Class	Old Class	kWh	SrChg [$/cust]	base [c/kWh]	Rider1 [c/kWh]	Rider2 [c/kWh]	VarChg [c/kWh]	[$/month]	SrChg [$/cust]	base [c/kWh]	Rider2 [c/kWh]	Rider3 [c/kWh]	VarChg [c/kWh]	[$/month]	c/kWh	c/kWh	c/kWh		$	kWhs	kWhs	Total $	[$/month]	[$/month]	[$/month]	%
GSe	**Stirling-Rawdo**	1,000	**24.12**	**1.30**	**0.21**	**0.09**	**1.60**	40.1	**26.06**	**2.47**	**0.09**	**(0.06)**	**2.50**	51.1	**0.93**	0.62	0.7	1.0545	23.3	750	250	55.5	118.9	129.9	11.0	9.2%
		2,000	24.12	1.30	0.21	0.09	1.60	56.1	26.06	2.47	0.09	(0.06)	2.50	76.1	0.93	0.62	0.70	1.05	46.7	750	1,250	117.7	220.5	240.5	20.0	9.1%
		5,000	24.12	1.30	0.21	0.09	1.60	104.1	26.06	2.47	0.09	(0.06)	2.50	151.2	0.93	0.62	0.70	1.05	116.7	750	4,250	304.3	525.2	572.3	47.1	9.0%
		10,000	24.12	1.30	0.21	0.09	1.60	184.1	26.06	2.47	0.09	(0.06)	2.50	276.4	0.93	0.62	0.70	1.05	233.4	750	9,250	615.4	1,033.0	1,125.2	92.3	8.9%
		15,000	24.12	1.30	0.21	0.09	1.60	264.1	26.06	2.47	0.09	(0.06)	2.50	401.6	0.93	0.62	0.70	1.05	350.2	750	14,250	926.5	1,540.8	1,678.2	137.4	8.9%
GSe	**Thedford**	1,000	**17.83**	**1.06**	**0.36**	**0.31**	**1.73**	35.1	**20.63**	**2.30**	**0.31**	**(0.06)**	**2.55**	46.2	**0.93**	0.62	0.7	1.0545	23.3	750	250	55.5	113.9	125.0	11.0	9.7%
		2,000	17.83	1.06	0.36	0.31	1.73	52.4	20.63	2.30	0.31	(0.06)	2.55	71.7	0.93	0.62	0.70	1.05	46.7	750	1,250	117.7	216.8	236.1	19.3	8.9%
		5,000	17.83	1.06	0.36	0.31	1.73	104.3	20.63	2.30	0.31	(0.06)	2.55	148.3	0.93	0.62	0.70	1.05	116.7	750	4,250	304.3	525.4	569.3	44.0	8.4%
		10,000	17.83	1.06	0.36	0.31	1.73	190.8	20.63	2.30	0.31	(0.06)	2.55	276.0	0.93	0.62	0.70	1.05	233.4	750	9,250	615.4	1,039.7	1,124.8	85.1	8.2%
		15,000	17.83	1.06	0.36	0.31	1.73	277.3	20.63	2.30	0.31	(0.06)	2.55	403.6	0.93	0.62	0.70	1.05	350.2	750	14,250	926.5	1,554.0	1,680.3	126.3	8.1%
GSe	**Thessalon**	1,000	**18.90**	**1.55**	**0.10**	**0.08**	**1.73**	36.2	**21.37**	**2.56**	**0.08**	**(0.06)**	**2.58**	47.2	**0.93**	0.62	0.7	1.0545	23.3	750	250	55.5	115.0	126.0	11.0	9.6%
		2,000	18.90	1.55	0.10	0.08	1.73	53.5	21.37	2.56	0.08	(0.06)	2.58	73.0	0.93	0.62	0.70	1.05	46.7	750	1,250	117.7	217.9	237.4	19.5	9.0%
		5,000	18.90	1.55	0.10	0.08	1.73	105.4	21.37	2.56	0.08	(0.06)	2.58	150.5	0.93	0.62	0.70	1.05	116.7	750	4,250	304.3	526.5	571.6	45.1	8.6%
		10,000	18.90	1.55	0.10	0.08	1.73	191.9	21.37	2.56	0.08	(0.06)	2.58	279.7	0.93	0.62	0.70	1.05	233.4	750	9,250	615.4	1,040.8	1,128.5	87.8	8.4%
		15,000	18.90	1.55	0.10	0.08	1.73	278.4	21.37	2.56	0.08	(0.06)	2.58	408.9	0.93	0.62	0.70	1.05	350.2	750	14,250	926.5	1,555.1	1,685.5	130.5	8.4%
GSe	**Thorndale**	1,000	**14.52**	**1.02**	**0.52**	**0.32**	**1.86**	33.1	**18.46**	**2.38**	**0.32**	**(0.06)**	**2.64**	44.9	**0.93**	0.62	0.7	1.0545	23.3	750	250	55.5	111.9	123.7	11.8	10.5%
		2,000	14.52	1.02	0.52	0.32	1.86	51.7	18.46	2.38	0.32	(0.06)	2.64	71.3	0.93	0.62	0.70	1.05	46.7	750	1,250	117.7	216.1	235.7	19.6	9.1%
		5,000	14.52	1.02	0.52	0.32	1.86	107.5	18.46	2.38	0.32	(0.06)	2.64	150.6	0.93	0.62	0.70	1.05	116.7	750	4,250	304.3	528.6	571.7	43.1	8.2%
		10,000	14.52	1.02	0.52	0.32	1.86	200.5	18.46	2.38	0.32	(0.06)	2.64	282.8	0.93	0.62	0.70	1.05	233.4	750	9,250	615.4	1,049.4	1,131.6	82.3	7.8%
		15,000	14.52	1.02	0.52	0.32	1.86	293.5	18.46	2.38	0.32	(0.06)	2.64	415.0	0.93	0.62	0.70	1.05	350.2	750	14,250	926.5	1,570.2	1,691.6	121.4	7.7%
UGe	**Thorold**	1,000	**22.63**	**1.50**	**0.15**	**0.06**	**1.71**	39.7	**19.43**	**2.00**	**0.06**	**(0.06)**	**2.01**	39.5	**0.93**	0.62	0.7	1.0545	23.3	750	250	55.5	118.5	118.3	(0.3)	-0.2%
		2,000	22.63	1.50	0.15	0.06	1.71	56.8	19.43	2.00	0.06	(0.06)	2.01	59.5	0.93	0.62	0.70	1.05	46.7	750	1,250	117.7	221.2	223.9	2.7	1.2%
		5,000	22.63	1.50	0.15	0.06	1.71	108.1	19.43	2.00	0.06	(0.06)	2.01	119.7	0.93	0.62	0.70	1.05	116.7	750	4,250	304.3	529.2	540.7	11.6	2.2%
		10,000	22.63	1.50	0.15	0.06	1.71	193.6	19.43	2.00	0.06	(0.06)	2.01	220.0	0.93	0.62	0.70	1.05	233.4	750	9,250	615.4	1,042.5	1,068.8	26.3	2.5%
		15,000	22.63	1.50	0.15	0.06	1.71	279.1	19.43	2.00	0.06	(0.06)	2.01	320.2	0.93	0.62	0.70	1.05	350.2	750	14,250	926.5	1,555.8	1,596.9	41.1	2.6%

New Rate Class: GSe - Metered

Total Bill Impacts of Proposed Distribution Rates [ol RTSR+TLF]: Threshold of 750 kWhs

Classes		Scenario	May 2007 Incl Rate Riders						May 2008 Incl Rate Riders						Non-Dx Compoent				Other Reg	Commodity Bands			Existing	New	$ Incr	% Incr
			Existing Dx Rates					Existing Dx	New Dx Rates					New Dx	RTSR old	WMSC	DRC	TLF old	Old	Band 1	Band 2	Old	Total Bill	Total Bill	Total Bill	Total Bill
																				750.0						
																				5.0	5.9					
New Class	Old Class	kWh	SrChg [$/cust]	base [c/kWh]	Rider1 [c/kWh]	Rider2 [c/kWh]	VarChg [c/kWh]	[$/month]	SrChg [$/cust]	base [c/kWh]	Rider2 [c/kWh]	Rider3 [c/kWh]	VarChg [c/kWh]	[$/month]	c/kWh	c/kWh	c/kWh		$	kWhs	kWhs	Total $	[$/month]	[$/month]	[$/month]	%
GSe	**Tweed**	1,000	**8.26**	**0.97**	**0.43**	**0.31**	**1.71**	25.4	**14.03**	**2.10**	**0.31**	**(0.06)**	**2.35**	37.6	**0.93**	0.62	0.7	1.0545	23.3	750	250	55.5	104.2	116.4	12.2	11.7%
		2,000	8.26	0.97	0.43	0.31	1.71	42.5	14.03	2.10	0.31	(0.06)	2.35	61.1	0.93	0.62	0.70	1.05	46.7	750	1,250	117.7	206.8	225.5	18.6	9.0%
		5,000	8.26	0.97	0.43	0.31	1.71	93.8	14.03	2.10	0.31	(0.06)	2.35	131.7	0.93	0.62	0.70	1.05	116.7	750	4,250	304.3	514.8	552.7	37.9	7.4%
		10,000	8.26	0.97	0.43	0.31	1.71	179.3	14.03	2.10	0.31	(0.06)	2.35	249.4	0.93	0.62	0.70	1.05	233.4	750	9,250	615.4	1,028.1	1,098.2	70.1	6.8%
		15,000	8.26	0.97	0.43	0.31	1.71	264.8	14.03	2.10	0.31	(0.06)	2.35	367.0	0.93	0.62	0.70	1.05	350.2	750	14,250	926.5	1,541.4	1,643.7	102.3	6.6%
GSe	**Wardsville**	1,000	**12.32**	**1.00**	**0.25**	**0.08**	**1.33**	25.6	**17.01**	**1.99**	**0.08**	**(0.06)**	**2.01**	37.1	**0.93**	0.62	0.7	1.0545	23.3	750	250	55.5	104.4	116.0	11.5	11.0%
		2,000	12.32	1.00	0.25	0.08	1.33	38.9	17.01	1.99	0.08	(0.06)	2.01	57.3	0.93	0.62	0.70	1.05	46.7	750	1,250	117.7	203.3	221.6	18.4	9.0%
		5,000	12.32	1.00	0.25	0.08	1.33	78.8	17.01	1.99	0.08	(0.06)	2.01	117.7	0.93	0.62	0.70	1.05	116.7	750	4,250	304.3	499.9	538.7	38.9	7.8%
		10,000	12.32	1.00	0.25	0.08	1.33	145.3	17.01	1.99	0.08	(0.06)	2.01	218.3	0.93	0.62	0.70	1.05	233.4	750	9,250	615.4	994.2	1,067.2	73.0	7.3%
		15,000	12.32	1.00	0.25	0.08	1.33	211.8	17.01	1.99	0.08	(0.06)	2.01	319.0	0.93	0.62	0.70	1.05	350.2	750	14,250	926.5	1,488.5	1,595.7	107.2	7.2%
GSe	**Warkworth**	1,000	**21.31**	**1.52**	**0.46**	**0.35**	**2.33**	44.6	**23.76**	**2.95**	**0.35**	**(0.06)**	**3.24**	56.2	**0.93**	0.62	0.7	1.0545	23.3	750	250	55.5	123.4	135.0	11.6	9.4%
		2,000	21.31	1.52	0.46	0.35	2.33	67.9	23.76	2.95	0.35	(0.06)	3.24	88.6	0.93	0.62	0.70	1.05	46.7	750	1,250	117.7	232.3	253.0	20.7	8.9%
		5,000	21.31	1.52	0.46	0.35	2.33	137.8	23.76	2.95	0.35	(0.06)	3.24	185.9	0.93	0.62	0.70	1.05	116.7	750	4,250	304.3	558.9	607.0	48.1	8.6%
		10,000	21.31	1.52	0.46	0.35	2.33	254.3	23.76	2.95	0.35	(0.06)	3.24	348.1	0.93	0.62	0.70	1.05	233.4	750	9,250	615.4	1,103.2	1,196.9	93.8	8.5%
		15,000	21.31	1.52	0.46	0.35	2.33	370.8	23.76	2.95	0.35	(0.06)	3.24	510.3	0.93	0.62	0.70	1.05	350.2	750	14,250	926.5	1,647.5	1,786.9	139.4	8.5%
GSe	**West Elgin**	1,000	**15.40**	**0.70**	**0.17**	**0.07**	**0.94**	24.8	**19.24**	**1.62**	**0.07**	**(0.06)**	**1.63**	35.6	**0.93**	0.62	0.7	1.0545	23.3	750	250	55.5	103.6	114.4	10.8	10.4%
		2,000	15.40	0.70	0.17	0.07	0.94	34.2	19.24	1.62	0.07	(0.06)	1.63	51.9	0.93	0.62	0.70	1.05	46.7	750	1,250	117.7	198.6	216.3	17.7	8.9%
		5,000	15.40	0.70	0.17	0.07	0.94	62.4	19.24	1.62	0.07	(0.06)	1.63	100.9	0.93	0.62	0.70	1.05	116.7	750	4,250	304.3	483.5	522.0	38.5	8.0%
		10,000	15.40	0.70	0.17	0.07	0.94	109.4	19.24	1.62	0.07	(0.06)	1.63	182.6	0.93	0.62	0.70	1.05	233.4	750	9,250	615.4	958.3	1,031.4	73.2	7.6%
		15,000	15.40	0.70	0.17	0.07	0.94	156.4	19.24	1.62	0.07	(0.06)	1.63	264.2	0.93	0.62	0.70	1.05	350.2	750	14,250	926.5	1,433.1	1,540.9	107.8	7.5%
UGe	**Whitchurch St**	1,000	**21.85**	**0.93**	**0.11**	**0.04**	**1.08**	32.7	**18.62**	**2.00**	**0.04**	**(0.06)**	**1.99**	38.5	**0.93**	0.62	0.7	1.0545	23.3	750	250	55.5	111.5	117.3	5.8	5.2%
		2,000	21.85	0.93	0.11	0.04	1.08	43.5	18.62	2.00	0.04	(0.06)	1.99	58.3	0.93	0.62	0.70	1.05	46.7	750	1,250	117.7	207.8	222.7	14.9	7.2%
		5,000	21.85	0.93	0.11	0.04	1.08	75.9	18.62	2.00	0.04	(0.06)	1.99	117.9	0.93	0.62	0.70	1.05	116.7	750	4,250	304.3	496.9	538.9	42.0	8.5%
		10,000	21.85	0.93	0.11	0.04	1.08	129.9	18.62	2.00	0.04	(0.06)	1.99	217.2	0.93	0.62	0.70	1.05	233.4	750	9,250	615.4	978.7	1,066.0	87.3	8.9%
		15,000	21.85	0.93	0.11	0.04	1.08	183.9	18.62	2.00	0.04	(0.06)	1.99	316.4	0.93	0.62	0.70	1.05	350.2	750	14,250	926.5	1,460.5	1,593.1	132.6	9.1%

New Rate Class: GSe - Metered

Total Bill Impacts of Proposed Distribution Rates [ol RTSR+TLF]: Threshold of 750 kWhs

Classes		Scenario	May 2007 Incl Rate Riders						May 2008 Incl Rate Riders						Non-Dx Compoent				Other Reg	Commodity Bands			Existing	New	$ Incr	% Incr
			Existing Dx Rates					Existing Dx	New Dx Rates					New Dx	RTSR old	WMSC	DRC	TLF old	Old	Band 1	Band 2	Old	Total Bill	Total Bill	Total Bill	Total Bill
																				750.0						
																				5.0	5.9					
New Class	Old Class	kWh	SrChg	base	Rider1	Rider2	VarChg	[$/month]	SrChg	base	Rider2	Rider3	VarChg	[$/month]	c/kWh	c/kWh	c/kWh		$	kWhs	kWhs	Total $	[$/month]	[$/month]	[$/month]	%
			[$/cust]	[c/kWh]	[c/kWh]	[c/kWh]	[c/kWh]		[$/cust]	[c/kWh]	[c/kWh]	[c/kWh]	[c/kWh]													
GSe	**Wiarton**	1,000	**23.78**	**1.89**	**0.19**	**0.09**	**2.17**	45.5	**25.15**	**3.10**	**0.09**	**(0.06)**	**3.13**	56.5	**0.93**	0.62	0.7	1.0545	23.3	750	250	55.5	124.3	135.3	11.0	8.9%
		2,000	23.78	1.89	0.19	0.09	2.17	67.2	25.15	3.10	0.09	(0.06)	3.13	87.8	0.93	0.62	0.70	1.05	46.7	750	1,250	117.7	231.6	252.2	20.6	8.9%
		5,000	23.78	1.89	0.19	0.09	2.17	132.3	25.15	3.10	0.09	(0.06)	3.13	181.8	0.93	0.62	0.70	1.05	116.7	750	4,250	304.3	553.3	602.9	49.5	9.0%
		10,000	23.78	1.89	0.19	0.09	2.17	240.8	25.15	3.10	0.09	(0.06)	3.13	338.5	0.93	0.62	0.70	1.05	233.4	750	9,250	615.4	1,089.6	1,187.3	97.7	9.0%
		15,000	23.78	1.89	0.19	0.09	2.17	349.3	25.15	3.10	0.09	(0.06)	3.13	495.1	0.93	0.62	0.70	1.05	350.2	750	14,250	926.5	1,625.9	1,771.8	145.9	9.0%
GSe	**Woodville**	1,000	**16.89**	**1.57**	**0.67**	**0.48**	**2.72**	44.1	**19.87**	**3.21**	**0.48**	**(0.06)**	**3.63**	56.2	**0.93**	0.62	0.7	1.0545	23.3	750	250	55.5	122.9	135.0	12.1	9.9%
		2,000	16.89	1.57	0.67	0.48	2.72	71.3	19.87	3.21	0.48	(0.06)	3.63	92.5	0.93	0.62	0.70	1.05	46.7	750	1,250	117.7	235.7	256.9	21.3	9.0%
		5,000	16.89	1.57	0.67	0.48	2.72	152.9	19.87	3.21	0.48	(0.06)	3.63	201.6	0.93	0.62	0.70	1.05	116.7	750	4,250	304.3	573.9	622.6	48.7	8.5%
		10,000	16.89	1.57	0.67	0.48	2.72	288.9	19.87	3.21	0.48	(0.06)	3.63	383.2	0.93	0.62	0.70	1.05	233.4	750	9,250	615.4	1,137.7	1,232.1	94.4	8.3%
		15,000	16.89	1.57	0.67	0.48	2.72	424.9	19.87	3.21	0.48	(0.06)	3.63	564.9	0.93	0.62	0.70	1.05	350.2	750	14,250	926.5	1,701.5	1,841.6	140.0	8.2%
GSe	**Wyoming**	1,000	**17.36**	**1.45**	**0.16**	**0.07**	**1.68**	34.2	**20.75**	**2.46**	**0.07**	**(0.06)**	**2.47**	45.5	**0.93**	0.62	0.7	1.0545	23.3	750	250	55.5	113.0	124.3	11.3	10.0%
		2,000	17.36	1.45	0.16	0.07	1.68	51.0	20.75	2.46	0.07	(0.06)	2.47	70.2	0.93	0.62	0.70	1.05	46.7	750	1,250	117.7	215.3	234.6	19.3	8.9%
		5,000	17.36	1.45	0.16	0.07	1.68	101.4	20.75	2.46	0.07	(0.06)	2.47	144.4	0.93	0.62	0.70	1.05	116.7	750	4,250	304.3	522.4	565.5	43.1	8.2%
		10,000	17.36	1.45	0.16	0.07	1.68	185.4	20.75	2.46	0.07	(0.06)	2.47	268.1	0.93	0.62	0.70	1.05	233.4	750	9,250	615.4	1,034.2	1,116.9	82.7	8.0%
		15,000	17.36	1.45	0.16	0.07	1.68	269.4	20.75	2.46	0.07	(0.06)	2.47	391.7	0.93	0.62	0.70	1.05	350.2	750	14,250	926.5	1,546.0	1,668.4	122.4	7.9%
GSe	**Terrace Bay**	1,000	**41.34**	**1.18**	**0.82**		**2.00**	61.3	**38.76**	**2.67**		**(0.06)**	**2.61**	64.9	**0.47**	0.62	0.7	1.0426	18.4	750	250	54.8	134.5	138.0	3.5	2.6%
		2,000	41.34	1.18	0.82	-	2.00	81.3	38.76	2.67	-	(0.06)	2.61	91.0	0.47	0.62	0.70	1.04	36.7	750	1,250	116.3	234.3	244.0	9.7	4.1%
		5,000	41.34	1.18	0.82	-	2.00	141.3	38.76	2.67	-	(0.06)	2.61	169.4	0.47	0.62	0.70	1.04	91.8	750	4,250	300.8	534.0	562.1	28.1	5.3%
		10,000	41.34	1.18	0.82	-	2.00	241.3	38.76	2.67	-	(0.06)	2.61	300.1	0.47	0.62	0.70	1.04	183.6	750	9,250	608.4	1,033.4	1,092.1	58.7	5.7%
		15,000	41.34	1.18	0.82	-	2.00	341.3	38.76	2.67	-	(0.06)	2.61	430.7	0.47	0.62	0.70	1.04	275.5	750	14,250	916.0	1,532.8	1,622.2	89.4	5.8%

New Rate Class: GSd

Total Bill Impacts of Proposed Distribution Rates [old RTSR+TLF]: Threshold of 750 kWhs

Classes		Scenario			May 2007 Incl Rate Riders						May 2008 Incl Rate Riders						Non-Dx Compoent				Other Reg	Commodity Bands			Existing	New	$ Incr	% Incr
					Existing Dx Rates					Existing Dx	New Dx Rates					New Dx	RTSR old	WMSC	DRC	TLF old	Old	Band 1	Band 2	Old	Total Bill	Total Bill	Total Bill	Total Bill
																						-	5.2					
New Class	Old Class	kWh	kW	LF	SrChg [$/cust]	base [$/kW]	Rider1 [$/kW]	Rider2 [$/kW]	VarChg [$/kW]	[$/month]	SrChg [$/cust]	base [$/kW]	Rider2 [$/kW]	Rider3 [$/kW]	VarChg [$/kW]	[$/month]	$/kW	c/kWh	c/kWh		$	kWhs	kWhs	Total $	[$/month]	[$/month]	[$/month]	%
GSd	**F1**	15,000	60	35%	**28.61**	**7.06**	**0.26**	**0.31**	**7.63**	486.4	**56.51**	**9.44**	**0.31**	**(0.22)**	**9.53**	628.5	**2.83**	0.62	0.7	**1.092**	391.9	-	15,000	851.8	1,730.1	1,872.2	142.1	8.2%
		43,164	133	45%	28.61	7.06	0.26	0.31	7.63	1,043.4	56.51	9.44	0.31	(0.22)	9.53	1,324.5	2.83	0.62	0.7	1.092	1,005.3	-	43,164	2,451.0	4,499.7	4,780.8	281.1	6.2%
with RRRP		100,000	500	28%	28.61	7.06	0.26	0.31	7.63	3,843.6	56.51	9.44	0.31	(0.22)	9.53	4,823.4	2.83	0.62	0.7	1.092	2,921.7	-	100,000	5,678.4	12,443.7	13,423.4	979.8	7.9%
		400,000	1000	56%	28.61	7.06	0.26	0.31	7.63	7,658.6	56.51	9.44	0.31	(0.22)	9.53	9,590.2	2.83	0.62	0.7	1.092	8,597.4	-	400,000	22,713.6	38,969.6	40,901.3	1,931.6	5.0%
		1,000,000	3000	46%	28.61	7.06	0.26	0.31	7.63	22,918.6	56.51	9.44	0.31	(0.22)	9.53	28,657.7	2.83	0.62	0.7	1.092	23,038.2	-	1,000,000	56,784.0	102,740.8	108,479.9	5,739.1	5.6%
		1,500,000	4000	52%	28.61	7.06	0.26	0.31	7.63	30,548.6	56.51	9.44	0.31	(0.22)	9.53	38,191.4	2.83	0.62	0.7	1.092	33,012.7	-	1,500,000	85,176.0	148,737.3	156,380.1	7,642.8	5.1%
GSd	**F1**	15,000	60	35%	**60.71**	**7.06**	**0.26**	**0.31**	**7.63**	518.5	**56.51**	**9.44**	**0.31**	**(0.22)**	**9.53**	628.5	**2.83**	0.62	0.7	**1.092**	391.9	-	15,000	851.8	1,762.2	1,872.2	110.0	6.2%
		43,164	133	45%	60.71	7.06	0.26	0.31	7.63	1,075.5	56.51	9.44	0.31	(0.22)	9.53	1,324.5	2.83	0.62	0.70	1.092	1,005.3	-	43,164	2,451.0	4,531.8	4,780.8	249.0	5.5%
no RRRP		100,000	500	28%	60.71	7.06	0.26	0.31	7.63	3,875.7	56.51	9.44	0.31	(0.22)	9.53	4,823.4	2.83	0.62	0.70	1.092	2,921.7	-	100,000	5,678.4	12,475.8	13,423.4	947.7	7.6%
		400,000	1000	56%	60.71	7.06	0.26	0.31	7.63	7,690.7	56.51	9.44	0.31	(0.22)	9.53	9,590.2	2.83	0.62	0.70	1.092	8,597.4	-	400,000	22,713.6	39,001.7	40,901.3	1,899.5	4.9%
		1,000,000	3000	46%	60.71	7.06	0.26	0.31	7.63	22,950.7	56.51	9.44	0.31	(0.22)	9.53	28,657.7	2.83	0.62	0.70	1.092	23,038.2	-	1,000,000	56,784.0	102,772.9	108,479.9	5,707.0	5.6%
		1,500,000	4000	52%	60.71	7.06	0.26	0.31	7.63	30,580.7	56.51	9.44	0.31	(0.22)	9.53	38,191.4	2.83	0.62	0.70	1.092	33,012.7	-	1,500,000	85,176.0	148,769.4	156,380.1	7,610.7	5.1%
GSd	**F3**	15,000	60	35%	**30.16**	**10.87**	**0.10**	**0.16**	**11.13**	698.0	**51.21**	**9.44**	**0.16**	**(0.22)**	**9.38**	614.2	**3.13**	0.62	0.7	**1.061**	402.9	-	15,000	827.6	1,928.4	1,844.7	(83.7)	-4.3%
		43,164	133	45%	30.16	10.87	0.10	0.16	11.13	1,510.5	51.21	9.44	0.16	(0.22)	9.38	1,299.2	3.13	0.62	0.70	1.061	1,027.6	-	43,164	2,381.4	4,919.5	4,708.3	(211.2)	-4.3%
with RRRP		100,000	500	28%	30.16	10.87	0.10	0.16	11.13	5,595.2	51.21	9.44	0.16	(0.22)	9.38	4,743.1	3.13	0.62	0.70	1.061	3,017.8	-	100,000	5,517.2	14,130.1	13,278.0	(852.1)	-6.0%
		400,000	1000	56%	30.16	10.87	0.10	0.16	11.13	11,160.2	51.21	9.44	0.16	(0.22)	9.38	9,434.9	3.13	0.62	0.70	1.061	8,751.1	-	400,000	22,068.8	41,980.1	40,254.9	(1,725.2)	-4.1%
		1,000,000	3000	46%	30.16	10.87	0.10	0.16	11.13	33,420.2	51.21	9.44	0.16	(0.22)	9.38	28,202.4	3.13	0.62	0.70	1.061	23,537.8	-	1,000,000	55,172.0	112,130.0	106,912.2	(5,217.8)	-4.7%
		1,500,000	4000	52%	30.16	10.87	0.10	0.16	11.13	44,550.2	51.21	9.44	0.16	(0.22)	9.38	37,586.1	3.13	0.62	0.70	1.061	33,646.8	-	1,500,000	82,758.0	160,954.9	153,990.9	(6,964.0)	-4.3%
GSd	**F3**	15,000	60	35%	**53.91**	**10.87**	**0.10**	**0.16**	**11.13**	721.7	**51.21**	**9.44**	**0.16**	**(0.22)**	**9.38**	614.2	**3.13**	0.62	0.7	**1.061**	402.9	-	15,000	827.6	1,952.2	1,844.7	(107.5)	-5.5%
		43,164	133	45%	53.91	10.87	0.10	0.16	11.13	1,534.2	51.21	9.44	0.16	(0.22)	9.38	1,299.2	3.13	0.62	0.7	1.061	1,027.6	-	43,164	2,381.4	4,943.3	4,708.3	(235.0)	-4.8%
no RRRP		100,000	500	28%	53.91	10.87	0.10	0.16	11.13	5,618.9	51.21	9.44	0.16	(0.22)	9.38	4,743.1	3.13	0.62	0.7	1.061	3,017.8	-	100,000	5,517.2	14,153.9	13,278.0	(875.8)	-6.2%
		400,000	1000	56%	53.91	10.87	0.10	0.16	11.13	11,183.9	51.21	9.44	0.16	(0.22)	9.38	9,434.9	3.13	0.62	0.7	1.061	8,751.1	-	400,000	22,068.8	42,003.9	40,254.9	(1,749.0)	-4.2%
		1,000,000	3000	46%	53.91	10.87	0.10	0.16	11.13	33,443.9	51.21	9.44	0.16	(0.22)	9.38	28,202.4	3.13	0.62	0.7	1.061	23,537.8	-	1,000,000	55,172.0	112,153.7	106,912.2	(5,241.5)	-4.7%
		1,500,000	4000	52%	53.91	10.87	0.10	0.16	11.13	44,573.9	51.21	9.44	0.16	(0.22)	9.38	37,586.1	3.13	0.62	0.7	1.061	33,646.8	-	1,500,000	82,758.0	160,978.7	153,990.9	(6,987.8)	-4.3%
GSd	**G1**	15,000	60	35%	**36.93**	**9.59**	**0.26**	**0.29**	**10.14**	645.3	**38.68**	**9.44**	**0.29**	**(0.22)**	**9.51**	609.5	**2.62**	0.62	0.7	**1.092**	378.2	-	15,000	851.8	1,875.2	1,839.4	(35.8)	-1.9%
		43,164	133	45%	36.93	9.59	0.26	0.29	10.14	1,385.6	38.68	9.44	0.29	(0.22)	9.51	1,304.0	2.62	0.62	0.70	1.092	974.8	-	43,164	2,451.0	4,811.3	4,729.8	(81.5)	-1.7%
		100,000	500	28%	36.93	9.59	0.26	0.29	10.14	5,106.9	38.68	9.44	0.29	(0.22)	9.51	4,795.5	2.62	0.62	0.70	1.092	2,807.0	-	100,000	5,678.4	13,592.3	13,281.0	(311.4)	-2.3%
		400,000	1000	56%	36.93	9.59	0.26	0.29	10.14	10,176.9	38.68	9.44	0.29	(0.22)	9.51	9,552.4	2.62	0.62	0.70	1.092	8,368.1	-	400,000	22,713.6	41,258.6	40,634.1	(624.5)	-1.5%
		1,000,000	3000	46%	36.93	9.59	0.26	0.29	10.14	30,456.9	38.68	9.44	0.29	(0.22)	9.51	28,579.9	2.62	0.62	0.70	1.092	22,350.2	-	1,000,000	56,784.0	109,591.2	107,714.1	(1,877.1)	-1.7%
		1,500,000	4000	52%	36.93	9.59	0.26	0.29	10.14	40,596.9	38.68	9.44	0.29	(0.22)	9.51	38,093.6	2.62	0.62	0.70	1.092	32,095.4	-	1,500,000	85,176.0	157,868.3	155,365.0	(2,503.3)	-1.6%

New Rate Class: GSd

Total Bill Impacts of Proposed Distribution Rates [old RTSR+TLF]: Threshold of 750 kWhs

Classes		Scenario			May 2007 Incl Rate Riders						May 2008 Incl Rate Riders						Non-Dx Compoent				Other Reg	Commodity Bands			Existing	New	$ Incr	% Incr
					Existing Dx Rates					Existing Dx	New Dx Rates					New Dx	RTSR old	WMSC	DRC	TLF old	Old	Band 1	Band 2	Old	Total Bill	Total Bill	Total Bill	Total Bill
																						-	5.2					
New Class	Old Class	kWh	kW	LF	SrChg [$/cust]	base [$/kW]	Rider1 [$/kW]	Rider2 [$/kW]	VarChg [$/kW]	[$/month]	SrChg [$/cust]	base [$/kW]	Rider2 [$/kW]	Rider3 [$/kW]	VarChg [$/kW]	[$/month]	$/kW	c/kWh	c/kWh		$	kWhs	kWhs	Total $	[$/month]	[$/month]	[$/month]	%
GSd	**G3**	15,000	60	35%	**46.78**	**9.91**	**0.08**	**0.15**	**10.14**	655.2	**46.00**	**9.44**	**0.15**	**(0.22)**	**9.37**	608.4	**2.75**	0.62	0.7	**1.061**	378.9	-	15,000	827.6	1,861.6	1,814.9	(46.8)	-2.5%
		43,164	133	45%	46.78	9.91	0.08	0.15	10.14	1,395.4	46.00	9.44	0.15	(0.22)	9.37	1,292.7	2.75	0.62	0.70	1.061	974.4	-	43,164	2,381.4	4,751.3	4,648.6	(102.7)	-2.2%
		100,000	500	28%	46.78	9.91	0.08	0.15	10.14	5,116.8	46.00	9.44	0.15	(0.22)	9.37	4,732.9	2.75	0.62	0.70	1.061	2,817.8	-	100,000	5,517.2	13,451.7	13,067.8	(383.9)	-2.9%
		400,000	1000	56%	46.78	9.91	0.08	0.15	10.14	10,186.8	46.00	9.44	0.15	(0.22)	9.37	9,419.7	2.75	0.62	0.70	1.061	8,351.2	-	400,000	22,068.8	40,606.7	39,839.7	(767.1)	-1.9%
		1,000,000	3000	46%	46.78	9.91	0.08	0.15	10.14	30,466.8	46.00	9.44	0.15	(0.22)	9.37	28,167.2	2.75	0.62	0.70	1.061	22,337.8	-	1,000,000	55,172.0	107,976.6	105,677.0	(2,299.6)	-2.1%
		1,500,000	4000	52%	46.78	9.91	0.08	0.15	10.14	40,606.8	46.00	9.44	0.15	(0.22)	9.37	37,540.9	2.75	0.62	0.70	1.061	32,046.8	-	1,500,000	82,758.0	155,411.6	152,345.7	(3,065.9)	-2.0%
GSd	**T**	15,000	60	35%	**261.54**	**8.16**	**0.04**	**0.09**	**8.29**	758.9	**207.30**	**9.44**	**0.09**	**(0.22)**	**9.31**	766.1	**2.82**	0.62	0.7	**1.061**	383.0	-	15,000	827.6	1,969.5	1,976.7	7.2	0.4%
		43,164	133	45%	261.54	8.16	0.04	0.09	8.29	1,364.1	207.30	9.44	0.09	(0.22)	9.31	1,446.0	2.82	0.62	0.70	1.061	983.6	-	43,164	2,381.4	4,729.2	4,811.1	81.9	1.7%
		100,000	500	28%	261.54	8.16	0.04	0.09	8.29	4,406.5	207.30	9.44	0.09	(0.22)	9.31	4,864.2	2.82	0.62	0.70	1.061	2,852.2	-	100,000	5,517.2	12,776.0	13,233.6	457.6	3.6%
		400,000	1000	56%	261.54	8.16	0.04	0.09	8.29	8,551.5	207.30	9.44	0.09	(0.22)	9.31	9,521.0	2.82	0.62	0.70	1.061	8,420.1	-	400,000	22,068.8	39,040.5	40,009.9	969.5	2.5%
		1,000,000	3000	46%	261.54	8.16	0.04	0.09	8.29	25,131.5	207.30	9.44	0.09	(0.22)	9.31	28,148.5	2.82	0.62	0.70	1.061	22,544.7	-	1,000,000	55,172.0	102,848.3	105,865.2	3,016.9	2.9%
		1,500,000	4000	52%	261.54	8.16	0.04	0.09	8.29	33,421.5	207.30	9.44	0.09	(0.22)	9.31	37,462.2	2.82	0.62	0.70	1.061	32,322.6	-	1,500,000	82,758.0	148,502.2	152,542.9	4,040.7	2.7%
GSd	**Ailsa Craig**	15,000	60	35%	**17.31**	**4.19**	**0.52**	**0.27**	**4.98**	316.1	**24.36**	**9.00**	**0.27**	**(0.22)**	**9.05**	567.5	**3.54**	0.62	0.7	1.0545	426.9	-	15,000	822.5	1,565.5	1,816.9	251.4	16.1%
		43,164	133	45%	17.31	4.19	0.52	0.27	4.98	679.7	24.36	9.00	0.27	(0.22)	9.05	1,228.4	3.54	0.62	0.70	1.05	1,080.5	-	43,164	2,366.9	4,127.1	4,675.8	548.7	13.3%
		100,000	500	28%	17.31	4.19	0.52	0.27	4.98	2,507.3	24.36	9.00	0.27	(0.22)	9.05	4,550.7	3.54	0.62	0.70	1.05	3,219.2	-	100,000	5,483.4	11,209.9	13,253.3	2,043.4	18.2%
		400,000	1000	56%	17.31	4.19	0.52	0.27	4.98	4,997.3	24.36	9.00	0.27	(0.22)	9.05	9,077.1	3.54	0.62	0.70	1.05	9,146.0	-	400,000	21,933.6	36,076.9	40,156.6	4,079.8	11.3%
		1,000,000	3000	46%	17.31	4.19	0.52	0.27	4.98	14,957.3	24.36	9.00	0.27	(0.22)	9.05	27,182.5	3.54	0.62	0.70	1.05	24,730.4	-	1,000,000	54,834.0	94,521.7	106,746.8	12,225.2	12.9%
		1,500,000	4000	52%	17.31	4.19	0.52	0.27	4.98	19,937.3	24.36	9.00	0.27	(0.22)	9.05	36,235.2	3.54	0.62	0.70	1.05	35,230.1	-	1,500,000	82,251.0	137,418.4	153,716.3	16,297.9	11.9%
GSd	**Arkona**	15,000	60	35%	**3.20**	**1.98**	**1.62**	**0.83**	**4.43**	269.0	**13.89**	**9.22**	**0.83**	**(0.22)**	**9.84**	604.1	**3.54**	0.62	0.7	1.0545	426.9	-	15,000	822.5	1,518.4	1,853.5	335.1	22.1%
	no customer	43,164	133	45%	3.20	1.98	1.62	0.83	4.43	592.4	13.89	9.22	0.83	(0.22)	9.84	1,322.1	3.54	0.62	0.70	1.05	1,080.5	-	43,164	2,366.9	4,039.8	4,769.5	729.7	18.1%
		100,000	500	28%	3.20	1.98	1.62	0.83	4.43	2,218.2	13.89	9.22	0.83	(0.22)	9.84	4,932.0	3.54	0.62	0.70	1.05	3,219.2	-	100,000	5,483.4	10,920.8	13,634.6	2,713.8	24.9%
		400,000	1000	56%	3.20	1.98	1.62	0.83	4.43	4,433.2	13.89	9.22	0.83	(0.22)	9.84	9,850.2	3.54	0.62	0.70	1.05	9,146.0	-	400,000	21,933.6	35,512.8	40,929.8	5,417.0	15.3%
		1,000,000	3000	46%	3.20	1.98	1.62	0.83	4.43	13,293.2	13.89	9.22	0.83	(0.22)	9.84	29,522.7	3.54	0.62	0.70	1.05	24,730.4	-	1,000,000	54,834.0	92,857.6	109,087.1	16,229.5	17.5%
		1,500,000	4000	52%	3.20	1.98	1.62	0.83	4.43	17,723.2	13.89	9.22	0.83	(0.22)	9.84	39,359.0	3.54	0.62	0.70	1.05	35,230.1	-	1,500,000	82,251.0	135,204.3	156,840.2	21,635.8	16.0%
UGd	**Arnprior**	15,000	60	35%	**21.38**	**3.70**	**0.50**	**0.20**	**4.40**	285.4	**22.95**	**7.33**	**0.20**	**(0.27)**	**7.26**	458.6	**3.54**	0.62	0.7	1.0545	426.9	-	15,000	822.5	1,534.8	1,708.0	173.2	11.3%
		43,164	133	45%	21.38	3.70	0.50	0.20	4.40	606.6	22.95	7.33	0.20	(0.27)	7.26	988.6	3.54	0.62	0.70	1.05	1,080.5	-	43,164	2,366.9	4,054.0	4,436.0	382.0	9.4%
		100,000	500	28%	21.38	3.70	0.50	0.20	4.40	2,221.4	22.95	7.33	0.20	(0.27)	7.26	3,653.1	3.54	0.62	0.70	1.05	3,219.2	-	100,000	5,483.4	10,924.0	12,355.7	1,431.7	13.1%
		400,000	1000	56%	21.38	3.70	0.50	0.20	4.40	4,421.4	22.95	7.33	0.20	(0.27)	7.26	7,283.2	3.54	0.62	0.70	1.05	9,146.0	-	400,000	21,933.6	35,501.0	38,362.7	2,861.8	8.1%
		1,000,000	3000	46%	21.38	3.70	0.50	0.20	4.40	13,221.4	22.95	7.33	0.20	(0.27)	7.26	21,803.6	3.54	0.62	0.70	1.05	24,730.4	-	1,000,000	54,834.0	92,785.7	101,367.9	8,582.2	9.2%
		1,500,000	4000	52%	21.38	3.70	0.50	0.20	4.40	17,621.4	22.95	7.33	0.20	(0.27)	7.26	29,063.8	3.54	0.62	0.70	1.05	35,230.1	-	1,500,000	82,251.0	135,102.5	146,544.9	11,442.4	8.5%

New Rate Class: GSd

Total Bill Impacts of Proposed Distribution Rates [old RTSR+TLF]: Threshold of 750 kWhs

Classes		Scenario			May 2007 Incl Rate Riders						May 2008 Incl Rate Riders						Non-Dx Compoent				Other Reg	Commodity Bands			Existing	New	$ Incr	% Incr
					Existing Dx Rates					Existing Dx	New Dx Rates					New Dx	RTSR old	WMSC	DRC	TLF old	Old	Band 1	Band 2	Old	Total Bill	Total Bill	Total Bill	Total Bill
																						-	5.2					
New Class	Old Class	kWh	kW	LF	SrChg [$/cust]	base [$/kW]	Rider1 [$/kW]	Rider2 [$/kW]	VarChg [$/kW]	[$/month]	SrChg [$/cust]	base [$/kW]	Rider2 [$/kW]	Rider3 [$/kW]	VarChg [$/kW]	[$/month]	$/kW	c/kWh	c/kWh		$	kWhs	kWhs	Total $	[$/month]	[$/month]	[$/month]	%
GSd	Arran-Elderslie	15,000	60	35%	**8.83**	**3.28**	**0.55**	**0.28**	**4.11**	255.4	**17.48**	**8.00**	**0.28**	**(0.22)**	**8.06**	501.2	**3.54**	0.62	0.7	1.0545	426.9	-	15,000	822.5	1,504.9	1,750.7	245.8	16.3%
		43,164	133	45%	8.83	3.28	0.55	0.28	4.11	555.5	17.48	8.00	0.28	(0.22)	8.06	1,089.8	3.54	0.62	0.70	1.05	1,080.5	-	43,164	2,366.9	4,002.9	4,537.2	534.4	13.3%
		100,000	500	28%	8.83	3.28	0.55	0.28	4.11	2,063.8	17.48	8.00	0.28	(0.22)	8.06	4,048.8	3.54	0.62	0.70	1.05	3,219.2	-	100,000	5,483.4	10,766.4	12,751.4	1,985.0	18.4%
		400,000	1000	56%	8.83	3.28	0.55	0.28	4.11	4,118.8	17.48	8.00	0.28	(0.22)	8.06	8,080.2	3.54	0.62	0.70	1.05	9,146.0	-	400,000	21,933.6	35,198.4	39,159.8	3,961.4	11.3%
		1,000,000	3000	46%	8.83	3.28	0.55	0.28	4.11	12,338.8	17.48	8.00	0.28	(0.22)	8.06	24,205.6	3.54	0.62	0.70	1.05	24,730.4	-	1,000,000	54,834.0	91,903.2	103,770.0	11,866.8	12.9%
		1,500,000	4000	52%	8.83	3.28	0.55	0.28	4.11	16,448.8	17.48	8.00	0.28	(0.22)	8.06	32,268.3	3.54	0.62	0.70	1.05	35,230.1	-	1,500,000	82,251.0	133,930.0	149,749.4	15,819.5	11.8%
GSd	Artemesia	15,000	60	35%	**19.62**	**5.49**	**1.55**	**1.08**	**8.12**	506.8	**25.78**	**9.22**	**1.08**	**(0.22)**	**10.09**	631.0	**3.54**	0.62	0.7	1.0545	426.9	-	15,000	822.5	1,756.2	1,880.4	124.1	7.1%
		43,164	133	45%	19.62	5.49	1.55	1.08	8.12	1,099.6	25.78	9.22	1.08	(0.22)	10.09	1,367.3	3.54	0.62	0.70	1.05	1,080.5	-	43,164	2,366.9	4,547.0	4,814.7	267.7	5.9%
		100,000	500	28%	19.62	5.49	1.55	1.08	8.12	4,079.6	25.78	9.22	1.08	(0.22)	10.09	5,068.9	3.54	0.62	0.70	1.05	3,219.2	-	100,000	5,483.4	12,782.2	13,771.5	989.3	7.7%
		400,000	1000	56%	19.62	5.49	1.55	1.08	8.12	8,139.6	25.78	9.22	1.08	(0.22)	10.09	10,112.1	3.54	0.62	0.70	1.05	9,146.0	-	400,000	21,933.6	39,219.2	41,191.6	1,972.4	5.0%
		1,000,000	3000	46%	19.62	5.49	1.55	1.08	8.12	24,379.6	25.78	9.22	1.08	(0.22)	10.09	30,284.6	3.54	0.62	0.70	1.05	24,730.4	-	1,000,000	54,834.0	103,944.0	109,849.0	5,905.0	5.7%
		1,500,000	4000	52%	19.62	5.49	1.55	1.08	8.12	32,499.6	25.78	9.22	1.08	(0.22)	10.09	40,370.9	3.54	0.62	0.70	1.05	35,230.1	-	1,500,000	82,251.0	149,980.8	157,852.1	7,871.3	5.2%
GSd	Bancroft	15,000	60	35%	**24.41**	**3.70**	**0.54**	**0.24**	**4.48**	293.2	**29.59**	**8.50**	**0.24**	**(0.22)**	**8.52**	540.9	**3.54**	0.62	0.7	1.0545	426.9	-	15,000	822.5	1,542.6	1,790.4	247.7	16.1%
		43,164	133	45%	24.41	3.70	0.54	0.24	4.48	620.3	29.59	8.50	0.24	(0.22)	8.52	1,163.1	3.54	0.62	0.70	1.05	1,080.5	-	43,164	2,366.9	4,067.7	4,610.5	542.9	13.3%
		100,000	500	28%	24.41	3.70	0.54	0.24	4.48	2,264.4	29.59	8.50	0.24	(0.22)	8.52	4,290.9	3.54	0.62	0.70	1.05	3,219.2	-	100,000	5,483.4	10,967.0	12,993.5	2,026.5	18.5%
		400,000	1000	56%	24.41	3.70	0.54	0.24	4.48	4,504.4	29.59	8.50	0.24	(0.22)	8.52	8,552.3	3.54	0.62	0.70	1.05	9,146.0	-	400,000	21,933.6	35,584.0	39,631.9	4,047.9	11.4%
		1,000,000	3000	46%	24.41	3.70	0.54	0.24	4.48	13,464.4	29.59	8.50	0.24	(0.22)	8.52	25,597.7	3.54	0.62	0.70	1.05	24,730.4	-	1,000,000	54,834.0	93,028.8	105,162.1	12,133.3	13.0%
		1,500,000	4000	52%	24.41	3.70	0.54	0.24	4.48	17,944.4	29.59	8.50	0.24	(0.22)	8.52	34,120.4	3.54	0.62	0.70	1.05	35,230.1	-	1,500,000	82,251.0	135,425.5	151,601.5	16,176.0	11.9%
GSd	Bath	15,000	60	35%	**10.65**	**3.77**	**0.93**	**0.63**	**5.33**	330.5	**19.03**	**9.00**	**0.63**	**(0.22)**	**9.41**	583.8	**3.54**	0.62	0.7	1.0545	426.9	-	15,000	822.5	1,579.9	1,833.2	253.3	16.0%
		43,164	133	45%	10.65	3.77	0.93	0.63	5.33	719.5	19.03	9.00	0.63	(0.22)	9.41	1,270.9	3.54	0.62	0.70	1.05	1,080.5	-	43,164	2,366.9	4,166.9	4,718.3	551.4	13.2%
		100,000	500	28%	10.65	3.77	0.93	0.63	5.33	2,675.7	19.03	9.00	0.63	(0.22)	9.41	4,725.4	3.54	0.62	0.70	1.05	3,219.2	-	100,000	5,483.4	11,378.3	13,428.0	2,049.7	18.0%
		400,000	1000	56%	10.65	3.77	0.93	0.63	5.33	5,340.7	19.03	9.00	0.63	(0.22)	9.41	9,431.7	3.54	0.62	0.70	1.05	9,146.0	-	400,000	21,933.6	36,420.2	40,511.3	4,091.1	11.2%
		1,000,000	3000	46%	10.65	3.77	0.93	0.63	5.33	16,000.7	19.03	9.00	0.63	(0.22)	9.41	28,257.1	3.54	0.62	0.70	1.05	24,730.4	-	1,000,000	54,834.0	95,565.0	107,821.5	12,256.5	12.8%
		1,500,000	4000	52%	10.65	3.77	0.93	0.63	5.33	21,330.7	19.03	9.00	0.63	(0.22)	9.41	37,669.8	3.54	0.62	0.70	1.05	35,230.1	-	1,500,000	82,251.0	138,811.8	155,151.0	16,339.2	11.8%
GSd	Blandford-Blenheim	15,000	60	35%	**23.85**	**3.63**	**0.91**	**0.65**	**5.19**	335.3	**28.73**	**8.90**	**0.65**	**(0.22)**	**9.33**	588.7	**3.54**	0.62	0.7	1.0545	426.9	-	15,000	822.5	1,584.7	1,838.1	253.4	16.0%
		43,164	133	45%	23.85	3.63	0.91	0.65	5.19	714.1	28.73	8.90	0.65	(0.22)	9.33	1,270.0	3.54	0.62	0.70	1.05	1,080.5	-	43,164	2,366.9	4,161.5	4,717.4	555.9	13.4%
		100,000	500	28%	23.85	3.63	0.91	0.65	5.19	2,618.9	28.73	8.90	0.65	(0.22)	9.33	4,695.1	3.54	0.62	0.70	1.05	3,219.2	-	100,000	5,483.4	11,321.5	13,397.7	2,076.2	18.3%
		400,000	1000	56%	23.85	3.63	0.91	0.65	5.19	5,213.9	28.73	8.90	0.65	(0.22)	9.33	9,361.4	3.54	0.62	0.70	1.05	9,146.0	-	400,000	21,933.6	36,293.4	40,441.0	4,147.6	11.4%
		1,000,000	3000	46%	23.85	3.63	0.91	0.65	5.19	15,593.9	28.73	8.90	0.65	(0.22)	9.33	28,026.8	3.54	0.62	0.70	1.05	24,730.4	-	1,000,000	54,834.0	95,158.2	107,591.2	12,433.0	13.1%
		1,500,000	4000	52%	23.85	3.63	0.91	0.65	5.19	20,783.9	28.73	8.90	0.65	(0.22)	9.33	37,359.5	3.54	0.62	0.70	1.05	35,230.1	-	1,500,000	82,251.0	138,265.0	154,840.7	16,575.7	12.0%

New Rate Class: GSd

Total Bill Impacts of Proposed Distribution Rates [old RTSR+TLF]: Threshold of 750 kWhs

Classes		Scenario			May 2007 Incl Rate Riders						May 2008 Incl Rate Riders						Non-Dx Compoent				Other Reg	Commodity Bands			Existing	New	$ Incr	% Incr
					Existing Dx Rates					Existing Dx	New Dx Rates					New Dx	RTSR old	WMSC	DRC	TLF old	Old	Band 1	Band 2	Old	Total Bill	Total Bill	Total Bill	Total Bill
																						-	5.2					
New Class	Old Class	kWh	kW	LF	SrChg [$/cust]	base [$/kW]	Rider1 [$/kW]	Rider2 [$/kW]	VarChg [$/kW]	[$/month]	SrChg [$/cust]	base [$/kW]	Rider2 [$/kW]	Rider3 [$/kW]	VarChg [$/kW]	[$/month]	$/kW	c/kWh	c/kWh		$	kWhs	kWhs	Total $	[$/month]	[$/month]	[$/month]	%
GSd	Blyth	15,000	60	35%	**21.63**	**3.37**	**0.82**	**0.64**	**4.83**	311.4	**27.28**	**8.50**	**0.64**	**(0.22)**	**8.92**	562.6	**3.54**	0.62	0.7	1.0545	426.9	-	15,000	822.5	1,560.9	1,812.1	251.2	16.1%
		43,164	133	45%	21.63	3.37	0.82	0.64	4.83	664.0	27.28	8.50	0.64	(0.22)	8.92	1,214.0	3.54	0.62	0.70	1.05	1,080.5	-	43,164	2,366.9	4,111.4	4,661.4	550.0	13.4%
		100,000	500	28%	21.63	3.37	0.82	0.64	4.83	2,436.6	27.28	8.50	0.64	(0.22)	8.92	4,488.6	3.54	0.62	0.70	1.05	3,219.2	-	100,000	5,483.4	11,139.2	13,191.2	2,052.0	18.4%
		400,000	1000	56%	21.63	3.37	0.82	0.64	4.83	4,851.6	27.28	8.50	0.64	(0.22)	8.92	8,950.0	3.54	0.62	0.70	1.05	9,146.0	-	400,000	21,933.6	35,931.2	40,029.6	4,098.4	11.4%
		1,000,000	3000	46%	21.63	3.37	0.82	0.64	4.83	14,511.6	27.28	8.50	0.64	(0.22)	8.92	26,795.4	3.54	0.62	0.70	1.05	24,730.4	-	1,000,000	54,834.0	94,076.0	106,359.8	12,283.8	13.1%
		1,500,000	4000	52%	21.63	3.37	0.82	0.64	4.83	19,341.6	27.28	8.50	0.64	(0.22)	8.92	35,718.1	3.54	0.62	0.70	1.05	35,230.1	-	1,500,000	82,251.0	136,822.8	153,199.2	16,376.5	12.0%
GSd	Bobcaygeon	15,000	60	35%	**23.20**	**4.35**	**0.58**	**0.27**	**5.20**	335.2	**28.89**	**9.22**	**0.27**	**(0.22)**	**9.28**	585.5	**3.54**	0.62	0.7	1.0545	426.9	-	15,000	822.5	1,584.6	1,834.9	250.3	15.8%
		43,164	133	45%	23.20	4.35	0.58	0.27	5.20	714.8	28.89	9.22	0.27	(0.22)	9.28	1,262.6	3.54	0.62	0.70	1.05	1,080.5	-	43,164	2,366.9	4,162.2	4,710.0	547.8	13.2%
		100,000	500	28%	23.20	4.35	0.58	0.27	5.20	2,623.2	28.89	9.22	0.27	(0.22)	9.28	4,667.0	3.54	0.62	0.70	1.05	3,219.2	-	100,000	5,483.4	11,325.8	13,369.6	2,043.8	18.0%
		400,000	1000	56%	23.20	4.35	0.58	0.27	5.20	5,223.2	28.89	9.22	0.27	(0.22)	9.28	9,305.2	3.54	0.62	0.70	1.05	9,146.0	-	400,000	21,933.6	36,302.8	40,384.8	4,082.0	11.2%
		1,000,000	3000	46%	23.20	4.35	0.58	0.27	5.20	15,623.2	28.89	9.22	0.27	(0.22)	9.28	27,857.7	3.54	0.62	0.70	1.05	24,730.4	-	1,000,000	54,834.0	95,187.6	107,422.1	12,234.5	12.9%
		1,500,000	4000	52%	23.20	4.35	0.58	0.27	5.20	20,823.2	28.89	9.22	0.27	(0.22)	9.28	37,134.0	3.54	0.62	0.70	1.05	35,230.1	-	1,500,000	82,251.0	138,304.3	154,615.2	16,310.8	11.8%
GSd	Brighton	15,000	60	35%	**22.90**	**4.24**	**0.65**	**0.25**	**5.14**	331.3	**27.96**	**9.22**	**0.25**	**(0.22)**	**9.26**	583.3	**3.54**	0.62	0.7	1.0545	426.9	-	15,000	822.5	1,580.7	1,832.8	252.0	15.9%
		43,164	133	45%	22.90	4.24	0.65	0.25	5.14	706.5	27.96	9.22	0.25	(0.22)	9.26	1,259.0	3.54	0.62	0.70	1.05	1,080.5	-	43,164	2,366.9	4,153.9	4,706.5	552.5	13.3%
		100,000	500	28%	22.90	4.24	0.65	0.25	5.14	2,592.9	27.96	9.22	0.25	(0.22)	9.26	4,656.1	3.54	0.62	0.70	1.05	3,219.2	-	100,000	5,483.4	11,295.5	13,358.7	2,063.2	18.3%
		400,000	1000	56%	22.90	4.24	0.65	0.25	5.14	5,162.9	27.96	9.22	0.25	(0.22)	9.26	9,284.2	3.54	0.62	0.70	1.05	9,146.0	-	400,000	21,933.6	36,242.5	40,363.8	4,121.3	11.4%
		1,000,000	3000	46%	22.90	4.24	0.65	0.25	5.14	15,442.9	27.96	9.22	0.25	(0.22)	9.26	27,796.8	3.54	0.62	0.70	1.05	24,730.4	-	1,000,000	54,834.0	95,007.3	107,361.2	12,353.9	13.0%
		1,500,000	4000	52%	22.90	4.24	0.65	0.25	5.14	20,582.9	27.96	9.22	0.25	(0.22)	9.26	37,053.1	3.54	0.62	0.70	1.05	35,230.1	-	1,500,000	82,251.0	138,064.0	154,534.2	16,470.2	11.9%
UGd	Brockville	15,000	60	35%	**21.65**	**2.49**	**0.41**	**0.12**	**3.02**	202.9	**22.89**	**6.70**	**0.12**	**(0.27)**	**6.55**	415.7	**3.54**	0.62	0.7	1.0545	426.9	-	15,000	822.5	1,452.3	1,665.1	212.9	14.7%
		43,164	133	45%	21.65	2.49	0.41	0.12	3.02	423.3	22.89	6.70	0.12	(0.27)	6.55	893.7	3.54	0.62	0.70	1.05	1,080.5	-	43,164	2,366.9	3,870.7	4,341.1	470.3	12.2%
		100,000	500	28%	21.65	2.49	0.41	0.12	3.02	1,531.7	22.89	6.70	0.12	(0.27)	6.55	3,296.4	3.54	0.62	0.70	1.05	3,219.2	-	100,000	5,483.4	10,234.3	11,999.0	1,764.8	17.2%
		400,000	1000	56%	21.65	2.49	0.41	0.12	3.02	3,041.7	22.89	6.70	0.12	(0.27)	6.55	6,570.0	3.54	0.62	0.70	1.05	9,146.0	-	400,000	21,933.6	34,121.2	37,649.6	3,528.4	10.3%
		1,000,000	3000	46%	21.65	2.49	0.41	0.12	3.02	9,081.7	22.89	6.70	0.12	(0.27)	6.55	19,664.3	3.54	0.62	0.70	1.05	24,730.4	-	1,000,000	54,834.0	88,646.0	99,228.6	10,582.6	11.9%
		1,500,000	4000	52%	21.65	2.49	0.41	0.12	3.02	12,101.7	22.89	6.70	0.12	(0.27)	6.55	26,211.4	3.54	0.62	0.70	1.05	35,230.1	-	1,500,000	82,251.0	129,582.8	143,692.5	14,109.7	10.9%
GSd	Caledon CH	15,000	60	35%	**24.21**	**5.73**	**0.45**	**0.27**	**6.45**	411.2	**29.64**	**9.22**	**0.27**	**(0.22)**	**9.28**	586.2	**3.54**	0.62	0.7	1.0545	426.9	-	15,000	822.5	1,660.6	1,835.6	175.0	10.5%
		43,164	133	45%	24.21	5.73	0.45	0.27	6.45	882.1	29.64	9.22	0.27	(0.22)	9.28	1,263.4	3.54	0.62	0.70	1.05	1,080.5	-	43,164	2,366.9	4,329.5	4,710.8	381.3	8.8%
		100,000	500	28%	24.21	5.73	0.45	0.27	6.45	3,249.2	29.64	9.22	0.27	(0.22)	9.28	4,667.8	3.54	0.62	0.70	1.05	3,219.2	-	100,000	5,483.4	11,951.8	13,370.4	1,418.6	11.9%
		400,000	1000	56%	24.21	5.73	0.45	0.27	6.45	6,474.2	29.64	9.22	0.27	(0.22)	9.28	9,305.9	3.54	0.62	0.70	1.05	9,146.0	-	400,000	21,933.6	37,553.8	40,385.5	2,831.7	7.5%
		1,000,000	3000	46%	24.21	5.73	0.45	0.27	6.45	19,374.2	29.64	9.22	0.27	(0.22)	9.28	27,858.5	3.54	0.62	0.70	1.05	24,730.4	-	1,000,000	54,834.0	98,938.6	107,422.9	8,484.3	8.6%
		1,500,000	4000	52%	24.21	5.73	0.45	0.27	6.45	25,824.2	29.64	9.22	0.27	(0.22)	9.28	37,134.8	3.54	0.62	0.70	1.05	35,230.1	-	1,500,000	82,251.0	143,305.3	154,615.9	11,310.6	7.9%

New Rate Class: GSd

Total Bill Impacts of Proposed Distribution Rates [old RTSR+TLF]: Threshold of 750 kWhs

Classes		Scenario			May 2007 Incl Rate Riders						May 2008 Incl Rate Riders						Non-Dx Compoent				Other Reg	Commodity Bands			Existing	New	$ Incr	% Incr
					Existing Dx Rates					Existing Dx	New Dx Rates					New Dx	RTSR old	WMSC	DRC	TLF old	Old	Band 1	Band 2	Old	Total Bill	Total Bill	Total Bill	Total Bill
																						-	5.2					
New Class	Old Class	kWh	kW	LF	SrChg [$/cust]	base [$/kW]	Rider1 [$/kW]	Rider2 [$/kW]	VarChg [$/kW]	[$/month]	SrChg [$/cust]	base [$/kW]	Rider2 [$/kW]	Rider3 [$/kW]	VarChg [$/kW]	[$/month]	$/kW	c/kWh	c/kWh		$	kWhs	kWhs	Total $	[$/month]	[$/month]	[$/month]	%
GSd	Caledon OH	15,000	60	35%	25.56	5.35	0.51	0.24	6.10	391.6	30.30	9.22	0.24	(0.22)	9.25	585.1	3.54	0.62	0.7	1.0545	426.9	-	15,000	822.5	1,641.0	1,834.5	193.5	11.8%
		43,164	133	45%	25.56	5.35	0.51	0.24	6.10	836.9	30.30	9.22	0.24	(0.22)	9.25	1,260.1	3.54	0.62	0.70	1.05	1,080.5	-	43,164	2,366.9	4,284.3	4,707.5	423.2	9.9%
		100,000	500	28%	25.56	5.35	0.51	0.24	6.10	3,075.6	30.30	9.22	0.24	(0.22)	9.25	4,653.4	3.54	0.62	0.70	1.05	3,219.2	-	100,000	5,483.4	11,778.2	13,356.0	1,577.9	13.4%
		400,000	1000	56%	25.56	5.35	0.51	0.24	6.10	6,125.6	30.30	9.22	0.24	(0.22)	9.25	9,276.6	3.54	0.62	0.70	1.05	9,146.0	-	400,000	21,933.6	37,205.1	40,356.2	3,151.0	8.5%
		1,000,000	3000	46%	25.56	5.35	0.51	0.24	6.10	18,325.6	30.30	9.22	0.24	(0.22)	9.25	27,769.1	3.54	0.62	0.70	1.05	24,730.4	-	1,000,000	54,834.0	97,889.9	107,333.5	9,443.6	9.6%
		1,500,000	4000	52%	25.56	5.35	0.51	0.24	6.10	24,425.6	30.30	9.22	0.24	(0.22)	9.25	37,015.4	3.54	0.62	0.70	1.05	35,230.1	-	1,500,000	82,251.0	141,906.7	154,496.6	12,589.9	8.9%
GSd	Campbellford-Seymou	15,000	60	35%	16.19	3.77	0.53	0.17	4.47	284.4	23.64	8.50	0.17	(0.22)	8.45	530.8	3.54	0.62	0.7	1.0545	426.9	-	15,000	822.5	1,533.8	1,780.2	246.4	16.1%
		43,164	133	45%	16.19	3.77	0.53	0.17	4.47	610.7	23.64	8.50	0.17	(0.22)	8.45	1,147.8	3.54	0.62	0.70	1.05	1,080.5	-	43,164	2,366.9	4,058.1	4,595.3	537.1	13.2%
		100,000	500	28%	16.19	3.77	0.53	0.17	4.47	2,251.2	23.64	8.50	0.17	(0.22)	8.45	4,250.0	3.54	0.62	0.70	1.05	3,219.2	-	100,000	5,483.4	10,953.8	12,952.6	1,998.8	18.2%
		400,000	1000	56%	16.19	3.77	0.53	0.17	4.47	4,486.2	23.64	8.50	0.17	(0.22)	8.45	8,476.3	3.54	0.62	0.70	1.05	9,146.0	-	400,000	21,933.6	35,565.8	39,555.9	3,990.2	11.2%
		1,000,000	3000	46%	16.19	3.77	0.53	0.17	4.47	13,426.2	23.64	8.50	0.17	(0.22)	8.45	25,381.8	3.54	0.62	0.70	1.05	24,730.4	-	1,000,000	54,834.0	92,990.6	104,946.1	11,955.6	12.9%
		1,500,000	4000	52%	16.19	3.77	0.53	0.17	4.47	17,896.2	23.64	8.50	0.17	(0.22)	8.45	33,834.5	3.54	0.62	0.70	1.05	35,230.1	-	1,500,000	82,251.0	135,377.3	151,315.6	15,938.3	11.8%
UGd	Carleton Place	15,000	60	35%	23.65	5.31	0.42	0.22	5.95	380.7	24.39	7.33	0.22	(0.27)	7.28	461.2	3.54	0.62	0.7	1.0545	426.9	-	15,000	822.5	1,630.1	1,710.6	80.5	4.9%
		43,164	133	45%	23.65	5.31	0.42	0.22	5.95	815.0	24.39	7.33	0.22	(0.27)	7.28	992.7	3.54	0.62	0.70	1.05	1,080.5	-	43,164	2,366.9	4,262.4	4,440.1	177.7	4.2%
		100,000	500	28%	23.65	5.31	0.42	0.22	5.95	2,998.7	24.39	7.33	0.22	(0.27)	7.28	3,664.5	3.54	0.62	0.70	1.05	3,219.2	-	100,000	5,483.4	11,701.3	12,367.1	665.8	5.7%
		400,000	1000	56%	23.65	5.31	0.42	0.22	5.95	5,973.7	24.39	7.33	0.22	(0.27)	7.28	7,304.6	3.54	0.62	0.70	1.05	9,146.0	-	400,000	21,933.6	37,053.2	38,384.2	1,330.9	3.6%
		1,000,000	3000	46%	23.65	5.31	0.42	0.22	5.95	17,873.7	24.39	7.33	0.22	(0.27)	7.28	21,865.0	3.54	0.62	0.70	1.05	24,730.4	-	1,000,000	54,834.0	97,438.0	101,429.4	3,991.3	4.1%
		1,500,000	4000	52%	23.65	5.31	0.42	0.22	5.95	23,823.7	24.39	7.33	0.22	(0.27)	7.28	29,145.2	3.54	0.62	0.70	1.05	35,230.1	-	1,500,000	82,251.0	141,304.8	146,626.3	5,321.6	3.8%
GSd	Cavan-Millbrook-Nortl	15,000	60	35%	22.28	4.67	1.06	0.81	6.54	414.7	28.12	9.22	0.81	(0.22)	9.82	617.1	3.54	0.62	0.7	1.0545	426.9	-	15,000	822.5	1,664.1	1,866.5	202.4	12.2%
		43,164	133	45%	22.28	4.67	1.06	0.81	6.54	892.1	28.12	9.22	0.81	(0.22)	9.82	1,333.7	3.54	0.62	0.70	1.05	1,080.5	-	43,164	2,366.9	4,339.5	4,781.1	441.6	10.2%
		100,000	500	28%	22.28	4.67	1.06	0.81	6.54	3,292.3	28.12	9.22	0.81	(0.22)	9.82	4,936.3	3.54	0.62	0.70	1.05	3,219.2	-	100,000	5,483.4	11,994.9	13,638.9	1,644.0	13.7%
		400,000	1000	56%	22.28	4.67	1.06	0.81	6.54	6,562.3	28.12	9.22	0.81	(0.22)	9.82	9,844.4	3.54	0.62	0.70	1.05	9,146.0	-	400,000	21,933.6	37,641.9	40,924.0	3,282.1	8.7%
		1,000,000	3000	46%	22.28	4.67	1.06	0.81	6.54	19,642.3	28.12	9.22	0.81	(0.22)	9.82	29,477.0	3.54	0.62	0.70	1.05	24,730.4	-	1,000,000	54,834.0	99,206.6	109,041.3	9,834.7	9.9%
		1,500,000	4000	52%	22.28	4.67	1.06	0.81	6.54	26,182.3	28.12	9.22	0.81	(0.22)	9.82	39,293.3	3.54	0.62	0.70	1.05	35,230.1	-	1,500,000	82,251.0	143,663.4	156,774.4	13,111.0	9.1%
GSd	Centre Hastings	15,000	60	35%	18.38	3.07	0.45	0.20	3.72	241.6	25.09	7.70	0.20	(0.22)	7.68	486.1	3.54	0.62	0.7	1.0545	426.9	-	15,000	822.5	1,491.0	1,735.5	244.5	16.4%
		43,164	133	45%	18.38	3.07	0.45	0.20	3.72	513.1	25.09	7.70	0.20	(0.22)	7.68	1,046.9	3.54	0.62	0.70	1.05	1,080.5	-	43,164	2,366.9	3,960.5	4,494.3	533.8	13.5%
		100,000	500	28%	18.38	3.07	0.45	0.20	3.72	1,878.4	25.09	7.70	0.20	(0.22)	7.68	3,866.4	3.54	0.62	0.70	1.05	3,219.2	-	100,000	5,483.4	10,581.0	12,569.0	1,988.1	18.8%
		400,000	1000	56%	18.38	3.07	0.45	0.20	3.72	3,738.4	25.09	7.70	0.20	(0.22)	7.68	7,707.8	3.54	0.62	0.70	1.05	9,146.0	-	400,000	21,933.6	34,818.0	38,787.4	3,969.4	11.4%
		1,000,000	3000	46%	18.38	3.07	0.45	0.20	3.72	11,178.4	25.09	7.70	0.20	(0.22)	7.68	23,073.2	3.54	0.62	0.70	1.05	24,730.4	-	1,000,000	54,834.0	90,742.7	102,637.6	11,894.8	13.1%
		1,500,000	4000	52%	18.38	3.07	0.45	0.20	3.72	14,898.4	25.09	7.70	0.20	(0.22)	7.68	30,755.9	3.54	0.62	0.70	1.05	35,230.1	-	1,500,000	82,251.0	132,379.5	148,237.0	15,857.5	12.0%

New Rate Class: GSd

Total Bill Impacts of Proposed Distribution Rates [old RTSR+TLF]: Threshold of 750 kWhs

Classes		Scenario			May 2007 Incl Rate Riders						May 2008 Incl Rate Riders						Non-Dx Compoent				Other Reg	Commodity Bands			Existing	New	$ Incr	% Incr
					Existing Dx Rates					Existing Dx	New Dx Rates					New Dx	RTSR old	WMSC	DRC	TLF old	Old	Band 1	Band 2	Old	Total Bill	Total Bill	Total Bill	Total Bill
																						-	5.2					
New Class	Old Class	kWh	kW	LF	SrChg [$/cust]	base [$/kW]	Rider1 [$/kW]	Rider2 [$/kW]	VarChg [$/kW]	[$/month]	SrChg [$/cust]	base [$/kW]	Rider2 [$/kW]	Rider3 [$/kW]	VarChg [$/kW]	[$/month]	$/kW	c/kWh	c/kWh		$	kWhs	kWhs	Total $	[$/month]	[$/month]	[$/month]	%
GSd	Chalk River	15,000	60	35%	**21.33**	**5.70**	**1.23**	**1.07**	**8.00**	501.3	**27.36**	**9.22**	**1.07**	**(0.22)**	**10.08**	631.9	**3.54**	0.62	0.7	1.0545	426.9	-	15,000	822.5	1,750.8	1,881.4	130.6	7.5%
		43,164	133	45%	21.33	5.70	1.23	1.07	8.00	1,085.3	27.36	9.22	1.07	(0.22)	10.08	1,367.5	3.54	0.62	0.70	1.05	1,080.5	-	43,164	2,366.9	4,532.7	4,814.9	282.2	6.2%
		100,000	500	28%	21.33	5.70	1.23	1.07	8.00	4,021.3	27.36	9.22	1.07	(0.22)	10.08	5,065.5	3.54	0.62	0.70	1.05	3,219.2	-	100,000	5,483.4	12,723.9	13,768.1	1,044.2	8.2%
		400,000	1000	56%	21.33	5.70	1.23	1.07	8.00	8,021.3	27.36	9.22	1.07	(0.22)	10.08	10,103.6	3.54	0.62	0.70	1.05	9,146.0	-	400,000	21,933.6	39,100.9	41,183.2	2,082.3	5.3%
		1,000,000	3000	46%	21.33	5.70	1.23	1.07	8.00	24,021.3	27.36	9.22	1.07	(0.22)	10.08	30,256.2	3.54	0.62	0.70	1.05	24,730.4	-	1,000,000	54,834.0	103,585.7	109,820.6	6,234.9	6.0%
		1,500,000	4000	52%	21.33	5.70	1.23	1.07	8.00	32,021.3	27.36	9.22	1.07	(0.22)	10.08	40,332.5	3.54	0.62	0.70	1.05	35,230.1	-	1,500,000	82,251.0	149,502.5	157,813.6	8,311.2	5.6%
GSd	Champlain	15,000	60	35%	**20.59**	**2.88**	**0.84**	**0.49**	**4.21**	273.2	**26.54**	**8.00**	**0.49**	**(0.22)**	**8.27**	522.9	**3.54**	0.62	0.7	1.0545	426.9	-	15,000	822.5	1,522.6	1,772.3	249.7	16.4%
		43,164	133	45%	20.59	2.88	0.84	0.49	4.21	580.5	26.54	8.00	0.49	(0.22)	8.27	1,126.8	3.54	0.62	0.70	1.05	1,080.5	-	43,164	2,366.9	4,027.9	4,574.2	546.3	13.6%
		100,000	500	28%	20.59	2.88	0.84	0.49	4.21	2,125.6	26.54	8.00	0.49	(0.22)	8.27	4,162.9	3.54	0.62	0.70	1.05	3,219.2	-	100,000	5,483.4	10,828.2	12,865.5	2,037.3	18.8%
		400,000	1000	56%	20.59	2.88	0.84	0.49	4.21	4,230.6	26.54	8.00	0.49	(0.22)	8.27	8,299.2	3.54	0.62	0.70	1.05	9,146.0	-	400,000	21,933.6	35,310.2	39,378.8	4,068.7	11.5%
		1,000,000	3000	46%	20.59	2.88	0.84	0.49	4.21	12,650.6	26.54	8.00	0.49	(0.22)	8.27	24,844.7	3.54	0.62	0.70	1.05	24,730.4	-	1,000,000	54,834.0	92,215.0	104,409.0	12,194.1	13.2%
		1,500,000	4000	52%	20.59	2.88	0.84	0.49	4.21	16,860.6	26.54	8.00	0.49	(0.22)	8.27	33,117.4	3.54	0.62	0.70	1.05	35,230.1	-	1,500,000	82,251.0	134,341.7	150,598.5	16,256.8	12.1%
GSd	Cobden	15,000	60	35%	**21.93**	**6.49**	**1.16**	**0.90**	**8.55**	534.9	**27.21**	**9.22**	**0.90**	**(0.22)**	**9.91**	621.6	**3.54**	0.62	0.7	1.0545	426.9	-	15,000	822.5	1,784.4	1,871.0	86.7	4.9%
		43,164	133	45%	21.93	6.49	1.16	0.90	8.55	1,159.1	27.21	9.22	0.90	(0.22)	9.91	1,344.7	3.54	0.62	0.70	1.05	1,080.5	-	43,164	2,366.9	4,606.5	4,792.1	185.7	4.0%
		100,000	500	28%	21.93	6.49	1.16	0.90	8.55	4,296.9	27.21	9.22	0.90	(0.22)	9.91	4,980.3	3.54	0.62	0.70	1.05	3,219.2	-	100,000	5,483.4	12,999.5	13,682.9	683.4	5.3%
		400,000	1000	56%	21.93	6.49	1.16	0.90	8.55	8,571.9	27.21	9.22	0.90	(0.22)	9.91	9,933.5	3.54	0.62	0.70	1.05	9,146.0	-	400,000	21,933.6	39,651.5	41,013.1	1,361.6	3.4%
		1,000,000	3000	46%	21.93	6.49	1.16	0.90	8.55	25,671.9	27.21	9.22	0.90	(0.22)	9.91	29,746.1	3.54	0.62	0.70	1.05	24,730.4	-	1,000,000	54,834.0	105,236.3	109,310.4	4,074.1	3.9%
		1,500,000	4000	52%	21.93	6.49	1.16	0.90	8.55	34,221.9	27.21	9.22	0.90	(0.22)	9.91	39,652.3	3.54	0.62	0.70	1.05	35,230.1	-	1,500,000	82,251.0	151,703.1	157,133.5	5,430.4	3.6%
GSd	Deep River	15,000	60	35%	**23.94**	**7.18**	**0.46**	**0.46**	**8.10**	509.9	**28.70**	**9.22**	**0.46**	**(0.22)**	**9.47**	596.7	**3.54**	0.62	0.7	1.0545	426.9	-	15,000	822.5	1,759.4	1,846.1	86.7	4.9%
		43,164	133	45%	23.94	7.18	0.46	0.46	8.10	1,101.2	28.70	9.22	0.46	(0.22)	9.47	1,287.7	3.54	0.62	0.70	1.05	1,080.5	-	43,164	2,366.9	4,548.6	4,735.1	186.5	4.1%
		100,000	500	28%	23.94	7.18	0.46	0.46	8.10	4,073.9	28.70	9.22	0.46	(0.22)	9.47	4,761.8	3.54	0.62	0.70	1.05	3,219.2	-	100,000	5,483.4	12,776.5	13,464.4	687.9	5.4%
		400,000	1000	56%	23.94	7.18	0.46	0.46	8.10	8,123.9	28.70	9.22	0.46	(0.22)	9.47	9,495.0	3.54	0.62	0.70	1.05	9,146.0	-	400,000	21,933.6	39,203.5	40,574.6	1,371.0	3.5%
		1,000,000	3000	46%	23.94	7.18	0.46	0.46	8.10	24,323.9	28.70	9.22	0.46	(0.22)	9.47	28,427.6	3.54	0.62	0.70	1.05	24,730.4	-	1,000,000	54,834.0	103,888.3	107,991.9	4,103.6	4.0%
		1,500,000	4000	52%	23.94	7.18	0.46	0.46	8.10	32,423.9	28.70	9.22	0.46	(0.22)	9.47	37,893.8	3.54	0.62	0.70	1.05	35,230.1	-	1,500,000	82,251.0	149,905.1	155,375.0	5,469.9	3.6%
GSd	Deseronto	15,000	60	35%	**10.14**	**3.85**	**0.41**	**0.14**	**4.40**	274.1	**19.15**	**8.50**	**0.14**	**(0.22)**	**8.42**	524.5	**3.54**	0.62	0.7	1.0545	426.9	-	15,000	822.5	1,523.6	1,773.9	250.4	16.4%
		43,164	133	45%	10.14	3.85	0.41	0.14	4.40	595.3	19.15	8.50	0.14	(0.22)	8.42	1,139.4	3.54	0.62	0.70	1.05	1,080.5	-	43,164	2,366.9	4,042.7	4,586.8	544.0	13.5%
		100,000	500	28%	10.14	3.85	0.41	0.14	4.40	2,210.1	19.15	8.50	0.14	(0.22)	8.42	4,230.5	3.54	0.62	0.70	1.05	3,219.2	-	100,000	5,483.4	10,912.7	12,933.1	2,020.4	18.5%
		400,000	1000	56%	10.14	3.85	0.41	0.14	4.40	4,410.1	19.15	8.50	0.14	(0.22)	8.42	8,441.9	3.54	0.62	0.70	1.05	9,146.0	-	400,000	21,933.6	35,489.7	39,521.4	4,031.7	11.4%
		1,000,000	3000	46%	10.14	3.85	0.41	0.14	4.40	13,210.1	19.15	8.50	0.14	(0.22)	8.42	25,287.3	3.54	0.62	0.70	1.05	24,730.4	-	1,000,000	54,834.0	92,774.5	104,851.6	12,077.1	13.0%
		1,500,000	4000	52%	10.14	3.85	0.41	0.14	4.40	17,610.1	19.15	8.50	0.14	(0.22)	8.42	33,710.0	3.54	0.62	0.70	1.05	35,230.1	-	1,500,000	82,251.0	135,091.3	151,191.1	16,099.8	11.9%

New Rate Class: GSd

Total Bill Impacts of Proposed Distribution Rates [old RTSR+TLF]: Threshold of 750 kWhs

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Classes		Scenario			May 2007 Incl Rate Riders						May 2008 Incl Rate Riders						Non-Dx Compoent				Other Reg	Commodity Bands			Existing	New	$ Incr	% Incr
					Existing Dx Rates					Existing Dx	New Dx Rates					New Dx	RTSR old	WMSC	DRC	TLF old	Old	Band 1	Band 2	Old	Total Bill	Total Bill	Total Bill	Total Bill
																						-	5.2					
New Class	Old Class	kWh	kW	LF	SrChg [$/cust]	base [$/kW]	Rider1 [$/kW]	Rider2 [$/kW]	VarChg [$/kW]	[$/month]	SrChg [$/cust]	base [$/kW]	Rider2 [$/kW]	Rider3 [$/kW]	VarChg [$/kW]	[$/month]	$/kW	c/kWh	c/kWh		$	kWhs	kWhs	Total $	[$/month]	[$/month]	[$/month]	%
UGd	**Dryden**	15,000	60	35%	**19.11**	**3.29**	**0.38**	**0.13**	**3.80**	247.1	**21.52**	**7.33**	**0.13**	**(0.27)**	**7.19**	452.9	**3.54**	0.62	0.7	1.0545	426.9	-	15,000	822.5	1,496.5	1,702.4	205.8	13.8%
		43,164	133	45%	19.11	3.29	0.38	0.13	3.80	524.5	21.52	7.33	0.13	(0.27)	7.19	977.8	3.54	0.62	0.70	1.05	1,080.5	-	43,164	2,366.9	3,971.9	4,425.2	453.3	11.4%
		100,000	500	28%	19.11	3.29	0.38	0.13	3.80	1,919.1	21.52	7.33	0.13	(0.27)	7.19	3,616.6	3.54	0.62	0.70	1.05	3,219.2	-	100,000	5,483.4	10,621.7	12,319.2	1,697.5	16.0%
		400,000	1000	56%	19.11	3.29	0.38	0.13	3.80	3,819.1	21.52	7.33	0.13	(0.27)	7.19	7,211.7	3.54	0.62	0.70	1.05	9,146.0	-	400,000	21,933.6	34,898.7	38,291.3	3,392.6	9.7%
		1,000,000	3000	46%	19.11	3.29	0.38	0.13	3.80	11,419.1	21.52	7.33	0.13	(0.27)	7.19	21,592.1	3.54	0.62	0.70	1.05	24,730.4	-	1,000,000	54,834.0	90,983.5	101,156.5	10,173.0	11.2%
		1,500,000	4000	52%	19.11	3.29	0.38	0.13	3.80	15,219.1	21.52	7.33	0.13	(0.27)	7.19	28,782.3	3.54	0.62	0.70	1.05	35,230.1	-	1,500,000	82,251.0	132,700.2	146,263.5	13,563.2	10.2%
GSd	**Dundalk**	15,000	60	35%	**23.56**	**5.17**	**0.74**	**0.28**	**6.19**	395.0	**28.80**	**9.22**	**0.28**	**(0.22)**	**9.29**	586.0	**3.54**	0.62	0.7	1.0545	426.9	-	15,000	822.5	1,644.4	1,835.4	191.0	11.6%
		43,164	133	45%	23.56	5.17	0.74	0.28	6.19	846.8	28.80	9.22	0.28	(0.22)	9.29	1,263.9	3.54	0.62	0.70	1.05	1,080.5	-	43,164	2,366.9	4,294.2	4,711.3	417.0	9.7%
		100,000	500	28%	23.56	5.17	0.74	0.28	6.19	3,118.6	28.80	9.22	0.28	(0.22)	9.29	4,671.9	3.54	0.62	0.70	1.05	3,219.2	-	100,000	5,483.4	11,821.2	13,374.5	1,553.4	13.1%
		400,000	1000	56%	23.56	5.17	0.74	0.28	6.19	6,213.6	28.80	9.22	0.28	(0.22)	9.29	9,315.1	3.54	0.62	0.70	1.05	9,146.0	-	400,000	21,933.6	37,293.1	40,394.7	3,101.5	8.3%
		1,000,000	3000	46%	23.56	5.17	0.74	0.28	6.19	18,593.6	28.80	9.22	0.28	(0.22)	9.29	27,887.6	3.54	0.62	0.70	1.05	24,730.4	-	1,000,000	54,834.0	98,157.9	107,452.0	9,294.1	9.5%
		1,500,000	4000	52%	23.56	5.17	0.74	0.28	6.19	24,783.6	28.80	9.22	0.28	(0.22)	9.29	37,173.9	3.54	0.62	0.70	1.05	35,230.1	-	1,500,000	82,251.0	142,264.7	154,655.1	12,390.4	8.7%
GSd	**Durham**	15,000	60	35%	**24.12**	**4.31**	**0.48**	**0.18**	**4.97**	322.3	**29.66**	**9.22**	**0.18**	**(0.22)**	**9.19**	580.8	**3.54**	0.62	0.7	1.0545	426.9	-	15,000	822.5	1,571.7	1,830.3	258.5	16.4%
		43,164	133	45%	24.12	4.31	0.48	0.18	4.97	685.1	29.66	9.22	0.18	(0.22)	9.19	1,251.4	3.54	0.62	0.70	1.05	1,080.5	-	43,164	2,366.9	4,132.5	4,698.8	566.3	13.7%
		100,000	500	28%	24.12	4.31	0.48	0.18	4.97	2,509.1	29.66	9.22	0.18	(0.22)	9.19	4,622.8	3.54	0.62	0.70	1.05	3,219.2	-	100,000	5,483.4	11,211.7	13,325.4	2,113.7	18.9%
		400,000	1000	56%	24.12	4.31	0.48	0.18	4.97	4,994.1	29.66	9.22	0.18	(0.22)	9.19	9,215.9	3.54	0.62	0.70	1.05	9,146.0	-	400,000	21,933.6	36,073.7	40,295.5	4,221.8	11.7%
		1,000,000	3000	46%	24.12	4.31	0.48	0.18	4.97	14,934.1	29.66	9.22	0.18	(0.22)	9.19	27,588.5	3.54	0.62	0.70	1.05	24,730.4	-	1,000,000	54,834.0	94,498.5	107,152.9	12,654.4	13.4%
		1,500,000	4000	52%	24.12	4.31	0.48	0.18	4.97	19,904.1	29.66	9.22	0.18	(0.22)	9.19	36,774.8	3.54	0.62	0.70	1.05	35,230.1	-	1,500,000	82,251.0	137,385.3	154,255.9	16,870.7	12.3%
GSd	**Eganville**	15,000	60	35%	**21.35**	**7.35**	**0.55**	**0.37**	**8.27**	517.6	**27.35**	**9.22**	**0.37**	**(0.22)**	**9.38**	589.9	**3.54**	0.62	0.7	1.0545	426.9	-	15,000	822.5	1,767.0	1,839.4	72.4	4.1%
		43,164	133	45%	21.35	7.35	0.55	0.37	8.27	1,121.3	27.35	9.22	0.37	(0.22)	9.38	1,274.4	3.54	0.62	0.70	1.05	1,080.5	-	43,164	2,366.9	4,568.7	4,721.8	153.1	3.4%
		100,000	500	28%	21.35	7.35	0.55	0.37	8.27	4,156.4	27.35	9.22	0.37	(0.22)	9.38	4,715.5	3.54	0.62	0.70	1.05	3,219.2	-	100,000	5,483.4	12,859.0	13,418.1	559.1	4.3%
		400,000	1000	56%	21.35	7.35	0.55	0.37	8.27	8,291.4	27.35	9.22	0.37	(0.22)	9.38	9,403.6	3.54	0.62	0.70	1.05	9,146.0	-	400,000	21,933.6	39,370.9	40,483.2	1,112.3	2.8%
		1,000,000	3000	46%	21.35	7.35	0.55	0.37	8.27	24,831.4	27.35	9.22	0.37	(0.22)	9.38	28,156.2	3.54	0.62	0.70	1.05	24,730.4	-	1,000,000	54,834.0	104,395.7	107,720.6	3,324.9	3.2%
		1,500,000	4000	52%	21.35	7.35	0.55	0.37	8.27	33,101.4	27.35	9.22	0.37	(0.22)	9.38	37,532.5	3.54	0.62	0.70	1.05	35,230.1	-	1,500,000	82,251.0	150,582.5	155,013.6	4,431.1	2.9%
GSd	**Erin**	15,000	60	35%	**40.38**	**2.36**	**0.59**	**0.25**	**3.20**	232.4	**41.59**	**7.20**	**0.25**	**(0.22)**	**7.23**	475.6	**3.54**	0.62	0.7	1.0545	426.9	-	15,000	822.5	1,481.8	1,725.0	243.2	16.4%
		43,164	133	45%	40.38	2.36	0.59	0.25	3.20	466.0	41.59	7.20	0.25	(0.22)	7.23	1,003.5	3.54	0.62	0.70	1.05	1,080.5	-	43,164	2,366.9	3,913.4	4,450.9	537.6	13.7%
		100,000	500	28%	40.38	2.36	0.59	0.25	3.20	1,640.4	41.59	7.20	0.25	(0.22)	7.23	3,657.9	3.54	0.62	0.70	1.05	3,219.2	-	100,000	5,483.4	10,343.0	12,360.5	2,017.6	19.5%
		400,000	1000	56%	40.38	2.36	0.59	0.25	3.20	3,240.4	41.59	7.20	0.25	(0.22)	7.23	7,274.3	3.54	0.62	0.70	1.05	9,146.0	-	400,000	21,933.6	34,320.0	38,353.9	4,033.9	11.8%
		1,000,000	3000	46%	40.38	2.36	0.59	0.25	3.20	9,640.4	41.59	7.20	0.25	(0.22)	7.23	21,739.7	3.54	0.62	0.70	1.05	24,730.4	-	1,000,000	54,834.0	89,204.7	101,304.1	12,099.3	13.6%
		1,500,000	4000	52%	40.38	2.36	0.59	0.25	3.20	12,840.4	41.59	7.20	0.25	(0.22)	7.23	28,972.4	3.54	0.62	0.70	1.05	35,230.1	-	1,500,000	82,251.0	130,321.5	146,453.5	16,132.0	12.4%

New Rate Class: GSd

Total Bill Impacts of Proposed Distribution Rates [old RTSR+TLF]: Threshold of 750 kWhs

Classes		Scenario			May 2007 Incl Rate Riders						May 2008 Incl Rate Riders						Non-Dx Compoent				Other Reg	Commodity Bands			Existing	New	$ Incr	% Incr
					Existing Dx Rates					Existing Dx	New Dx Rates					New Dx	RTSR old	WMSC	DRC	TLF old	Old	Band 1	Band 2	Old	Total Bill	Total Bill	Total Bill	Total Bill
																						-	5.2					
New Class	Old Class	kWh	kW	LF	SrChg [$/cust]	base [$/kW]	Rider1 [$/kW]	Rider2 [$/kW]	VarChg [$/kW]	[$/month]	SrChg [$/cust]	base [$/kW]	Rider2 [$/kW]	Rider3 [$/kW]	VarChg [$/kW]	[$/month]	$/kW	c/kWh	c/kWh		$	kWhs	kWhs	Total $	[$/month]	[$/month]	[$/month]	%
GSd	**Exeter**	15,000	60	35%	**11.36**	**4.11**	**0.49**	**0.18**	**4.78**	298.2	**19.85**	**8.95**	**0.18**	**(0.22)**	**8.91**	554.6	**3.54**	0.62	0.7	1.0545	426.9	-	15,000	822.5	1,547.6	1,804.0	256.4	16.6%
		43,164	133	45%	11.36	4.11	0.49	0.18	4.78	647.1	19.85	8.95	0.18	(0.22)	8.91	1,205.2	3.54	0.62	0.70	1.05	1,080.5	-	43,164	2,366.9	4,094.5	4,652.6	558.1	13.6%
		100,000	500	28%	11.36	4.11	0.49	0.18	4.78	2,401.4	19.85	8.95	0.18	(0.22)	8.91	4,476.2	3.54	0.62	0.70	1.05	3,219.2	-	100,000	5,483.4	11,104.0	13,178.8	2,074.8	18.7%
		400,000	1000	56%	11.36	4.11	0.49	0.18	4.78	4,791.4	19.85	8.95	0.18	(0.22)	8.91	8,932.6	3.54	0.62	0.70	1.05	9,146.0	-	400,000	21,933.6	35,870.9	40,012.1	4,141.2	11.5%
		1,000,000	3000	46%	11.36	4.11	0.49	0.18	4.78	14,351.4	19.85	8.95	0.18	(0.22)	8.91	26,758.0	3.54	0.62	0.70	1.05	24,730.4	-	1,000,000	54,834.0	93,915.7	106,322.3	12,406.6	13.2%
		1,500,000	4000	52%	11.36	4.11	0.49	0.18	4.78	19,131.4	19.85	8.95	0.18	(0.22)	8.91	35,670.7	3.54	0.62	0.70	1.05	35,230.1	-	1,500,000	82,251.0	136,612.5	153,151.8	16,539.3	12.1%
GSd	**Fenelon Falls**	15,000	60	35%	**19.81**	**3.02**	**0.47**	**0.24**	**3.73**	243.6	**25.74**	**7.75**	**0.24**	**(0.22)**	**7.77**	492.1	**3.54**	0.62	0.7	1.0545	426.9	-	15,000	822.5	1,493.0	1,741.5	248.5	16.6%
		43,164	133	45%	19.81	3.02	0.47	0.24	3.73	515.9	25.74	7.75	0.24	(0.22)	7.77	1,059.5	3.54	0.62	0.70	1.05	1,080.5	-	43,164	2,366.9	3,963.3	4,506.9	543.6	13.7%
		100,000	500	28%	19.81	3.02	0.47	0.24	3.73	1,884.8	25.74	7.75	0.24	(0.22)	7.77	3,912.1	3.54	0.62	0.70	1.05	3,219.2	-	100,000	5,483.4	10,587.4	12,614.7	2,027.3	19.1%
		400,000	1000	56%	19.81	3.02	0.47	0.24	3.73	3,749.8	25.74	7.75	0.24	(0.22)	7.77	7,798.4	3.54	0.62	0.70	1.05	9,146.0	-	400,000	21,933.6	34,829.4	38,878.0	4,048.6	11.6%
		1,000,000	3000	46%	19.81	3.02	0.47	0.24	3.73	11,209.8	25.74	7.75	0.24	(0.22)	7.77	23,343.8	3.54	0.62	0.70	1.05	24,730.4	-	1,000,000	54,834.0	90,774.2	102,908.2	12,134.0	13.4%
		1,500,000	4000	52%	19.81	3.02	0.47	0.24	3.73	14,939.8	25.74	7.75	0.24	(0.22)	7.77	31,116.5	3.54	0.62	0.70	1.05	35,230.1	-	1,500,000	82,251.0	132,420.9	148,597.7	16,176.7	12.2%
GSd	**Forest**	15,000	60	35%	**24.91**	**3.74**	**0.50**	**0.20**	**4.44**	291.3	**29.46**	**8.50**	**0.20**	**(0.22)**	**8.48**	538.4	**3.54**	0.62	0.7	1.0545	426.9	-	15,000	822.5	1,540.7	1,787.8	247.1	16.0%
		43,164	133	45%	24.91	3.74	0.50	0.20	4.44	615.4	29.46	8.50	0.20	(0.22)	8.48	1,157.7	3.54	0.62	0.70	1.05	1,080.5	-	43,164	2,366.9	4,062.8	4,605.1	542.2	13.3%
		100,000	500	28%	24.91	3.74	0.50	0.20	4.44	2,244.9	29.46	8.50	0.20	(0.22)	8.48	4,270.8	3.54	0.62	0.70	1.05	3,219.2	-	100,000	5,483.4	10,947.5	12,973.4	2,025.9	18.5%
		400,000	1000	56%	24.91	3.74	0.50	0.20	4.44	4,464.9	29.46	8.50	0.20	(0.22)	8.48	8,512.2	3.54	0.62	0.70	1.05	9,146.0	-	400,000	21,933.6	35,544.5	39,591.7	4,047.3	11.4%
		1,000,000	3000	46%	24.91	3.74	0.50	0.20	4.44	13,344.9	29.46	8.50	0.20	(0.22)	8.48	25,477.6	3.54	0.62	0.70	1.05	24,730.4	-	1,000,000	54,834.0	92,909.3	105,041.9	12,132.7	13.1%
		1,500,000	4000	52%	24.91	3.74	0.50	0.20	4.44	17,784.9	29.46	8.50	0.20	(0.22)	8.48	33,960.3	3.54	0.62	0.70	1.05	35,230.1	-	1,500,000	82,251.0	135,266.0	151,441.4	16,175.4	12.0%
UGd	**GBE**	15,000	60	35%	**10.77**	**3.64**	**0.49**	**0.19**	**4.32**	270.0	**14.61**	**7.33**	**0.19**	**(0.27)**	**7.25**	449.6	**3.54**	0.62	0.7	1.0545	426.9	-	15,000	822.5	1,519.4	1,699.0	179.6	11.8%
		43,164	133	45%	10.77	3.64	0.49	0.19	4.32	585.3	14.61	7.33	0.19	(0.27)	7.25	978.9	3.54	0.62	0.70	1.05	1,080.5	-	43,164	2,366.9	4,032.7	4,426.3	393.6	9.8%
		100,000	500	28%	10.77	3.64	0.49	0.19	4.32	2,170.8	14.61	7.33	0.19	(0.27)	7.25	3,639.7	3.54	0.62	0.70	1.05	3,219.2	-	100,000	5,483.4	10,873.4	12,342.3	1,468.9	13.5%
		400,000	1000	56%	10.77	3.64	0.49	0.19	4.32	4,330.8	14.61	7.33	0.19	(0.27)	7.25	7,264.8	3.54	0.62	0.70	1.05	9,146.0	-	400,000	21,933.6	35,410.4	38,344.4	2,934.0	8.3%
		1,000,000	3000	46%	10.77	3.64	0.49	0.19	4.32	12,970.8	14.61	7.33	0.19	(0.27)	7.25	21,765.2	3.54	0.62	0.70	1.05	24,730.4	-	1,000,000	54,834.0	92,535.1	101,329.6	8,794.4	9.5%
		1,500,000	4000	52%	10.77	3.64	0.49	0.19	4.32	17,290.8	14.61	7.33	0.19	(0.27)	7.25	29,015.4	3.54	0.62	0.70	1.05	35,230.1	-	1,500,000	82,251.0	134,771.9	146,496.6	11,724.7	8.7%
GSd	**Georgina**	15,000	60	35%	**17.40**	**5.10**	**0.51**	**0.25**	**5.86**	369.0	**24.34**	**9.22**	**0.25**	**(0.22)**	**9.26**	579.7	**3.54**	0.62	0.7	1.0545	426.9	-	15,000	822.5	1,618.4	1,829.1	210.7	13.0%
		43,164	133	45%	17.40	5.10	0.51	0.25	5.86	796.8	24.34	9.22	0.25	(0.22)	9.26	1,255.4	3.54	0.62	0.70	1.05	1,080.5	-	43,164	2,366.9	4,244.2	4,702.8	458.6	10.8%
		100,000	500	28%	17.40	5.10	0.51	0.25	5.86	2,947.4	24.34	9.22	0.25	(0.22)	9.26	4,652.5	3.54	0.62	0.70	1.05	3,219.2	-	100,000	5,483.4	11,650.0	13,355.1	1,705.1	14.6%
		400,000	1000	56%	17.40	5.10	0.51	0.25	5.86	5,877.4	24.34	9.22	0.25	(0.22)	9.26	9,280.6	3.54	0.62	0.70	1.05	9,146.0	-	400,000	21,933.6	36,957.0	40,360.2	3,403.2	9.2%
		1,000,000	3000	46%	17.40	5.10	0.51	0.25	5.86	17,597.4	24.34	9.22	0.25	(0.22)	9.26	27,793.2	3.54	0.62	0.70	1.05	24,730.4	-	1,000,000	54,834.0	97,161.8	107,357.6	10,195.8	10.5%
		1,500,000	4000	52%	17.40	5.10	0.51	0.25	5.86	23,457.4	24.34	9.22	0.25	(0.22)	9.26	37,049.5	3.54	0.62	0.70	1.05	35,230.1	-	1,500,000	82,251.0	140,938.5	154,530.6	13,592.1	9.6%

New Rate Class: GSd

Total Bill Impacts of Proposed Distribution Rates [old RTSR+TLF]: Threshold of 750 kWhs

Classes		Scenario			May 2007 Incl Rate Riders						May 2008 Incl Rate Riders						Non-Dx Compoent				Other Reg	Commodity Bands			Existing	New	$ Incr	% Incr
					Existing Dx Rates					Existing Dx	New Dx Rates					New Dx	RTSR old	WMSC	DRC	TLF old	Old	Band 1	Band 2	Old	Total Bill	Total Bill	Total Bill	Total Bill
																						-	5.2					
New Class	Old Class	kWh	kW	LF	SrChg [$/cust]	base [$/kW]	Rider1 [$/kW]	Rider2 [$/kW]	VarChg [$/kW]	[$/month]	SrChg [$/cust]	base [$/kW]	Rider2 [$/kW]	Rider3 [$/kW]	VarChg [$/kW]	[$/month]	$/kW	c/kWh	c/kWh		$	kWhs	kWhs	Total $	[$/month]	[$/month]	[$/month]	%
GSd	Glencoe	15,000	60	35%	**11.37**	**2.55**	**0.69**	**0.44**	**3.68**	232.2	**19.85**	**7.40**	**0.44**	**(0.22)**	**7.62**	477.2	**3.54**	0.62	0.7	1.0545	426.9	-	15,000	822.5	1,481.6	1,726.6	245.0	16.5%
		43,164	133	45%	11.37	2.55	0.69	0.44	3.68	500.8	19.85	7.40	0.44	(0.22)	7.62	1,033.7	3.54	0.62	0.70	1.05	1,080.5	-	43,164	2,366.9	3,948.2	4,481.1	532.9	13.5%
		100,000	500	28%	11.37	2.55	0.69	0.44	3.68	1,851.4	19.85	7.40	0.44	(0.22)	7.62	3,831.2	3.54	0.62	0.70	1.05	3,219.2	-	100,000	5,483.4	10,554.0	12,533.8	1,979.8	18.8%
		400,000	1000	56%	11.37	2.55	0.69	0.44	3.68	3,691.4	19.85	7.40	0.44	(0.22)	7.62	7,642.5	3.54	0.62	0.70	1.05	9,146.0	-	400,000	21,933.6	34,771.0	38,722.1	3,951.2	11.4%
		1,000,000	3000	46%	11.37	2.55	0.69	0.44	3.68	11,051.4	19.85	7.40	0.44	(0.22)	7.62	22,888.0	3.54	0.62	0.70	1.05	24,730.4	-	1,000,000	54,834.0	90,615.7	102,452.3	11,836.6	13.1%
		1,500,000	4000	52%	11.37	2.55	0.69	0.44	3.68	14,731.4	19.85	7.40	0.44	(0.22)	7.62	30,510.7	3.54	0.62	0.70	1.05	35,230.1	-	1,500,000	82,251.0	132,212.5	147,991.8	15,779.3	11.9%
GSd	Grand Bend	15,000	60	35%	**22.20**	**3.90**	**0.59**	**0.23**	**4.72**	305.4	**28.14**	**8.75**	**0.23**	**(0.22)**	**8.76**	553.9	**3.54**	0.62	0.7	1.0545	426.9	-	15,000	822.5	1,554.8	1,803.3	248.5	16.0%
		43,164	133	45%	22.20	3.90	0.59	0.23	4.72	650.0	28.14	8.75	0.23	(0.22)	8.76	1,193.6	3.54	0.62	0.70	1.05	1,080.5	-	43,164	2,366.9	4,097.4	4,641.0	543.6	13.3%
		100,000	500	28%	22.20	3.90	0.59	0.23	4.72	2,382.2	28.14	8.75	0.23	(0.22)	8.76	4,409.5	3.54	0.62	0.70	1.05	3,219.2	-	100,000	5,483.4	11,084.8	13,112.1	2,027.3	18.3%
		400,000	1000	56%	22.20	3.90	0.59	0.23	4.72	4,742.2	28.14	8.75	0.23	(0.22)	8.76	8,790.8	3.54	0.62	0.70	1.05	9,146.0	-	400,000	21,933.6	35,821.8	39,870.4	4,048.6	11.3%
		1,000,000	3000	46%	22.20	3.90	0.59	0.23	4.72	14,182.2	28.14	8.75	0.23	(0.22)	8.76	26,316.2	3.54	0.62	0.70	1.05	24,730.4	-	1,000,000	54,834.0	93,746.6	105,880.6	12,134.0	12.9%
		1,500,000	4000	52%	22.20	3.90	0.59	0.23	4.72	18,902.2	28.14	8.75	0.23	(0.22)	8.76	35,079.0	3.54	0.62	0.70	1.05	35,230.1	-	1,500,000	82,251.0	136,383.3	152,560.1	16,176.8	11.9%
GSd	Hastings	15,000	60	35%	**22.89**	**5.32**	**0.74**	**0.29**	**6.35**	403.9	**27.97**	**9.22**	**0.29**	**(0.22)**	**9.30**	585.7	**3.54**	0.62	0.7	1.0545	426.9	-	15,000	822.5	1,653.3	1,835.2	181.9	11.0%
		43,164	133	45%	22.89	5.32	0.74	0.29	6.35	867.4	27.97	9.22	0.29	(0.22)	9.30	1,264.4	3.54	0.62	0.70	1.05	1,080.5	-	43,164	2,366.9	4,314.8	4,711.8	396.9	9.2%
		100,000	500	28%	22.89	5.32	0.74	0.29	6.35	3,197.9	27.97	9.22	0.29	(0.22)	9.30	4,676.1	3.54	0.62	0.70	1.05	3,219.2	-	100,000	5,483.4	11,900.5	13,378.7	1,478.2	12.4%
		400,000	1000	56%	22.89	5.32	0.74	0.29	6.35	6,372.9	27.97	9.22	0.29	(0.22)	9.30	9,324.2	3.54	0.62	0.70	1.05	9,146.0	-	400,000	21,933.6	37,452.5	40,403.8	2,951.4	7.9%
		1,000,000	3000	46%	22.89	5.32	0.74	0.29	6.35	19,072.9	27.97	9.22	0.29	(0.22)	9.30	27,916.8	3.54	0.62	0.70	1.05	24,730.4	-	1,000,000	54,834.0	98,637.3	107,481.2	8,843.9	9.0%
		1,500,000	4000	52%	22.89	5.32	0.74	0.29	6.35	25,422.9	27.97	9.22	0.29	(0.22)	9.30	37,213.1	3.54	0.62	0.70	1.05	35,230.1	-	1,500,000	82,251.0	142,904.0	154,694.2	11,790.2	8.3%
GSd	Havelock	15,000	60	35%	**22.18**	**4.82**	**0.50**	**0.28**	**5.60**	358.2	**28.14**	**9.22**	**0.28**	**(0.22)**	**9.29**	585.3	**3.54**	0.62	0.7	1.0545	426.9	-	15,000	822.5	1,607.6	1,834.7	227.1	14.1%
		43,164	133	45%	22.18	4.82	0.50	0.28	5.60	767.0	28.14	9.22	0.28	(0.22)	9.29	1,263.2	3.54	0.62	0.70	1.05	1,080.5	-	43,164	2,366.9	4,214.4	4,710.6	496.2	11.8%
		100,000	500	28%	22.18	4.82	0.50	0.28	5.60	2,822.2	28.14	9.22	0.28	(0.22)	9.29	4,671.3	3.54	0.62	0.70	1.05	3,219.2	-	100,000	5,483.4	11,524.8	13,373.9	1,849.1	16.0%
		400,000	1000	56%	22.18	4.82	0.50	0.28	5.60	5,622.2	28.14	9.22	0.28	(0.22)	9.29	9,314.4	3.54	0.62	0.70	1.05	9,146.0	-	400,000	21,933.6	36,701.8	40,394.0	3,692.2	10.1%
		1,000,000	3000	46%	22.18	4.82	0.50	0.28	5.60	16,822.2	28.14	9.22	0.28	(0.22)	9.29	27,887.0	3.54	0.62	0.70	1.05	24,730.4	-	1,000,000	54,834.0	96,386.5	107,451.4	11,064.8	11.5%
		1,500,000	4000	52%	22.18	4.82	0.50	0.28	5.60	22,422.2	28.14	9.22	0.28	(0.22)	9.29	37,173.3	3.54	0.62	0.70	1.05	35,230.1	-	1,500,000	82,251.0	139,903.3	154,654.4	14,751.1	10.5%
GSd	Kirkfield	15,000	60	35%	**14.69**	**5.92**	**1.95**	**1.34**	**9.21**	567.3	**22.02**	**9.22**	**1.34**	**(0.22)**	**10.35**	642.8	**3.54**	0.62	0.7	1.0545	426.9	-	15,000	822.5	1,816.7	1,892.2	75.5	4.2%
		43,164	133	45%	14.69	5.92	1.95	1.34	9.21	1,239.6	22.02	9.22	1.34	(0.22)	10.35	1,398.1	3.54	0.62	0.70	1.05	1,080.5	-	43,164	2,366.9	4,687.0	4,845.5	158.5	3.4%
		100,000	500	28%	14.69	5.92	1.95	1.34	9.21	4,619.7	22.02	9.22	1.34	(0.22)	10.35	5,195.2	3.54	0.62	0.70	1.05	3,219.2	-	100,000	5,483.4	13,322.3	13,897.8	575.5	4.3%
		400,000	1000	56%	14.69	5.92	1.95	1.34	9.21	9,224.7	22.02	9.22	1.34	(0.22)	10.35	10,368.3	3.54	0.62	0.70	1.05	9,146.0	-	400,000	21,933.6	40,304.3	41,447.9	1,143.6	2.8%
		1,000,000	3000	46%	14.69	5.92	1.95	1.34	9.21	27,644.7	22.02	9.22	1.34	(0.22)	10.35	31,060.9	3.54	0.62	0.70	1.05	24,730.4	-	1,000,000	54,834.0	107,209.1	110,625.2	3,416.2	3.2%
		1,500,000	4000	52%	14.69	5.92	1.95	1.34	9.21	36,854.7	22.02	9.22	1.34	(0.22)	10.35	41,407.2	3.54	0.62	0.70	1.05	35,230.1	-	1,500,000	82,251.0	154,335.8	158,888.3	4,552.5	2.9%

New Rate Class: GSd

Total Bill Impacts of Proposed Distribution Rates [old RTSR+TLF]: Threshold of 750 kWhs

Classes		Scenario			May 2007 Incl Rate Riders						May 2008 Incl Rate Riders						Non-Dx Compoent				Other Reg	Commodity Bands			Existing	New	$ Incr	% Incr
					Existing Dx Rates					Existing Dx	New Dx Rates					New Dx	RTSR old	WMSC	DRC	TLF old	Old	Band 1	Band 2	Old	Total Bill	Total Bill	Total Bill	Total Bill
																						-	5.2					
New Class	Old Class	kWh	kW	LF	SrChg [$/cust]	base [$/kW]	Rider1 [$/kW]	Rider2 [$/kW]	VarChg [$/kW]	[$/month]	SrChg [$/cust]	base [$/kW]	Rider2 [$/kW]	Rider3 [$/kW]	VarChg [$/kW]	[$/month]	$/kW	c/kWh	c/kWh		$	kWhs	kWhs	Total $	[$/month]	[$/month]	[$/month]	%
GSd	Lanark Highlands	15,000	60	35%	**18.43**	**5.26**	**1.99**	**1.32**	**8.57**	532.6	**25.08**	**9.22**	**1.32**	**(0.22)**	**10.33**	644.7	**3.54**	0.62	0.7	1.0545	426.9	-	15,000	822.5	1,782.1	1,894.1	112.0	6.3%
		43,164	133	45%	18.43	5.26	1.99	1.32	8.57	1,158.2	25.08	9.22	1.32	(0.22)	10.33	1,398.5	3.54	0.62	0.70	1.05	1,080.5	-	43,164	2,366.9	4,605.6	4,845.9	240.2	5.2%
		100,000	500	28%	18.43	5.26	1.99	1.32	8.57	4,303.4	25.08	9.22	1.32	(0.22)	10.33	5,188.2	3.54	0.62	0.70	1.05	3,219.2	-	100,000	5,483.4	13,006.0	13,890.8	884.8	6.8%
		400,000	1000	56%	18.43	5.26	1.99	1.32	8.57	8,588.4	25.08	9.22	1.32	(0.22)	10.33	10,351.4	3.54	0.62	0.70	1.05	9,146.0	-	400,000	21,933.6	39,668.0	41,430.9	1,762.9	4.4%
		1,000,000	3000	46%	18.43	5.26	1.99	1.32	8.57	25,728.4	25.08	9.22	1.32	(0.22)	10.33	31,003.9	3.54	0.62	0.70	1.05	24,730.4	-	1,000,000	54,834.0	105,292.8	110,568.3	5,275.5	5.0%
		1,500,000	4000	52%	18.43	5.26	1.99	1.32	8.57	34,298.4	25.08	9.22	1.32	(0.22)	10.33	41,330.2	3.54	0.62	0.70	1.05	35,230.1	-	1,500,000	82,251.0	151,779.6	158,811.4	7,031.8	4.6%
GSd	Larder Lake	15,000	60	35%	**20.18**	**4.30**	**1.61**	**0.99**	**6.90**	434.2	**26.64**	**9.22**	**0.99**	**(0.22)**	**10.00**	626.4	**3.54**	0.62	0.7	1.0545	426.9	-	15,000	822.5	1,683.6	1,875.8	192.2	11.4%
		43,164	133	45%	20.18	4.30	1.61	0.99	6.90	937.9	26.64	9.22	0.99	(0.22)	10.00	1,356.1	3.54	0.62	0.70	1.05	1,080.5	-	43,164	2,366.9	4,385.3	4,803.6	418.3	9.5%
		100,000	500	28%	20.18	4.30	1.61	0.99	6.90	3,470.2	26.64	9.22	0.99	(0.22)	10.00	5,024.8	3.54	0.62	0.70	1.05	3,219.2	-	100,000	5,483.4	12,172.8	13,727.4	1,554.6	12.8%
		400,000	1000	56%	20.18	4.30	1.61	0.99	6.90	6,920.2	26.64	9.22	0.99	(0.22)	10.00	10,022.9	3.54	0.62	0.70	1.05	9,146.0	-	400,000	21,933.6	37,999.8	41,102.5	3,102.7	8.2%
		1,000,000	3000	46%	20.18	4.30	1.61	0.99	6.90	20,720.2	26.64	9.22	0.99	(0.22)	10.00	30,015.5	3.54	0.62	0.70	1.05	24,730.4	-	1,000,000	54,834.0	100,284.5	109,579.9	9,295.3	9.3%
		1,500,000	4000	52%	20.18	4.30	1.61	0.99	6.90	27,620.2	26.64	9.22	0.99	(0.22)	10.00	40,011.8	3.54	0.62	0.70	1.05	35,230.1	-	1,500,000	82,251.0	145,101.3	157,492.9	12,391.6	8.5%
GSd	Latchford	15,000	60	35%	**2.88**	**2.44**	**2.06**	**0.48**	**4.98**	301.7	**12.97**	**8.80**	**0.48**	**(0.22)**	**9.06**	556.7	**3.54**	0.62	0.7	1.0545	426.9	-	15,000	822.5	1,551.1	1,806.2	255.0	16.4%
		43,164	133	45%	2.88	2.44	2.06	0.48	4.98	665.2	12.97	8.80	0.48	(0.22)	9.06	1,218.3	3.54	0.62	0.70	1.05	1,080.5	-	43,164	2,366.9	4,112.6	4,665.7	553.1	13.4%
		100,000	500	28%	2.88	2.44	2.06	0.48	4.98	2,492.9	12.97	8.80	0.48	(0.22)	9.06	4,544.3	3.54	0.62	0.70	1.05	3,219.2	-	100,000	5,483.4	11,195.5	13,246.9	2,051.4	18.3%
		400,000	1000	56%	2.88	2.44	2.06	0.48	4.98	4,982.9	12.97	8.80	0.48	(0.22)	9.06	9,075.7	3.54	0.62	0.70	1.05	9,146.0	-	400,000	21,933.6	36,062.5	40,155.3	4,092.8	11.3%
		1,000,000	3000	46%	2.88	2.44	2.06	0.48	4.98	14,942.9	12.97	8.80	0.48	(0.22)	9.06	27,201.1	3.54	0.62	0.70	1.05	24,730.4	-	1,000,000	54,834.0	94,507.2	106,765.4	12,258.2	13.0%
		1,500,000	4000	52%	2.88	2.44	2.06	0.48	4.98	19,922.9	12.97	8.80	0.48	(0.22)	9.06	36,263.8	3.54	0.62	0.70	1.05	35,230.1	-	1,500,000	82,251.0	137,404.0	153,744.9	16,340.9	11.9%
UGd	Lindsay	15,000	60	35%	**23.94**	**4.36**	**0.49**	**0.19**	**5.04**	326.3	**24.31**	**7.33**	**0.19**	**(0.27)**	**7.25**	459.3	**3.54**	0.62	0.7	1.0545	426.9	-	15,000	822.5	1,575.8	1,708.8	133.0	8.4%
		43,164	133	45%	23.94	4.36	0.49	0.19	5.04	694.3	24.31	7.33	0.19	(0.27)	7.25	988.6	3.54	0.62	0.70	1.05	1,080.5	-	43,164	2,366.9	4,141.7	4,436.0	294.3	7.1%
		100,000	500	28%	23.94	4.36	0.49	0.19	5.04	2,543.9	24.31	7.33	0.19	(0.27)	7.25	3,649.4	3.54	0.62	0.70	1.05	3,219.2	-	100,000	5,483.4	11,246.5	12,352.0	1,105.5	9.8%
		400,000	1000	56%	23.94	4.36	0.49	0.19	5.04	5,063.9	24.31	7.33	0.19	(0.27)	7.25	7,274.5	3.54	0.62	0.70	1.05	9,146.0	-	400,000	21,933.6	36,143.5	38,354.1	2,210.6	6.1%
		1,000,000	3000	46%	23.94	4.36	0.49	0.19	5.04	15,143.9	24.31	7.33	0.19	(0.27)	7.25	21,774.9	3.54	0.62	0.70	1.05	24,730.4	-	1,000,000	54,834.0	94,708.3	101,339.3	6,631.0	7.0%
		1,500,000	4000	52%	23.94	4.36	0.49	0.19	5.04	20,183.9	24.31	7.33	0.19	(0.27)	7.25	29,025.1	3.54	0.62	0.70	1.05	35,230.1	-	1,500,000	82,251.0	137,665.1	146,506.3	8,841.2	6.4%
GSd	Lucan Granton	15,000	60	35%	**16.99**	**4.61**	**0.53**	**0.30**	**5.44**	343.4	**23.44**	**9.22**	**0.30**	**(0.22)**	**9.31**	581.8	**3.54**	0.62	0.7	1.0545	426.9	-	15,000	822.5	1,592.8	1,831.2	238.4	15.0%
		43,164	133	45%	16.99	4.61	0.53	0.30	5.44	740.5	23.44	9.22	0.30	(0.22)	9.31	1,261.2	3.54	0.62	0.70	1.05	1,080.5	-	43,164	2,366.9	4,187.9	4,708.6	520.7	12.4%
		100,000	500	28%	16.99	4.61	0.53	0.30	5.44	2,737.0	23.44	9.22	0.30	(0.22)	9.31	4,676.6	3.54	0.62	0.70	1.05	3,219.2	-	100,000	5,483.4	11,439.6	13,379.2	1,939.6	17.0%
		400,000	1000	56%	16.99	4.61	0.53	0.30	5.44	5,457.0	23.44	9.22	0.30	(0.22)	9.31	9,329.7	3.54	0.62	0.70	1.05	9,146.0	-	400,000	21,933.6	36,536.6	40,409.3	3,872.7	10.6%
		1,000,000	3000	46%	16.99	4.61	0.53	0.30	5.44	16,337.0	23.44	9.22	0.30	(0.22)	9.31	27,942.3	3.54	0.62	0.70	1.05	24,730.4	-	1,000,000	54,834.0	95,901.4	107,506.7	11,605.3	12.1%
		1,500,000	4000	52%	16.99	4.61	0.53	0.30	5.44	21,777.0	23.44	9.22	0.30	(0.22)	9.31	37,248.6	3.54	0.62	0.70	1.05	35,230.1	-	1,500,000	82,251.0	139,258.1	154,729.7	15,471.6	11.1%

New Rate Class: GSd

Total Bill Impacts of Proposed Distribution Rates [old RTSR+TLF]: Threshold of 750 kWhs

Classes		Scenario			May 2007 Incl Rate Riders						May 2008 Incl Rate Riders						Non-Dx Compoent				Other Reg	Commodity Bands			Existing	New	$ Incr	% Incr
					Existing Dx Rates					Existing Dx	New Dx Rates					New Dx	RTSR old	WMSC	DRC	TLF old	Old	Band 1	Band 2	Old	Total Bill	Total Bill	Total Bill	Total Bill
																						-	5.2					
New Class	Old Class	kWh	kW	LF	SrChg [$/cust]	base [$/kW]	Rider1 [$/kW]	Rider2 [$/kW]	VarChg [$/kW]	[$/month]	SrChg [$/cust]	base [$/kW]	Rider2 [$/kW]	Rider3 [$/kW]	VarChg [$/kW]	[$/month]	$/kW	c/kWh	c/kWh		$	kWhs	kWhs	Total $	[$/month]	[$/month]	[$/month]	%
GSd	**Malahide**	15,000	60	35%	**15.99**	**5.42**	**2.57**	**1.32**	**9.31**	574.6	**22.69**	**9.22**	**1.32**	**(0.22)**	**10.33**	642.3	**3.54**	0.62	0.7	1.0545	426.9	-	15,000	822.5	1,824.0	1,891.7	67.7	3.7%
		43,164	133	45%	15.99	5.42	2.57	1.32	9.31	1,254.2	22.69	9.22	1.32	(0.22)	10.33	1,396.1	3.54	0.62	0.70	1.05	1,080.5	-	43,164	2,366.9	4,701.6	4,843.5	141.9	3.0%
		100,000	500	28%	15.99	5.42	2.57	1.32	9.31	4,671.0	22.69	9.22	1.32	(0.22)	10.33	5,185.8	3.54	0.62	0.70	1.05	3,219.2	-	100,000	5,483.4	13,373.6	13,888.4	514.8	3.8%
		400,000	1000	56%	15.99	5.42	2.57	1.32	9.31	9,326.0	22.69	9.22	1.32	(0.22)	10.33	10,349.0	3.54	0.62	0.70	1.05	9,146.0	-	400,000	21,933.6	40,405.6	41,428.6	1,023.0	2.5%
		1,000,000	3000	46%	15.99	5.42	2.57	1.32	9.31	27,946.0	22.69	9.22	1.32	(0.22)	10.33	31,001.5	3.54	0.62	0.70	1.05	24,730.4	-	1,000,000	54,834.0	107,510.4	110,565.9	3,055.6	2.8%
		1,500,000	4000	52%	15.99	5.42	2.57	1.32	9.31	37,256.0	22.69	9.22	1.32	(0.22)	10.33	41,327.8	3.54	0.62	0.70	1.05	35,230.1	-	1,500,000	82,251.0	154,737.1	158,809.0	4,071.8	2.6%
GSd	**Mapleton**	15,000	60	35%	**21.55**	**5.42**	**1.26**	**0.93**	**7.61**	478.2	**27.30**	**9.22**	**0.93**	**(0.22)**	**9.94**	623.5	**3.54**	0.62	0.7	1.0545	426.9	-	15,000	822.5	1,727.6	1,872.9	145.3	8.4%
		43,164	133	45%	21.55	5.42	1.26	0.93	7.61	1,033.7	27.30	9.22	0.93	(0.22)	9.94	1,348.8	3.54	0.62	0.70	1.05	1,080.5	-	43,164	2,366.9	4,481.1	4,796.2	315.1	7.0%
		100,000	500	28%	21.55	5.42	1.26	0.93	7.61	3,826.6	27.30	9.22	0.93	(0.22)	9.94	4,995.4	3.54	0.62	0.70	1.05	3,219.2	-	100,000	5,483.4	12,529.2	13,698.0	1,168.9	9.3%
		400,000	1000	56%	21.55	5.42	1.26	0.93	7.61	7,631.6	27.30	9.22	0.93	(0.22)	9.94	9,963.6	3.54	0.62	0.70	1.05	9,146.0	-	400,000	21,933.6	38,711.1	41,043.2	2,332.0	6.0%
		1,000,000	3000	46%	21.55	5.42	1.26	0.93	7.61	22,851.6	27.30	9.22	0.93	(0.22)	9.94	29,836.2	3.54	0.62	0.70	1.05	24,730.4	-	1,000,000	54,834.0	102,415.9	109,400.5	6,984.6	6.8%
		1,500,000	4000	52%	21.55	5.42	1.26	0.93	7.61	30,461.6	27.30	9.22	0.93	(0.22)	9.94	39,772.4	3.54	0.62	0.70	1.05	35,230.1	-	1,500,000	82,251.0	147,942.7	157,253.6	9,310.9	6.3%
GSd	**Markdale**	15,000	60	35%	**23.00**	**2.54**	**0.49**	**0.13**	**3.16**	212.6	**28.94**	**7.25**	**0.13**	**(0.22)**	**7.16**	458.7	**3.54**	0.62	0.7	1.0545	426.9	-	15,000	822.5	1,462.0	1,708.1	246.1	16.8%
		43,164	133	45%	23.00	2.54	0.49	0.13	3.16	443.3	28.94	7.25	0.13	(0.22)	7.16	981.6	3.54	0.62	0.70	1.05	1,080.5	-	43,164	2,366.9	3,890.7	4,429.0	538.3	13.8%
		100,000	500	28%	23.00	2.54	0.49	0.13	3.16	1,603.0	28.94	7.25	0.13	(0.22)	7.16	3,610.3	3.54	0.62	0.70	1.05	3,219.2	-	100,000	5,483.4	10,305.6	12,312.9	2,007.3	19.5%
		400,000	1000	56%	23.00	2.54	0.49	0.13	3.16	3,183.0	28.94	7.25	0.13	(0.22)	7.16	7,191.6	3.54	0.62	0.70	1.05	9,146.0	-	400,000	21,933.6	34,262.6	38,271.2	4,008.6	11.7%
		1,000,000	3000	46%	23.00	2.54	0.49	0.13	3.16	9,503.0	28.94	7.25	0.13	(0.22)	7.16	21,517.0	3.54	0.62	0.70	1.05	24,730.4	-	1,000,000	54,834.0	89,067.4	101,081.4	12,014.0	13.5%
		1,500,000	4000	52%	23.00	2.54	0.49	0.13	3.16	12,663.0	28.94	7.25	0.13	(0.22)	7.16	28,679.8	3.54	0.62	0.70	1.05	35,230.1	-	1,500,000	82,251.0	130,144.1	146,160.9	16,016.8	12.3%
GSd	**Marmora**	15,000	60	35%	**10.02**	**3.33**	**0.49**	**0.16**	**3.98**	248.8	**19.18**	**8.00**	**0.16**	**(0.22)**	**7.94**	495.7	**3.54**	0.62	0.7	1.0545	426.9	-	15,000	822.5	1,498.2	1,745.2	246.9	16.5%
		43,164	133	45%	10.02	3.33	0.49	0.16	3.98	539.4	19.18	8.00	0.16	(0.22)	7.94	1,075.6	3.54	0.62	0.70	1.05	1,080.5	-	43,164	2,366.9	3,986.8	4,523.0	536.2	13.4%
		100,000	500	28%	10.02	3.33	0.49	0.16	3.98	2,000.0	19.18	8.00	0.16	(0.22)	7.94	3,990.5	3.54	0.62	0.70	1.05	3,219.2	-	100,000	5,483.4	10,702.6	12,693.1	1,990.5	18.6%
		400,000	1000	56%	10.02	3.33	0.49	0.16	3.98	3,990.0	19.18	8.00	0.16	(0.22)	7.94	7,961.9	3.54	0.62	0.70	1.05	9,146.0	-	400,000	21,933.6	35,069.6	39,041.5	3,971.9	11.3%
		1,000,000	3000	46%	10.02	3.33	0.49	0.16	3.98	11,950.0	19.18	8.00	0.16	(0.22)	7.94	23,847.3	3.54	0.62	0.70	1.05	24,730.4	-	1,000,000	54,834.0	91,514.4	103,411.7	11,897.3	13.0%
		1,500,000	4000	52%	10.02	3.33	0.49	0.16	3.98	15,930.0	19.18	8.00	0.16	(0.22)	7.94	31,790.0	3.54	0.62	0.70	1.05	35,230.1	-	1,500,000	82,251.0	133,411.2	149,271.1	15,860.0	11.9%
GSd	**McGarry**	15,000	60	35%	**20.18**	**5.68**	**1.80**	**1.42**	**8.90**	554.2	**26.64**	**9.22**	**1.42**	**(0.22)**	**10.43**	652.2	**3.54**	0.62	0.7	1.0545	426.9	-	15,000	822.5	1,803.6	1,901.6	98.0	5.4%
		43,164	133	45%	20.18	5.68	1.80	1.42	8.90	1,203.9	26.64	9.22	1.42	(0.22)	10.43	1,413.3	3.54	0.62	0.70	1.05	1,080.5	-	43,164	2,366.9	4,651.3	4,860.7	209.5	4.5%
		100,000	500	28%	20.18	5.68	1.80	1.42	8.90	4,470.2	26.64	9.22	1.42	(0.22)	10.43	5,239.8	3.54	0.62	0.70	1.05	3,219.2	-	100,000	5,483.4	13,172.8	13,942.4	769.6	5.8%
		400,000	1000	56%	20.18	5.68	1.80	1.42	8.90	8,920.2	26.64	9.22	1.42	(0.22)	10.43	10,452.9	3.54	0.62	0.70	1.05	9,146.0	-	400,000	21,933.6	39,999.8	41,532.5	1,532.7	3.8%
		1,000,000	3000	46%	20.18	5.68	1.80	1.42	8.90	26,720.2	26.64	9.22	1.42	(0.22)	10.43	31,305.5	3.54	0.62	0.70	1.05	24,730.4	-	1,000,000	54,834.0	106,284.5	110,869.9	4,585.3	4.3%
		1,500,000	4000	52%	20.18	5.68	1.80	1.42	8.90	35,620.2	26.64	9.22	1.42	(0.22)	10.43	41,731.8	3.54	0.62	0.70	1.05	35,230.1	-	1,500,000	82,251.0	153,101.3	159,212.9	6,111.6	4.0%

New Rate Class: GSd

Total Bill Impacts of Proposed Distribution Rates [old RTSR+TLF]: Threshold of 750 kWhs

Classes		Scenario			May 2007 Incl Rate Riders						May 2008 Incl Rate Riders						Non-Dx Compoent				Other Reg	Commodity Bands			Existing	New	$ Incr	% Incr
					Existing Dx Rates					Existing Dx	New Dx Rates					New Dx	RTSR old	WMSC	DRC	TLF old	Old	Band 1	Band 2	Old	Total Bill	Total Bill	Total Bill	Total Bill
																						-	5.2					
New Class	Old Class	kWh	kW	LF	SrChg [$/cust]	base [$/kW]	Rider1 [$/kW]	Rider2 [$/kW]	VarChg [$/kW]	[$/month]	SrChg [$/cust]	base [$/kW]	Rider2 [$/kW]	Rider3 [$/kW]	VarChg [$/kW]	[$/month]	$/kW	c/kWh	c/kWh		$	kWhs	kWhs	Total $	[$/month]	[$/month]	[$/month]	%
GSd	**Meaford**	15,000	60	35%	**24.05**	**3.90**	**0.50**	**0.21**	**4.61**	300.7	**29.68**	**8.75**	**0.21**	**(0.22)**	**8.74**	554.2	**3.54**	0.62	0.7	1.0545	426.9	-	15,000	822.5	1,550.1	1,803.7	253.6	16.4%
		43,164	133	45%	24.05	3.90	0.50	0.21	4.61	637.2	29.68	8.75	0.21	(0.22)	8.74	1,192.5	3.54	0.62	0.70	1.05	1,080.5	-	43,164	2,366.9	4,084.6	4,639.9	555.3	13.6%
		100,000	500	28%	24.05	3.90	0.50	0.21	4.61	2,329.1	29.68	8.75	0.21	(0.22)	8.74	4,401.0	3.54	0.62	0.70	1.05	3,219.2	-	100,000	5,483.4	11,031.7	13,103.6	2,072.0	18.8%
		400,000	1000	56%	24.05	3.90	0.50	0.21	4.61	4,634.1	29.68	8.75	0.21	(0.22)	8.74	8,772.4	3.54	0.62	0.70	1.05	9,146.0	-	400,000	21,933.6	35,713.6	39,852.0	4,138.3	11.6%
		1,000,000	3000	46%	24.05	3.90	0.50	0.21	4.61	13,854.1	29.68	8.75	0.21	(0.22)	8.74	26,257.8	3.54	0.62	0.70	1.05	24,730.4	-	1,000,000	54,834.0	93,418.4	105,822.1	12,403.7	13.3%
		1,500,000	4000	52%	24.05	3.90	0.50	0.21	4.61	18,464.1	29.68	8.75	0.21	(0.22)	8.74	35,000.5	3.54	0.62	0.70	1.05	35,230.1	-	1,500,000	82,251.0	135,945.2	152,481.6	16,536.4	12.2%
GSd	**Middlesex Centre**	15,000	60	35%	**17.35**	**3.29**	**1.39**	**0.84**	**5.52**	348.6	**24.35**	**9.00**	**0.84**	**(0.22)**	**9.62**	601.7	**3.54**	0.62	0.7	1.0545	426.9	-	15,000	822.5	1,598.0	1,851.1	253.2	15.8%
		43,164	133	45%	17.35	3.29	1.39	0.84	5.52	751.5	24.35	9.00	0.84	(0.22)	9.62	1,304.2	3.54	0.62	0.70	1.05	1,080.5	-	43,164	2,366.9	4,198.9	4,751.6	552.7	13.2%
		100,000	500	28%	17.35	3.29	1.39	0.84	5.52	2,777.4	24.35	9.00	0.84	(0.22)	9.62	4,835.7	3.54	0.62	0.70	1.05	3,219.2	-	100,000	5,483.4	11,480.0	13,538.3	2,058.4	17.9%
		400,000	1000	56%	17.35	3.29	1.39	0.84	5.52	5,537.4	24.35	9.00	0.84	(0.22)	9.62	9,647.1	3.54	0.62	0.70	1.05	9,146.0	-	400,000	21,933.6	36,616.9	40,726.6	4,109.7	11.2%
		1,000,000	3000	46%	17.35	3.29	1.39	0.84	5.52	16,577.4	24.35	9.00	0.84	(0.22)	9.62	28,892.5	3.54	0.62	0.70	1.05	24,730.4	-	1,000,000	54,834.0	96,141.7	108,456.8	12,315.1	12.8%
		1,500,000	4000	52%	17.35	3.29	1.39	0.84	5.52	22,097.4	24.35	9.00	0.84	(0.22)	9.62	38,515.2	3.54	0.62	0.70	1.05	35,230.1	-	1,500,000	82,251.0	139,578.5	155,996.3	16,417.8	11.8%
GSd	**Napanee**	15,000	60	35%	**22.17**	**4.04**	**0.52**	**0.20**	**4.76**	307.8	**28.15**	**8.90**	**0.20**	**(0.22)**	**8.88**	561.1	**3.54**	0.62	0.7	1.0545	426.9	-	15,000	822.5	1,557.2	1,810.5	253.3	16.3%
		43,164	133	45%	22.17	4.04	0.52	0.20	4.76	655.3	28.15	8.90	0.20	(0.22)	8.88	1,209.5	3.54	0.62	0.70	1.05	1,080.5	-	43,164	2,366.9	4,102.7	4,656.9	554.3	13.5%
		100,000	500	28%	22.17	4.04	0.52	0.20	4.76	2,402.2	28.15	8.90	0.20	(0.22)	8.88	4,469.5	3.54	0.62	0.70	1.05	3,219.2	-	100,000	5,483.4	11,104.8	13,172.1	2,067.3	18.6%
		400,000	1000	56%	22.17	4.04	0.52	0.20	4.76	4,782.2	28.15	8.90	0.20	(0.22)	8.88	8,910.8	3.54	0.62	0.70	1.05	9,146.0	-	400,000	21,933.6	35,861.8	39,990.4	4,128.7	11.5%
		1,000,000	3000	46%	22.17	4.04	0.52	0.20	4.76	14,302.2	28.15	8.90	0.20	(0.22)	8.88	26,676.3	3.54	0.62	0.70	1.05	24,730.4	-	1,000,000	54,834.0	93,866.5	106,240.6	12,374.1	13.2%
		1,500,000	4000	52%	22.17	4.04	0.52	0.20	4.76	19,062.2	28.15	8.90	0.20	(0.22)	8.88	35,559.0	3.54	0.62	0.70	1.05	35,230.1	-	1,500,000	82,251.0	136,543.3	153,040.1	16,496.8	12.1%
GSd	**Nipigon**	15,000	60	35%	**23.32**	**3.38**	**1.07**	**0.68**	**5.13**	331.1	**28.86**	**8.80**	**0.68**	**(0.22)**	**9.26**	584.6	**3.54**	0.62	0.7	1.0545	426.9	-	15,000	822.5	1,580.5	1,834.0	253.5	16.0%
		43,164	133	45%	23.32	3.38	1.07	0.68	5.13	705.6	28.86	8.80	0.68	(0.22)	9.26	1,260.8	3.54	0.62	0.70	1.05	1,080.5	-	43,164	2,366.9	4,153.0	4,708.2	555.2	13.4%
		100,000	500	28%	23.32	3.38	1.07	0.68	5.13	2,588.3	28.86	8.80	0.68	(0.22)	9.26	4,660.2	3.54	0.62	0.70	1.05	3,219.2	-	100,000	5,483.4	11,290.9	13,362.8	2,071.9	18.4%
		400,000	1000	56%	23.32	3.38	1.07	0.68	5.13	5,153.3	28.86	8.80	0.68	(0.22)	9.26	9,291.6	3.54	0.62	0.70	1.05	9,146.0	-	400,000	21,933.6	36,232.9	40,371.1	4,138.2	11.4%
		1,000,000	3000	46%	23.32	3.38	1.07	0.68	5.13	15,413.3	28.86	8.80	0.68	(0.22)	9.26	27,817.0	3.54	0.62	0.70	1.05	24,730.4	-	1,000,000	54,834.0	94,977.7	107,381.3	12,403.6	13.1%
		1,500,000	4000	52%	23.32	3.38	1.07	0.68	5.13	20,543.3	28.86	8.80	0.68	(0.22)	9.26	37,079.7	3.54	0.62	0.70	1.05	35,230.1	-	1,500,000	82,251.0	138,024.5	154,560.8	16,536.4	12.0%
GSd	**North Dorchester**	15,000	60	35%	**15.88**	**2.85**	**1.12**	**0.81**	**4.78**	302.7	**22.72**	**8.30**	**0.81**	**(0.22)**	**8.89**	556.3	**3.54**	0.62	0.7	1.0545	426.9	-	15,000	822.5	1,552.1	1,805.7	253.6	16.3%
		43,164	133	45%	15.88	2.85	1.12	0.81	4.78	651.6	22.72	8.30	0.81	(0.22)	8.89	1,205.4	3.54	0.62	0.70	1.05	1,080.5	-	43,164	2,366.9	4,099.0	4,652.9	553.8	13.5%
		100,000	500	28%	15.88	2.85	1.12	0.81	4.78	2,405.9	22.72	8.30	0.81	(0.22)	8.89	4,469.1	3.54	0.62	0.70	1.05	3,219.2	-	100,000	5,483.4	11,108.5	13,171.7	2,063.2	18.6%
		400,000	1000	56%	15.88	2.85	1.12	0.81	4.78	4,795.9	22.72	8.30	0.81	(0.22)	8.89	8,915.4	3.54	0.62	0.70	1.05	9,146.0	-	400,000	21,933.6	35,875.5	39,995.0	4,119.5	11.5%
		1,000,000	3000	46%	15.88	2.85	1.12	0.81	4.78	14,355.9	22.72	8.30	0.81	(0.22)	8.89	26,700.8	3.54	0.62	0.70	1.05	24,730.4	-	1,000,000	54,834.0	93,920.2	106,265.2	12,344.9	13.1%
		1,500,000	4000	52%	15.88	2.85	1.12	0.81	4.78	19,135.9	22.72	8.30	0.81	(0.22)	8.89	35,593.5	3.54	0.62	0.70	1.05	35,230.1	-	1,500,000	82,251.0	136,617.0	153,074.7	16,457.7	12.0%

New Rate Class: GSd

Total Bill Impacts of Proposed Distribution Rates [old RTSR+TLF]: Threshold of 750 kWhs

Classes		Scenario			May 2007 Incl Rate Riders						May 2008 Incl Rate Riders						Non-Dx Compoent				Other Reg	Commodity Bands			Existing	New	$ Incr	% Incr
					Existing Dx Rates					Existing Dx	New Dx Rates					New Dx	RTSR old	WMSC	DRC	TLF old	Old	Band 1	Band 2	Old	Total Bill	Total Bill	Total Bill	Total Bill
																						-	5.2					
New Class	Old Class	kWh	kW	LF	SrChg [$/cust]	base [$/kW]	Rider1 [$/kW]	Rider2 [$/kW]	VarChg [$/kW]	[$/month]	SrChg [$/cust]	base [$/kW]	Rider2 [$/kW]	Rider3 [$/kW]	VarChg [$/kW]	[$/month]	$/kW	c/kWh	c/kWh		$	kWhs	kWhs	Total $	[$/month]	[$/month]	[$/month]	%
GSd	North Dundas	15,000	60	35%	**13.52**	**2.42**	**0.52**	**0.11**	**3.05**	196.5	**21.31**	**7.00**	**0.11**	**(0.22)**	**6.89**	434.9	**3.54**	0.62	0.7	1.0545	426.9	-	15,000	822.5	1,445.9	1,684.3	238.3	16.5%
		43,164	133	45%	13.52	2.42	0.52	0.11	3.05	419.2	21.31	7.00	0.11	(0.22)	6.89	938.0	3.54	0.62	0.70	1.05	1,080.5	-	43,164	2,366.9	3,866.6	4,385.4	518.9	13.4%
		100,000	500	28%	13.52	2.42	0.52	0.11	3.05	1,538.5	21.31	7.00	0.11	(0.22)	6.89	3,467.7	3.54	0.62	0.70	1.05	3,219.2	-	100,000	5,483.4	10,241.1	12,170.3	1,929.1	18.8%
		400,000	1000	56%	13.52	2.42	0.52	0.11	3.05	3,063.5	21.31	7.00	0.11	(0.22)	6.89	6,914.0	3.54	0.62	0.70	1.05	9,146.0	-	400,000	21,933.6	34,143.1	37,993.6	3,850.5	11.3%
		1,000,000	3000	46%	13.52	2.42	0.52	0.11	3.05	9,163.5	21.31	7.00	0.11	(0.22)	6.89	20,699.4	3.54	0.62	0.70	1.05	24,730.4	-	1,000,000	54,834.0	88,727.9	100,263.8	11,535.9	13.0%
		1,500,000	4000	52%	13.52	2.42	0.52	0.11	3.05	12,213.5	21.31	7.00	0.11	(0.22)	6.89	27,592.1	3.54	0.62	0.70	1.05	35,230.1	-	1,500,000	82,251.0	129,694.7	145,073.3	15,378.6	11.9%
GSd	North Glengarry	15,000	60	35%	**17.72**	**2.82**	**0.69**	**0.39**	**3.90**	251.7	**24.26**	**7.70**	**0.39**	**(0.22)**	**7.87**	496.6	**3.54**	0.62	0.7	1.0545	426.9	-	15,000	822.5	1,501.1	1,746.0	244.9	16.3%
		43,164	133	45%	17.72	2.82	0.69	0.39	3.90	536.4	24.26	7.70	0.39	(0.22)	7.87	1,071.3	3.54	0.62	0.70	1.05	1,080.5	-	43,164	2,366.9	3,983.8	4,518.7	534.9	13.4%
		100,000	500	28%	17.72	2.82	0.69	0.39	3.90	1,967.7	24.26	7.70	0.39	(0.22)	7.87	3,960.6	3.54	0.62	0.70	1.05	3,219.2	-	100,000	5,483.4	10,670.3	12,663.2	1,992.9	18.7%
		400,000	1000	56%	17.72	2.82	0.69	0.39	3.90	3,917.7	24.26	7.70	0.39	(0.22)	7.87	7,897.0	3.54	0.62	0.70	1.05	9,146.0	-	400,000	21,933.6	34,997.3	38,976.5	3,979.2	11.4%
		1,000,000	3000	46%	17.72	2.82	0.69	0.39	3.90	11,717.7	24.26	7.70	0.39	(0.22)	7.87	23,642.4	3.54	0.62	0.70	1.05	24,730.4	-	1,000,000	54,834.0	91,282.1	103,206.7	11,924.6	13.1%
		1,500,000	4000	52%	17.72	2.82	0.69	0.39	3.90	15,617.7	24.26	7.70	0.39	(0.22)	7.87	31,515.1	3.54	0.62	0.70	1.05	35,230.1	-	1,500,000	82,251.0	133,098.9	148,996.2	15,897.4	11.9%
GSd	North Grenville	15,000	60	35%	**20.42**	**5.41**	**0.45**	**0.25**	**6.11**	387.0	**26.58**	**9.22**	**0.25**	**(0.22)**	**9.26**	582.0	**3.54**	0.62	0.7	1.0545	426.9	-	15,000	822.5	1,636.4	1,831.4	194.9	11.9%
		43,164	133	45%	20.42	5.41	0.45	0.25	6.11	833.1	26.58	9.22	0.25	(0.22)	9.26	1,257.7	3.54	0.62	0.70	1.05	1,080.5	-	43,164	2,366.9	4,280.5	4,705.1	424.6	9.9%
		100,000	500	28%	20.42	5.41	0.45	0.25	6.11	3,075.4	26.58	9.22	0.25	(0.22)	9.26	4,654.7	3.54	0.62	0.70	1.05	3,219.2	-	100,000	5,483.4	11,778.0	13,357.3	1,579.3	13.4%
		400,000	1000	56%	20.42	5.41	0.45	0.25	6.11	6,130.4	26.58	9.22	0.25	(0.22)	9.26	9,282.9	3.54	0.62	0.70	1.05	9,146.0	-	400,000	21,933.6	37,210.0	40,362.4	3,152.4	8.5%
		1,000,000	3000	46%	20.42	5.41	0.45	0.25	6.11	18,350.4	26.58	9.22	0.25	(0.22)	9.26	27,795.4	3.54	0.62	0.70	1.05	24,730.4	-	1,000,000	54,834.0	97,914.8	107,359.8	9,445.0	9.6%
		1,500,000	4000	52%	20.42	5.41	0.45	0.25	6.11	24,460.4	26.58	9.22	0.25	(0.22)	9.26	37,051.7	3.54	0.62	0.70	1.05	35,230.1	-	1,500,000	82,251.0	141,941.6	154,532.9	12,591.3	8.9%
GSd	North Perth	15,000	60	35%	**29.52**	**3.16**	**0.36**	**0.13**	**3.65**	248.5	**33.31**	**7.70**	**0.13**	**(0.22)**	**7.61**	490.1	**3.54**	0.62	0.7	1.0545	426.9	-	15,000	822.5	1,497.9	1,739.5	241.5	16.1%
		43,164	133	45%	29.52	3.16	0.36	0.13	3.65	515.0	33.31	7.70	0.13	(0.22)	7.61	1,045.8	3.54	0.62	0.70	1.05	1,080.5	-	43,164	2,366.9	3,962.4	4,493.2	530.8	13.4%
		100,000	500	28%	29.52	3.16	0.36	0.13	3.65	1,854.5	33.31	7.70	0.13	(0.22)	7.61	3,839.7	3.54	0.62	0.70	1.05	3,219.2	-	100,000	5,483.4	10,557.1	12,542.3	1,985.1	18.8%
		400,000	1000	56%	29.52	3.16	0.36	0.13	3.65	3,679.5	33.31	7.70	0.13	(0.22)	7.61	7,646.0	3.54	0.62	0.70	1.05	9,146.0	-	400,000	21,933.6	34,759.1	38,725.6	3,966.5	11.4%
		1,000,000	3000	46%	29.52	3.16	0.36	0.13	3.65	10,979.5	33.31	7.70	0.13	(0.22)	7.61	22,871.4	3.54	0.62	0.70	1.05	24,730.4	-	1,000,000	54,834.0	90,543.9	102,435.8	11,891.9	13.1%
		1,500,000	4000	52%	29.52	3.16	0.36	0.13	3.65	14,629.5	33.31	7.70	0.13	(0.22)	7.61	30,484.1	3.54	0.62	0.70	1.05	35,230.1	-	1,500,000	82,251.0	132,110.7	147,965.3	15,854.6	12.0%
GSd	North Stormont	15,000	60	35%	**5.37**	**2.52**	**1.17**	**0.82**	**4.51**	276.0	**15.35**	**9.22**	**0.82**	**(0.22)**	**9.83**	604.9	**3.54**	0.62	0.7	1.0545	426.9	-	15,000	822.5	1,525.4	1,854.3	329.0	21.6%
	no customer	43,164	133	45%	5.37	2.52	1.17	0.82	4.51	605.2	15.35	9.22	0.82	(0.22)	9.83	1,322.2	3.54	0.62	0.70	1.05	1,080.5	-	43,164	2,366.9	4,052.6	4,769.6	717.0	17.7%
		100,000	500	28%	5.37	2.52	1.17	0.82	4.51	2,260.4	15.35	9.22	0.82	(0.22)	9.83	4,928.5	3.54	0.62	0.70	1.05	3,219.2	-	100,000	5,483.4	10,963.0	13,631.1	2,668.1	24.3%
		400,000	1000	56%	5.37	2.52	1.17	0.82	4.51	4,515.4	15.35	9.22	0.82	(0.22)	9.83	9,841.6	3.54	0.62	0.70	1.05	9,146.0	-	400,000	21,933.6	35,595.0	40,921.2	5,326.3	15.0%
		1,000,000	3000	46%	5.37	2.52	1.17	0.82	4.51	13,535.4	15.35	9.22	0.82	(0.22)	9.83	29,494.2	3.54	0.62	0.70	1.05	24,730.4	-	1,000,000	54,834.0	93,099.7	109,058.6	15,958.8	17.1%
		1,500,000	4000	52%	5.37	2.52	1.17	0.82	4.51	18,045.4	15.35	9.22	0.82	(0.22)	9.83	39,320.5	3.54	0.62	0.70	1.05	35,230.1	-	1,500,000	82,251.0	135,526.5	156,801.6	21,275.1	15.7%

New Rate Class: GSd

Total Bill Impacts of Proposed Distribution Rates [old RTSR+TLF]: Threshold of 750 kWhs

Classes		Scenario			May 2007 Incl Rate Riders						May 2008 Incl Rate Riders						Non-Dx Compoent				Other Reg	Commodity Bands			Existing	New	$ Incr	% Incr
					Existing Dx Rates					Existing Dx	New Dx Rates					New Dx	RTSR old	WMSC	DRC	TLF old	Old	Band 1	Band 2	Old	Total Bill	Total Bill	Total Bill	Total Bill
																						-	5.2					
New Class	Old Class	kWh	kW	LF	SrChg [$/cust]	base [$/kW]	Rider1 [$/kW]	Rider2 [$/kW]	VarChg [$/kW]	[$/month]	SrChg [$/cust]	base [$/kW]	Rider2 [$/kW]	Rider3 [$/kW]	VarChg [$/kW]	[$/month]	$/kW	c/kWh	c/kWh		$	kWhs	kWhs	Total $	[$/month]	[$/month]	[$/month]	%
GSd	Omemee	15,000	60	35%	**21.28**	**4.64**	**0.55**	**0.27**	**5.46**	348.9	**27.37**	**9.22**	**0.27**	**(0.22)**	**9.28**	583.9	**3.54**	0.62	0.7	1.0545	426.9	-	15,000	822.5	1,598.3	1,833.4	235.1	14.7%
		43,164	133	45%	21.28	4.64	0.55	0.27	5.46	747.5	27.37	9.22	0.27	(0.22)	9.28	1,261.1	3.54	0.62	0.70	1.05	1,080.5	-	43,164	2,366.9	4,194.9	4,708.5	513.7	12.2%
		100,000	500	28%	21.28	4.64	0.55	0.27	5.46	2,751.3	27.37	9.22	0.27	(0.22)	9.28	4,665.5	3.54	0.62	0.70	1.05	3,219.2	-	100,000	5,483.4	11,453.9	13,368.1	1,914.2	16.7%
		400,000	1000	56%	21.28	4.64	0.55	0.27	5.46	5,481.3	27.37	9.22	0.27	(0.22)	9.28	9,303.7	3.54	0.62	0.70	1.05	9,146.0	-	400,000	21,933.6	36,560.9	40,383.2	3,822.4	10.5%
		1,000,000	3000	46%	21.28	4.64	0.55	0.27	5.46	16,401.3	27.37	9.22	0.27	(0.22)	9.28	27,856.2	3.54	0.62	0.70	1.05	24,730.4	-	1,000,000	54,834.0	95,965.6	107,420.6	11,454.9	11.9%
		1,500,000	4000	52%	21.28	4.64	0.55	0.27	5.46	21,861.3	27.37	9.22	0.27	(0.22)	9.28	37,132.5	3.54	0.62	0.70	1.05	35,230.1	-	1,500,000	82,251.0	139,342.4	154,613.6	15,271.2	11.0%
UGd	Perth	15,000	60	35%	**19.92**	**2.87**	**0.42**	**0.12**	**3.41**	224.5	**21.32**	**7.15**	**0.12**	**(0.27)**	**7.00**	441.1	**3.54**	0.62	0.7	1.0545	426.9	-	15,000	822.5	1,473.9	1,690.6	216.6	14.7%
		43,164	133	45%	19.92	2.87	0.42	0.12	3.41	473.5	21.32	7.15	0.12	(0.27)	7.00	951.9	3.54	0.62	0.70	1.05	1,080.5	-	43,164	2,366.9	3,920.9	4,399.3	478.5	12.2%
		100,000	500	28%	19.92	2.87	0.42	0.12	3.41	1,724.9	21.32	7.15	0.12	(0.27)	7.00	3,519.9	3.54	0.62	0.70	1.05	3,219.2	-	100,000	5,483.4	10,427.5	12,222.5	1,795.0	17.2%
		400,000	1000	56%	19.92	2.87	0.42	0.12	3.41	3,429.9	21.32	7.15	0.12	(0.27)	7.00	7,018.4	3.54	0.62	0.70	1.05	9,146.0	-	400,000	21,933.6	34,509.5	38,098.0	3,588.5	10.4%
		1,000,000	3000	46%	19.92	2.87	0.42	0.12	3.41	10,249.9	21.32	7.15	0.12	(0.27)	7.00	21,012.7	3.54	0.62	0.70	1.05	24,730.4	-	1,000,000	54,834.0	89,814.3	100,577.1	10,762.8	12.0%
		1,500,000	4000	52%	19.92	2.87	0.42	0.12	3.41	13,659.9	21.32	7.15	0.12	(0.27)	7.00	28,009.8	3.54	0.62	0.70	1.05	35,230.1	-	1,500,000	82,251.0	131,141.1	145,491.0	14,349.9	10.9%
GSd	Perth East	15,000	60	35%	**14.65**	**4.08**	**0.52**	**0.27**	**4.87**	306.9	**22.03**	**8.95**	**0.27**	**(0.22)**	**9.00**	562.2	**3.54**	0.62	0.7	1.0545	426.9	-	15,000	822.5	1,556.3	1,811.6	255.3	16.4%
		43,164	133	45%	14.65	4.08	0.52	0.27	4.87	662.4	22.03	8.95	0.27	(0.22)	9.00	1,219.4	3.54	0.62	0.70	1.05	1,080.5	-	43,164	2,366.9	4,109.8	4,666.8	557.0	13.6%
		100,000	500	28%	14.65	4.08	0.52	0.27	4.87	2,449.7	22.03	8.95	0.27	(0.22)	9.00	4,523.4	3.54	0.62	0.70	1.05	3,219.2	-	100,000	5,483.4	11,152.3	13,226.0	2,073.7	18.6%
		400,000	1000	56%	14.65	4.08	0.52	0.27	4.87	4,884.7	22.03	8.95	0.27	(0.22)	9.00	9,024.7	3.54	0.62	0.70	1.05	9,146.0	-	400,000	21,933.6	35,964.2	40,104.3	4,140.1	11.5%
		1,000,000	3000	46%	14.65	4.08	0.52	0.27	4.87	14,624.7	22.03	8.95	0.27	(0.22)	9.00	27,030.1	3.54	0.62	0.70	1.05	24,730.4	-	1,000,000	54,834.0	94,189.0	106,594.5	12,405.5	13.2%
		1,500,000	4000	52%	14.65	4.08	0.52	0.27	4.87	19,494.7	22.03	8.95	0.27	(0.22)	9.00	36,032.8	3.54	0.62	0.70	1.05	35,230.1	-	1,500,000	82,251.0	136,975.8	153,514.0	16,538.2	12.1%
GSd	Prince Edward	15,000	60	35%	**22.85**	**4.45**	**0.58**	**0.24**	**5.27**	339.1	**27.98**	**9.22**	**0.24**	**(0.22)**	**9.25**	582.8	**3.54**	0.62	0.7	1.0545	426.9	-	15,000	822.5	1,588.5	1,832.2	243.7	15.3%
		43,164	133	45%	22.85	4.45	0.58	0.24	5.27	723.8	27.98	9.22	0.24	(0.22)	9.25	1,257.7	3.54	0.62	0.70	1.05	1,080.5	-	43,164	2,366.9	4,171.2	4,705.1	534.0	12.8%
		100,000	500	28%	22.85	4.45	0.58	0.24	5.27	2,657.9	27.98	9.22	0.24	(0.22)	9.25	4,651.1	3.54	0.62	0.70	1.05	3,219.2	-	100,000	5,483.4	11,360.5	13,353.7	1,993.3	17.5%
		400,000	1000	56%	22.85	4.45	0.58	0.24	5.27	5,292.9	27.98	9.22	0.24	(0.22)	9.25	9,274.3	3.54	0.62	0.70	1.05	9,146.0	-	400,000	21,933.6	36,372.4	40,353.8	3,981.4	10.9%
		1,000,000	3000	46%	22.85	4.45	0.58	0.24	5.27	15,832.9	27.98	9.22	0.24	(0.22)	9.25	27,766.8	3.54	0.62	0.70	1.05	24,730.4	-	1,000,000	54,834.0	95,397.2	107,331.2	11,934.0	12.5%
		1,500,000	4000	52%	22.85	4.45	0.58	0.24	5.27	21,102.9	27.98	9.22	0.24	(0.22)	9.25	37,013.1	3.54	0.62	0.70	1.05	35,230.1	-	1,500,000	82,251.0	138,584.0	154,494.2	15,910.3	11.5%
UGd	Quinte West	15,000	60	35%	**3.74**	**3.32**	**0.46**	**0.18**	**3.96**	241.3	**9.36**	**7.33**	**0.18**	**(0.27)**	**7.24**	443.8	**3.54**	0.62	0.7	1.0545	426.9	-	15,000	822.5	1,490.8	1,693.2	202.4	13.6%
		43,164	133	45%	3.74	3.32	0.46	0.18	3.96	530.4	9.36	7.33	0.18	(0.27)	7.24	972.3	3.54	0.62	0.70	1.05	1,080.5	-	43,164	2,366.9	3,977.8	4,419.7	441.9	11.1%
		100,000	500	28%	3.74	3.32	0.46	0.18	3.96	1,983.7	9.36	7.33	0.18	(0.27)	7.24	3,629.5	3.54	0.62	0.70	1.05	3,219.2	-	100,000	5,483.4	10,686.3	12,332.1	1,645.7	15.4%
		400,000	1000	56%	3.74	3.32	0.46	0.18	3.96	3,963.7	9.36	7.33	0.18	(0.27)	7.24	7,249.6	3.54	0.62	0.70	1.05	9,146.0	-	400,000	21,933.6	35,043.3	38,329.1	3,285.8	9.4%
		1,000,000	3000	46%	3.74	3.32	0.46	0.18	3.96	11,883.7	9.36	7.33	0.18	(0.27)	7.24	21,730.0	3.54	0.62	0.70	1.05	24,730.4	-	1,000,000	54,834.0	91,448.1	101,294.3	9,846.2	10.8%
		1,500,000	4000	52%	3.74	3.32	0.46	0.18	3.96	15,843.7	9.36	7.33	0.18	(0.27)	7.24	28,970.2	3.54	0.62	0.70	1.05	35,230.1	-	1,500,000	82,251.0	133,324.9	146,451.3	13,126.4	9.8%

New Rate Class: GSd

Total Bill Impacts of Proposed Distribution Rates [old RTSR+TLF]: Threshold of 750 kWhs

Classes		Scenario			May 2007 Incl Rate Riders						May 2008 Incl Rate Riders						Non-Dx Compoent				Other Reg	Commodity Bands			Existing	New	$ Incr	% Incr
					Existing Dx Rates					Existing Dx	New Dx Rates					New Dx	RTSR old	WMSC	DRC	TLF old	Old	Band 1	Band 2	Old	Total Bill	Total Bill	Total Bill	Total Bill
																						-	5.2					
New Class	Old Class	kWh	kW	LF	SrChg [$/cust]	base [$/kW]	Rider1 [$/kW]	Rider2 [$/kW]	VarChg [$/kW]	[$/month]	SrChg [$/cust]	base [$/kW]	Rider2 [$/kW]	Rider3 [$/kW]	VarChg [$/kW]	[$/month]	$/kW	c/kWh	c/kWh		$	kWhs	kWhs	Total $	[$/month]	[$/month]	[$/month]	%
GSd	Rainy River	15,000	60	35%	19.29	5.59	1.44	1.14	8.17	509.5	25.87	9.22	1.14	(0.22)	10.15	634.6	3.54	0.62	0.7	1.0545	426.9	-	15,000	822.5	1,758.9	1,884.1	125.2	7.1%
		43,164	133	45%	19.29	5.59	1.44	1.14	8.17	1,105.9	25.87	9.22	1.14	(0.22)	10.15	1,375.3	3.54	0.62	0.70	1.05	1,080.5	-	43,164	2,366.9	4,553.3	4,822.7	269.4	5.9%
		100,000	500	28%	19.29	5.59	1.44	1.14	8.17	4,104.3	25.87	9.22	1.14	(0.22)	10.15	5,099.0	3.54	0.62	0.70	1.05	3,219.2	-	100,000	5,483.4	12,806.9	13,801.6	994.7	7.8%
		400,000	1000	56%	19.29	5.59	1.44	1.14	8.17	8,189.3	25.87	9.22	1.14	(0.22)	10.15	10,172.1	3.54	0.62	0.70	1.05	9,146.0	-	400,000	21,933.6	39,268.9	41,251.7	1,982.9	5.0%
		1,000,000	3000	46%	19.29	5.59	1.44	1.14	8.17	24,529.3	25.87	9.22	1.14	(0.22)	10.15	30,464.7	3.54	0.62	0.70	1.05	24,730.4	-	1,000,000	54,834.0	104,093.7	110,029.1	5,935.4	5.7%
		1,500,000	4000	52%	19.29	5.59	1.44	1.14	8.17	32,699.3	25.87	9.22	1.14	(0.22)	10.15	40,611.0	3.54	0.62	0.70	1.05	35,230.1	-	1,500,000	82,251.0	150,180.4	158,092.1	7,911.7	5.3%
GSd	Ramara	15,000	60	35%	20.97	3.35	1.43	1.16	5.94	377.4	26.45	9.22	1.16	(0.22)	10.17	636.4	3.54	0.62	0.7	1.0545	426.9	-	15,000	822.5	1,626.8	1,885.8	259.1	15.9%
		43,164	133	45%	20.97	3.35	1.43	1.16	5.94	811.0	26.45	9.22	1.16	(0.22)	10.17	1,378.6	3.54	0.62	0.70	1.05	1,080.5	-	43,164	2,366.9	4,258.4	4,826.0	567.6	13.3%
		100,000	500	28%	20.97	3.35	1.43	1.16	5.94	2,991.0	26.45	9.22	1.16	(0.22)	10.17	5,109.6	3.54	0.62	0.70	1.05	3,219.2	-	100,000	5,483.4	11,693.6	13,812.2	2,118.6	18.1%
		400,000	1000	56%	20.97	3.35	1.43	1.16	5.94	5,961.0	26.45	9.22	1.16	(0.22)	10.17	10,192.7	3.54	0.62	0.70	1.05	9,146.0	-	400,000	21,933.6	37,040.6	41,272.3	4,231.8	11.4%
		1,000,000	3000	46%	20.97	3.35	1.43	1.16	5.94	17,841.0	26.45	9.22	1.16	(0.22)	10.17	30,525.3	3.54	0.62	0.70	1.05	24,730.4	-	1,000,000	54,834.0	97,405.3	110,089.7	12,684.3	13.0%
		1,500,000	4000	52%	20.97	3.35	1.43	1.16	5.94	23,781.0	26.45	9.22	1.16	(0.22)	10.17	40,691.6	3.54	0.62	0.70	1.05	35,230.1	-	1,500,000	82,251.0	141,262.1	158,172.7	16,910.6	12.0%
GSd	Red Rock	15,000	60	35%	21.64	6.15	0.86	0.75	7.76	487.2	27.28	9.22	0.75	(0.22)	9.76	612.7	3.54	0.62	0.7	1.0545	426.9	-	15,000	822.5	1,736.7	1,862.1	125.4	7.2%
		43,164	133	45%	21.64	6.15	0.86	0.75	7.76	1,053.7	27.28	9.22	0.75	(0.22)	9.76	1,324.9	3.54	0.62	0.70	1.05	1,080.5	-	43,164	2,366.9	4,501.1	4,772.3	271.1	6.0%
		100,000	500	28%	21.64	6.15	0.86	0.75	7.76	3,901.6	27.28	9.22	0.75	(0.22)	9.76	4,905.4	3.54	0.62	0.70	1.05	3,219.2	-	100,000	5,483.4	12,604.2	13,608.0	1,003.8	8.0%
		400,000	1000	56%	21.64	6.15	0.86	0.75	7.76	7,781.6	27.28	9.22	0.75	(0.22)	9.76	9,783.6	3.54	0.62	0.70	1.05	9,146.0	-	400,000	21,933.6	38,861.2	40,863.1	2,001.9	5.2%
		1,000,000	3000	46%	21.64	6.15	0.86	0.75	7.76	23,301.6	27.28	9.22	0.75	(0.22)	9.76	29,296.1	3.54	0.62	0.70	1.05	24,730.4	-	1,000,000	54,834.0	102,866.0	108,860.5	5,994.5	5.8%
		1,500,000	4000	52%	21.64	6.15	0.86	0.75	7.76	31,061.6	27.28	9.22	0.75	(0.22)	9.76	39,052.4	3.54	0.62	0.70	1.05	35,230.1	-	1,500,000	82,251.0	148,542.8	156,533.5	7,990.8	5.4%
GSd	Rockland	15,000	60	35%	7.27	2.59	0.53	0.57	3.69	228.7	16.87	7.25	0.57	(0.22)	7.60	473.0	3.54	0.62	0.7	1.0545	426.9	-	15,000	822.5	1,478.1	1,722.5	244.4	16.5%
		43,164	133	45%	7.27	2.59	0.53	0.57	3.69	498.0	16.87	7.25	0.57	(0.22)	7.60	1,028.0	3.54	0.62	0.70	1.05	1,080.5	-	43,164	2,366.9	3,945.4	4,475.4	530.0	13.4%
		100,000	500	28%	7.27	2.59	0.53	0.57	3.69	1,852.3	16.87	7.25	0.57	(0.22)	7.60	3,818.2	3.54	0.62	0.70	1.05	3,219.2	-	100,000	5,483.4	10,554.9	12,520.8	1,966.0	18.6%
		400,000	1000	56%	7.27	2.59	0.53	0.57	3.69	3,697.3	16.87	7.25	0.57	(0.22)	7.60	7,619.6	3.54	0.62	0.70	1.05	9,146.0	-	400,000	21,933.6	34,776.9	38,699.2	3,922.3	11.3%
		1,000,000	3000	46%	7.27	2.59	0.53	0.57	3.69	11,077.3	16.87	7.25	0.57	(0.22)	7.60	22,825.0	3.54	0.62	0.70	1.05	24,730.4	-	1,000,000	54,834.0	90,641.6	102,389.3	11,747.7	13.0%
		1,500,000	4000	52%	7.27	2.59	0.53	0.57	3.69	14,767.3	16.87	7.25	0.57	(0.22)	7.60	30,427.7	3.54	0.62	0.70	1.05	35,230.1	-	1,500,000	82,251.0	132,248.4	147,908.8	15,660.4	11.8%
GSd	Russell	15,000	60	35%	19.26	7.10	0.58	0.36	8.04	501.7	25.87	9.22	0.36	(0.22)	9.37	587.8	3.54	0.62	0.7	1.0545	426.9	-	15,000	822.5	1,751.1	1,837.3	86.2	4.9%
		43,164	133	45%	19.26	7.10	0.58	0.36	8.04	1,088.6	25.87	9.22	0.36	(0.22)	9.37	1,271.6	3.54	0.62	0.70	1.05	1,080.5	-	43,164	2,366.9	4,536.0	4,719.0	183.0	4.0%
		100,000	500	28%	19.26	7.10	0.58	0.36	8.04	4,039.3	25.87	9.22	0.36	(0.22)	9.37	4,709.0	3.54	0.62	0.70	1.05	3,219.2	-	100,000	5,483.4	12,741.9	13,411.6	669.8	5.3%
		400,000	1000	56%	19.26	7.10	0.58	0.36	8.04	8,059.3	25.87	9.22	0.36	(0.22)	9.37	9,392.2	3.54	0.62	0.70	1.05	9,146.0	-	400,000	21,933.6	39,138.8	40,471.7	1,332.9	3.4%
		1,000,000	3000	46%	19.26	7.10	0.58	0.36	8.04	24,139.3	25.87	9.22	0.36	(0.22)	9.37	28,124.7	3.54	0.62	0.70	1.05	24,730.4	-	1,000,000	54,834.0	103,703.6	107,689.1	3,985.5	3.8%
		1,500,000	4000	52%	19.26	7.10	0.58	0.36	8.04	32,179.3	25.87	9.22	0.36	(0.22)	9.37	37,491.0	3.54	0.62	0.70	1.05	35,230.1	-	1,500,000	82,251.0	149,660.4	154,972.1	5,311.7	3.5%

New Rate Class: GSd

Total Bill Impacts of Proposed Distribution Rates [old RTSR+TLF]: Threshold of 750 kWhs

Classes		Scenario			May 2007 Incl Rate Riders						May 2008 Incl Rate Riders						Non-Dx Compoent				Other Reg	Commodity Bands			Existing	New	$ Incr	% Incr
					Existing Dx Rates					Existing Dx	New Dx Rates					New Dx	RTSR old	WMSC	DRC	TLF old	Old	Band 1	Band 2	Old	Total Bill	Total Bill	Total Bill	Total Bill
																						-	5.2					
New Class	Old Class	kWh	kW	LF	SrChg [$/cust]	base [$/kW]	Rider1 [$/kW]	Rider2 [$/kW]	VarChg [$/kW]	[$/month]	SrChg [$/cust]	base [$/kW]	Rider2 [$/kW]	Rider3 [$/kW]	VarChg [$/kW]	[$/month]	$/kW	c/kWh	c/kWh		$	kWhs	kWhs	Total $	[$/month]	[$/month]	[$/month]	%
GSd	Schreiber	15,000	60	35%	**20.70**	**7.36**	**1.57**	**1.17**	**10.10**	626.7	**26.51**	**9.22**	**1.17**	**(0.22)**	**10.18**	637.1	**3.54**	0.62	0.7	1.0545	426.9	-	15,000	822.5	1,876.1	1,886.5	10.4	0.6%
		43,164	133	45%	20.70	7.36	1.57	1.17	10.10	1,364.0	26.51	9.22	1.17	(0.22)	10.18	1,380.0	3.54	0.62	0.70	1.05	1,080.5	-	43,164	2,366.9	4,811.4	4,827.4	16.0	0.3%
		100,000	500	28%	20.70	7.36	1.57	1.17	10.10	5,070.7	26.51	9.22	1.17	(0.22)	10.18	5,114.7	3.54	0.62	0.70	1.05	3,219.2	-	100,000	5,483.4	13,773.3	13,817.3	44.0	0.3%
		400,000	1000	56%	20.70	7.36	1.57	1.17	10.10	10,120.7	26.51	9.22	1.17	(0.22)	10.18	10,202.8	3.54	0.62	0.70	1.05	9,146.0	-	400,000	21,933.6	41,200.3	41,282.4	82.1	0.2%
		1,000,000	3000	46%	20.70	7.36	1.57	1.17	10.10	30,320.7	26.51	9.22	1.17	(0.22)	10.18	30,555.4	3.54	0.62	0.70	1.05	24,730.4	-	1,000,000	54,834.0	109,885.1	110,119.7	234.7	0.2%
		1,500,000	4000	52%	20.70	7.36	1.57	1.17	10.10	40,420.7	26.51	9.22	1.17	(0.22)	10.18	40,731.6	3.54	0.62	0.70	1.05	35,230.1	-	1,500,000	82,251.0	157,901.8	158,212.8	310.9	0.2%
GSd	Severn	15,000	60	35%	**22.17**	**3.35**	**0.98**	**0.69**	**5.02**	323.4	**28.15**	**8.70**	**0.69**	**(0.22)**	**9.17**	578.5	**3.54**	0.62	0.7	1.0545	426.9	-	15,000	822.5	1,572.8	1,827.9	255.1	16.2%
		43,164	133	45%	22.17	3.35	0.98	0.69	5.02	689.8	28.15	8.70	0.69	(0.22)	9.17	1,248.1	3.54	0.62	0.70	1.05	1,080.5	-	43,164	2,366.9	4,137.2	4,695.5	558.3	13.5%
		100,000	500	28%	22.17	3.35	0.98	0.69	5.02	2,532.2	28.15	8.70	0.69	(0.22)	9.17	4,614.5	3.54	0.62	0.70	1.05	3,219.2	-	100,000	5,483.4	11,234.8	13,317.1	2,082.3	18.5%
		400,000	1000	56%	22.17	3.35	0.98	0.69	5.02	5,042.2	28.15	8.70	0.69	(0.22)	9.17	9,200.8	3.54	0.62	0.70	1.05	9,146.0	-	400,000	21,933.6	36,121.8	40,280.4	4,158.7	11.5%
		1,000,000	3000	46%	22.17	3.35	0.98	0.69	5.02	15,082.2	28.15	8.70	0.69	(0.22)	9.17	27,546.3	3.54	0.62	0.70	1.05	24,730.4	-	1,000,000	54,834.0	94,646.5	107,110.6	12,464.1	13.2%
		1,500,000	4000	52%	22.17	3.35	0.98	0.69	5.02	20,102.2	28.15	8.70	0.69	(0.22)	9.17	36,719.0	3.54	0.62	0.70	1.05	35,230.1	-	1,500,000	82,251.0	137,583.3	154,200.1	16,616.8	12.1%
GSd	Shelburne	15,000	60	35%	**20.01**	**2.78**	**0.32**	**0.08**	**3.18**	210.8	**26.69**	**7.25**	**0.08**	**(0.22)**	**7.11**	453.4	**3.54**	0.62	0.7	1.0545	426.9	-	15,000	822.5	1,460.2	1,702.9	242.6	16.6%
		43,164	133	45%	20.01	2.78	0.32	0.08	3.18	443.0	26.69	7.25	0.08	(0.22)	7.11	972.7	3.54	0.62	0.70	1.05	1,080.5	-	43,164	2,366.9	3,890.4	4,420.1	529.7	13.6%
		100,000	500	28%	20.01	2.78	0.32	0.08	3.18	1,610.0	26.69	7.25	0.08	(0.22)	7.11	3,583.0	3.54	0.62	0.70	1.05	3,219.2	-	100,000	5,483.4	10,312.6	12,285.6	1,973.0	19.1%
		400,000	1000	56%	20.01	2.78	0.32	0.08	3.18	3,200.0	26.69	7.25	0.08	(0.22)	7.11	7,139.4	3.54	0.62	0.70	1.05	9,146.0	-	400,000	21,933.6	34,279.6	38,219.0	3,939.4	11.5%
		1,000,000	3000	46%	20.01	2.78	0.32	0.08	3.18	9,560.0	26.69	7.25	0.08	(0.22)	7.11	21,364.8	3.54	0.62	0.70	1.05	24,730.4	-	1,000,000	54,834.0	89,124.4	100,929.2	11,804.8	13.2%
		1,500,000	4000	52%	20.01	2.78	0.32	0.08	3.18	12,740.0	26.69	7.25	0.08	(0.22)	7.11	28,477.5	3.54	0.62	0.70	1.05	35,230.1	-	1,500,000	82,251.0	130,221.1	145,958.6	15,737.5	12.1%
UGd	Smiths Falls	15,000	60	35%	**9.84**	**3.33**	**0.39**	**0.13**	**3.85**	240.8	**13.84**	**7.33**	**0.13**	**(0.27)**	**7.19**	445.2	**3.54**	0.62	0.7	1.0545	426.9	-	15,000	822.5	1,490.3	1,694.7	204.4	13.7%
		43,164	133	45%	9.84	3.33	0.39	0.13	3.85	521.9	13.84	7.33	0.13	(0.27)	7.19	970.1	3.54	0.62	0.70	1.05	1,080.5	-	43,164	2,366.9	3,969.3	4,417.5	448.2	11.3%
		100,000	500	28%	9.84	3.33	0.39	0.13	3.85	1,934.8	13.84	7.33	0.13	(0.27)	7.19	3,608.9	3.54	0.62	0.70	1.05	3,219.2	-	100,000	5,483.4	10,637.4	12,311.5	1,674.1	15.7%
		400,000	1000	56%	9.84	3.33	0.39	0.13	3.85	3,859.8	13.84	7.33	0.13	(0.27)	7.19	7,204.0	3.54	0.62	0.70	1.05	9,146.0	-	400,000	21,933.6	34,939.4	38,283.6	3,344.2	9.6%
		1,000,000	3000	46%	9.84	3.33	0.39	0.13	3.85	11,559.8	13.84	7.33	0.13	(0.27)	7.19	21,584.5	3.54	0.62	0.70	1.05	24,730.4	-	1,000,000	54,834.0	91,124.2	101,148.8	10,024.6	11.0%
		1,500,000	4000	52%	9.84	3.33	0.39	0.13	3.85	15,409.8	13.84	7.33	0.13	(0.27)	7.19	28,774.7	3.54	0.62	0.70	1.05	35,230.1	-	1,500,000	82,251.0	132,891.0	146,255.8	13,364.8	10.1%
GSd	South Glengarry	15,000	60	35%	**17.41**	**2.37**	**1.18**	**0.94**	**4.49**	286.8	**24.34**	**7.75**	**0.94**	**(0.22)**	**8.47**	532.7	**3.54**	0.62	0.7	1.0545	426.9	-	15,000	822.5	1,536.2	1,782.1	245.9	16.0%
		43,164	133	45%	17.41	2.37	1.18	0.94	4.49	614.6	24.34	7.75	0.94	(0.22)	8.47	1,151.2	3.54	0.62	0.70	1.05	1,080.5	-	43,164	2,366.9	4,062.0	4,598.6	536.6	13.2%
		100,000	500	28%	17.41	2.37	1.18	0.94	4.49	2,262.4	24.34	7.75	0.94	(0.22)	8.47	4,260.7	3.54	0.62	0.70	1.05	3,219.2	-	100,000	5,483.4	10,965.0	12,963.3	1,998.3	18.2%
		400,000	1000	56%	17.41	2.37	1.18	0.94	4.49	4,507.4	24.34	7.75	0.94	(0.22)	8.47	8,497.0	3.54	0.62	0.70	1.05	9,146.0	-	400,000	21,933.6	35,587.0	39,576.6	3,989.6	11.2%
		1,000,000	3000	46%	17.41	2.37	1.18	0.94	4.49	13,487.4	24.34	7.75	0.94	(0.22)	8.47	25,442.4	3.54	0.62	0.70	1.05	24,730.4	-	1,000,000	54,834.0	93,051.8	105,006.8	11,955.0	12.8%
		1,500,000	4000	52%	17.41	2.37	1.18	0.94	4.49	17,977.4	24.34	7.75	0.94	(0.22)	8.47	33,915.1	3.54	0.62	0.70	1.05	35,230.1	-	1,500,000	82,251.0	135,458.5	151,396.3	15,937.7	11.8%

New Rate Class: GSd

Total Bill Impacts of Proposed Distribution Rates [old RTSR+TLF]: Threshold of 750 kWhs

Classes		Scenario			May 2007 Incl Rate Riders						May 2008 Incl Rate Riders						Non-Dx Compoent				Other Reg	Commodity Bands			Existing	New	$ Incr	% Incr
					Existing Dx Rates					Existing Dx	New Dx Rates					New Dx	RTSR old	WMSC	DRC	TLF old	Old	Band 1	Band 2	Old	Total Bill	Total Bill	Total Bill	Total Bill
																						-	5.2					
New Class	Old Class	kWh	kW	LF	SrChg [$/cust]	base [$/kW]	Rider1 [$/kW]	Rider2 [$/kW]	VarChg [$/kW]	[$/month]	SrChg [$/cust]	base [$/kW]	Rider2 [$/kW]	Rider3 [$/kW]	VarChg [$/kW]	[$/month]	$/kW	c/kWh	c/kWh		$	kWhs	kWhs	Total $	[$/month]	[$/month]	[$/month]	%
GSd	South River	15,000	60	35%	22.11	4.87	1.22	0.92	7.01	442.7	28.16	9.22	0.92	(0.22)	9.93	623.7	3.54	0.62	0.7	1.0545	426.9	-	15,000	822.5	1,692.1	1,873.2	181.0	10.7%
		43,164	133	45%	22.11	4.87	1.22	0.92	7.01	954.4	28.16	9.22	0.92	(0.22)	9.93	1,348.4	3.54	0.62	0.70	1.05	1,080.5	-	43,164	2,366.9	4,401.8	4,795.8	393.9	8.9%
		100,000	500	28%	22.11	4.87	1.22	0.92	7.01	3,527.1	28.16	9.22	0.92	(0.22)	9.93	4,991.3	3.54	0.62	0.70	1.05	3,219.2	-	100,000	5,483.4	12,229.7	13,693.9	1,464.2	12.0%
		400,000	1000	56%	22.11	4.87	1.22	0.92	7.01	7,032.1	28.16	9.22	0.92	(0.22)	9.93	9,954.4	3.54	0.62	0.70	1.05	9,146.0	-	400,000	21,933.6	38,111.7	41,034.0	2,922.3	7.7%
		1,000,000	3000	46%	22.11	4.87	1.22	0.92	7.01	21,052.1	28.16	9.22	0.92	(0.22)	9.93	29,807.0	3.54	0.62	0.70	1.05	24,730.4	-	1,000,000	54,834.0	100,616.5	109,371.4	8,754.9	8.7%
		1,500,000	4000	52%	22.11	4.87	1.22	0.92	7.01	28,062.1	28.16	9.22	0.92	(0.22)	9.93	39,733.3	3.54	0.62	0.70	1.05	35,230.1	-	1,500,000	82,251.0	145,543.2	157,214.4	11,671.2	8.0%
GSd	Springwater	15,000	60	35%	20.53	3.42	0.85	0.53	4.80	308.5	26.56	8.60	0.53	(0.22)	8.91	561.3	3.54	0.62	0.7	1.0545	426.9	-	15,000	822.5	1,558.0	1,810.7	252.8	16.2%
		43,164	133	45%	20.53	3.42	0.85	0.53	4.80	658.9	26.56	8.60	0.53	(0.22)	8.91	1,211.9	3.54	0.62	0.70	1.05	1,080.5	-	43,164	2,366.9	4,106.3	4,659.3	553.0	13.5%
		100,000	500	28%	20.53	3.42	0.85	0.53	4.80	2,420.5	26.56	8.60	0.53	(0.22)	8.91	4,482.9	3.54	0.62	0.70	1.05	3,219.2	-	100,000	5,483.4	11,123.1	13,185.5	2,062.4	18.5%
		400,000	1000	56%	20.53	3.42	0.85	0.53	4.80	4,820.5	26.56	8.60	0.53	(0.22)	8.91	8,939.3	3.54	0.62	0.70	1.05	9,146.0	-	400,000	21,933.6	35,900.1	40,018.8	4,118.7	11.5%
		1,000,000	3000	46%	20.53	3.42	0.85	0.53	4.80	14,420.5	26.56	8.60	0.53	(0.22)	8.91	26,764.7	3.54	0.62	0.70	1.05	24,730.4	-	1,000,000	54,834.0	93,984.9	106,329.0	12,344.1	13.1%
		1,500,000	4000	52%	20.53	3.42	0.85	0.53	4.80	19,220.5	26.56	8.60	0.53	(0.22)	8.91	35,677.4	3.54	0.62	0.70	1.05	35,230.1	-	1,500,000	82,251.0	136,701.7	153,158.5	16,456.8	12.0%
GSd	Stirling-Rawdon	15,000	60	35%	24.12	4.11	0.67	0.30	5.08	328.9	29.66	9.22	0.30	(0.22)	9.31	588.0	3.54	0.62	0.7	1.0545	426.9	-	15,000	822.5	1,578.3	1,837.5	259.1	16.4%
		43,164	133	45%	24.12	4.11	0.67	0.30	5.08	699.8	29.66	9.22	0.30	(0.22)	9.31	1,267.4	3.54	0.62	0.70	1.05	1,080.5	-	43,164	2,366.9	4,147.2	4,714.8	567.6	13.7%
		100,000	500	28%	24.12	4.11	0.67	0.30	5.08	2,564.1	29.66	9.22	0.30	(0.22)	9.31	4,682.8	3.54	0.62	0.70	1.05	3,219.2	-	100,000	5,483.4	11,266.7	13,385.4	2,118.7	18.8%
		400,000	1000	56%	24.12	4.11	0.67	0.30	5.08	5,104.1	29.66	9.22	0.30	(0.22)	9.31	9,335.9	3.54	0.62	0.70	1.05	9,146.0	-	400,000	21,933.6	36,183.7	40,415.5	4,231.8	11.7%
		1,000,000	3000	46%	24.12	4.11	0.67	0.30	5.08	15,264.1	29.66	9.22	0.30	(0.22)	9.31	27,948.5	3.54	0.62	0.70	1.05	24,730.4	-	1,000,000	54,834.0	94,828.5	107,512.9	12,684.4	13.4%
		1,500,000	4000	52%	24.12	4.11	0.67	0.30	5.08	20,344.1	29.66	9.22	0.30	(0.22)	9.31	37,254.8	3.54	0.62	0.70	1.05	35,230.1	-	1,500,000	82,251.0	137,825.3	154,735.9	16,910.7	12.3%
GSd	Thedford	15,000	60	35%	17.83	3.38	1.14	1.00	5.52	349.0	24.23	8.95	1.00	(0.22)	9.73	608.2	3.54	0.62	0.7	1.0545	426.9	-	15,000	822.5	1,598.5	1,857.6	259.2	16.2%
		43,164	133	45%	17.83	3.38	1.14	1.00	5.52	752.0	24.23	8.95	1.00	(0.22)	9.73	1,318.7	3.54	0.62	0.70	1.05	1,080.5	-	43,164	2,366.9	4,199.4	4,766.1	566.7	13.5%
		100,000	500	28%	17.83	3.38	1.14	1.00	5.52	2,777.8	24.23	8.95	1.00	(0.22)	9.73	4,890.6	3.54	0.62	0.70	1.05	3,219.2	-	100,000	5,483.4	11,480.4	13,593.2	2,112.8	18.4%
		400,000	1000	56%	17.83	3.38	1.14	1.00	5.52	5,537.8	24.23	8.95	1.00	(0.22)	9.73	9,756.9	3.54	0.62	0.70	1.05	9,146.0	-	400,000	21,933.6	36,617.4	40,836.5	4,219.1	11.5%
		1,000,000	3000	46%	17.83	3.38	1.14	1.00	5.52	16,577.8	24.23	8.95	1.00	(0.22)	9.73	29,222.3	3.54	0.62	0.70	1.05	24,730.4	-	1,000,000	54,834.0	96,142.2	108,786.7	12,644.5	13.2%
		1,500,000	4000	52%	17.83	3.38	1.14	1.00	5.52	22,097.8	24.23	8.95	1.00	(0.22)	9.73	38,955.0	3.54	0.62	0.70	1.05	35,230.1	-	1,500,000	82,251.0	139,579.0	156,436.2	16,857.2	12.1%
GSd	Thessalon	15,000	60	35%	18.90	3.22	0.21	0.17	3.60	234.9	24.96	7.60	0.17	(0.22)	7.55	478.1	3.54	0.62	0.7	1.0545	426.9	-	15,000	822.5	1,484.3	1,727.6	243.2	16.4%
		43,164	133	45%	18.90	3.22	0.21	0.17	3.60	497.7	24.96	7.60	0.17	(0.22)	7.55	1,029.5	3.54	0.62	0.70	1.05	1,080.5	-	43,164	2,366.9	3,945.1	4,476.9	531.8	13.5%
		100,000	500	28%	18.90	3.22	0.21	0.17	3.60	1,818.9	24.96	7.60	0.17	(0.22)	7.55	3,801.3	3.54	0.62	0.70	1.05	3,219.2	-	100,000	5,483.4	10,521.5	12,503.9	1,982.4	18.8%
		400,000	1000	56%	18.90	3.22	0.21	0.17	3.60	3,618.9	24.96	7.60	0.17	(0.22)	7.55	7,577.7	3.54	0.62	0.70	1.05	9,146.0	-	400,000	21,933.6	34,698.5	38,657.2	3,958.8	11.4%
		1,000,000	3000	46%	18.90	3.22	0.21	0.17	3.60	10,818.9	24.96	7.60	0.17	(0.22)	7.55	22,683.1	3.54	0.62	0.70	1.05	24,730.4	-	1,000,000	54,834.0	90,383.3	102,247.4	11,864.2	13.1%
		1,500,000	4000	52%	18.90	3.22	0.21	0.17	3.60	14,418.9	24.96	7.60	0.17	(0.22)	7.55	30,235.8	3.54	0.62	0.70	1.05	35,230.1	-	1,500,000	82,251.0	131,900.0	147,716.9	15,816.9	12.0%

New Rate Class: GSd

Total Bill Impacts of Proposed Distribution Rates [old RTSR+TLF]: Threshold of 750 kWhs

Classes		Scenario			May 2007 Incl Rate Riders						May 2008 Incl Rate Riders						Non-Dx Compoent				Other Reg	Commodity Bands			Existing	New	$ Incr	% Incr
					Existing Dx Rates					Existing Dx	New Dx Rates					New Dx	RTSR old	WMSC	DRC	TLF old	Old	Band 1	Band 2	Old	Total Bill	Total Bill	Total Bill	Total Bill
																						-	5.2					
New Class	Old Class	kWh	kW	LF	SrChg [$/cust]	base [$/kW]	Rider1 [$/kW]	Rider2 [$/kW]	VarChg [$/kW]	[$/month]	SrChg [$/cust]	base [$/kW]	Rider2 [$/kW]	Rider3 [$/kW]	VarChg [$/kW]	[$/month]	$/kW	c/kWh	c/kWh		$	kWhs	kWhs	Total $	[$/month]	[$/month]	[$/month]	%
GSd	**Thorndale**	15,000	60	35%	**14.52**	**3.25**	**1.67**	**1.03**	**5.95**	371.5	**22.06**	**9.22**	**1.03**	**(0.22)**	**10.04**	624.2	**3.54**	0.62	0.7	1.0545	426.9	-	15,000	822.5	1,620.9	1,873.7	252.7	15.6%
		43,164	133	45%	14.52	3.25	1.67	1.03	5.95	805.9	22.06	9.22	1.03	(0.22)	10.04	1,356.9	3.54	0.62	0.70	1.05	1,080.5	-	43,164	2,366.9	4,253.3	4,804.3	551.0	13.0%
		100,000	500	28%	14.52	3.25	1.67	1.03	5.95	2,989.5	22.06	9.22	1.03	(0.22)	10.04	5,040.2	3.54	0.62	0.70	1.05	3,219.2	-	100,000	5,483.4	11,692.1	13,742.8	2,050.7	17.5%
		400,000	1000	56%	14.52	3.25	1.67	1.03	5.95	5,964.5	22.06	9.22	1.03	(0.22)	10.04	10,058.3	3.54	0.62	0.70	1.05	9,146.0	-	400,000	21,933.6	37,044.1	41,137.9	4,093.8	11.1%
		1,000,000	3000	46%	14.52	3.25	1.67	1.03	5.95	17,864.5	22.06	9.22	1.03	(0.22)	10.04	30,130.9	3.54	0.62	0.70	1.05	24,730.4	-	1,000,000	54,834.0	97,428.9	109,695.3	12,266.4	12.6%
		1,500,000	4000	52%	14.52	3.25	1.67	1.03	5.95	23,814.5	22.06	9.22	1.03	(0.22)	10.04	40,167.2	3.54	0.62	0.70	1.05	35,230.1	-	1,500,000	82,251.0	141,295.7	157,648.3	16,352.7	11.6%
UGd	**Thorold**	15,000	60	35%	**22.63**	**4.76**	**0.46**	**0.20**	**5.42**	347.8	**23.64**	**7.33**	**0.20**	**(0.27)**	**7.26**	459.3	**3.54**	0.62	0.7	1.0545	426.9	-	15,000	822.5	1,597.3	1,708.7	111.4	7.0%
		43,164	133	45%	22.63	4.76	0.46	0.20	5.42	743.5	23.64	7.33	0.20	(0.27)	7.26	989.2	3.54	0.62	0.70	1.05	1,080.5	-	43,164	2,366.9	4,190.9	4,436.7	245.8	5.9%
		100,000	500	28%	22.63	4.76	0.46	0.20	5.42	2,732.6	23.64	7.33	0.20	(0.27)	7.26	3,653.7	3.54	0.62	0.70	1.05	3,219.2	-	100,000	5,483.4	11,435.2	12,356.3	921.1	8.1%
		400,000	1000	56%	22.63	4.76	0.46	0.20	5.42	5,442.6	23.64	7.33	0.20	(0.27)	7.26	7,283.8	3.54	0.62	0.70	1.05	9,146.0	-	400,000	21,933.6	36,522.2	38,363.4	1,841.2	5.0%
		1,000,000	3000	46%	22.63	4.76	0.46	0.20	5.42	16,282.6	23.64	7.33	0.20	(0.27)	7.26	21,804.3	3.54	0.62	0.70	1.05	24,730.4	-	1,000,000	54,834.0	95,847.0	101,368.6	5,521.6	5.8%
		1,500,000	4000	52%	22.63	4.76	0.46	0.20	5.42	21,702.6	23.64	7.33	0.20	(0.27)	7.26	29,064.5	3.54	0.62	0.70	1.05	35,230.1	-	1,500,000	82,251.0	139,183.8	146,545.6	7,361.8	5.3%
GSd	**Tweed**	15,000	60	35%	**8.26**	**3.11**	**1.35**	**0.99**	**5.45**	335.3	**17.62**	**8.80**	**0.99**	**(0.22)**	**9.57**	592.0	**3.54**	0.62	0.7	1.0545	426.9	-	15,000	822.5	1,584.7	1,841.4	256.7	16.2%
		43,164	133	45%	8.26	3.11	1.35	0.99	5.45	733.1	17.62	8.80	0.99	(0.22)	9.57	1,290.8	3.54	0.62	0.70	1.05	1,080.5	-	43,164	2,366.9	4,180.5	4,738.2	557.7	13.3%
		100,000	500	28%	8.26	3.11	1.35	0.99	5.45	2,733.3	17.62	8.80	0.99	(0.22)	9.57	4,804.0	3.54	0.62	0.70	1.05	3,219.2	-	100,000	5,483.4	11,435.9	13,506.6	2,070.7	18.1%
		400,000	1000	56%	8.26	3.11	1.35	0.99	5.45	5,458.3	17.62	8.80	0.99	(0.22)	9.57	9,590.3	3.54	0.62	0.70	1.05	9,146.0	-	400,000	21,933.6	36,537.8	40,669.9	4,132.1	11.3%
		1,000,000	3000	46%	8.26	3.11	1.35	0.99	5.45	16,358.3	17.62	8.80	0.99	(0.22)	9.57	28,735.7	3.54	0.62	0.70	1.05	24,730.4	-	1,000,000	54,834.0	95,922.6	108,300.1	12,377.5	12.9%
		1,500,000	4000	52%	8.26	3.11	1.35	0.99	5.45	21,808.3	17.62	8.80	0.99	(0.22)	9.57	38,308.4	3.54	0.62	0.70	1.05	35,230.1	-	1,500,000	82,251.0	139,289.4	155,789.6	16,500.2	11.8%
GSd	**Wardsville**	15,000	60	35%	**12.32**	**3.16**	**0.81**	**0.26**	**4.23**	266.1	**20.61**	**8.20**	**0.26**	**(0.22)**	**8.24**	515.2	**3.54**	0.62	0.7	1.0545	426.9	-	15,000	822.5	1,515.5	1,764.6	249.0	16.4%
		43,164	133	45%	12.32	3.16	0.81	0.26	4.23	574.9	20.61	8.20	0.26	(0.22)	8.24	1,116.9	3.54	0.62	0.70	1.05	1,080.5	-	43,164	2,366.9	4,022.3	4,564.3	542.0	13.5%
		100,000	500	28%	12.32	3.16	0.81	0.26	4.23	2,127.3	20.61	8.20	0.26	(0.22)	8.24	4,142.0	3.54	0.62	0.70	1.05	3,219.2	-	100,000	5,483.4	10,829.9	12,844.6	2,014.6	18.6%
		400,000	1000	56%	12.32	3.16	0.81	0.26	4.23	4,242.3	20.61	8.20	0.26	(0.22)	8.24	8,263.3	3.54	0.62	0.70	1.05	9,146.0	-	400,000	21,933.6	35,321.9	39,342.9	4,021.0	11.4%
		1,000,000	3000	46%	12.32	3.16	0.81	0.26	4.23	12,702.3	20.61	8.20	0.26	(0.22)	8.24	24,748.7	3.54	0.62	0.70	1.05	24,730.4	-	1,000,000	54,834.0	92,266.7	104,313.1	12,046.4	13.1%
		1,500,000	4000	52%	12.32	3.16	0.81	0.26	4.23	16,932.3	20.61	8.20	0.26	(0.22)	8.24	32,991.4	3.54	0.62	0.70	1.05	35,230.1	-	1,500,000	82,251.0	134,413.5	150,472.6	16,059.1	11.9%
GSd	**Warkworth**	15,000	60	35%	**21.31**	**4.47**	**1.44**	**1.03**	**6.94**	437.7	**27.36**	**9.22**	**1.03**	**(0.22)**	**10.04**	629.5	**3.54**	0.62	0.7	1.0545	426.9	-	15,000	822.5	1,687.1	1,879.0	191.8	11.4%
		43,164	133	45%	21.31	4.47	1.44	1.03	6.94	944.3	27.36	9.22	1.03	(0.22)	10.04	1,362.2	3.54	0.62	0.70	1.05	1,080.5	-	43,164	2,366.9	4,391.7	4,809.6	417.9	9.5%
		100,000	500	28%	21.31	4.47	1.44	1.03	6.94	3,491.3	27.36	9.22	1.03	(0.22)	10.04	5,045.5	3.54	0.62	0.70	1.05	3,219.2	-	100,000	5,483.4	12,193.9	13,748.1	1,554.2	12.7%
		400,000	1000	56%	21.31	4.47	1.44	1.03	6.94	6,961.3	27.36	9.22	1.03	(0.22)	10.04	10,063.6	3.54	0.62	0.70	1.05	9,146.0	-	400,000	21,933.6	38,040.9	41,143.2	3,102.3	8.2%
		1,000,000	3000	46%	21.31	4.47	1.44	1.03	6.94	20,841.3	27.36	9.22	1.03	(0.22)	10.04	30,136.2	3.54	0.62	0.70	1.05	24,730.4	-	1,000,000	54,834.0	100,405.7	109,700.6	9,294.9	9.3%
		1,500,000	4000	52%	21.31	4.47	1.44	1.03	6.94	27,781.3	27.36	9.22	1.03	(0.22)	10.04	40,172.5	3.54	0.62	0.70	1.05	35,230.1	-	1,500,000	82,251.0	145,262.4	157,653.6	12,391.2	8.5%

New Rate Class: GSd

Total Bill Impacts of Proposed Distribution Rates [old RTSR+TLF]: Threshold of 750 kWhs

Classes		Scenario			May 2007 Incl Rate Riders						May 2008 Incl Rate Riders						Non-Dx Compoent				Other Reg	Commodity Bands			Existing	New	$ Incr	% Incr
					Existing Dx Rates					Existing Dx	New Dx Rates					New Dx	RTSR old	WMSC	DRC	TLF old	Old	Band 1	Band 2	Old	Total Bill	Total Bill	Total Bill	Total Bill
																						-	5.2					
New Class	Old Class	kWh	kW	LF	SrChg	base	Rider1	Rider2	VarChg	[$/month]	SrChg	base	Rider2	Rider3	VarChg	[$/month]	$/kW	c/kWh	c/kWh		$	kWhs	kWhs	Total $	[$/month]	[$/month]	[$/month]	%
					[$/cust]	[$/kW]	[$/kW]	[$/kW]	[$/kW]		[$/cust]	[$/kW]	[$/kW]	[$/kW]	[$/kW]													
GSd	West Elgin	15,000	60	35%	15.40	2.21	0.54	0.21	2.96	193.0	22.84	6.85	0.21	(0.22)	6.84	433.4	3.54	0.62	0.7	1.0545	426.9	-	15,000	822.5	1,442.4	1,682.8	240.4	16.7%
		43,164	133	45%	15.40	2.21	0.54	0.21	2.96	409.1	22.84	6.85	0.21	(0.22)	6.84	932.9	3.54	0.62	0.70	1.05	1,080.5	-	43,164	2,366.9	3,856.5	4,380.3	523.8	13.6%
		100,000	500	28%	15.40	2.21	0.54	0.21	2.96	1,495.4	22.84	6.85	0.21	(0.22)	6.84	3,444.2	3.54	0.62	0.70	1.05	3,219.2	-	100,000	5,483.4	10,198.0	12,146.8	1,948.8	19.1%
		400,000	1000	56%	15.40	2.21	0.54	0.21	2.96	2,975.4	22.84	6.85	0.21	(0.22)	6.84	6,865.5	3.54	0.62	0.70	1.05	9,146.0	-	400,000	21,933.6	34,055.0	37,945.1	3,890.1	11.4%
		1,000,000	3000	46%	15.40	2.21	0.54	0.21	2.96	8,895.4	22.84	6.85	0.21	(0.22)	6.84	20,550.9	3.54	0.62	0.70	1.05	24,730.4	-	1,000,000	54,834.0	88,459.8	100,115.3	11,655.5	13.2%
		1,500,000	4000	52%	15.40	2.21	0.54	0.21	2.96	11,855.4	22.84	6.85	0.21	(0.22)	6.84	27,393.7	3.54	0.62	0.70	1.05	35,230.1	-	1,500,000	82,251.0	129,336.5	144,874.8	15,538.3	12.0%
UGd	Whitchurch Stouffville	15,000	60	35%	21.85	2.93	0.35	0.13	3.41	226.5	22.84	7.15	0.13	(0.27)	7.01	443.3	3.54	0.62	0.7	1.0545	426.9	-	15,000	822.5	1,475.9	1,692.7	216.8	14.7%
		43,164	133	45%	21.85	2.93	0.35	0.13	3.41	475.4	22.84	7.15	0.13	(0.27)	7.01	954.8	3.54	0.62	0.70	1.05	1,080.5	-	43,164	2,366.9	3,922.8	4,402.2	479.4	12.2%
		100,000	500	28%	21.85	2.93	0.35	0.13	3.41	1,726.9	22.84	7.15	0.13	(0.27)	7.01	3,526.4	3.54	0.62	0.70	1.05	3,219.2	-	100,000	5,483.4	10,429.5	12,229.0	1,799.5	17.3%
		400,000	1000	56%	21.85	2.93	0.35	0.13	3.41	3,431.9	22.84	7.15	0.13	(0.27)	7.01	7,030.0	3.54	0.62	0.70	1.05	9,146.0	-	400,000	21,933.6	34,511.4	38,109.5	3,598.1	10.4%
		1,000,000	3000	46%	21.85	2.93	0.35	0.13	3.41	10,251.9	22.84	7.15	0.13	(0.27)	7.01	21,044.2	3.54	0.62	0.70	1.05	24,730.4	-	1,000,000	54,834.0	89,816.2	100,608.6	10,792.4	12.0%
		1,500,000	4000	52%	21.85	2.93	0.35	0.13	3.41	13,661.9	22.84	7.15	0.13	(0.27)	7.01	28,051.3	3.54	0.62	0.70	1.05	35,230.1	-	1,500,000	82,251.0	131,143.0	145,532.5	14,389.5	11.0%
GSd	Wiarton	15,000	60	35%	23.78	5.99	0.59	0.29	6.87	436.0	28.74	9.22	0.29	(0.22)	9.30	586.5	3.54	0.62	0.7	1.0545	426.9	-	15,000	822.5	1,685.4	1,835.9	150.5	8.9%
		43,164	133	45%	23.78	5.99	0.59	0.29	6.87	937.5	28.74	9.22	0.29	(0.22)	9.30	1,265.1	3.54	0.62	0.70	1.05	1,080.5	-	43,164	2,366.9	4,384.9	4,712.6	327.7	7.5%
		100,000	500	28%	23.78	5.99	0.59	0.29	6.87	3,458.8	28.74	9.22	0.29	(0.22)	9.30	4,676.9	3.54	0.62	0.70	1.05	3,219.2	-	100,000	5,483.4	12,161.4	13,379.5	1,218.1	10.0%
		400,000	1000	56%	23.78	5.99	0.59	0.29	6.87	6,893.8	28.74	9.22	0.29	(0.22)	9.30	9,325.0	3.54	0.62	0.70	1.05	9,146.0	-	400,000	21,933.6	37,973.4	40,404.6	2,431.2	6.4%
		1,000,000	3000	46%	23.78	5.99	0.59	0.29	6.87	20,633.8	28.74	9.22	0.29	(0.22)	9.30	27,917.6	3.54	0.62	0.70	1.05	24,730.4	-	1,000,000	54,834.0	100,198.1	107,482.0	7,283.8	7.3%
		1,500,000	4000	52%	23.78	5.99	0.59	0.29	6.87	27,503.8	28.74	9.22	0.29	(0.22)	9.30	37,213.9	3.54	0.62	0.70	1.05	35,230.1	-	1,500,000	82,251.0	144,984.9	154,695.0	9,710.1	6.7%
GSd	Woodville	15,000	60	35%	16.89	4.34	2.12	1.35	7.81	485.5	23.47	9.22	1.35	(0.22)	10.36	644.8	3.54	0.62	0.7	1.0545	426.9	-	15,000	822.5	1,734.9	1,894.3	159.4	9.2%
		43,164	133	45%	16.89	4.34	2.12	1.35	7.81	1,055.6	23.47	9.22	1.35	(0.22)	10.36	1,400.9	3.54	0.62	0.70	1.05	1,080.5	-	43,164	2,366.9	4,503.0	4,848.3	345.2	7.7%
		100,000	500	28%	16.89	4.34	2.12	1.35	7.81	3,921.9	23.47	9.22	1.35	(0.22)	10.36	5,201.6	3.54	0.62	0.70	1.05	3,219.2	-	100,000	5,483.4	12,624.5	13,904.2	1,279.7	10.1%
		400,000	1000	56%	16.89	4.34	2.12	1.35	7.81	7,826.9	23.47	9.22	1.35	(0.22)	10.36	10,379.7	3.54	0.62	0.70	1.05	9,146.0	-	400,000	21,933.6	38,906.5	41,459.3	2,552.9	6.6%
		1,000,000	3000	46%	16.89	4.34	2.12	1.35	7.81	23,446.9	23.47	9.22	1.35	(0.22)	10.36	31,092.3	3.54	0.62	0.70	1.05	24,730.4	-	1,000,000	54,834.0	103,011.3	110,656.7	7,645.4	7.4%
		1,500,000	4000	52%	16.89	4.34	2.12	1.35	7.81	31,256.9	23.47	9.22	1.35	(0.22)	10.36	41,448.6	3.54	0.62	0.70	1.05	35,230.1	-	1,500,000	82,251.0	148,738.0	158,929.7	10,191.7	6.9%
GSd	Wyoming	15,000	60	35%	17.36	4.57	0.52	0.23	5.32	336.6	24.35	9.22	0.23	(0.22)	9.24	578.5	3.54	0.62	0.7	1.0545	426.9	-	15,000	822.5	1,586.0	1,828.0	242.0	15.3%
		43,164	133	45%	17.36	4.57	0.52	0.23	5.32	724.9	24.35	9.22	0.23	(0.22)	9.24	1,252.8	3.54	0.62	0.70	1.05	1,080.5	-	43,164	2,366.9	4,172.3	4,700.2	527.9	12.7%
		100,000	500	28%	17.36	4.57	0.52	0.23	5.32	2,677.4	24.35	9.22	0.23	(0.22)	9.24	4,642.5	3.54	0.62	0.70	1.05	3,219.2	-	100,000	5,483.4	11,380.0	13,345.1	1,965.1	17.3%
		400,000	1000	56%	17.36	4.57	0.52	0.23	5.32	5,337.4	24.35	9.22	0.23	(0.22)	9.24	9,260.6	3.54	0.62	0.70	1.05	9,146.0	-	400,000	21,933.6	36,416.9	40,340.2	3,923.3	10.8%
		1,000,000	3000	46%	17.36	4.57	0.52	0.23	5.32	15,977.4	24.35	9.22	0.23	(0.22)	9.24	27,733.2	3.54	0.62	0.70	1.05	24,730.4	-	1,000,000	54,834.0	95,541.7	107,297.6	11,755.8	12.3%
		1,500,000	4000	52%	17.36	4.57	0.52	0.23	5.32	21,297.4	24.35	9.22	0.23	(0.22)	9.24	36,969.5	3.54	0.62	0.70	1.05	35,230.1	-	1,500,000	82,251.0	138,778.5	154,450.6	15,672.1	11.3%

New Rate Class: GSd

Total Bill Impacts of Proposed Distribution Rates [old RTSR+TLF]: Threshold of 750 kWhs

Classes		Scenario			May 2007 Incl Rate Riders						May 2008 Incl Rate Riders						Non-Dx Compoent				Other Reg	Commodity Bands			Existing	New	$ Incr	% Incr
					Existing Dx Rates					Existing Dx	New Dx Rates					New Dx	RTSR old	WMSC	DRC	TLF old	Old	Band 1	Band 2	Old	Total Bill	Total Bill	Total Bill	Total Bill
																						-	5.2					
New Class	Old Class	kWh	kW	LF	SrChg [$/cust]	base [$/kW]	Rider1 [$/kW]	Rider2 [$/kW]	VarChg [$/kW]	[$/month]	SrChg [$/cust]	base [$/kW]	Rider2 [$/kW]	Rider3 [$/kW]	VarChg [$/kW]	[$/month]	$/kW	c/kWh	c/kWh		$	kWhs	kWhs	Total $	[$/month]	[$/month]	[$/month]	%
GSd	**Terrace Bay**	15,000	60	35%	**293.24**	**4.00**	**2.27**		**6.27**	669.7	**231.38**	**9.22**	**-**	**(0.22)**	**9.01**	771.8	**1.91**	0.62	0.7	1.0321	319.4	-	15,000	805.0	1,794.1	1,896.1	102.0	5.7%
		43,164	133	45%	293.24	4.00	2.27	-	6.27	1,127.8	231.38	9.22	-	(0.22)	9.01	1,429.2	1.91	0.62	0.70	1.03	840.7	-	43,164	2,316.6	4,285.1	4,586.5	301.5	7.0%
		100,000	500	28%	293.24	4.00	2.27	-	6.27	3,430.5	231.38	9.22	-	(0.22)	9.01	4,734.5	1.91	0.62	0.70	1.03	2,326.3	-	100,000	5,366.9	11,123.8	12,427.8	1,304.0	11.7%
		400,000	1000	56%	293.24	4.00	2.27	-	6.27	6,567.8	231.38	9.22	-	(0.22)	9.01	9,237.7	1.91	0.62	0.70	1.03	7,332.5	-	400,000	21,467.7	35,368.0	38,037.8	2,669.8	7.5%
		1,000,000	3000	46%	293.24	4.00	2.27	-	6.27	19,117.0	231.38	9.22	-	(0.22)	9.01	27,250.2	1.91	0.62	0.70	1.03	19,317.6	-	1,000,000	53,669.2	92,103.8	100,237.0	8,133.2	8.8%
		1,500,000	4000	52%	293.24	4.00	2.27	-	6.27	25,391.6	231.38	9.22	-	(0.22)	9.01	36,256.5	1.91	0.62	0.70	1.03	27,990.0	-	1,500,000	80,503.8	133,885.4	144,750.3	10,864.9	8.1%

New Rate Class: Gse - Unmetered

Total Bill Impacts of Proposed Distribution Rates [old RTSR+TLF]: Threshold of 600 kWhs

600.0

Classes		Scenario	May 2007 Incl Rate Riders						May 2008 Incl Rate Riders						Non-Dx Compoent				Other Reg	Commodity Bands			Existing	New	$ Incr	% Incr
			Existing Dx Rates					Existing Dx	New Dx Rates					New Dx	RTSR old	WMSC	DRC	TLF old	Old	Band 1	Band 2	Old	Total Bill	Total Bill	Total Bill	Total Bill
																				5.0	5.9					
New Class	Old Class	kWh	SrChg [$/cust]	base [c/kWh]	Rider1 [c/kWh]	Rider2 [c/kWh]	VarChg [c/kWh]	[$/month]	SrChg [$/cust]	base [c/kWh]	Rider2 [c/kWh]	Rider3 [c/kWh]	VarChg [c/kWh]	[$/month]	c/kWh	c/kWh	c/kWh		$	kWhs	kWhs	Total $	[$/month]	[$/month]	[$/month]	%
Unmtr	G1	100	**22.16**	**3.12**	**0.09**	**0.09**	**3.30**	25.5	**22.84**	**5.38**	**0.09**	**(0.06)**	**5.41**	28.2	**0.86**	0.62	0.7	**1.092**	2.3	100	-	5.5	33.2	36.0	2.8	8.4%
		250	22.16	3.12	0.09	0.09	3.30	30.4	22.84	5.38	0.09	(0.06)	5.41	36.4	0.86	0.62	0.7	1.092	5.8	250	-	13.7	49.9	55.8	6.0	12.0%
		500	22.16	3.12	0.09	0.09	3.30	38.7	22.84	5.38	0.09	(0.06)	5.41	49.9	0.86	0.62	0.7	1.092	11.6	500	-	27.3	77.5	88.8	11.2	14.5%
		750	22.16	3.12	0.09	0.09	3.30	46.9	22.84	5.38	0.09	(0.06)	5.41	63.4	0.86	0.62	0.7	1.092	17.4	600	150	42.9	107.2	123.7	16.5	15.4%
		1,000	22.16	3.12	0.09	0.09	3.30	55.2	22.84	5.38	0.09	(0.06)	5.41	77.0	0.86	0.62	0.7	1.092	23.2	600	400	59.0	137.3	159.1	21.8	15.9%
Unmtr	G3	100	**6.29**	**3.07**	**0.02**	**0.05**	**3.14**	9.4	**10.81**	**3.60**	**0.05**	**(0.06)**	**3.59**	14.4	**0.85**	0.62	0.7	**1.061**	2.3	100	-	5.3	17.0	22.0	5.0	29.2%
		250	6.29	3.07	0.02	0.05	3.14	14.1	10.81	3.60	0.05	(0.06)	3.59	19.8	0.85	0.62	0.70	1.061	5.6	250	-	13.3	33.1	38.7	5.6	17.1%
		500	6.29	3.07	0.02	0.05	3.14	22.0	10.81	3.60	0.05	(0.06)	3.59	28.8	0.85	0.62	0.70	1.061	11.3	500	-	26.5	59.8	66.6	6.8	11.3%
		750	6.29	3.07	0.02	0.05	3.14	29.8	10.81	3.60	0.05	(0.06)	3.59	37.8	0.85	0.62	0.70	1.061	16.9	600	150	41.5	88.3	96.3	7.9	9.0%
		1,000	6.29	3.07	0.02	0.05	3.14	37.7	10.81	3.60	0.05	(0.06)	3.59	46.7	0.85	0.62	0.70	1.061	22.6	600	400	57.2	117.5	126.5	9.0	7.7%
Unmtr	UG	100	**0.79**	**2.74**	**0.03**	**0.03**	**2.80**	3.6	**6.18**	**3.50**	**0.03**	**(0.06)**	**3.47**	9.7	**0.85**	0.62	0.7	**1.092**	2.3	100	-	5.5	11.4	17.4	6.1	53.4%
		250	0.79	2.74	0.03	0.03	2.80	7.8	6.18	3.50	0.03	(0.06)	3.47	14.9	0.85	0.62	0.70	1.092	5.8	250	-	13.7	27.2	34.3	7.1	26.0%
		500	0.79	2.74	0.03	0.03	2.80	14.8	6.18	3.50	0.03	(0.06)	3.47	23.5	0.85	0.62	0.70	1.092	11.5	500	-	27.3	53.6	62.4	8.8	16.3%
		750	0.79	2.74	0.03	0.03	2.80	21.8	6.18	3.50	0.03	(0.06)	3.47	32.2	0.85	0.62	0.70	1.092	17.3	600	150	42.9	82.0	92.4	10.4	12.7%
		1,000	0.79	2.74	0.03	0.03	2.80	28.8	6.18	3.50	0.03	(0.06)	3.47	40.9	0.85	0.62	0.70	1.092	23.1	600	400	59.0	110.9	123.0	12.1	10.9%
Unmtr	Ailsa Craig	100	**8.20**	**1.32**	**0.17**	**0.09**	**1.58**	9.8	**12.33**	**2.00**	**0.09**	**(0.06)**	**2.03**	14.4	**0.93**	0.62	0.7	1.055	2.3	100	-	5.3	17.4	22.0	4.6	26.3%
		250	8.20	1.32	0.17	0.09	1.58	12.2	12.33	2.00	0.09	(0.06)	2.03	17.4	0.93	0.62	0.70	1.055	5.8	250	-	13.2	31.2	36.4	5.3	16.9%
		500	8.20	1.32	0.17	0.09	1.58	16.1	12.33	2.00	0.09	(0.06)	2.03	22.5	0.93	0.62	0.70	1.055	11.7	500	-	26.4	54.1	60.5	6.4	11.8%
		750	8.20	1.32	0.17	0.09	1.58	20.1	12.33	2.00	0.09	(0.06)	2.03	27.6	0.93	0.62	0.70	1.055	17.5	600	150	41.3	78.8	86.3	7.5	9.5%
		1,000	8.20	1.32	0.17	0.09	1.58	24.0	12.33	2.00	0.09	(0.06)	2.03	32.7	0.93	0.62	0.70	1.055	23.3	600	400	56.8	104.2	112.8	8.7	8.3%
Unmtr	Arkona	100	**1.14**	**0.86**	**0.51**	**0.36**	**1.73**	2.9	**7.09**	**2.00**	**0.36**	**(0.06)**	**2.30**	9.4	**0.93**	0.62	0.7	1.055	2.3	100	-	5.3	10.5	17.0	6.5	62.3%
		250	1.14	0.86	0.51	0.36	1.73	5.5	7.09	2.00	0.36	(0.06)	2.30	12.9	0.93	0.62	0.70	1.055	5.8	250	-	13.2	24.5	31.9	7.4	30.2%
		500	1.14	0.86	0.51	0.36	1.73	9.8	7.09	2.00	0.36	(0.06)	2.30	18.6	0.93	0.62	0.70	1.055	11.7	500	-	26.4	47.8	56.6	8.8	18.4%
		750	1.14	0.86	0.51	0.36	1.73	14.1	7.09	2.00	0.36	(0.06)	2.30	24.4	0.93	0.62	0.70	1.055	17.5	600	150	41.3	72.9	83.1	10.3	14.1%
		1,000	1.14	0.86	0.51	0.36	1.73	18.4	7.09	2.00	0.36	(0.06)	2.30	30.1	0.93	0.62	0.70	1.055	23.3	600	400	56.8	98.6	110.3	11.7	11.9%

New Rate Class: Gse - Unmetered

Total Bill Impacts of Proposed Distribution Rates [old RTSR+TLF]: Threshold of 600 kWhs

Classes		Scenario	May 2007 Incl Rate Riders						May 2008 Incl Rate Riders						Non-Dx Compoent				Other Reg	Commodity Bands			Existing	New	$ Incr	% Incr
			Existing Dx Rates					Existing Dx	New Dx Rates					New Dx	RTSR old	WMSC	DRC	TLF old	Old	Band 1	Band 2	Old	Total Bill	Total Bill	Total Bill	Total Bill
																				600.0						
																				5.0	5.9					
New Class	Old Class	kWh	SrChg [$/cust]	base [c/kWh]	Rider1 [c/kWh]	Rider2 [c/kWh]	VarChg [c/kWh]	[$/month]	SrChg [$/cust]	base [c/kWh]	Rider2 [c/kWh]	Rider3 [c/kWh]	VarChg [c/kWh]	[$/month]	c/kWh	c/kWh	c/kWh		$	kWhs	kWhs	Total $	[$/month]	[$/month]	[$/month]	%
Unmtr	Arnprior	100	**10.23**	**1.17**	**0.16**	**0.06**	**1.39**	11.6	**13.82**	**2.00**	**0.06**	**(0.06)**	**2.00**	15.8	**0.93**	0.62	0.7	1.055	2.3	100	-	5.3	19.2	23.4	4.2	21.9%
		250	10.23	1.17	0.16	0.06	1.39	13.7	13.82	2.00	0.06	(0.06)	2.00	18.8	0.93	0.62	0.70	1.055	5.8	250	-	13.2	32.7	37.8	5.1	15.7%
		500	10.23	1.17	0.16	0.06	1.39	17.2	13.82	2.00	0.06	(0.06)	2.00	23.8	0.93	0.62	0.70	1.055	11.7	500	-	26.4	55.2	61.9	6.7	12.1%
		750	10.23	1.17	0.16	0.06	1.39	20.7	13.82	2.00	0.06	(0.06)	2.00	28.8	0.93	0.62	0.70	1.055	17.5	600	150	41.3	79.4	87.6	8.2	10.3%
		1,000	10.23	1.17	0.16	0.06	1.39	24.1	13.82	2.00	0.06	(0.06)	2.00	33.9	0.93	0.62	0.70	1.055	23.3	600	400	56.8	104.3	114.0	9.7	9.3%
Unmtr	Arran-Elderslie	100	**3.95**	**1.03**	**0.17**	**0.09**	**1.29**	5.2	**8.39**	**2.00**	**0.09**	**(0.06)**	**2.03**	10.4	**0.93**	0.62	0.7	1.055	2.3	100	-	5.3	12.8	18.0	5.2	40.3%
		250	3.95	1.03	0.17	0.09	1.29	7.2	8.39	2.00	0.09	(0.06)	2.03	13.5	0.93	0.62	0.70	1.055	5.8	250	-	13.2	26.2	32.5	6.3	24.0%
		500	3.95	1.03	0.17	0.09	1.29	10.4	8.39	2.00	0.09	(0.06)	2.03	18.6	0.93	0.62	0.70	1.055	11.7	500	-	26.4	48.4	56.6	8.2	16.8%
		750	3.95	1.03	0.17	0.09	1.29	13.6	8.39	2.00	0.09	(0.06)	2.03	23.6	0.93	0.62	0.70	1.055	17.5	600	150	41.3	72.4	82.4	10.0	13.8%
		1,000	3.95	1.03	0.17	0.09	1.29	16.9	8.39	2.00	0.09	(0.06)	2.03	28.7	0.93	0.62	0.70	1.055	23.3	600	400	56.8	97.0	108.9	11.9	12.2%
Unmtr	Artemesia	100	**9.34**	**1.74**	**0.49**	**0.34**	**2.57**	11.9	**13.04**	**2.00**	**0.34**	**(0.06)**	**2.28**	15.3	**0.93**	0.62	0.7	1.055	2.3	100	-	5.3	19.5	22.9	3.4	17.5%
		250	9.34	1.74	0.49	0.34	2.57	15.8	13.04	2.00	0.34	(0.06)	2.28	18.8	0.93	0.62	0.70	1.055	5.8	250	-	13.2	34.8	37.8	3.0	8.6%
		500	9.34	1.74	0.49	0.34	2.57	22.2	13.04	2.00	0.34	(0.06)	2.28	24.5	0.93	0.62	0.70	1.055	11.7	500	-	26.4	60.2	62.5	2.3	3.8%
		750	9.34	1.74	0.49	0.34	2.57	28.6	13.04	2.00	0.34	(0.06)	2.28	30.2	0.93	0.62	0.70	1.055	17.5	600	150	41.3	87.4	88.9	1.6	1.8%
		1,000	9.34	1.74	0.49	0.34	2.57	35.0	13.04	2.00	0.34	(0.06)	2.28	35.9	0.93	0.62	0.70	1.055	23.3	600	400	56.8	115.2	116.0	0.8	0.7%
Unmtr	Bancroft	100	**11.73**	**1.18**	**0.17**	**0.08**	**1.43**	13.2	**14.45**	**2.00**	**0.08**	**(0.06)**	**2.02**	16.5	**0.93**	0.62	0.7	1.055	2.3	100	-	5.3	20.8	24.1	3.3	15.9%
		250	11.73	1.18	0.17	0.08	1.43	15.3	14.45	2.00	0.08	(0.06)	2.02	19.5	0.93	0.62	0.70	1.055	5.8	250	-	13.2	34.3	38.5	4.2	12.2%
		500	11.73	1.18	0.17	0.08	1.43	18.9	14.45	2.00	0.08	(0.06)	2.02	24.6	0.93	0.62	0.70	1.055	11.7	500	-	26.4	56.9	62.6	5.7	10.0%
		750	11.73	1.18	0.17	0.08	1.43	22.5	14.45	2.00	0.08	(0.06)	2.02	29.6	0.93	0.62	0.70	1.055	17.5	600	150	41.3	81.2	88.4	7.2	8.8%
		1,000	11.73	1.18	0.17	0.08	1.43	26.0	14.45	2.00	0.08	(0.06)	2.02	34.7	0.93	0.62	0.70	1.055	23.3	600	400	56.8	106.2	114.8	8.6	8.1%
Unmtr	Bath	100	**4.86**	**1.47**	**0.29**	**0.24**	**2.00**	6.9	**9.16**	**2.00**	**0.24**	**(0.06)**	**2.18**	11.3	**0.93**	0.62	0.7	1.055	2.3	100	-	5.3	14.5	19.0	4.5	31.0%
		250	4.86	1.47	0.29	0.24	2.00	9.9	9.16	2.00	0.24	(0.06)	2.18	14.6	0.93	0.62	0.70	1.055	5.8	250	-	13.2	28.9	33.6	4.8	16.5%
		500	4.86	1.47	0.29	0.24	2.00	14.9	9.16	2.00	0.24	(0.06)	2.18	20.1	0.93	0.62	0.70	1.055	11.7	500	-	26.4	52.9	58.1	5.2	9.9%
		750	4.86	1.47	0.29	0.24	2.00	19.9	9.16	2.00	0.24	(0.06)	2.18	25.5	0.93	0.62	0.70	1.055	17.5	600	150	41.3	78.6	84.3	5.7	7.2%
		1,000	4.86	1.47	0.29	0.24	2.00	24.9	9.16	2.00	0.24	(0.06)	2.18	31.0	0.93	0.62	0.70	1.055	23.3	600	400	56.8	105.0	111.2	6.1	5.8%

New Rate Class: Gse - Unmetered

Total Bill Impacts of Proposed Distribution Rates [old RTSR+TLF]: Threshold of 600 kWhs

Classes		Scenario	May 2007 Incl Rate Riders						May 2008 Incl Rate Riders						Non-Dx Compoent				Other Reg	Commodity Bands (600.0)			Existing	New	$ Incr	% Incr
			Existing Dx Rates					Existing Dx	New Dx Rates					New Dx	RTSR old	WMSC	DRC	TLF old	Old	Band 1 (5.0)	Band 2 (5.9)	Old	Total Bill	Total Bill	Total Bill	Total Bill
New Class	Old Class	kWh	SrChg [$/cust]	base [c/kWh]	Rider1 [c/kWh]	Rider2 [c/kWh]	VarChg [c/kWh]	[$/month]	SrChg [$/cust]	base [c/kWh]	Rider2 [c/kWh]	Rider3 [c/kWh]	VarChg [c/kWh]	[$/month]	c/kWh	c/kWh	c/kWh		$	kWhs	kWhs	Total $	[$/month]	[$/month]	[$/month]	%
Unmtr	Blandford-Blenhe	100	**11.46**	**1.14**	**0.28**	**0.20**	**1.62**	13.1	**14.51**	**2.00**	**0.20**	**(0.06)**	**2.14**	16.7	**0.93**	0.62	0.7	1.055	2.3	100	-	5.3	20.7	24.3	3.6	17.3%
		250	11.46	1.14	0.28	0.20	1.62	15.5	14.51	2.00	0.20	(0.06)	2.14	19.9	0.93	0.62	0.70	1.055	5.8	250	-	13.2	34.5	38.9	4.4	12.6%
		500	11.46	1.14	0.28	0.20	1.62	19.6	14.51	2.00	0.20	(0.06)	2.14	25.2	0.93	0.62	0.70	1.055	11.7	500	-	26.4	57.6	63.3	5.7	9.8%
		750	11.46	1.14	0.28	0.20	1.62	23.6	14.51	2.00	0.20	(0.06)	2.14	30.6	0.93	0.62	0.70	1.055	17.5	600	150	41.3	82.4	89.4	7.0	8.5%
		1,000	11.46	1.14	0.28	0.20	1.62	27.7	14.51	2.00	0.20	(0.06)	2.14	35.9	0.93	0.62	0.70	1.055	23.3	600	400	56.8	107.8	116.1	8.3	7.7%
Unmtr	Blyth	100	**10.35**	**1.05**	**0.26**	**0.20**	**1.51**	11.9	**13.79**	**2.00**	**0.20**	**(0.06)**	**2.14**	15.9	**0.93**	0.62	0.7	1.055	2.3	100	-	5.3	19.5	23.5	4.1	20.9%
		250	10.35	1.05	0.26	0.20	1.51	14.1	13.79	2.00	0.20	(0.06)	2.14	19.1	0.93	0.62	0.70	1.055	5.8	250	-	13.2	33.1	38.2	5.0	15.2%
		500	10.35	1.05	0.26	0.20	1.51	17.9	13.79	2.00	0.20	(0.06)	2.14	24.5	0.93	0.62	0.70	1.055	11.7	500	-	26.4	55.9	62.5	6.6	11.8%
		750	10.35	1.05	0.26	0.20	1.51	21.7	13.79	2.00	0.20	(0.06)	2.14	29.9	0.93	0.62	0.70	1.055	17.5	600	150	41.3	80.4	88.6	8.2	10.2%
		1,000	10.35	1.05	0.26	0.20	1.51	25.5	13.79	2.00	0.20	(0.06)	2.14	35.2	0.93	0.62	0.70	1.055	23.3	600	400	56.8	105.6	115.4	9.8	9.3%
Unmtr	Bobcaygeon	100	**11.14**	**1.38**	**0.18**	**0.09**	**1.65**	12.8	**14.59**	**2.00**	**0.09**	**(0.06)**	**2.03**	16.6	**0.93**	0.62	0.7	1.055	2.3	100	-	5.3	20.4	24.2	3.8	18.8%
		250	11.14	1.38	0.18	0.09	1.65	15.3	14.59	2.00	0.09	(0.06)	2.03	19.7	0.93	0.62	0.70	1.055	5.8	250	-	13.2	34.3	38.7	4.4	12.9%
		500	11.14	1.38	0.18	0.09	1.65	19.4	14.59	2.00	0.09	(0.06)	2.03	24.8	0.93	0.62	0.70	1.055	11.7	500	-	26.4	57.4	62.8	5.4	9.3%
		750	11.14	1.38	0.18	0.09	1.65	23.5	14.59	2.00	0.09	(0.06)	2.03	29.8	0.93	0.62	0.70	1.055	17.5	600	150	41.3	82.3	88.6	6.3	7.7%
		1,000	11.14	1.38	0.18	0.09	1.65	27.6	14.59	2.00	0.09	(0.06)	2.03	34.9	0.93	0.62	0.70	1.055	23.3	600	400	56.8	107.8	115.1	7.3	6.8%
Unmtr	Brighton	100	**10.99**	**1.35**	**0.20**	**0.08**	**1.63**	12.6	**13.63**	**2.00**	**0.08**	**(0.06)**	**2.02**	15.7	**0.93**	0.62	0.7	1.055	2.3	100	-	5.3	20.2	23.3	3.0	15.0%
		250	10.99	1.35	0.20	0.08	1.63	15.1	13.63	2.00	0.08	(0.06)	2.02	18.7	0.93	0.62	0.70	1.055	5.8	250	-	13.2	34.1	37.7	3.6	10.6%
		500	10.99	1.35	0.20	0.08	1.63	19.1	13.63	2.00	0.08	(0.06)	2.02	23.7	0.93	0.62	0.70	1.055	11.7	500	-	26.4	57.2	61.8	4.6	8.1%
		750	10.99	1.35	0.20	0.08	1.63	23.2	13.63	2.00	0.08	(0.06)	2.02	28.8	0.93	0.62	0.70	1.055	17.5	600	150	41.3	82.0	87.6	5.6	6.8%
		1,000	10.99	1.35	0.20	0.08	1.63	27.3	13.63	2.00	0.08	(0.06)	2.02	33.9	0.93	0.62	0.70	1.055	23.3	600	400	56.8	107.5	114.0	6.6	6.1%
Unmtr	Brockville	100	**10.37**	**0.78**	**0.13**	**0.04**	**0.95**	11.3	**13.79**	**2.00**	**0.04**	**(0.06)**	**1.98**	15.8	**0.93**	0.62	0.7	1.055	2.3	100	-	5.3	18.9	23.4	4.4	23.5%
		250	10.37	0.78	0.13	0.04	0.95	12.7	13.79	2.00	0.04	(0.06)	1.98	18.7	0.93	0.62	0.70	1.055	5.8	250	-	13.2	31.8	37.8	6.0	18.9%
		500	10.37	0.78	0.13	0.04	0.95	15.1	13.79	2.00	0.04	(0.06)	1.98	23.7	0.93	0.62	0.70	1.055	11.7	500	-	26.4	53.2	61.7	8.6	16.1%
		750	10.37	0.78	0.13	0.04	0.95	17.5	13.79	2.00	0.04	(0.06)	1.98	28.7	0.93	0.62	0.70	1.055	17.5	600	150	41.3	76.3	87.4	11.2	14.6%
		1,000	10.37	0.78	0.13	0.04	0.95	19.9	13.79	2.00	0.04	(0.06)	1.98	33.6	0.93	0.62	0.70	1.055	23.3	600	400	56.8	100.0	113.8	13.7	13.7%

New Rate Class: Gse - Unmetered

Total Bill Impacts of Proposed Distribution Rates [old RTSR+TLF]: Threshold of 600 kWhs

Classes		Scenario	May 2007 Incl Rate Riders						May 2008 Incl Rate Riders						Non-Dx Compoent				Other Reg	Commodity Bands			Existing	New	$ Incr	% Incr
			Existing Dx Rates					Existing Dx	New Dx Rates					New Dx	RTSR old	WMSC	DRC	TLF old	Old	Band 1	Band 2	Old	Total Bill	Total Bill	Total Bill	Total Bill
																				5.0	5.9	600.0				
New Class	Old Class	kWh	SrChg [$/cust]	base [c/kWh]	Rider1 [c/kWh]	Rider2 [c/kWh]	VarChg [c/kWh]	[$/month]	SrChg [$/cust]	base [c/kWh]	Rider2 [c/kWh]	Rider3 [c/kWh]	VarChg [c/kWh]	[$/month]	c/kWh	c/kWh	c/kWh		$	kWhs	kWhs	Total $	[$/month]	[$/month]	[$/month]	%
Unmtr	Caledon CH	100	**11.63**	**1.80**	**0.14**	**0.08**	**2.02**	13.7	**14.47**	**2.00**	**0.08**	**(0.06)**	**2.02**	16.5	**0.93**	0.62	0.7	1.055	2.3	100	-	5.3	21.3	24.1	2.8	13.4%
		250	11.63	1.80	0.14	0.08	2.02	16.7	14.47	2.00	0.08	(0.06)	2.02	19.5	0.93	0.62	0.70	1.055	5.8	250	-	13.2	35.7	38.5	2.8	8.0%
		500	11.63	1.80	0.14	0.08	2.02	21.7	14.47	2.00	0.08	(0.06)	2.02	24.6	0.93	0.62	0.70	1.055	11.7	500	-	26.4	59.8	62.6	2.9	4.8%
		750	11.63	1.80	0.14	0.08	2.02	26.8	14.47	2.00	0.08	(0.06)	2.02	29.6	0.93	0.62	0.70	1.055	17.5	600	150	41.3	85.6	88.4	2.9	3.3%
		1,000	11.63	1.80	0.14	0.08	2.02	31.8	14.47	2.00	0.08	(0.06)	2.02	34.7	0.93	0.62	0.70	1.055	23.3	600	400	56.8	112.0	114.9	2.9	2.6%
Unmtr	Campbellford-Sey	100	**7.63**	**1.19**	**0.17**	**0.05**	**1.41**	9.0	**11.47**	**2.00**	**0.05**	**(0.06)**	**1.99**	13.5	**0.93**	0.62	0.7	1.055	2.3	100	-	5.3	16.6	21.1	4.4	26.6%
		250	7.63	1.19	0.17	0.05	1.41	11.2	11.47	2.00	0.05	(0.06)	1.99	16.5	0.93	0.62	0.70	1.055	5.8	250	-	13.2	30.2	35.5	5.3	17.6%
		500	7.63	1.19	0.17	0.05	1.41	14.7	11.47	2.00	0.05	(0.06)	1.99	21.4	0.93	0.62	0.70	1.055	11.7	500	-	26.4	52.7	59.5	6.8	12.8%
		750	7.63	1.19	0.17	0.05	1.41	18.2	11.47	2.00	0.05	(0.06)	1.99	26.4	0.93	0.62	0.70	1.055	17.5	600	150	41.3	77.0	85.2	8.2	10.7%
		1,000	7.63	1.19	0.17	0.05	1.41	21.7	11.47	2.00	0.05	(0.06)	1.99	31.4	0.93	0.62	0.70	1.055	23.3	600	400	56.8	101.9	111.6	9.7	9.5%
Unmtr	Carleton Place	100	**11.36**	**1.68**	**0.13**	**0.07**	**1.88**	13.2	**14.54**	**2.00**	**0.07**	**(0.06)**	**2.01**	16.6	**0.93**	0.62	0.7	1.055	2.3	100	-	5.3	20.8	24.2	3.3	15.9%
		250	11.36	1.68	0.13	0.07	1.88	16.1	14.54	2.00	0.07	(0.06)	2.01	19.6	0.93	0.62	0.70	1.055	5.8	250	-	13.2	35.1	38.6	3.5	10.0%
		500	11.36	1.68	0.13	0.07	1.88	20.8	14.54	2.00	0.07	(0.06)	2.01	24.6	0.93	0.62	0.70	1.055	11.7	500	-	26.4	58.8	62.6	3.8	6.5%
		750	11.36	1.68	0.13	0.07	1.88	25.5	14.54	2.00	0.07	(0.06)	2.01	29.6	0.93	0.62	0.70	1.055	17.5	600	150	41.3	84.2	88.4	4.2	5.0%
		1,000	11.36	1.68	0.13	0.07	1.88	30.2	14.54	2.00	0.07	(0.06)	2.01	34.7	0.93	0.62	0.70	1.055	23.3	600	400	56.8	110.3	114.8	4.5	4.1%
Unmtr	Cavan-Millbrook-N	100	**10.68**	**1.50**	**0.33**	**0.26**	**2.09**	12.8	**13.71**	**2.00**	**0.26**	**(0.06)**	**2.20**	15.9	**0.93**	0.62	0.7	1.055	2.3	100	-	5.3	20.4	23.5	3.1	15.4%
		250	10.68	1.50	0.33	0.26	2.09	15.9	13.71	2.00	0.26	(0.06)	2.20	19.2	0.93	0.62	0.70	1.055	5.8	250	-	13.2	34.9	38.2	3.3	9.5%
		500	10.68	1.50	0.33	0.26	2.09	21.1	13.71	2.00	0.26	(0.06)	2.20	24.7	0.93	0.62	0.70	1.055	11.7	500	-	26.4	59.2	62.8	3.6	6.1%
		750	10.68	1.50	0.33	0.26	2.09	26.4	13.71	2.00	0.26	(0.06)	2.20	30.2	0.93	0.62	0.70	1.055	17.5	600	150	41.3	85.1	89.0	3.9	4.6%
		1,000	10.68	1.50	0.33	0.26	2.09	31.6	13.71	2.00	0.26	(0.06)	2.20	35.7	0.93	0.62	0.70	1.055	23.3	600	400	56.8	111.7	115.9	4.2	3.7%
Unmtr	Centre Hastings	100	**8.73**	**0.97**	**0.14**	**0.06**	**1.17**	9.9	**12.20**	**2.00**	**0.06**	**(0.06)**	**2.00**	14.2	**0.93**	0.62	0.7	1.055	2.3	100	-	5.3	17.5	21.8	4.3	24.6%
		250	8.73	0.97	0.14	0.06	1.17	11.7	12.20	2.00	0.06	(0.06)	2.00	17.2	0.93	0.62	0.70	1.055	5.8	250	-	13.2	30.7	36.2	5.5	18.1%
		500	8.73	0.97	0.14	0.06	1.17	14.6	12.20	2.00	0.06	(0.06)	2.00	22.2	0.93	0.62	0.70	1.055	11.7	500	-	26.4	52.6	60.2	7.6	14.5%
		750	8.73	0.97	0.14	0.06	1.17	17.5	12.20	2.00	0.06	(0.06)	2.00	27.2	0.93	0.62	0.70	1.055	17.5	600	150	41.3	76.3	86.0	9.7	12.7%
		1,000	8.73	0.97	0.14	0.06	1.17	20.4	12.20	2.00	0.06	(0.06)	2.00	32.2	0.93	0.62	0.70	1.055	23.3	600	400	56.8	100.6	112.4	11.8	11.7%

New Rate Class: Gse - Unmetered

Total Bill Impacts of Proposed Distribution Rates [old RTSR+TLF]: Threshold of 600 kWhs

600.0

Classes		Scenario	May 2007 Incl Rate Riders						May 2008 Incl Rate Riders						Non-Dx Compoent				Other Reg	Commodity Bands			Existing	New	$ Incr	% Incr
			Existing Dx Rates					Existing Dx	New Dx Rates					New Dx	RTSR old	WMSC	DRC	TLF old	Old	Band 1	Band 2	Old	Total Bill	Total Bill	Total Bill	Total Bill
																				5.0	5.9					
New Class	Old Class	kWh	SrChg [$/cust]	base [c/kWh]	Rider1 [c/kWh]	Rider2 [c/kWh]	VarChg [c/kWh]	[$/month]	SrChg [$/cust]	base [c/kWh]	Rider2 [c/kWh]	Rider3 [c/kWh]	VarChg [c/kWh]	[$/month]	c/kWh	c/kWh	c/kWh		$	kWhs	kWhs	Total $	[$/month]	[$/month]	[$/month]	%
Unmtr	Chalk River	100	10.20	1.79	0.39	0.34	2.52	12.7	13.83	2.00	0.34	(0.06)	2.28	16.1	0.93	0.62	0.7	1.055	2.3	100	-	5.3	20.3	23.7	3.4	16.7%
		250	10.20	1.79	0.39	0.34	2.52	16.5	13.83	2.00	0.34	(0.06)	2.28	19.5	0.93	0.62	0.70	1.055	5.8	250	-	13.2	35.5	38.6	3.0	8.5%
		500	10.20	1.79	0.39	0.34	2.52	22.8	13.83	2.00	0.34	(0.06)	2.28	25.2	0.93	0.62	0.70	1.055	11.7	500	-	26.4	60.8	63.3	2.4	4.0%
		750	10.20	1.79	0.39	0.34	2.52	29.1	13.83	2.00	0.34	(0.06)	2.28	31.0	0.93	0.62	0.70	1.055	17.5	600	150	41.3	87.9	89.7	1.9	2.1%
		1,000	10.20	1.79	0.39	0.34	2.52	35.4	13.83	2.00	0.34	(0.06)	2.28	36.7	0.93	0.62	0.70	1.055	23.3	600	400	56.8	115.6	116.8	1.3	1.1%
Unmtr	Champlain	100	9.83	0.91	0.26	0.15	1.32	11.2	12.92	2.00	0.15	(0.06)	2.09	15.0	0.93	0.62	0.7	1.055	2.3	100	-	5.3	18.8	22.6	3.9	20.6%
		250	9.83	0.91	0.26	0.15	1.32	13.1	12.92	2.00	0.15	(0.06)	2.09	18.2	0.93	0.62	0.70	1.055	5.8	250	-	13.2	32.1	37.2	5.0	15.6%
		500	9.83	0.91	0.26	0.15	1.32	16.4	12.92	2.00	0.15	(0.06)	2.09	23.4	0.93	0.62	0.70	1.055	11.7	500	-	26.4	54.5	61.4	7.0	12.8%
		750	9.83	0.91	0.26	0.15	1.32	19.7	12.92	2.00	0.15	(0.06)	2.09	28.6	0.93	0.62	0.70	1.055	17.5	600	150	41.3	78.5	87.4	8.9	11.3%
		1,000	9.83	0.91	0.26	0.15	1.32	23.0	12.92	2.00	0.15	(0.06)	2.09	33.9	0.93	0.62	0.70	1.055	23.3	600	400	56.8	103.2	114.0	10.8	10.5%
Unmtr	Cobden	100	10.50	2.13	0.36	0.30	2.79	13.3	13.75	2.00	0.30	(0.06)	2.24	16.0	0.93	0.62	0.7	1.055	2.3	100	-	5.3	20.9	23.6	2.7	12.9%
		250	10.50	2.13	0.36	0.30	2.79	17.5	13.75	2.00	0.30	(0.06)	2.24	19.4	0.93	0.62	0.70	1.055	5.8	250	-	13.2	36.5	38.4	1.9	5.2%
		500	10.50	2.13	0.36	0.30	2.79	24.5	13.75	2.00	0.30	(0.06)	2.24	25.0	0.93	0.62	0.70	1.055	11.7	500	-	26.4	62.5	63.0	0.5	0.8%
		750	10.50	2.13	0.36	0.30	2.79	31.4	13.75	2.00	0.30	(0.06)	2.24	30.6	0.93	0.62	0.70	1.055	17.5	600	150	41.3	90.2	89.3	(0.8)	-0.9%
		1,000	10.50	2.13	0.36	0.30	2.79	38.4	13.75	2.00	0.30	(0.06)	2.24	36.2	0.93	0.62	0.70	1.055	23.3	600	400	56.8	118.6	116.3	(2.2)	-1.9%
Unmtr	Deep River	100	11.50	2.26	0.15	0.14	2.55	14.1	14.50	2.00	0.14	(0.06)	2.08	16.6	0.93	0.62	0.7	1.055	2.3	100	-	5.3	21.7	24.2	2.5	11.7%
		250	11.50	2.26	0.15	0.14	2.55	17.9	14.50	2.00	0.14	(0.06)	2.08	19.7	0.93	0.62	0.70	1.055	5.8	250	-	13.2	36.9	38.7	1.8	5.0%
		500	11.50	2.26	0.15	0.14	2.55	24.3	14.50	2.00	0.14	(0.06)	2.08	24.9	0.93	0.62	0.70	1.055	11.7	500	-	26.4	62.3	63.0	0.7	1.1%
		750	11.50	2.26	0.15	0.14	2.55	30.6	14.50	2.00	0.14	(0.06)	2.08	30.1	0.93	0.62	0.70	1.055	17.5	600	150	41.3	89.4	88.9	(0.5)	-0.6%
		1,000	11.50	2.26	0.15	0.14	2.55	37.0	14.50	2.00	0.14	(0.06)	2.08	35.3	0.93	0.62	0.70	1.055	23.3	600	400	56.8	117.2	115.5	(1.7)	-1.4%
Unmtr	Deseronto	100	4.61	1.35	0.13	0.05	1.53	6.1	9.23	2.00	0.05	(0.06)	1.99	11.2	0.93	0.62	0.7	1.055	2.3	100	-	5.3	13.7	18.8	5.1	36.9%
		250	4.61	1.35	0.13	0.05	1.53	8.4	9.23	2.00	0.05	(0.06)	1.99	14.2	0.93	0.62	0.70	1.055	5.8	250	-	13.2	27.5	33.2	5.8	21.0%
		500	4.61	1.35	0.13	0.05	1.53	12.3	9.23	2.00	0.05	(0.06)	1.99	19.2	0.93	0.62	0.70	1.055	11.7	500	-	26.4	50.3	57.2	6.9	13.8%
		750	4.61	1.35	0.13	0.05	1.53	16.1	9.23	2.00	0.05	(0.06)	1.99	24.2	0.93	0.62	0.70	1.055	17.5	600	150	41.3	74.9	82.9	8.1	10.8%
		1,000	4.61	1.35	0.13	0.05	1.53	19.9	9.23	2.00	0.05	(0.06)	1.99	29.2	0.93	0.62	0.70	1.055	23.3	600	400	56.8	100.1	109.3	9.2	9.2%

New Rate Class: Gse - Unmetered

Total Bill Impacts of Proposed Distribution Rates [old RTSR+TLF]: Threshold of 600 kWhs

Classes		Scenario	May 2007 Incl Rate Riders						May 2008 Incl Rate Riders						Non-Dx Compoent				Other Reg	Commodity Bands			Existing	New	$ Incr	% Incr
			Existing Dx Rates					Existing Dx	New Dx Rates					New Dx	RTSR old	WMSC	DRC	TLF old	Old	Band 1	Band 2	Old	Total Bill	Total Bill	Total Bill	Total Bill
																				600.0						
																				5.0	5.9					
New Class	Old Class	kWh	SrChg [$/cust]	base [c/kWh]	Rider1 [c/kWh]	Rider2 [c/kWh]	VarChg [c/kWh]	[$/month]	SrChg [$/cust]	base [c/kWh]	Rider2 [c/kWh]	Rider3 [c/kWh]	VarChg [c/kWh]	[$/month]	c/kWh	c/kWh	c/kWh		$	kWhs	kWhs	Total $	[$/month]	[$/month]	[$/month]	%
Unmtr	**Dryden**	100	**9.09**	**1.03**	**0.12**	**0.04**	**1.19**	10.3	**13.11**	**2.00**	**0.04**	**(0.06)**	**1.98**	15.1	**0.93**	0.62	0.7	1.055	2.3	100	-	5.3	17.9	22.7	4.8	26.9%
		250	9.09	1.03	0.12	0.04	1.19	12.1	13.11	2.00	0.04	(0.06)	1.98	18.1	0.93	0.62	0.70	1.055	5.8	250	-	13.2	31.1	37.1	6.0	19.3%
		500	9.09	1.03	0.12	0.04	1.19	15.0	13.11	2.00	0.04	(0.06)	1.98	23.0	0.93	0.62	0.70	1.055	11.7	500	-	26.4	53.1	61.1	8.0	15.0%
		750	9.09	1.03	0.12	0.04	1.19	18.0	13.11	2.00	0.04	(0.06)	1.98	28.0	0.93	0.62	0.70	1.055	17.5	600	150	41.3	76.8	86.7	10.0	13.0%
		1,000	9.09	1.03	0.12	0.04	1.19	21.0	13.11	2.00	0.04	(0.06)	1.98	32.9	0.93	0.62	0.70	1.055	23.3	600	400	56.8	101.2	113.1	11.9	11.8%
Unmtr	**Dundalk**	100	**11.32**	**1.64**	**0.23**	**0.09**	**1.96**	13.3	**14.55**	**2.00**	**0.09**	**(0.06)**	**2.03**	16.6	**0.93**	0.62	0.7	1.055	2.3	100	-	5.3	20.9	24.2	3.3	15.8%
		250	11.32	1.64	0.23	0.09	1.96	16.2	14.55	2.00	0.09	(0.06)	2.03	19.6	0.93	0.62	0.70	1.055	5.8	250	-	13.2	35.2	38.6	3.4	9.7%
		500	11.32	1.64	0.23	0.09	1.96	21.1	14.55	2.00	0.09	(0.06)	2.03	24.7	0.93	0.62	0.70	1.055	11.7	500	-	26.4	59.2	62.7	3.6	6.1%
		750	11.32	1.64	0.23	0.09	1.96	26.0	14.55	2.00	0.09	(0.06)	2.03	29.8	0.93	0.62	0.70	1.055	17.5	600	150	41.3	84.8	88.6	3.8	4.5%
		1,000	11.32	1.64	0.23	0.09	1.96	30.9	14.55	2.00	0.09	(0.06)	2.03	34.9	0.93	0.62	0.70	1.055	23.3	600	400	56.8	111.1	115.0	4.0	3.6%
Unmtr	**Durham**	100	**11.59**	**1.37**	**0.15**	**0.06**	**1.58**	13.2	**14.48**	**2.00**	**0.06**	**(0.06)**	**2.00**	16.5	**0.93**	0.62	0.7	1.055	2.3	100	-	5.3	20.8	24.1	3.3	15.9%
		250	11.59	1.37	0.15	0.06	1.58	15.5	14.48	2.00	0.06	(0.06)	2.00	19.5	0.93	0.62	0.70	1.055	5.8	250	-	13.2	34.6	38.5	3.9	11.4%
		500	11.59	1.37	0.15	0.06	1.58	19.5	14.48	2.00	0.06	(0.06)	2.00	24.5	0.93	0.62	0.70	1.055	11.7	500	-	26.4	57.5	62.5	5.0	8.7%
		750	11.59	1.37	0.15	0.06	1.58	23.4	14.48	2.00	0.06	(0.06)	2.00	29.5	0.93	0.62	0.70	1.055	17.5	600	150	41.3	82.2	88.3	6.1	7.4%
		1,000	11.59	1.37	0.15	0.06	1.58	27.4	14.48	2.00	0.06	(0.06)	2.00	34.5	0.93	0.62	0.70	1.055	23.3	600	400	56.8	107.6	114.7	7.1	6.6%
Unmtr	**Eganville**	100	**10.22**	**2.32**	**0.17**	**0.12**	**2.61**	12.8	**13.82**	**2.00**	**0.12**	**(0.06)**	**2.06**	15.9	**0.93**	0.62	0.7	1.055	2.3	100	-	5.3	20.4	23.5	3.1	15.0%
		250	10.22	2.32	0.17	0.12	2.61	16.7	13.82	2.00	0.12	(0.06)	2.06	19.0	0.93	0.62	0.70	1.055	5.8	250	-	13.2	35.8	38.0	2.2	6.3%
		500	10.22	2.32	0.17	0.12	2.61	23.3	13.82	2.00	0.12	(0.06)	2.06	24.1	0.93	0.62	0.70	1.055	11.7	500	-	26.4	61.3	62.2	0.9	1.4%
		750	10.22	2.32	0.17	0.12	2.61	29.8	13.82	2.00	0.12	(0.06)	2.06	29.3	0.93	0.62	0.70	1.055	17.5	600	150	41.3	88.6	88.1	(0.5)	-0.6%
		1,000	10.22	2.32	0.17	0.12	2.61	36.3	13.82	2.00	0.12	(0.06)	2.06	34.5	0.93	0.62	0.70	1.055	23.3	600	400	56.8	116.5	114.6	(1.9)	-1.6%
Unmtr	**Erin**	100	**19.72**	**0.73**	**0.19**	**0.08**	**1.00**	20.7	**20.45**	**2.00**	**0.08**	**(0.06)**	**2.02**	22.5	**0.93**	0.62	0.7	1.055	2.3	100	-	5.3	28.3	30.1	1.8	6.2%
		250	19.72	0.73	0.19	0.08	1.00	22.2	20.45	2.00	0.08	(0.06)	2.02	25.5	0.93	0.62	0.70	1.055	5.8	250	-	13.2	41.2	44.5	3.3	8.0%
		500	19.72	0.73	0.19	0.08	1.00	24.7	20.45	2.00	0.08	(0.06)	2.02	30.6	0.93	0.62	0.70	1.055	11.7	500	-	26.4	62.8	68.6	5.8	9.3%
		750	19.72	0.73	0.19	0.08	1.00	27.2	20.45	2.00	0.08	(0.06)	2.02	35.6	0.93	0.62	0.70	1.055	17.5	600	150	41.3	86.0	94.4	8.4	9.8%
		1,000	19.72	0.73	0.19	0.08	1.00	29.7	20.45	2.00	0.08	(0.06)	2.02	40.7	0.93	0.62	0.70	1.055	23.3	600	400	56.8	109.9	120.8	11.0	10.0%

New Rate Class: Gse - Unmetered

Total Bill Impacts of Proposed Distribution Rates [old RTSR+TLF]: Threshold of 600 kWhs

Classes		Scenario	May 2007 Incl Rate Riders						May 2008 Incl Rate Riders						Non-Dx Compoent				Other Reg	Commodity Bands (600.0)			Existing	New	$ Incr	% Incr
			Existing Dx Rates					Existing Dx	New Dx Rates					New Dx	RTSR old	WMSC	DRC	TLF old	Old	Band 1 (5.0)	Band 2 (5.9)	Old	Total Bill	Total Bill	Total Bill	Total Bill
New Class	Old Class	kWh	SrChg [$/cust]	base [c/kWh]	Rider1 [c/kWh]	Rider2 [c/kWh]	VarChg [c/kWh]	[$/month]	SrChg [$/cust]	base [c/kWh]	Rider2 [c/kWh]	Rider3 [c/kWh]	VarChg [c/kWh]	[$/month]	c/kWh	c/kWh	c/kWh		$	kWhs	kWhs	Total $	[$/month]	[$/month]	[$/month]	%
Unmtr	**Exeter**	100	**5.21**	**1.30**	**0.15**	**0.06**	**1.51**	6.7	**10.08**	**2.00**	**0.06**	**(0.06)**	**2.00**	12.1	**0.93**	0.62	0.7	1.055	2.3	100	-	5.3	14.3	19.7	5.4	37.4%
		250	5.21	1.30	0.15	0.06	1.51	9.0	10.08	2.00	0.06	(0.06)	2.00	15.1	0.93	0.62	0.70	1.055	5.8	250	-	13.2	28.0	34.1	6.1	21.8%
		500	5.21	1.30	0.15	0.06	1.51	12.8	10.08	2.00	0.06	(0.06)	2.00	20.1	0.93	0.62	0.70	1.055	11.7	500	-	26.4	50.8	58.1	7.3	14.4%
		750	5.21	1.30	0.15	0.06	1.51	16.5	10.08	2.00	0.06	(0.06)	2.00	25.1	0.93	0.62	0.70	1.055	17.5	600	150	41.3	75.3	83.9	8.6	11.4%
		1,000	5.21	1.30	0.15	0.06	1.51	20.3	10.08	2.00	0.06	(0.06)	2.00	30.1	0.93	0.62	0.70	1.055	23.3	600	400	56.8	100.5	110.3	9.8	9.8%
Unmtr	**Fenelon Falls**	100	**9.43**	**0.95**	**0.15**	**0.08**	**1.18**	10.6	**13.02**	**2.00**	**0.08**	**(0.06)**	**2.02**	15.0	**0.93**	0.62	0.7	1.055	2.3	100	-	5.3	18.2	22.7	4.4	24.3%
		250	9.43	0.95	0.15	0.08	1.18	12.4	13.02	2.00	0.08	(0.06)	2.02	18.1	0.93	0.62	0.70	1.055	5.8	250	-	13.2	31.4	37.1	5.7	18.1%
		500	9.43	0.95	0.15	0.08	1.18	15.3	13.02	2.00	0.08	(0.06)	2.02	23.1	0.93	0.62	0.70	1.055	11.7	500	-	26.4	53.4	61.2	7.8	14.6%
		750	9.43	0.95	0.15	0.08	1.18	18.3	13.02	2.00	0.08	(0.06)	2.02	28.2	0.93	0.62	0.70	1.055	17.5	600	150	41.3	77.1	87.0	9.9	12.9%
		1,000	9.43	0.95	0.15	0.08	1.18	21.2	13.02	2.00	0.08	(0.06)	2.02	33.3	0.93	0.62	0.70	1.055	23.3	600	400	56.8	101.4	113.4	12.0	11.9%
Unmtr	**Forest**	100	**11.98**	**1.18**	**0.16**	**0.06**	**1.40**	13.4	**14.38**	**2.00**	**0.06**	**(0.06)**	**2.00**	16.4	**0.93**	0.62	0.7	1.055	2.3	100	-	5.3	21.0	24.0	3.0	14.3%
		250	11.98	1.18	0.16	0.06	1.40	15.5	14.38	2.00	0.06	(0.06)	2.00	19.4	0.93	0.62	0.70	1.055	5.8	250	-	13.2	34.5	38.4	3.9	11.3%
		500	11.98	1.18	0.16	0.06	1.40	19.0	14.38	2.00	0.06	(0.06)	2.00	24.4	0.93	0.62	0.70	1.055	11.7	500	-	26.4	57.0	62.4	5.4	9.5%
		750	11.98	1.18	0.16	0.06	1.40	22.5	14.38	2.00	0.06	(0.06)	2.00	29.4	0.93	0.62	0.70	1.055	17.5	600	150	41.3	81.3	88.2	6.9	8.5%
		1,000	11.98	1.18	0.16	0.06	1.40	26.0	14.38	2.00	0.06	(0.06)	2.00	34.4	0.93	0.62	0.70	1.055	23.3	600	400	56.8	106.1	114.6	8.4	7.9%
Unmtr	**GBE**	100	**4.92**	**1.14**	**0.16**	**0.06**	**1.36**	6.3	**9.15**	**2.00**	**0.06**	**(0.06)**	**2.00**	11.2	**0.93**	0.62	0.7	1.055	2.3	100	-	5.3	13.9	18.8	4.9	35.1%
		250	4.92	1.14	0.16	0.06	1.36	8.3	9.15	2.00	0.06	(0.06)	2.00	14.2	0.93	0.62	0.70	1.055	5.8	250	-	13.2	27.3	33.2	5.8	21.3%
		500	4.92	1.14	0.16	0.06	1.36	11.7	9.15	2.00	0.06	(0.06)	2.00	19.2	0.93	0.62	0.70	1.055	11.7	500	-	26.4	49.8	57.2	7.4	15.0%
		750	4.92	1.14	0.16	0.06	1.36	15.1	9.15	2.00	0.06	(0.06)	2.00	24.2	0.93	0.62	0.70	1.055	17.5	600	150	41.3	73.9	82.9	9.1	12.3%
		1,000	4.92	1.14	0.16	0.06	1.36	18.5	9.15	2.00	0.06	(0.06)	2.00	29.2	0.93	0.62	0.70	1.055	23.3	600	400	56.8	98.7	109.3	10.7	10.8%
Unmtr	**Georgina**	100	**8.24**	**1.62**	**0.16**	**0.08**	**1.86**	10.1	**12.32**	**2.00**	**0.08**	**(0.06)**	**2.02**	14.3	**0.93**	0.62	0.7	1.055	2.3	100	-	5.3	17.7	21.9	4.2	24.0%
		250	8.24	1.62	0.16	0.08	1.86	12.9	12.32	2.00	0.08	(0.06)	2.02	17.4	0.93	0.62	0.70	1.055	5.8	250	-	13.2	31.9	36.4	4.5	14.1%
		500	8.24	1.62	0.16	0.08	1.86	17.5	12.32	2.00	0.08	(0.06)	2.02	22.4	0.93	0.62	0.70	1.055	11.7	500	-	26.4	55.6	60.5	4.9	8.8%
		750	8.24	1.62	0.16	0.08	1.86	22.2	12.32	2.00	0.08	(0.06)	2.02	27.5	0.93	0.62	0.70	1.055	17.5	600	150	41.3	81.0	86.3	5.3	6.5%
		1,000	8.24	1.62	0.16	0.08	1.86	26.8	12.32	2.00	0.08	(0.06)	2.02	32.6	0.93	0.62	0.70	1.055	23.3	600	400	56.8	107.0	112.7	5.7	5.3%

New Rate Class: Gse - Unmetered

Total Bill Impacts of Proposed Distribution Rates [old RTSR+TLF]: Threshold of 600 kWhs

Classes		Scenario	May 2007 Incl Rate Riders						May 2008 Incl Rate Riders						Non-Dx Compoent				Other Reg	Commodity Bands (600.0)			Existing	New	$ Incr	% Incr
			Existing Dx Rates					Existing Dx	New Dx Rates					New Dx	RTSR old	WMSC	DRC	TLF old	Old	Band 1	Band 2	Old	Total Bill	Total Bill	Total Bill	Total Bill
																				5.0	5.9					
New Class	Old Class	kWh	SrChg [$/cust]	base [c/kWh]	Rider1 [c/kWh]	Rider2 [c/kWh]	VarChg [c/kWh]	[$/month]	SrChg [$/cust]	base [c/kWh]	Rider2 [c/kWh]	Rider3 [c/kWh]	VarChg [c/kWh]	[$/month]	c/kWh	c/kWh	c/kWh		$	kWhs	kWhs	Total $	[$/month]	[$/month]	[$/month]	%
Unmtr	Glencoe	100	**5.21**	**0.81**	**0.22**	**0.14**	**1.17**	6.4	**10.08**	**2.00**	**0.14**	**(0.06)**	**2.08**	12.2	**0.93**	0.62	0.7	1.055	2.3	100	-	5.3	14.0	19.8	5.8	41.3%
		250	5.21	0.81	0.22	0.14	1.17	8.1	10.08	2.00	0.14	(0.06)	2.08	15.3	0.93	0.62	0.70	1.055	5.8	250	-	13.2	27.2	34.3	7.1	26.3%
		500	5.21	0.81	0.22	0.14	1.17	11.1	10.08	2.00	0.14	(0.06)	2.08	20.5	0.93	0.62	0.70	1.055	11.7	500	-	26.4	49.1	58.5	9.4	19.2%
		750	5.21	0.81	0.22	0.14	1.17	14.0	10.08	2.00	0.14	(0.06)	2.08	25.7	0.93	0.62	0.70	1.055	17.5	600	150	41.3	72.8	84.5	11.7	16.1%
		1,000	5.21	0.81	0.22	0.14	1.17	16.9	10.08	2.00	0.14	(0.06)	2.08	30.9	0.93	0.62	0.70	1.055	23.3	600	400	56.8	97.1	111.1	14.0	14.4%
Unmtr	Grand Bend	100	**10.63**	**1.23**	**0.19**	**0.07**	**1.49**	12.1	**13.72**	**2.00**	**0.07**	**(0.06)**	**2.01**	15.7	**0.93**	0.62	0.7	1.055	2.3	100	-	5.3	19.7	23.3	3.6	18.3%
		250	10.63	1.23	0.19	0.07	1.49	14.4	13.72	2.00	0.07	(0.06)	2.01	18.8	0.93	0.62	0.70	1.055	5.8	250	-	13.2	33.4	37.8	4.4	13.2%
		500	10.63	1.23	0.19	0.07	1.49	18.1	13.72	2.00	0.07	(0.06)	2.01	23.8	0.93	0.62	0.70	1.055	11.7	500	-	26.4	56.1	61.8	5.7	10.2%
		750	10.63	1.23	0.19	0.07	1.49	21.8	13.72	2.00	0.07	(0.06)	2.01	28.8	0.93	0.62	0.70	1.055	17.5	600	150	41.3	80.6	87.6	7.0	8.7%
		1,000	10.63	1.23	0.19	0.07	1.49	25.5	13.72	2.00	0.07	(0.06)	2.01	33.9	0.93	0.62	0.70	1.055	23.3	600	400	56.8	105.7	114.0	8.3	7.9%
Unmtr	Hastings	100	**10.98**	**1.69**	**0.23**	**0.09**	**2.01**	13.0	**13.63**	**2.00**	**0.09**	**(0.06)**	**2.03**	15.7	**0.93**	0.62	0.7	1.055	2.3	100	-	5.3	20.6	23.3	2.7	13.0%
		250	10.98	1.69	0.23	0.09	2.01	16.0	13.63	2.00	0.09	(0.06)	2.03	18.7	0.93	0.62	0.70	1.055	5.8	250	-	13.2	35.0	37.7	2.7	7.7%
		500	10.98	1.69	0.23	0.09	2.01	21.0	13.63	2.00	0.09	(0.06)	2.03	23.8	0.93	0.62	0.70	1.055	11.7	500	-	26.4	59.1	61.8	2.8	4.7%
		750	10.98	1.69	0.23	0.09	2.01	26.1	13.63	2.00	0.09	(0.06)	2.03	28.9	0.93	0.62	0.70	1.055	17.5	600	150	41.3	84.8	87.7	2.8	3.3%
		1,000	10.98	1.69	0.23	0.09	2.01	31.1	13.63	2.00	0.09	(0.06)	2.03	34.0	0.93	0.62	0.70	1.055	23.3	600	400	56.8	111.2	114.1	2.9	2.6%
Unmtr	Havelock	100	**10.63**	**1.52**	**0.16**	**0.09**	**1.77**	12.4	**13.72**	**2.00**	**0.09**	**(0.06)**	**2.03**	15.8	**0.93**	0.62	0.7	1.055	2.3	100	-	5.3	20.0	23.4	3.4	16.8%
		250	10.63	1.52	0.16	0.09	1.77	15.1	13.72	2.00	0.09	(0.06)	2.03	18.8	0.93	0.62	0.70	1.055	5.8	250	-	13.2	34.1	37.8	3.7	11.0%
		500	10.63	1.52	0.16	0.09	1.77	19.5	13.72	2.00	0.09	(0.06)	2.03	23.9	0.93	0.62	0.70	1.055	11.7	500	-	26.4	57.5	61.9	4.4	7.7%
		750	10.63	1.52	0.16	0.09	1.77	23.9	13.72	2.00	0.09	(0.06)	2.03	29.0	0.93	0.62	0.70	1.055	17.5	600	150	41.3	82.7	87.7	5.1	6.1%
		1,000	10.63	1.52	0.16	0.09	1.77	28.3	13.72	2.00	0.09	(0.06)	2.03	34.1	0.93	0.62	0.70	1.055	23.3	600	400	56.8	108.5	114.2	5.7	5.3%
Unmtr	Kirkfield	100	**6.88**	**1.95**	**0.61**	**0.44**	**3.00**	9.9	**10.66**	**2.00**	**0.44**	**(0.06)**	**2.38**	13.0	**0.93**	0.62	0.7	1.055	2.3	100	-	5.3	17.5	20.6	3.2	18.1%
		250	6.88	1.95	0.61	0.44	3.00	14.4	10.66	2.00	0.44	(0.06)	2.38	16.6	0.93	0.62	0.70	1.055	5.8	250	-	13.2	33.4	35.6	2.2	6.7%
		500	6.88	1.95	0.61	0.44	3.00	21.9	10.66	2.00	0.44	(0.06)	2.38	22.6	0.93	0.62	0.70	1.055	11.7	500	-	26.4	59.9	60.6	0.7	1.2%
		750	6.88	1.95	0.61	0.44	3.00	29.4	10.66	2.00	0.44	(0.06)	2.38	28.5	0.93	0.62	0.70	1.055	17.5	600	150	41.3	88.2	87.3	(0.8)	-1.0%
		1,000	6.88	1.95	0.61	0.44	3.00	36.9	10.66	2.00	0.44	(0.06)	2.38	34.5	0.93	0.62	0.70	1.055	23.3	600	400	56.8	117.0	114.7	(2.4)	-2.0%

New Rate Class: Gse - Unmetered

Total Bill Impacts of Proposed Distribution Rates [old RTSR+TLF]: Threshold of 600 kWhs

600.0

Classes		Scenario	May 2007 Incl Rate Riders						May 2008 Incl Rate Riders						Non-Dx Compoent				Other Reg	Commodity Bands			Existing	New	$ Incr	% Incr
			Existing Dx Rates					Existing Dx	New Dx Rates					New Dx	RTSR old	WMSC	DRC	TLF old	Old	Band 1	Band 2	Old	Total Bill	Total Bill	Total Bill	Total Bill
																				5.0	5.9					
New Class	Old Class	kWh	SrChg [$/cust]	base [c/kWh]	Rider1 [c/kWh]	Rider2 [c/kWh]	VarChg [c/kWh]	[$/month]	SrChg [$/cust]	base [c/kWh]	Rider2 [c/kWh]	Rider3 [c/kWh]	VarChg [c/kWh]	[$/month]	c/kWh	c/kWh	c/kWh		$	kWhs	kWhs	Total $	[$/month]	[$/month]	[$/month]	%
Unmtr	**Lanark Highlands**	100	**8.75**	**1.99**	**0.63**	**0.50**	**3.12**	11.9	**12.19**	**2.00**	**0.50**	**(0.06)**	**2.44**	14.6	**0.93**	0.62	0.7	1.055	2.3	100	-	5.3	19.5	22.2	2.8	14.2%
		250	8.75	1.99	0.63	0.50	3.12	16.6	12.19	2.00	0.50	(0.06)	2.44	18.3	0.93	0.62	0.70	1.055	5.8	250	-	13.2	35.6	37.3	1.7	4.9%
		500	8.75	1.99	0.63	0.50	3.12	24.4	12.19	2.00	0.50	(0.06)	2.44	24.4	0.93	0.62	0.70	1.055	11.7	500	-	26.4	62.4	62.4	0.1	0.1%
		750	8.75	1.99	0.63	0.50	3.12	32.2	12.19	2.00	0.50	(0.06)	2.44	30.5	0.93	0.62	0.70	1.055	17.5	600	150	41.3	90.9	89.3	(1.6)	-1.8%
		1,000	8.75	1.99	0.63	0.50	3.12	40.0	12.19	2.00	0.50	(0.06)	2.44	36.6	0.93	0.62	0.70	1.055	23.3	600	400	56.8	120.1	116.8	(3.3)	-2.8%
Unmtr	**Larder Lake**	100	**9.62**	**1.58**	**0.51**	**0.36**	**2.45**	12.1	**12.97**	**2.00**	**0.36**	**(0.06)**	**2.30**	15.3	**0.93**	0.62	0.7	1.055	2.3	100	-	5.3	19.7	22.9	3.2	16.3%
		250	9.62	1.58	0.51	0.36	2.45	15.7	12.97	2.00	0.36	(0.06)	2.30	18.7	0.93	0.62	0.70	1.055	5.8	250	-	13.2	34.8	37.7	3.0	8.6%
		500	9.62	1.58	0.51	0.36	2.45	21.9	12.97	2.00	0.36	(0.06)	2.30	24.5	0.93	0.62	0.70	1.055	11.7	500	-	26.4	59.9	62.5	2.6	4.4%
		750	9.62	1.58	0.51	0.36	2.45	28.0	12.97	2.00	0.36	(0.06)	2.30	30.2	0.93	0.62	0.70	1.055	17.5	600	150	41.3	86.8	89.0	2.3	2.6%
		1,000	9.62	1.58	0.51	0.36	2.45	34.1	12.97	2.00	0.36	(0.06)	2.30	36.0	0.93	0.62	0.70	1.055	23.3	600	400	56.8	114.3	116.2	1.9	1.6%
Unmtr	**Latchford**	100	**0.97**	**1.02**	**0.65**	**0.20**	**1.87**	2.8	**6.14**	**2.00**	**0.20**	**(0.06)**	**2.14**	8.3	**0.93**	0.62	0.7	1.055	2.3	100	-	5.3	10.4	15.9	5.4	52.1%
		250	0.97	1.02	0.65	0.20	1.87	5.6	6.14	2.00	0.20	(0.06)	2.14	11.5	0.93	0.62	0.70	1.055	5.8	250	-	13.2	24.7	30.5	5.8	23.7%
		500	0.97	1.02	0.65	0.20	1.87	10.3	6.14	2.00	0.20	(0.06)	2.14	16.9	0.93	0.62	0.70	1.055	11.7	500	-	26.4	48.4	54.9	6.5	13.5%
		750	0.97	1.02	0.65	0.20	1.87	15.0	6.14	2.00	0.20	(0.06)	2.14	22.2	0.93	0.62	0.70	1.055	17.5	600	150	41.3	73.8	81.0	7.2	9.8%
		1,000	0.97	1.02	0.65	0.20	1.87	19.7	6.14	2.00	0.20	(0.06)	2.14	27.6	0.93	0.62	0.70	1.055	23.3	600	400	56.8	99.8	107.7	7.9	7.9%
Unmtr	**Lindsay**	100	**11.50**	**1.38**	**0.15**	**0.06**	**1.59**	13.1	**14.50**	**2.00**	**0.06**	**(0.06)**	**2.00**	16.5	**0.93**	0.62	0.7	1.055	2.3	100	-	5.3	20.7	24.1	3.4	16.5%
		250	11.50	1.38	0.15	0.06	1.59	15.5	14.50	2.00	0.06	(0.06)	2.00	19.5	0.93	0.62	0.70	1.055	5.8	250	-	13.2	34.5	38.5	4.0	11.7%
		500	11.50	1.38	0.15	0.06	1.59	19.5	14.50	2.00	0.06	(0.06)	2.00	24.5	0.93	0.62	0.70	1.055	11.7	500	-	26.4	57.5	62.6	5.1	8.8%
		750	11.50	1.38	0.15	0.06	1.59	23.4	14.50	2.00	0.06	(0.06)	2.00	29.5	0.93	0.62	0.70	1.055	17.5	600	150	41.3	82.2	88.3	6.1	7.4%
		1,000	11.50	1.38	0.15	0.06	1.59	27.4	14.50	2.00	0.06	(0.06)	2.00	34.5	0.93	0.62	0.70	1.055	23.3	600	400	56.8	107.6	114.7	7.1	6.6%
Unmtr	**Lucan Granton**	100	**8.03**	**1.47**	**0.17**	**0.10**	**1.74**	9.8	**12.37**	**2.00**	**0.10**	**(0.06)**	**2.04**	14.4	**0.93**	0.62	0.7	1.055	2.3	100	-	5.3	17.4	22.0	4.6	26.7%
		250	8.03	1.47	0.17	0.10	1.74	12.4	12.37	2.00	0.10	(0.06)	2.04	17.5	0.93	0.62	0.70	1.055	5.8	250	-	13.2	31.4	36.5	5.1	16.2%
		500	8.03	1.47	0.17	0.10	1.74	16.7	12.37	2.00	0.10	(0.06)	2.04	22.6	0.93	0.62	0.70	1.055	11.7	500	-	26.4	54.8	60.6	5.9	10.7%
		750	8.03	1.47	0.17	0.10	1.74	21.1	12.37	2.00	0.10	(0.06)	2.04	27.7	0.93	0.62	0.70	1.055	17.5	600	150	41.3	79.9	86.5	6.6	8.3%
		1,000	8.03	1.47	0.17	0.10	1.74	25.4	12.37	2.00	0.10	(0.06)	2.04	32.8	0.93	0.62	0.70	1.055	23.3	600	400	56.8	105.6	113.0	7.4	7.0%

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Exhibit G2
Tab 5
Schedule 5

New Rate Class: Gse - Unmetered

Total Bill Impacts of Proposed Distribution Rates [old RTSR+TLF]: Threshold of 600 kWhs

600.0

Classes		Scenario	May 2007 Incl Rate Riders						May 2008 Incl Rate Riders						Non-Dx Compoent				Other Reg	Commodity Bands			Existing	New	$ Incr	% Incr
			Existing Dx Rates					Existing Dx	New Dx Rates					New Dx	RTSR old	WMSC	DRC	TLF old	Old	Band 1	Band 2	Old	Total Bill	Total Bill	Total Bill	Total Bill
																				5.0	5.9					
New Class	Old Class	kWh	SrChg [$/cust]	base [c/kWh]	Rider1 [c/kWh]	Rider2 [c/kWh]	VarChg [c/kWh]	[$/month]	SrChg [$/cust]	base [c/kWh]	Rider2 [c/kWh]	Rider3 [c/kWh]	VarChg [c/kWh]	[$/month]	c/kWh	c/kWh	c/kWh		$	kWhs	kWhs	Total $	[$/month]	[$/month]	[$/month]	%
Unmtr	**Malahide**	100	**7.45**	**1.98**	**0.81**	**0.49**	**3.28**	10.7	**11.52**	**2.00**	**0.49**	**(0.06)**	**2.43**	13.9	**0.93**	0.62	0.7	1.055	2.3	100	-	5.3	18.3	21.6	3.2	17.6%
		250	7.45	1.98	0.81	0.49	3.28	15.7	11.52	2.00	0.49	(0.06)	2.43	17.6	0.93	0.62	0.70	1.055	5.8	250	-	13.2	34.7	36.6	1.9	5.6%
		500	7.45	1.98	0.81	0.49	3.28	23.9	11.52	2.00	0.49	(0.06)	2.43	23.7	0.93	0.62	0.70	1.055	11.7	500	-	26.4	61.9	61.7	(0.2)	-0.3%
		750	7.45	1.98	0.81	0.49	3.28	32.1	11.52	2.00	0.49	(0.06)	2.43	29.8	0.93	0.62	0.70	1.055	17.5	600	150	41.3	90.8	88.5	(2.3)	-2.5%
		1,000	7.45	1.98	0.81	0.49	3.28	40.3	11.52	2.00	0.49	(0.06)	2.43	35.8	0.93	0.62	0.70	1.055	23.3	600	400	56.8	120.4	116.0	(4.4)	-3.7%
Unmtr	**Mapleton**	100	**10.32**	**1.71**	**0.40**	**0.29**	**2.40**	12.7	**13.80**	**2.00**	**0.29**	**(0.06)**	**2.23**	16.0	**0.93**	0.62	0.7	1.055	2.3	100	-	5.3	20.3	23.6	3.3	16.3%
		250	10.32	1.71	0.40	0.29	2.40	16.3	13.80	2.00	0.29	(0.06)	2.23	19.4	0.93	0.62	0.70	1.055	5.8	250	-	13.2	35.3	38.4	3.1	8.7%
		500	10.32	1.71	0.40	0.29	2.40	22.3	13.80	2.00	0.29	(0.06)	2.23	25.0	0.93	0.62	0.70	1.055	11.7	500	-	26.4	60.4	63.0	2.6	4.4%
		750	10.32	1.71	0.40	0.29	2.40	28.3	13.80	2.00	0.29	(0.06)	2.23	30.5	0.93	0.62	0.70	1.055	17.5	600	150	41.3	87.1	89.3	2.2	2.6%
		1,000	10.32	1.71	0.40	0.29	2.40	34.3	13.80	2.00	0.29	(0.06)	2.23	36.1	0.93	0.62	0.70	1.055	23.3	600	400	56.8	114.5	116.3	1.8	1.6%
Unmtr	**Markdale**	100	**11.04**	**0.80**	**0.15**	**0.04**	**0.99**	12.0	**14.62**	**2.00**	**0.04**	**(0.06)**	**1.98**	16.6	**0.93**	0.62	0.7	1.055	2.3	100	-	5.3	19.6	24.2	4.6	23.3%
		250	11.04	0.80	0.15	0.04	0.99	13.5	14.62	2.00	0.04	(0.06)	1.98	19.6	0.93	0.62	0.70	1.055	5.8	250	-	13.2	32.5	38.6	6.1	18.6%
		500	11.04	0.80	0.15	0.04	0.99	16.0	14.62	2.00	0.04	(0.06)	1.98	24.5	0.93	0.62	0.70	1.055	11.7	500	-	26.4	54.0	62.6	8.5	15.8%
		750	11.04	0.80	0.15	0.04	0.99	18.5	14.62	2.00	0.04	(0.06)	1.98	29.5	0.93	0.62	0.70	1.055	17.5	600	150	41.3	77.2	88.3	11.0	14.3%
		1,000	11.04	0.80	0.15	0.04	0.99	20.9	14.62	2.00	0.04	(0.06)	1.98	34.5	0.93	0.62	0.70	1.055	23.3	600	400	56.8	101.1	114.6	13.5	13.4%
Unmtr	**Marmora**	100	**4.54**	**1.05**	**0.15**	**0.05**	**1.25**	5.8	**9.24**	**2.00**	**0.05**	**(0.06)**	**1.99**	11.2	**0.93**	0.62	0.7	1.055	2.3	100	-	5.3	13.4	18.8	5.4	40.7%
		250	4.54	1.05	0.15	0.05	1.25	7.7	9.24	2.00	0.05	(0.06)	1.99	14.2	0.93	0.62	0.70	1.055	5.8	250	-	13.2	26.7	33.2	6.6	24.6%
		500	4.54	1.05	0.15	0.05	1.25	10.8	9.24	2.00	0.05	(0.06)	1.99	19.2	0.93	0.62	0.70	1.055	11.7	500	-	26.4	48.8	57.2	8.4	17.2%
		750	4.54	1.05	0.15	0.05	1.25	13.9	9.24	2.00	0.05	(0.06)	1.99	24.2	0.93	0.62	0.70	1.055	17.5	600	150	41.3	72.7	83.0	10.3	14.1%
		1,000	4.54	1.05	0.15	0.05	1.25	17.0	9.24	2.00	0.05	(0.06)	1.99	29.2	0.93	0.62	0.70	1.055	23.3	600	400	56.8	97.2	109.3	12.1	12.5%
Unmtr	**McGarry**	100	**9.52**	**2.00**	**0.57**	**0.50**	**3.07**	12.6	**13.00**	**2.00**	**0.50**	**(0.06)**	**2.44**	15.4	**0.93**	0.62	0.7	1.055	2.3	100	-	5.3	20.2	23.0	2.9	14.1%
		250	9.52	2.00	0.57	0.50	3.07	17.2	13.00	2.00	0.50	(0.06)	2.44	19.1	0.93	0.62	0.70	1.055	5.8	250	-	13.2	36.2	38.1	1.9	5.3%
		500	9.52	2.00	0.57	0.50	3.07	24.9	13.00	2.00	0.50	(0.06)	2.44	25.2	0.93	0.62	0.70	1.055	11.7	500	-	26.4	62.9	63.2	0.3	0.5%
		750	9.52	2.00	0.57	0.50	3.07	32.5	13.00	2.00	0.50	(0.06)	2.44	31.3	0.93	0.62	0.70	1.055	17.5	600	150	41.3	91.3	90.1	(1.2)	-1.3%
		1,000	9.52	2.00	0.57	0.50	3.07	40.2	13.00	2.00	0.50	(0.06)	2.44	37.4	0.93	0.62	0.70	1.055	23.3	600	400	56.8	120.4	117.6	(2.8)	-2.3%

New Rate Class: Gse - Unmetered

Total Bill Impacts of Proposed Distribution Rates [old RTSR+TLF]: Threshold of 600 kWhs

Classes		Scenario	May 2007 Incl Rate Riders						May 2008 Incl Rate Riders						Non-Dx Compoent				Other Reg	Commodity Bands			Existing	New	$ Incr	% Incr
			Existing Dx Rates					Existing Dx	New Dx Rates					New Dx	RTSR old	WMSC	DRC	TLF old	Old	Band 1	Band 2	Old	Total Bill	Total Bill	Total Bill	Total Bill
																				600.0						
																				5.0	5.9					
New Class	Old Class	kWh	SrChg [$/cust]	base [c/kWh]	Rider1 [c/kWh]	Rider2 [c/kWh]	VarChg [c/kWh]	[$/month]	SrChg [$/cust]	base [c/kWh]	Rider2 [c/kWh]	Rider3 [c/kWh]	VarChg [c/kWh]	[$/month]	c/kWh	c/kWh	c/kWh		$	kWhs	kWhs	Total $	[$/month]	[$/month]	[$/month]	%
Unmtr	**Meaford**	100	**11.55**	**1.23**	**0.16**	**0.07**	**1.46**	13.0	**14.49**	**2.00**	**0.07**	**(0.06)**	**2.01**	16.5	**0.93**	0.62	0.7	1.055	2.3	100	-	5.3	20.6	24.1	3.5	16.9%
		250	11.55	1.23	0.16	0.07	1.46	15.2	14.49	2.00	0.07	(0.06)	2.01	19.5	0.93	0.62	0.70	1.055	5.8	250	-	13.2	34.2	38.5	4.3	12.6%
		500	11.55	1.23	0.16	0.07	1.46	18.9	14.49	2.00	0.07	(0.06)	2.01	24.6	0.93	0.62	0.70	1.055	11.7	500	-	26.4	56.9	62.6	5.7	10.0%
		750	11.55	1.23	0.16	0.07	1.46	22.5	14.49	2.00	0.07	(0.06)	2.01	29.6	0.93	0.62	0.70	1.055	17.5	600	150	41.3	81.3	88.4	7.1	8.7%
		1,000	11.55	1.23	0.16	0.07	1.46	26.2	14.49	2.00	0.07	(0.06)	2.01	34.6	0.93	0.62	0.70	1.055	23.3	600	400	56.8	106.3	114.8	8.5	8.0%
Unmtr	**Middlesex Centre**	100	**8.21**	**1.37**	**0.44**	**0.35**	**2.16**	10.4	**12.33**	**2.00**	**0.35**	**(0.06)**	**2.29**	14.6	**0.93**	0.62	0.7	1.055	2.3	100	-	5.3	18.0	22.2	4.2	23.6%
		250	8.21	1.37	0.44	0.35	2.16	13.6	12.33	2.00	0.35	(0.06)	2.29	18.1	0.93	0.62	0.70	1.055	5.8	250	-	13.2	32.6	37.1	4.4	13.6%
		500	8.21	1.37	0.44	0.35	2.16	19.0	12.33	2.00	0.35	(0.06)	2.29	23.8	0.93	0.62	0.70	1.055	11.7	500	-	26.4	57.0	61.8	4.8	8.4%
		750	8.21	1.37	0.44	0.35	2.16	24.4	12.33	2.00	0.35	(0.06)	2.29	29.5	0.93	0.62	0.70	1.055	17.5	600	150	41.3	83.2	88.3	5.1	6.1%
		1,000	8.21	1.37	0.44	0.35	2.16	29.8	12.33	2.00	0.35	(0.06)	2.29	35.3	0.93	0.62	0.70	1.055	23.3	600	400	56.8	110.0	115.4	5.4	5.0%
Unmtr	**Napanee**	100	**10.62**	**1.28**	**0.16**	**0.06**	**1.50**	12.1	**13.72**	**2.00**	**0.06**	**(0.06)**	**2.00**	15.7	**0.93**	0.62	0.7	1.055	2.3	100	-	5.3	19.7	23.3	3.6	18.3%
		250	10.62	1.28	0.16	0.06	1.50	14.4	13.72	2.00	0.06	(0.06)	2.00	18.7	0.93	0.62	0.70	1.055	5.8	250	-	13.2	33.4	37.7	4.4	13.1%
		500	10.62	1.28	0.16	0.06	1.50	18.1	13.72	2.00	0.06	(0.06)	2.00	23.7	0.93	0.62	0.70	1.055	11.7	500	-	26.4	56.2	61.8	5.6	10.0%
		750	10.62	1.28	0.16	0.06	1.50	21.9	13.72	2.00	0.06	(0.06)	2.00	28.7	0.93	0.62	0.70	1.055	17.5	600	150	41.3	80.6	87.5	6.9	8.5%
		1,000	10.62	1.28	0.16	0.06	1.50	25.6	13.72	2.00	0.06	(0.06)	2.00	33.8	0.93	0.62	0.70	1.055	23.3	600	400	56.8	105.8	113.9	8.1	7.7%
Unmtr	**Nipigon**	100	**11.19**	**1.05**	**0.34**	**0.21**	**1.60**	12.8	**14.58**	**2.00**	**0.21**	**(0.06)**	**2.15**	16.7	**0.93**	0.62	0.7	1.055	2.3	100	-	5.3	20.4	24.3	3.9	19.3%
		250	11.19	1.05	0.34	0.21	1.60	15.2	14.58	2.00	0.21	(0.06)	2.15	20.0	0.93	0.62	0.70	1.055	5.8	250	-	13.2	34.2	39.0	4.8	14.0%
		500	11.19	1.05	0.34	0.21	1.60	19.2	14.58	2.00	0.21	(0.06)	2.15	25.3	0.93	0.62	0.70	1.055	11.7	500	-	26.4	57.2	63.4	6.2	10.8%
		750	11.19	1.05	0.34	0.21	1.60	23.2	14.58	2.00	0.21	(0.06)	2.15	30.7	0.93	0.62	0.70	1.055	17.5	600	150	41.3	82.0	89.5	7.5	9.2%
		1,000	11.19	1.05	0.34	0.21	1.60	27.2	14.58	2.00	0.21	(0.06)	2.15	36.1	0.93	0.62	0.70	1.055	23.3	600	400	56.8	107.4	116.3	8.9	8.3%
Unmtr	**North Dorchester**	100	**7.47**	**0.90**	**0.35**	**0.26**	**1.51**	9.0	**11.51**	**2.00**	**0.26**	**(0.06)**	**2.20**	13.7	**0.93**	0.62	0.7	1.055	2.3	100	-	5.3	16.6	21.3	4.7	28.5%
		250	7.47	0.90	0.35	0.26	1.51	11.2	11.51	2.00	0.26	(0.06)	2.20	17.0	0.93	0.62	0.70	1.055	5.8	250	-	13.2	30.3	36.0	5.8	19.1%
		500	7.47	0.90	0.35	0.26	1.51	15.0	11.51	2.00	0.26	(0.06)	2.20	22.5	0.93	0.62	0.70	1.055	11.7	500	-	26.4	53.1	60.6	7.5	14.1%
		750	7.47	0.90	0.35	0.26	1.51	18.8	11.51	2.00	0.26	(0.06)	2.20	28.0	0.93	0.62	0.70	1.055	17.5	600	150	41.3	77.6	86.8	9.2	11.9%
		1,000	7.47	0.90	0.35	0.26	1.51	22.6	11.51	2.00	0.26	(0.06)	2.20	33.5	0.93	0.62	0.70	1.055	23.3	600	400	56.8	102.7	113.7	11.0	10.7%

New Rate Class: Gse - Unmetered

Total Bill Impacts of Proposed Distribution Rates [old RTSR+TLF]: Threshold of 600 kWhs

600.0

Classes		Scenario	May 2007 Incl Rate Riders						May 2008 Incl Rate Riders						Non-Dx Compoent				Other Reg	Commodity Bands			Existing	New	$ Incr	% Incr
			Existing Dx Rates					Existing Dx	New Dx Rates					New Dx	RTSR old	WMSC	DRC	TLF old	Old	Band 1	Band 2	Old	Total Bill	Total Bill	Total Bill	Total Bill
																				5.0	5.9					
New Class	Old Class	kWh	SrChg [$/cust]	base [c/kWh]	Rider1 [c/kWh]	Rider2 [c/kWh]	VarChg [c/kWh]	[$/month]	SrChg [$/cust]	base [c/kWh]	Rider2 [c/kWh]	Rider3 [c/kWh]	VarChg [c/kWh]	[$/month]	c/kWh	c/kWh	c/kWh		$	kWhs	kWhs	Total $	[$/month]	[$/month]	[$/month]	%
Unmtr	North Dundas	100	6.29	0.83	0.16	0.04	1.03	7.3	10.81	2.00	0.04	(0.06)	1.98	12.8	0.93	0.62	0.7	1.055	2.3	100	-	5.3	14.9	20.4	5.5	36.6%
		250	6.29	0.83	0.16	0.04	1.03	8.9	10.81	2.00	0.04	(0.06)	1.98	15.8	0.93	0.62	0.70	1.055	5.8	250	-	13.2	27.9	34.8	6.9	24.7%
		500	6.29	0.83	0.16	0.04	1.03	11.4	10.81	2.00	0.04	(0.06)	1.98	20.7	0.93	0.62	0.70	1.055	11.7	500	-	26.4	49.5	58.8	9.3	18.8%
		750	6.29	0.83	0.16	0.04	1.03	14.0	10.81	2.00	0.04	(0.06)	1.98	25.7	0.93	0.62	0.70	1.055	17.5	600	150	41.3	72.8	84.4	11.7	16.0%
		1,000	6.29	0.83	0.16	0.04	1.03	16.6	10.81	2.00	0.04	(0.06)	1.98	30.6	0.93	0.62	0.70	1.055	23.3	600	400	56.8	96.8	110.8	14.0	14.5%
Unmtr	North Glengarry	100	8.40	0.90	0.21	0.12	1.23	9.6	12.28	2.00	0.12	(0.06)	2.06	14.3	0.93	0.62	0.7	1.055	2.3	100	-	5.3	17.2	21.9	4.7	27.3%
		250	8.40	0.90	0.21	0.12	1.23	11.5	12.28	2.00	0.12	(0.06)	2.06	17.4	0.93	0.62	0.70	1.055	5.8	250	-	13.2	30.5	36.5	6.0	19.5%
		500	8.40	0.90	0.21	0.12	1.23	14.6	12.28	2.00	0.12	(0.06)	2.06	22.6	0.93	0.62	0.70	1.055	11.7	500	-	26.4	52.6	60.6	8.0	15.3%
		750	8.40	0.90	0.21	0.12	1.23	17.6	12.28	2.00	0.12	(0.06)	2.06	27.8	0.93	0.62	0.70	1.055	17.5	600	150	41.3	76.4	86.5	10.1	13.3%
		1,000	8.40	0.90	0.21	0.12	1.23	20.7	12.28	2.00	0.12	(0.06)	2.06	32.9	0.93	0.62	0.70	1.055	23.3	600	400	56.8	100.9	113.1	12.2	12.1%
Unmtr	North Grenville	100	9.74	1.71	0.14	0.08	1.93	11.7	12.94	2.00	0.08	(0.06)	2.02	15.0	0.93	0.62	0.7	1.055	2.3	100	-	5.3	19.3	22.6	3.3	17.1%
		250	9.74	1.71	0.14	0.08	1.93	14.6	12.94	2.00	0.08	(0.06)	2.02	18.0	0.93	0.62	0.70	1.055	5.8	250	-	13.2	33.6	37.0	3.4	10.2%
		500	9.74	1.71	0.14	0.08	1.93	19.4	12.94	2.00	0.08	(0.06)	2.02	23.1	0.93	0.62	0.70	1.055	11.7	500	-	26.4	57.4	61.1	3.7	6.4%
		750	9.74	1.71	0.14	0.08	1.93	24.2	12.94	2.00	0.08	(0.06)	2.02	28.1	0.93	0.62	0.70	1.055	17.5	600	150	41.3	83.0	86.9	3.9	4.7%
		1,000	9.74	1.71	0.14	0.08	1.93	29.0	12.94	2.00	0.08	(0.06)	2.02	33.2	0.93	0.62	0.70	1.055	23.3	600	400	56.8	109.2	113.3	4.1	3.8%
Unmtr	North Perth	100	14.30	1.00	0.12	0.04	1.16	15.5	16.80	2.00	0.04	(0.06)	1.98	18.8	0.93	0.62	0.7	1.055	2.3	100	-	5.3	23.1	26.4	3.3	14.4%
		250	14.30	1.00	0.12	0.04	1.16	17.2	16.80	2.00	0.04	(0.06)	1.98	21.8	0.93	0.62	0.70	1.055	5.8	250	-	13.2	36.2	40.8	4.6	12.6%
		500	14.30	1.00	0.12	0.04	1.16	20.1	16.80	2.00	0.04	(0.06)	1.98	26.7	0.93	0.62	0.70	1.055	11.7	500	-	26.4	58.1	64.8	6.6	11.4%
		750	14.30	1.00	0.12	0.04	1.16	23.0	16.80	2.00	0.04	(0.06)	1.98	31.7	0.93	0.62	0.70	1.055	17.5	600	150	41.3	81.8	90.4	8.7	10.6%
		1,000	14.30	1.00	0.12	0.04	1.16	25.9	16.80	2.00	0.04	(0.06)	1.98	36.6	0.93	0.62	0.70	1.055	23.3	600	400	56.8	106.1	116.8	10.7	10.1%
Unmtr	North Stormont	100	2.22	0.78	0.37	0.26	1.41	3.6	7.82	2.00	0.26	(0.06)	2.20	10.0	0.93	0.62	0.7	1.055	2.3	100	-	5.3	11.2	17.6	6.4	56.9%
		250	2.22	0.78	0.37	0.26	1.41	5.7	7.82	2.00	0.26	(0.06)	2.20	13.3	0.93	0.62	0.70	1.055	5.8	250	-	13.2	24.8	32.3	7.6	30.6%
		500	2.22	0.78	0.37	0.26	1.41	9.3	7.82	2.00	0.26	(0.06)	2.20	18.8	0.93	0.62	0.70	1.055	11.7	500	-	26.4	47.3	56.9	9.6	20.2%
		750	2.22	0.78	0.37	0.26	1.41	12.8	7.82	2.00	0.26	(0.06)	2.20	24.3	0.93	0.62	0.70	1.055	17.5	600	150	41.3	71.6	83.1	11.6	16.1%
		1,000	2.22	0.78	0.37	0.26	1.41	16.3	7.82	2.00	0.26	(0.06)	2.20	29.9	0.93	0.62	0.70	1.055	23.3	600	400	56.8	96.5	110.0	13.5	14.0%

New Rate Class: Gse - Unmetered

Total Bill Impacts of Proposed Distribution Rates [old RTSR+TLF]: Threshold of 600 kWhs

Classes		Scenario	May 2007 Incl Rate Riders						May 2008 Incl Rate Riders						Non-Dx Compoent				Other Reg	Commodity Bands			Existing	New	$ Incr	% Incr
			Existing Dx Rates					Existing Dx	New Dx Rates					New Dx	RTSR old	WMSC	DRC	TLF old	Old	Band 1	Band 2	Old	Total Bill	Total Bill	Total Bill	Total Bill
																				600.0						
																				5.0	5.9					
New Class	Old Class	kWh	SrChg [$/cust]	base [c/kWh]	Rider1 [c/kWh]	Rider2 [c/kWh]	VarChg [c/kWh]	[$/month]	SrChg [$/cust]	base [c/kWh]	Rider2 [c/kWh]	Rider3 [c/kWh]	VarChg [c/kWh]	[$/month]	c/kWh	c/kWh	c/kWh		$	kWhs	kWhs	Total $	[$/month]	[$/month]	[$/month]	%
Unmtr	Omemee	100	**10.18**	**1.47**	**0.18**	**0.09**	**1.74**	11.9	**13.83**	**2.00**	**0.09**	**(0.06)**	**2.03**	15.9	**0.93**	0.62	0.7	1.055	2.3	100	-	5.3	19.5	23.5	3.9	20.2%
		250	10.18	1.47	0.18	0.09	1.74	14.5	13.83	2.00	0.09	(0.06)	2.03	18.9	0.93	0.62	0.70	1.055	5.8	250	-	13.2	33.5	37.9	4.4	13.1%
		500	10.18	1.47	0.18	0.09	1.74	18.9	13.83	2.00	0.09	(0.06)	2.03	24.0	0.93	0.62	0.70	1.055	11.7	500	-	26.4	56.9	62.0	5.1	9.0%
		750	10.18	1.47	0.18	0.09	1.74	23.2	13.83	2.00	0.09	(0.06)	2.03	29.1	0.93	0.62	0.70	1.055	17.5	600	150	41.3	82.0	87.9	5.9	7.1%
		1,000	10.18	1.47	0.18	0.09	1.74	27.6	13.83	2.00	0.09	(0.06)	2.03	34.2	0.93	0.62	0.70	1.055	23.3	600	400	56.8	107.7	114.3	6.6	6.1%
Unmtr	Perth	100	**9.49**	**0.92**	**0.13**	**0.04**	**1.09**	10.6	**13.01**	**2.00**	**0.04**	**(0.06)**	**1.98**	15.0	**0.93**	0.62	0.7	1.055	2.3	100	-	5.3	18.2	22.6	4.4	24.2%
		250	9.49	0.92	0.13	0.04	1.09	12.2	13.01	2.00	0.04	(0.06)	1.98	18.0	0.93	0.62	0.70	1.055	5.8	250	-	13.2	31.2	37.0	5.7	18.4%
		500	9.49	0.92	0.13	0.04	1.09	14.9	13.01	2.00	0.04	(0.06)	1.98	22.9	0.93	0.62	0.70	1.055	11.7	500	-	26.4	53.0	61.0	8.0	15.1%
		750	9.49	0.92	0.13	0.04	1.09	17.7	13.01	2.00	0.04	(0.06)	1.98	27.9	0.93	0.62	0.70	1.055	17.5	600	150	41.3	76.4	86.6	10.2	13.4%
		1,000	9.49	0.92	0.13	0.04	1.09	20.4	13.01	2.00	0.04	(0.06)	1.98	32.8	0.93	0.62	0.70	1.055	23.3	600	400	56.8	100.6	113.0	12.4	12.4%
Unmtr	Perth East	100	**6.86**	**1.29**	**0.16**	**0.09**	**1.54**	8.4	**10.66**	**2.00**	**0.09**	**(0.06)**	**2.03**	12.7	**0.93**	0.62	0.7	1.055	2.3	100	-	5.3	16.0	20.3	4.3	26.8%
		250	6.86	1.29	0.16	0.09	1.54	10.7	10.66	2.00	0.09	(0.06)	2.03	15.7	0.93	0.62	0.70	1.055	5.8	250	-	13.2	29.7	34.8	5.0	16.9%
		500	6.86	1.29	0.16	0.09	1.54	14.6	10.66	2.00	0.09	(0.06)	2.03	20.8	0.93	0.62	0.70	1.055	11.7	500	-	26.4	52.6	58.9	6.3	11.9%
		750	6.86	1.29	0.16	0.09	1.54	18.4	10.66	2.00	0.09	(0.06)	2.03	25.9	0.93	0.62	0.70	1.055	17.5	600	150	41.3	77.2	84.7	7.5	9.7%
		1,000	6.86	1.29	0.16	0.09	1.54	22.3	10.66	2.00	0.09	(0.06)	2.03	31.0	0.93	0.62	0.70	1.055	23.3	600	400	56.8	102.4	111.2	8.7	8.5%
Unmtr	Prince Edward	100	**10.96**	**1.42**	**0.18**	**0.08**	**1.68**	12.6	**13.64**	**2.00**	**0.08**	**(0.06)**	**2.02**	15.7	**0.93**	0.62	0.7	1.055	2.3	100	-	5.3	20.2	23.3	3.0	14.9%
		250	10.96	1.42	0.18	0.08	1.68	15.2	13.64	2.00	0.08	(0.06)	2.02	18.7	0.93	0.62	0.70	1.055	5.8	250	-	13.2	34.2	37.7	3.5	10.3%
		500	10.96	1.42	0.18	0.08	1.68	19.4	13.64	2.00	0.08	(0.06)	2.02	23.8	0.93	0.62	0.70	1.055	11.7	500	-	26.4	57.4	61.8	4.4	7.7%
		750	10.96	1.42	0.18	0.08	1.68	23.6	13.64	2.00	0.08	(0.06)	2.02	28.8	0.93	0.62	0.70	1.055	17.5	600	150	41.3	82.3	87.6	5.3	6.4%
		1,000	10.96	1.42	0.18	0.08	1.68	27.8	13.64	2.00	0.08	(0.06)	2.02	33.9	0.93	0.62	0.70	1.055	23.3	600	400	56.8	107.9	114.0	6.1	5.7%
Unmtr	Quinte West	100	**1.41**	**1.05**	**0.14**	**0.06**	**1.25**	2.7	**7.03**	**2.00**	**0.06**	**(0.06)**	**2.00**	9.0	**0.93**	0.62	0.7	1.055	2.3	100	-	5.3	10.3	16.6	6.4	62.0%
		250	1.41	1.05	0.14	0.06	1.25	4.5	7.03	2.00	0.06	(0.06)	2.00	12.0	0.93	0.62	0.70	1.055	5.8	250	-	13.2	23.6	31.1	7.5	31.8%
		500	1.41	1.05	0.14	0.06	1.25	7.7	7.03	2.00	0.06	(0.06)	2.00	17.0	0.93	0.62	0.70	1.055	11.7	500	-	26.4	45.7	55.1	9.4	20.5%
		750	1.41	1.05	0.14	0.06	1.25	10.8	7.03	2.00	0.06	(0.06)	2.00	22.0	0.93	0.62	0.70	1.055	17.5	600	150	41.3	69.6	80.8	11.3	16.2%
		1,000	1.41	1.05	0.14	0.06	1.25	13.9	7.03	2.00	0.06	(0.06)	2.00	27.1	0.93	0.62	0.70	1.055	23.3	600	400	56.8	94.1	107.2	13.1	14.0%

New Rate Class: Gse - Unmetered

Total Bill Impacts of Proposed Distribution Rates [old RTSR+TLF]: Threshold of 600 kWhs

Classes		Scenario	May 2007 Incl Rate Riders						May 2008 Incl Rate Riders						Non-Dx Compoent				Other Reg	Commodity Bands (600.0)			Existing	New	$ Incr	% Incr
			Existing Dx Rates					Existing Dx	New Dx Rates					New Dx	RTSR old	WMSC	DRC	TLF old	Old	Band 1	Band 2	Old	Total Bill	Total Bill	Total Bill	Total Bill
																				5.0	5.9					
New Class	Old Class	kWh	SrChg [$/cust]	base [c/kWh]	Rider1 [c/kWh]	Rider2 [c/kWh]	VarChg [c/kWh]	[$/month]	SrChg [$/cust]	base [c/kWh]	Rider2 [c/kWh]	Rider3 [c/kWh]	VarChg [c/kWh]	[$/month]	c/kWh	c/kWh	c/kWh		$	kWhs	kWhs	Total $	[$/month]	[$/month]	[$/month]	%
Unmtr	Rainy River	100	9.18	1.76	0.45	0.36	2.57	11.8	13.08	2.00	0.36	(0.06)	2.30	15.4	0.93	0.62	0.7	1.055	2.3	100	-	5.3	19.4	23.0	3.6	18.8%
		250	9.18	1.76	0.45	0.36	2.57	15.6	13.08	2.00	0.36	(0.06)	2.30	18.8	0.93	0.62	0.70	1.055	5.8	250	-	13.2	34.6	37.9	3.2	9.3%
		500	9.18	1.76	0.45	0.36	2.57	22.0	13.08	2.00	0.36	(0.06)	2.30	24.6	0.93	0.62	0.70	1.055	11.7	500	-	26.4	60.1	62.6	2.6	4.3%
		750	9.18	1.76	0.45	0.36	2.57	28.5	13.08	2.00	0.36	(0.06)	2.30	30.4	0.93	0.62	0.70	1.055	17.5	600	150	41.3	87.2	89.1	1.9	2.2%
		1,000	9.18	1.76	0.45	0.36	2.57	34.9	13.08	2.00	0.36	(0.06)	2.30	36.1	0.93	0.62	0.70	1.055	23.3	600	400	56.8	115.0	116.3	1.2	1.1%
Unmtr	Ramara	100	10.02	1.06	0.45	0.37	1.88	11.9	13.87	2.00	0.37	(0.06)	2.31	16.2	0.93	0.62	0.7	1.055	2.3	100	-	5.3	19.5	23.8	4.3	22.0%
		250	10.02	1.06	0.45	0.37	1.88	14.7	13.87	2.00	0.37	(0.06)	2.31	19.7	0.93	0.62	0.70	1.055	5.8	250	-	13.2	33.7	38.7	4.9	14.6%
		500	10.02	1.06	0.45	0.37	1.88	19.4	13.87	2.00	0.37	(0.06)	2.31	25.4	0.93	0.62	0.70	1.055	11.7	500	-	26.4	57.5	63.5	6.0	10.5%
		750	10.02	1.06	0.45	0.37	1.88	24.1	13.87	2.00	0.37	(0.06)	2.31	31.2	0.93	0.62	0.70	1.055	17.5	600	150	41.3	82.9	90.0	7.1	8.6%
		1,000	10.02	1.06	0.45	0.37	1.88	28.8	13.87	2.00	0.37	(0.06)	2.31	37.0	0.93	0.62	0.70	1.055	23.3	600	400	56.8	109.0	117.2	8.2	7.5%
Unmtr	Red Rock	100	10.36	1.94	0.27	0.24	2.45	12.8	13.79	2.00	0.24	(0.06)	2.18	16.0	0.93	0.62	0.7	1.055	2.3	100	-	5.3	20.4	23.6	3.2	15.5%
		250	10.36	1.94	0.27	0.24	2.45	16.5	13.79	2.00	0.24	(0.06)	2.18	19.2	0.93	0.62	0.70	1.055	5.8	250	-	13.2	35.5	38.3	2.8	7.8%
		500	10.36	1.94	0.27	0.24	2.45	22.6	13.79	2.00	0.24	(0.06)	2.18	24.7	0.93	0.62	0.70	1.055	11.7	500	-	26.4	60.6	62.7	2.1	3.5%
		750	10.36	1.94	0.27	0.24	2.45	28.7	13.79	2.00	0.24	(0.06)	2.18	30.2	0.93	0.62	0.70	1.055	17.5	600	150	41.3	87.5	88.9	1.4	1.6%
		1,000	10.36	1.94	0.27	0.24	2.45	34.9	13.79	2.00	0.24	(0.06)	2.18	35.6	0.93	0.62	0.70	1.055	23.3	600	400	56.8	115.0	115.8	0.8	0.7%
Unmtr	Rockland	100	3.16	1.00	0.17	0.22	1.39	4.6	8.59	2.00	0.22	(0.06)	2.16	10.8	0.93	0.62	0.7	1.055	2.3	100	-	5.3	12.2	18.4	6.2	51.0%
		250	3.16	1.00	0.17	0.22	1.39	6.6	8.59	2.00	0.22	(0.06)	2.16	14.0	0.93	0.62	0.70	1.055	5.8	250	-	13.2	25.7	33.0	7.4	28.7%
		500	3.16	1.00	0.17	0.22	1.39	10.1	8.59	2.00	0.22	(0.06)	2.16	19.4	0.93	0.62	0.70	1.055	11.7	500	-	26.4	48.1	57.4	9.3	19.3%
		750	3.16	1.00	0.17	0.22	1.39	13.6	8.59	2.00	0.22	(0.06)	2.16	24.8	0.93	0.62	0.70	1.055	17.5	600	150	41.3	72.4	83.6	11.2	15.5%
		1,000	3.16	1.00	0.17	0.22	1.39	17.1	8.59	2.00	0.22	(0.06)	2.16	30.2	0.93	0.62	0.70	1.055	23.3	600	400	56.8	97.2	110.4	13.2	13.5%
Unmtr	Russell	100	9.17	2.24	0.18	0.11	2.53	11.7	13.09	2.00	0.11	(0.06)	2.05	15.1	0.93	0.62	0.7	1.055	2.3	100	-	5.3	19.3	22.7	3.4	17.8%
		250	9.17	2.24	0.18	0.11	2.53	15.5	13.09	2.00	0.11	(0.06)	2.05	18.2	0.93	0.62	0.70	1.055	5.8	250	-	13.2	34.5	37.2	2.7	7.9%
		500	9.17	2.24	0.18	0.11	2.53	21.8	13.09	2.00	0.11	(0.06)	2.05	23.4	0.93	0.62	0.70	1.055	11.7	500	-	26.4	59.9	61.4	1.5	2.6%
		750	9.17	2.24	0.18	0.11	2.53	28.1	13.09	2.00	0.11	(0.06)	2.05	28.5	0.93	0.62	0.70	1.055	17.5	600	150	41.3	86.9	87.3	0.3	0.4%
		1,000	9.17	2.24	0.18	0.11	2.53	34.5	13.09	2.00	0.11	(0.06)	2.05	33.6	0.93	0.62	0.70	1.055	23.3	600	400	56.8	114.6	113.8	(0.9)	-0.7%

New Rate Class: Gse - Unmetered

Total Bill Impacts of Proposed Distribution Rates [old RTSR+TLF]: Threshold of 600 kWhs

600.0

Classes		Scenario	May 2007 Incl Rate Riders						May 2008 Incl Rate Riders						Non-Dx Compoent				Other Reg	Commodity Bands			Existing	New	$ Incr	% Incr
			Existing Dx Rates					Existing Dx	New Dx Rates					New Dx	RTSR old	WMSC	DRC	TLF old	Old	Band 1	Band 2	Old	Total Bill	Total Bill	Total Bill	Total Bill
																				5.0	5.9					
New Class	Old Class	kWh	SrChg [$/cust]	base [c/kWh]	Rider1 [c/kWh]	Rider2 [c/kWh]	VarChg [c/kWh]	[$/month]	SrChg [$/cust]	base [c/kWh]	Rider2 [c/kWh]	Rider3 [c/kWh]	VarChg [c/kWh]	[$/month]	c/kWh	c/kWh	c/kWh		$	kWhs	kWhs	Total $	[$/month]	[$/month]	[$/month]	%
Unmtr	**Schreiber**	100	**9.88**	**2.51**	**0.50**	**0.40**	**3.41**	13.3	**12.91**	**2.00**	**0.40**	**(0.06)**	**2.34**	15.3	**0.93**	0.62	0.7	1.055	2.3	100	-	5.3	20.9	22.9	2.0	9.4%
		250	9.88	2.51	0.50	0.40	3.41	18.4	12.91	2.00	0.40	(0.06)	2.34	18.8	0.93	0.62	0.70	1.055	5.8	250	-	13.2	37.4	37.8	0.4	1.0%
		500	9.88	2.51	0.50	0.40	3.41	26.9	12.91	2.00	0.40	(0.06)	2.34	24.6	0.93	0.62	0.70	1.055	11.7	500	-	26.4	65.0	62.7	(2.3)	-3.5%
		750	9.88	2.51	0.50	0.40	3.41	35.5	12.91	2.00	0.40	(0.06)	2.34	30.5	0.93	0.62	0.70	1.055	17.5	600	150	41.3	94.2	89.3	(5.0)	-5.3%
		1,000	9.88	2.51	0.50	0.40	3.41	44.0	12.91	2.00	0.40	(0.06)	2.34	36.3	0.93	0.62	0.70	1.055	23.3	600	400	56.8	124.1	116.5	(7.6)	-6.2%
Unmtr	**Severn**	100	**10.62**	**1.06**	**0.31**	**0.22**	**1.59**	12.2	**13.72**	**2.00**	**0.22**	**(0.06)**	**2.16**	15.9	**0.93**	0.62	0.7	1.055	2.3	100	-	5.3	19.8	23.5	3.7	18.5%
		250	10.62	1.06	0.31	0.22	1.59	14.6	13.72	2.00	0.22	(0.06)	2.16	19.1	0.93	0.62	0.70	1.055	5.8	250	-	13.2	33.6	38.1	4.5	13.5%
		500	10.62	1.06	0.31	0.22	1.59	18.6	13.72	2.00	0.22	(0.06)	2.16	24.5	0.93	0.62	0.70	1.055	11.7	500	-	26.4	56.6	62.6	6.0	10.5%
		750	10.62	1.06	0.31	0.22	1.59	22.5	13.72	2.00	0.22	(0.06)	2.16	29.9	0.93	0.62	0.70	1.055	17.5	600	150	41.3	81.3	88.7	7.4	9.1%
		1,000	10.62	1.06	0.31	0.22	1.59	26.5	13.72	2.00	0.22	(0.06)	2.16	35.4	0.93	0.62	0.70	1.055	23.3	600	400	56.8	106.7	115.5	8.8	8.3%
Unmtr	**Shelburne**	100	**9.53**	**0.87**	**0.10**	**0.02**	**0.99**	10.5	**13.00**	**2.00**	**0.02**	**(0.06)**	**1.96**	15.0	**0.93**	0.62	0.7	1.055	2.3	100	-	5.3	18.1	22.6	4.4	24.5%
		250	9.53	0.87	0.10	0.02	0.99	12.0	13.00	2.00	0.02	(0.06)	1.96	17.9	0.93	0.62	0.70	1.055	5.8	250	-	13.2	31.0	36.9	5.9	19.0%
		500	9.53	0.87	0.10	0.02	0.99	14.5	13.00	2.00	0.02	(0.06)	1.96	22.8	0.93	0.62	0.70	1.055	11.7	500	-	26.4	52.5	60.8	8.3	15.9%
		750	9.53	0.87	0.10	0.02	0.99	17.0	13.00	2.00	0.02	(0.06)	1.96	27.7	0.93	0.62	0.70	1.055	17.5	600	150	41.3	75.7	86.5	10.8	14.2%
		1,000	9.53	0.87	0.10	0.02	0.99	19.4	13.00	2.00	0.02	(0.06)	1.96	32.6	0.93	0.62	0.70	1.055	23.3	600	400	56.8	99.6	112.8	13.2	13.3%
Unmtr	**Smiths Falls**	100	**4.46**	**1.05**	**0.12**	**0.04**	**1.21**	5.7	**9.26**	**2.00**	**0.04**	**(0.06)**	**1.98**	11.2	**0.93**	0.62	0.7	1.055	2.3	100	-	5.3	13.3	18.9	5.6	42.0%
		250	4.46	1.05	0.12	0.04	1.21	7.5	9.26	2.00	0.04	(0.06)	1.98	14.2	0.93	0.62	0.70	1.055	5.8	250	-	13.2	26.5	33.2	6.7	25.4%
		500	4.46	1.05	0.12	0.04	1.21	10.5	9.26	2.00	0.04	(0.06)	1.98	19.2	0.93	0.62	0.70	1.055	11.7	500	-	26.4	48.5	57.2	8.7	17.9%
		750	4.46	1.05	0.12	0.04	1.21	13.5	9.26	2.00	0.04	(0.06)	1.98	24.1	0.93	0.62	0.70	1.055	17.5	600	150	41.3	72.3	82.9	10.6	14.7%
		1,000	4.46	1.05	0.12	0.04	1.21	16.6	9.26	2.00	0.04	(0.06)	1.98	29.1	0.93	0.62	0.70	1.055	23.3	600	400	56.8	96.7	109.3	12.5	13.0%
Unmtr	**South Glengarry**	100	**8.25**	**0.75**	**0.37**	**0.30**	**1.42**	9.7	**12.32**	**2.00**	**0.30**	**(0.06)**	**2.24**	14.6	**0.93**	0.62	0.7	1.055	2.3	100	-	5.3	17.3	22.2	4.9	28.3%
		250	8.25	0.75	0.37	0.30	1.42	11.8	12.32	2.00	0.30	(0.06)	2.24	17.9	0.93	0.62	0.70	1.055	5.8	250	-	13.2	30.8	36.9	6.1	19.9%
		500	8.25	0.75	0.37	0.30	1.42	15.4	12.32	2.00	0.30	(0.06)	2.24	23.5	0.93	0.62	0.70	1.055	11.7	500	-	26.4	53.4	61.6	8.2	15.3%
		750	8.25	0.75	0.37	0.30	1.42	18.9	12.32	2.00	0.30	(0.06)	2.24	29.1	0.93	0.62	0.70	1.055	17.5	600	150	41.3	77.7	87.9	10.2	13.2%
		1,000	8.25	0.75	0.37	0.30	1.42	22.5	12.32	2.00	0.30	(0.06)	2.24	34.7	0.93	0.62	0.70	1.055	23.3	600	400	56.8	102.6	114.9	12.3	12.0%

New Rate Class: Gse - Unmetered

Total Bill Impacts of Proposed Distribution Rates [old RTSR+TLF]: Threshold of 600 kWhs

600.0

Classes		Scenario	May 2007 Incl Rate Riders						May 2008 Incl Rate Riders						Non-Dx Compoent				Other Reg	Commodity Bands			Existing	New	$ Incr	% Incr
			Existing Dx Rates					Existing Dx	New Dx Rates					New Dx	RTSR old	WMSC	DRC	TLF old	Old	Band 1	Band 2	Old	Total Bill	Total Bill	Total Bill	Total Bill
																				5.0	5.9					
New Class	Old Class	kWh	SrChg [$/cust]	base [c/kWh]	Rider1 [c/kWh]	Rider2 [c/kWh]	VarChg [c/kWh]	[$/month]	SrChg [$/cust]	base [c/kWh]	Rider2 [c/kWh]	Rider3 [c/kWh]	VarChg [c/kWh]	[$/month]	c/kWh	c/kWh	c/kWh		$	kWhs	kWhs	Total $	[$/month]	[$/month]	[$/month]	%
Unmtr	**South River**	100	**10.59**	**1.58**	**0.39**	**0.30**	**2.27**	12.9	**13.73**	**2.00**	**0.30**	**(0.06)**	**2.24**	16.0	**0.93**	0.62	0.7	1.055	2.3	100	-	5.3	20.5	23.6	3.1	15.2%
		250	10.59	1.58	0.39	0.30	2.27	16.3	13.73	2.00	0.30	(0.06)	2.24	19.3	0.93	0.62	0.70	1.055	5.8	250	-	13.2	35.3	38.4	3.1	8.7%
		500	10.59	1.58	0.39	0.30	2.27	21.9	13.73	2.00	0.30	(0.06)	2.24	24.9	0.93	0.62	0.70	1.055	11.7	500	-	26.4	60.0	63.0	3.0	5.0%
		750	10.59	1.58	0.39	0.30	2.27	27.6	13.73	2.00	0.30	(0.06)	2.24	30.6	0.93	0.62	0.70	1.055	17.5	600	150	41.3	86.4	89.3	2.9	3.4%
		1,000	10.59	1.58	0.39	0.30	2.27	33.3	13.73	2.00	0.30	(0.06)	2.24	36.2	0.93	0.62	0.70	1.055	23.3	600	400	56.8	113.5	116.3	2.9	2.5%
Unmtr	**Springwater**	100	**9.80**	**1.07**	**0.27**	**0.17**	**1.51**	11.3	**12.93**	**2.00**	**0.17**	**(0.06)**	**2.11**	15.0	**0.93**	0.62	0.7	1.055	2.3	100	-	5.3	18.9	22.6	3.7	19.7%
		250	9.80	1.07	0.27	0.17	1.51	13.6	12.93	2.00	0.17	(0.06)	2.11	18.2	0.93	0.62	0.70	1.055	5.8	250	-	13.2	32.6	37.2	4.6	14.2%
		500	9.80	1.07	0.27	0.17	1.51	17.4	12.93	2.00	0.17	(0.06)	2.11	23.5	0.93	0.62	0.70	1.055	11.7	500	-	26.4	55.4	61.5	6.1	11.1%
		750	9.80	1.07	0.27	0.17	1.51	21.1	12.93	2.00	0.17	(0.06)	2.11	28.8	0.93	0.62	0.70	1.055	17.5	600	150	41.3	79.9	87.5	7.7	9.6%
		1,000	9.80	1.07	0.27	0.17	1.51	24.9	12.93	2.00	0.17	(0.06)	2.11	34.1	0.93	0.62	0.70	1.055	23.3	600	400	56.8	105.1	114.2	9.2	8.7%
Unmtr	**Stirling-Rawdon**	100	**11.59**	**1.30**	**0.21**	**0.09**	**1.60**	13.2	**14.48**	**2.00**	**0.09**	**(0.06)**	**2.03**	16.5	**0.93**	0.62	0.7	1.055	2.3	100	-	5.3	20.8	24.1	3.3	16.0%
		250	11.59	1.30	0.21	0.09	1.60	15.6	14.48	2.00	0.09	(0.06)	2.03	19.6	0.93	0.62	0.70	1.055	5.8	250	-	13.2	34.6	38.6	4.0	11.5%
		500	11.59	1.30	0.21	0.09	1.60	19.6	14.48	2.00	0.09	(0.06)	2.03	24.6	0.93	0.62	0.70	1.055	11.7	500	-	26.4	57.6	62.7	5.1	8.8%
		750	11.59	1.30	0.21	0.09	1.60	23.6	14.48	2.00	0.09	(0.06)	2.03	29.7	0.93	0.62	0.70	1.055	17.5	600	150	41.3	82.4	88.5	6.1	7.5%
		1,000	11.59	1.30	0.21	0.09	1.60	27.6	14.48	2.00	0.09	(0.06)	2.03	34.8	0.93	0.62	0.70	1.055	23.3	600	400	56.8	107.8	115.0	7.2	6.7%
Unmtr	**Thedford**	100	**8.45**	**1.06**	**0.36**	**0.31**	**1.73**	10.2	**12.27**	**2.00**	**0.31**	**(0.06)**	**2.25**	14.5	**0.93**	0.62	0.7	1.055	2.3	100	-	5.3	17.8	22.1	4.3	24.4%
		250	8.45	1.06	0.36	0.31	1.73	12.8	12.27	2.00	0.31	(0.06)	2.25	17.9	0.93	0.62	0.70	1.055	5.8	250	-	13.2	31.8	36.9	5.1	16.1%
		500	8.45	1.06	0.36	0.31	1.73	17.1	12.27	2.00	0.31	(0.06)	2.25	23.5	0.93	0.62	0.70	1.055	11.7	500	-	26.4	55.1	61.6	6.4	11.7%
		750	8.45	1.06	0.36	0.31	1.73	21.4	12.27	2.00	0.31	(0.06)	2.25	29.2	0.93	0.62	0.70	1.055	17.5	600	150	41.3	80.2	87.9	7.7	9.7%
		1,000	8.45	1.06	0.36	0.31	1.73	25.8	12.27	2.00	0.31	(0.06)	2.25	34.8	0.93	0.62	0.70	1.055	23.3	600	400	56.8	105.9	115.0	9.0	8.5%
Unmtr	**Thessalon**	100	**8.99**	**1.55**	**0.10**	**0.08**	**1.73**	10.7	**12.13**	**2.00**	**0.08**	**(0.06)**	**2.02**	14.2	**0.93**	0.62	0.7	1.055	2.3	100	-	5.3	18.3	21.8	3.4	18.7%
		250	8.99	1.55	0.10	0.08	1.73	13.3	12.13	2.00	0.08	(0.06)	2.02	17.2	0.93	0.62	0.70	1.055	5.8	250	-	13.2	32.3	36.2	3.9	12.0%
		500	8.99	1.55	0.10	0.08	1.73	17.6	12.13	2.00	0.08	(0.06)	2.02	22.2	0.93	0.62	0.70	1.055	11.7	500	-	26.4	55.7	60.3	4.6	8.3%
		750	8.99	1.55	0.10	0.08	1.73	22.0	12.13	2.00	0.08	(0.06)	2.02	27.3	0.93	0.62	0.70	1.055	17.5	600	150	41.3	80.7	86.1	5.3	6.6%
		1,000	8.99	1.55	0.10	0.08	1.73	26.3	12.13	2.00	0.08	(0.06)	2.02	32.4	0.93	0.62	0.70	1.055	23.3	600	400	56.8	106.5	112.5	6.1	5.7%

New Rate Class: Gse - Unmetered

Total Bill Impacts of Proposed Distribution Rates [old RTSR+TLF]: Threshold of 600 kWhs

600.0

Classes		Scenario	May 2007 Incl Rate Riders						May 2008 Incl Rate Riders						Non-Dx Compoent				Other Reg	Commodity Bands			Existing	New	$ Incr	% Incr
			Existing Dx Rates					Existing Dx	New Dx Rates					New Dx	RTSR old	WMSC	DRC	TLF old	Old	Band 1	Band 2	Old	Total Bill	Total Bill	Total Bill	Total Bill
																				5.0	5.9					
New Class	Old Class	kWh	SrChg [$/cust]	base [c/kWh]	Rider1 [c/kWh]	Rider2 [c/kWh]	VarChg [c/kWh]	[$/month]	SrChg [$/cust]	base [c/kWh]	Rider2 [c/kWh]	Rider3 [c/kWh]	VarChg [c/kWh]	[$/month]	c/kWh	c/kWh	c/kWh		$	kWhs	kWhs	Total $	[$/month]	[$/month]	[$/month]	%
Unmtr	Thorndale	100	6.79	1.02	0.52	0.32	1.86	8.7	10.68	2.00	0.32	(0.06)	2.26	12.9	0.93	0.62	0.7	1.055	2.3	100	-	5.3	16.3	20.6	4.3	26.4%
		250	6.79	1.02	0.52	0.32	1.86	11.4	10.68	2.00	0.32	(0.06)	2.26	16.3	0.93	0.62	0.70	1.055	5.8	250	-	13.2	30.5	35.4	4.9	16.1%
		500	6.79	1.02	0.52	0.32	1.86	16.1	10.68	2.00	0.32	(0.06)	2.26	22.0	0.93	0.62	0.70	1.055	11.7	500	-	26.4	54.1	60.0	5.9	10.9%
		750	6.79	1.02	0.52	0.32	1.86	20.7	10.68	2.00	0.32	(0.06)	2.26	27.7	0.93	0.62	0.70	1.055	17.5	600	150	41.3	79.5	86.4	6.9	8.7%
		1,000	6.79	1.02	0.52	0.32	1.86	25.4	10.68	2.00	0.32	(0.06)	2.26	33.3	0.93	0.62	0.70	1.055	23.3	600	400	56.8	105.6	113.5	7.9	7.5%
Unmtr	Thorold	100	10.85	1.50	0.15	0.06	1.71	12.6	13.67	2.00	0.06	(0.06)	2.00	15.7	0.93	0.62	0.7	1.055	2.3	100	-	5.3	20.2	23.3	3.1	15.4%
		250	10.85	1.50	0.15	0.06	1.71	15.1	13.67	2.00	0.06	(0.06)	2.00	18.7	0.93	0.62	0.70	1.055	5.8	250	-	13.2	34.1	37.7	3.5	10.4%
		500	10.85	1.50	0.15	0.06	1.71	19.4	13.67	2.00	0.06	(0.06)	2.00	23.7	0.93	0.62	0.70	1.055	11.7	500	-	26.4	57.4	61.7	4.3	7.5%
		750	10.85	1.50	0.15	0.06	1.71	23.7	13.67	2.00	0.06	(0.06)	2.00	28.7	0.93	0.62	0.70	1.055	17.5	600	150	41.3	82.4	87.5	5.0	6.1%
		1,000	10.85	1.50	0.15	0.06	1.71	28.0	13.67	2.00	0.06	(0.06)	2.00	33.7	0.93	0.62	0.70	1.055	23.3	600	400	56.8	108.1	113.9	5.7	5.3%
Unmtr	Tweed	100	3.67	0.97	0.43	0.31	1.71	5.4	8.46	2.00	0.31	(0.06)	2.25	10.7	0.93	0.62	0.7	1.055	2.3	100	-	5.3	13.0	18.3	5.3	41.1%
		250	3.67	0.97	0.43	0.31	1.71	7.9	8.46	2.00	0.31	(0.06)	2.25	14.1	0.93	0.62	0.70	1.055	5.8	250	-	13.2	27.0	33.1	6.1	22.8%
		500	3.67	0.97	0.43	0.31	1.71	12.2	8.46	2.00	0.31	(0.06)	2.25	19.7	0.93	0.62	0.70	1.055	11.7	500	-	26.4	50.3	57.8	7.5	14.9%
		750	3.67	0.97	0.43	0.31	1.71	16.5	8.46	2.00	0.31	(0.06)	2.25	25.4	0.93	0.62	0.70	1.055	17.5	600	150	41.3	75.3	84.1	8.9	11.8%
		1,000	3.67	0.97	0.43	0.31	1.71	20.8	8.46	2.00	0.31	(0.06)	2.25	31.0	0.93	0.62	0.70	1.055	23.3	600	400	56.8	100.9	111.2	10.2	10.1%
Unmtr	Wardsville	100	5.70	1.00	0.25	0.08	1.33	7.0	9.95	2.00	0.08	(0.06)	2.02	12.0	0.93	0.62	0.7	1.055	2.3	100	-	5.3	14.6	19.6	4.9	33.8%
		250	5.70	1.00	0.25	0.08	1.33	9.0	9.95	2.00	0.08	(0.06)	2.02	15.0	0.93	0.62	0.70	1.055	5.8	250	-	13.2	28.0	34.0	6.0	21.3%
		500	5.70	1.00	0.25	0.08	1.33	12.4	9.95	2.00	0.08	(0.06)	2.02	20.1	0.93	0.62	0.70	1.055	11.7	500	-	26.4	50.4	58.1	7.7	15.3%
		750	5.70	1.00	0.25	0.08	1.33	15.7	9.95	2.00	0.08	(0.06)	2.02	25.1	0.93	0.62	0.70	1.055	17.5	600	150	41.3	74.4	83.9	9.5	12.7%
		1,000	5.70	1.00	0.25	0.08	1.33	19.0	9.95	2.00	0.08	(0.06)	2.02	30.2	0.93	0.62	0.70	1.055	23.3	600	400	56.8	99.2	110.3	11.2	11.3%
Unmtr	Warkworth	100	10.20	1.52	0.46	0.35	2.33	12.5	13.83	2.00	0.35	(0.06)	2.29	16.1	0.93	0.62	0.7	1.055	2.3	100	-	5.3	20.1	23.7	3.6	17.8%
		250	10.20	1.52	0.46	0.35	2.33	16.0	13.83	2.00	0.35	(0.06)	2.29	19.6	0.93	0.62	0.70	1.055	5.8	250	-	13.2	35.0	38.6	3.5	10.1%
		500	10.20	1.52	0.46	0.35	2.33	21.9	13.83	2.00	0.35	(0.06)	2.29	25.3	0.93	0.62	0.70	1.055	11.7	500	-	26.4	59.9	63.3	3.4	5.8%
		750	10.20	1.52	0.46	0.35	2.33	27.7	13.83	2.00	0.35	(0.06)	2.29	31.0	0.93	0.62	0.70	1.055	17.5	600	150	41.3	86.4	89.8	3.4	3.9%
		1,000	10.20	1.52	0.46	0.35	2.33	33.5	13.83	2.00	0.35	(0.06)	2.29	36.8	0.93	0.62	0.70	1.055	23.3	600	400	56.8	113.7	116.9	3.3	2.9%

New Rate Class: Gse - Unmetered

Total Bill Impacts of Proposed Distribution Rates [old RTSR+TLF]: Threshold of 600 kWhs

600.0

Classes		Scenario	May 2007 Incl Rate Riders						May 2008 Incl Rate Riders						Non-Dx Compoent				Other Reg	Commodity Bands			Existing	New	$ Incr	% Incr
			Existing Dx Rates					Existing Dx	New Dx Rates					New Dx	RTSR old	WMSC	DRC	TLF old	Old	Band 1	Band 2	Old	Total Bill	Total Bill	Total Bill	Total Bill
																				5.0	5.9					
New Class	Old Class	kWh	SrChg	base	Rider1	Rider2	VarChg	[$/month]	SrChg	base	Rider2	Rider3	VarChg	[$/month]	c/kWh	c/kWh	c/kWh		$	kWhs	kWhs	Total $	[$/month]	[$/month]	[$/month]	%
			[$/cust]	[c/kWh]	[c/kWh]	[c/kWh]	[c/kWh]		[$/cust]	[c/kWh]	[c/kWh]	[c/kWh]	[c/kWh]													
Unmtr	West Elgin	100	7.23	0.70	0.17	0.07	0.94	8.2	11.57	2.00	0.07	(0.06)	2.01	13.6	0.93	0.62	0.7	1.055	2.3	100	-	5.3	15.8	21.2	5.4	34.3%
		250	7.23	0.70	0.17	0.07	0.94	9.6	11.57	2.00	0.07	(0.06)	2.01	16.6	0.93	0.62	0.70	1.055	5.8	250	-	13.2	28.6	35.6	7.0	24.6%
		500	7.23	0.70	0.17	0.07	0.94	11.9	11.57	2.00	0.07	(0.06)	2.01	21.6	0.93	0.62	0.70	1.055	11.7	500	-	26.4	50.0	59.7	9.7	19.4%
		750	7.23	0.70	0.17	0.07	0.94	14.3	11.57	2.00	0.07	(0.06)	2.01	26.7	0.93	0.62	0.70	1.055	17.5	600	150	41.3	73.1	85.4	12.4	17.0%
		1,000	7.23	0.70	0.17	0.07	0.94	16.6	11.57	2.00	0.07	(0.06)	2.01	31.7	0.93	0.62	0.70	1.055	23.3	600	400	56.8	96.8	111.9	15.1	15.6%
Unmtr	Whitchurch Stouf	100	10.46	0.93	0.11	0.04	1.08	11.5	13.76	2.00	0.04	(0.06)	1.98	15.7	0.93	0.62	0.7	1.055	2.3	100	-	5.3	19.1	23.4	4.2	22.0%
		250	10.46	0.93	0.11	0.04	1.08	13.2	13.76	2.00	0.04	(0.06)	1.98	18.7	0.93	0.62	0.70	1.055	5.8	250	-	13.2	32.2	37.7	5.6	17.3%
		500	10.46	0.93	0.11	0.04	1.08	15.9	13.76	2.00	0.04	(0.06)	1.98	23.7	0.93	0.62	0.70	1.055	11.7	500	-	26.4	53.9	61.7	7.8	14.5%
		750	10.46	0.93	0.11	0.04	1.08	18.6	13.76	2.00	0.04	(0.06)	1.98	28.6	0.93	0.62	0.70	1.055	17.5	600	150	41.3	77.3	87.4	10.1	13.0%
		1,000	10.46	0.93	0.11	0.04	1.08	21.3	13.76	2.00	0.04	(0.06)	1.98	33.6	0.93	0.62	0.70	1.055	23.3	600	400	56.8	101.4	113.8	12.3	12.2%
Unmtr	Wiarton	100	11.42	1.89	0.19	0.09	2.17	13.6	14.52	2.00	0.09	(0.06)	2.03	16.6	0.93	0.62	0.7	1.055	2.3	100	-	5.3	21.2	24.2	3.0	14.0%
		250	11.42	1.89	0.19	0.09	2.17	16.8	14.52	2.00	0.09	(0.06)	2.03	19.6	0.93	0.62	0.70	1.055	5.8	250	-	13.2	35.9	38.6	2.8	7.7%
		500	11.42	1.89	0.19	0.09	2.17	22.3	14.52	2.00	0.09	(0.06)	2.03	24.7	0.93	0.62	0.70	1.055	11.7	500	-	26.4	60.3	62.7	2.4	4.0%
		750	11.42	1.89	0.19	0.09	2.17	27.7	14.52	2.00	0.09	(0.06)	2.03	29.8	0.93	0.62	0.70	1.055	17.5	600	150	41.3	86.5	88.5	2.1	2.4%
		1,000	11.42	1.89	0.19	0.09	2.17	33.1	14.52	2.00	0.09	(0.06)	2.03	34.9	0.93	0.62	0.70	1.055	23.3	600	400	56.8	113.3	115.0	1.7	1.5%
Unmtr	Woodville	100	7.98	1.57	0.67	0.48	2.72	10.7	11.38	2.00	0.48	(0.06)	2.42	13.8	0.93	0.62	0.7	1.055	2.3	100	-	5.3	18.3	21.4	3.1	17.0%
		250	7.98	1.57	0.67	0.48	2.72	14.8	11.38	2.00	0.48	(0.06)	2.42	17.4	0.93	0.62	0.70	1.055	5.8	250	-	13.2	33.8	36.5	2.7	7.9%
		500	7.98	1.57	0.67	0.48	2.72	21.6	11.38	2.00	0.48	(0.06)	2.42	23.5	0.93	0.62	0.70	1.055	11.7	500	-	26.4	59.6	61.5	1.9	3.2%
		750	7.98	1.57	0.67	0.48	2.72	28.4	11.38	2.00	0.48	(0.06)	2.42	29.6	0.93	0.62	0.70	1.055	17.5	600	150	41.3	87.2	88.3	1.2	1.4%
		1,000	7.98	1.57	0.67	0.48	2.72	35.2	11.38	2.00	0.48	(0.06)	2.42	35.6	0.93	0.62	0.70	1.055	23.3	600	400	56.8	115.3	115.8	0.4	0.4%
Unmtr	Wyoming	100	8.22	1.45	0.16	0.07	1.68	9.9	12.32	2.00	0.07	(0.06)	2.01	14.3	0.93	0.62	0.7	1.055	2.3	100	-	5.3	17.5	21.9	4.4	25.3%
		250	8.22	1.45	0.16	0.07	1.68	12.4	12.32	2.00	0.07	(0.06)	2.01	17.4	0.93	0.62	0.70	1.055	5.8	250	-	13.2	31.4	36.4	4.9	15.7%
		500	8.22	1.45	0.16	0.07	1.68	16.6	12.32	2.00	0.07	(0.06)	2.01	22.4	0.93	0.62	0.70	1.055	11.7	500	-	26.4	54.7	60.4	5.8	10.6%
		750	8.22	1.45	0.16	0.07	1.68	20.8	12.32	2.00	0.07	(0.06)	2.01	27.4	0.93	0.62	0.70	1.055	17.5	600	150	41.3	79.6	86.2	6.6	8.3%
		1,000	8.22	1.45	0.16	0.07	1.68	25.0	12.32	2.00	0.07	(0.06)	2.01	32.5	0.93	0.62	0.70	1.055	23.3	600	400	56.8	105.2	112.6	7.4	7.1%

New Rate Class: Gse - Unmetered

Total Bill Impacts of Proposed Distribution Rates [old RTSR+TLF]: Threshold of 600 kWhs

Classes		Scenario	May 2007 Incl Rate Riders						May 2008 Incl Rate Riders						Non-Dx Compoent				Other Reg	Commodity Bands	600.0		Existing	New	$ Incr	% Incr
			Existing Dx Rates					Existing Dx	New Dx Rates					New Dx	RTSR old	WMSC	DRC	TLF old	Old	Band 1	Band 2	Old	Total Bill	Total Bill	Total Bill	Total Bill
																				5.0	5.9					
New Class	Old Class	kWh	SrChg [$/cust]	base [c/kWh]	Rider1 [c/kWh]	Rider2 [c/kWh]	VarChg [c/kWh]	[$/month]	SrChg [$/cust]	base [c/kWh]	Rider2 [c/kWh]	Rider3 [c/kWh]	VarChg [c/kWh]	[$/month]	c/kWh	c/kWh	c/kWh		$	kWhs	kWhs	Total $	[$/month]	[$/month]	[$/month]	%
Unmtr	**Terrace Bay**	100	**20.53**	**1.29**	**0.82**		**2.11**	22.6	**21.25**	**2.00**		**(0.06)**	**1.94**	23.2	**0.47**	0.62	0.7	1.043	1.8	100	-	5.2	29.7	30.2	0.5	1.8%
		250	20.53	1.29	0.82	-	2.11	25.8	21.25	2.00	-	(0.06)	1.94	26.1	0.47	0.62	0.70	1.043	4.6	250	-	13.0	43.4	43.7	0.3	0.7%
		500	20.53	1.29	0.82	-	2.11	31.1	21.25	2.00	-	(0.06)	1.94	31.0	0.47	0.62	0.70	1.043	9.2	500	-	26.1	66.3	66.2	(0.1)	-0.2%
		750	20.53	1.29	0.82	-	2.11	36.4	21.25	2.00	-	(0.06)	1.94	35.8	0.47	0.62	0.70	1.043	13.8	600	150	40.7	90.9	90.3	(0.5)	-0.6%
		1,000	20.53	1.29	0.82	-	2.11	41.6	21.25	2.00	-	(0.06)	1.94	40.7	0.47	0.62	0.70	1.043	18.4	600	400	56.1	116.1	115.2	(1.0)	-0.8%

New Rate Class: DGen

Total Bill Impacts of Proposed Distribution Rates [old RTSR+TLF]: Threshold of 750 kWhs

Classes		Scenario			May 2007 Incl Rate Riders						May 2008 Incl Rate Riders						Non-Dx Compoent				Other Reg	Commodity Bands 750.0			Existing	New	$ Incr	% Incr
					Existing Dx Rates					Existing Dx	New Dx Rates					New Dx	RTSR old	WMSC	DRC	TLF old	Old	Band 1	Band 2	Old	Total Bill	Total Bill	Total Bill	Total Bill
																						5.0	5.9					
New Class	Old Class	kWh	kW	LF	SrChg	base	Rider1	Rider2	VarChg	[$/month]	SrChg	base	Rider2	Rider3	VarChg	[$/month]	$/kW	c/kWh	c/kWh		$	kWhs	kWhs	Total $	[$/month]	[$/month]	[$/month]	%
					[$/cust]	[$/kW]	[$/kW]	[$/kW]	[$/kW]		[$/cust]	[$/kW]	[$/kW]	[$/kW]	[$/kW]													
Dgen	G3	5,000	10	69%	46.78	9.91	0.08	0.15	10.14	148.2	36.66	7.07	0.15	(0.04)	7.18	108.4	2.75	0.62	0.7	1.061	97.1	750	4,250	306.2	551.5	511.8	(39.76)	-7.2%
	D-billed	5,000	20	35%	46.78	9.91	0.08	0.15	10.14	249.6	36.66	7.07	0.15	(0.04)	7.18	180.2	2.75	0.62	0.7	1.061	126.3	750	4,250	306.2	682.1	612.7	(69.40)	-10.2%
		5,000	30	23%	46.78	9.91	0.08	0.15	10.14	351.0	36.66	7.07	0.15	(0.04)	7.18	251.9	2.75	0.62	0.7	1.061	155.5	750	4,250	306.2	812.7	713.7	(99.05)	-12.2%
		5,000	40	17%	46.78	9.91	0.08	0.15	10.14	452.4	36.66	7.07	0.15	(0.04)	7.18	323.7	2.75	0.62	0.7	1.061	184.7	750	4,250	306.2	943.3	814.6	(128.69)	-13.6%
		5,000	50	14%	46.78	9.91	0.08	0.15	10.14	553.8	36.66	7.07	0.15	(0.04)	7.18	395.4	2.75	0.62	0.7	1.061	213.9	750	4,250	306.2	1,073.9	915.6	(158.33)	-14.7%
		5,000	60	12%	46.78	9.91	0.08	0.15	10.14	655.2	36.66	7.07	0.15	(0.04)	7.18	467.2	2.75	0.62	0.7	1.061	243.1	750	4,250	306.2	1,204.5	1,016.5	(187.98)	-15.6%
		35,000	90	54%	46.78	9.91	0.08	0.15	10.14	956.7	36.66	7.07	0.15	(0.04)	7.18	680.6	2.75	0.62	0.7	1.061	737.2	750	34,250	2,184.2	3,878.1	3,602.0	(276.11)	-7.1%
					[$/cust]	[$/kW]	[$/kW]	[$/kW]	[$/kW]																			
Dgen	T	5,000	10	69%	261.54	8.16	0.04	0.09	8.29	344.4	36.66	7.07	0.09	(0.04)	7.12	107.8	2.82	0.62	0.7	1.061	97.8	750	4,250	306.2	748.5	511.8	(236.62)	-31.6%
	D-billed	5,000	20	35%	261.54	8.16	0.04	0.09	8.29	427.3	36.66	7.07	0.09	(0.04)	7.12	179.0	2.82	0.62	0.70	1.061	127.7	750	4,250	306.2	861.3	612.9	(248.36)	-28.8%
		5,000	30	23%	261.54	8.16	0.04	0.09	8.29	510.2	36.66	7.07	0.09	(0.04)	7.12	250.1	2.82	0.62	0.70	1.061	157.6	750	4,250	306.2	974.0	713.9	(260.11)	-26.7%
		5,000	40	17%	261.54	8.16	0.04	0.09	8.29	593.1	36.66	7.07	0.09	(0.04)	7.12	321.3	2.82	0.62	0.70	1.061	187.4	750	4,250	306.2	1,086.8	815.0	(271.85)	-25.0%
		5,000	50	14%	261.54	8.16	0.04	0.09	8.29	676.0	36.66	7.07	0.09	(0.04)	7.12	392.4	2.82	0.62	0.70	1.061	217.3	750	4,250	306.2	1,199.6	916.0	(283.59)	-23.6%
		5,000	60	12%	261.54	8.16	0.04	0.09	8.29	758.9	36.66	7.07	0.09	(0.04)	7.12	463.6	2.82	0.62	0.70	1.061	247.2	750	4,250	306.2	1,312.4	1,017.1	(295.34)	-22.5%
		7,700	##	5%	261.54	8.16	0.04	0.09	8.29	1,920.5	36.66	7.07	0.09	(0.04)	7.12	1,460.6	2.82	0.62	0.70	1.061	702.7	750	6,950	475.3	3,098.5	2,638.6	(459.88)	-14.8%
					[$/cust]	[c/kWh]	[c/kWh]	[c/kWh]	[c/kWh]								[c/kWh]											
Dgen	G3	5,000	10	69%	46.78	3.07	0.02	0.05	3.14	203.8	36.66	7.07	0.15	(0.04)	7.18	108.4	0.85	0.62	0.7	1.061	113.0	750	4,250	306.2	623.0	527.6	(95.36)	-15.3%
	E-billed	5,000	20	35%	46.78	3.07	0.02	0.05	3.14	203.8	36.66	7.07	0.15	(0.04)	7.18	180.2	0.85	0.62	0.7	1.061	113.0	750	4,250	306.2	623.0	599.4	(23.60)	-3.8%
		5,000	30	23%	46.78	3.07	0.02	0.05	3.14	203.8	36.66	7.07	0.15	(0.04)	7.18	251.9	0.85	0.62	0.7	1.061	113.0	750	4,250	306.2	623.0	671.2	48.15	7.7%
		5,000	40	17%	46.78	3.07	0.02	0.05	3.14	203.8	36.66	7.07	0.15	(0.04)	7.18	323.7	0.85	0.62	0.7	1.061	113.0	750	4,250	306.2	623.0	742.9	119.91	19.2%
		5,000	50	14%	46.78	3.07	0.02	0.05	3.14	203.8	36.66	7.07	0.15	(0.04)	7.18	395.4	0.85	0.62	0.7	1.061	113.0	750	4,250	306.2	623.0	814.7	191.67	30.8%
		5,000	60	12%	46.78	3.07	0.02	0.05	3.14	203.8	36.66	7.07	0.15	(0.04)	7.18	467.2	0.85	0.62	0.7	1.061	113.0	750	4,250	306.2	623.0	886.4	263.42	42.3%
		802	8	14%	46.78	3.07	0.02	0.05	3.14	72.0	36.66	7.07	0.15	(0.04)	7.18	95.2	0.85	0.62	0.7	1.061	18.1	750	52	43.5	133.5	156.8	23.24	17.4%
					[$/cust]	[c/kWh]	[c/kWh]	[c/kWh]	[c/kWh]								[c/kWh]											
Dgen	T	5,000	10	69%	261.54	2.43	0.01	0.03	2.47	385.0	36.66	7.07	0.09	(0.04)	7.12	107.8	0.84	0.62	0.7	1.061	112.5	750	4,250	306.2	803.7	526.5	(277.22)	-34.5%
	E-billed	5,000	20	35%	261.54	2.43	0.01	0.03	2.47	385.0	36.66	7.07	0.09	(0.04)	7.12	179.0	0.84	0.62	0.70	1.061	112.5	750	4,250	306.2	803.7	597.7	(206.06)	-25.6%
		5,000	30	23%	261.54	2.43	0.01	0.03	2.47	385.0	36.66	7.07	0.09	(0.04)	7.12	250.1	0.84	0.62	0.70	1.061	112.5	750	4,250	306.2	803.7	668.8	(134.91)	-16.8%
		5,000	40	17%	261.54	2.43	0.01	0.03	2.47	385.0	36.66	7.07	0.09	(0.04)	7.12	321.3	0.84	0.62	0.70	1.061	112.5	750	4,250	306.2	803.7	740.0	(63.75)	-7.9%
		5,000	50	14%	261.54	2.43	0.01	0.03	2.47	385.0	36.66	7.07	0.09	(0.04)	7.12	392.4	0.84	0.62	0.70	1.061	112.5	750	4,250	306.2	803.7	811.1	7.41	0.9%
		5,000	60	12%	261.54	2.43	0.01	0.03	2.47	385.0	36.66	7.07	0.09	(0.04)	7.12	463.6	0.84	0.62	0.70	1.061	112.5	750	4,250	306.2	803.7	882.3	78.56	9.8%
		846	26	5%	261.54	2.43	0.01	0.03	2.47	282.4	36.66	7.07	0.09	(0.04)	7.12	221.4	0.84	0.62	0.70	1.061	19.0	750	96	46.2	347.7	286.6	(61.05)	-17.6%
					[$/cust]	[c/kWh]	[c/kWh]	[c/kWh]	[c/kWh]								[c/kWh]											
Dgen	Eganville	5,000	10	69%	21.35	2.32	0.17	0.12	2.61	151.9	36.66	7.07	0.37	(0.04)	7.40	110.6	0.93	0.62	0.7	1.0545	116.7	750	4,250	304.3	572.9	531.7	(41.23)	-7.2%
	E-billed	5,000	20	35%	21.35	2.32	0.17	0.12	2.61	151.9	36.66	7.07	0.37	(0.04)	7.40	184.6	0.93	0.62	0.70	1.0545	116.7	750	4,250	304.3	572.9	605.6	32.73	5.7%
		5,000	30	23%	21.35	2.32	0.17	0.12	2.61	151.9	36.66	7.07	0.37	(0.04)	7.40	258.5	0.93	0.62	0.70	1.0545	116.7	750	4,250	304.3	572.9	679.6	106.68	18.6%
		5,000	40	17%	21.35	2.32	0.17	0.12	2.61	151.9	36.66	7.07	0.37	(0.04)	7.40	332.5	0.93	0.62	0.70	1.0545	116.7	750	4,250	304.3	572.9	753.5	180.64	31.5%
		5,000	50	14%	21.35	2.32	0.17	0.12	2.61	151.9	36.66	7.07	0.37	(0.04)	7.40	406.4	0.93	0.62	0.70	1.0545	116.7	750	4,250	304.3	572.9	827.5	254.60	44.4%
		5,000	60	12%	21.35	2.32	0.17	0.12	2.61	151.9	36.66	7.07	0.37	(0.04)	7.40	480.4	0.93	0.62	0.70	1.0545	116.7	750	4,250	304.3	572.9	901.5	328.55	57.3%
		6	1	1%	21.35	2.32	0.17	0.12	2.61	21.5	36.66	7.07	0.37	(0.04)	7.40	45.5	0.93	0.62	0.70	1.0545	0.1	6	-	0.3	22.0	46.0	24.01	109.3%

New Rate Class: GSe - Low Use Secondary

Total Bill Impacts of Proposed Distribution Rates [old RTSR+TLF]: Threshold of 750 kWhs

Classes		Scenario	May 2007 Incl Rate Riders						May 2008 Incl Rate Riders						Non-Dx Compoent				Other Reg	Commodity Bands			Existing	New	$ Incr	% Incr
			Existing Dx Rates					Existing Dx	New Dx Rates					New Dx	RTSR old	WMSC	DRC	TLF old	Old	Band 1	Band 2	Old	Total Bill	Total Bill	Total Bill	Total Bill
																				600.0						
																				5.0	5.9					
New Class	Old Class	kWh	$/cust	base	Rider1	Rider2	VarChg	[$/month]	$/cust	base	Rider2	Rider3	VarChg	[$/month]	c/kWh	c/kWh	c/kWh		$	kWhs	kWhs	Total $	[$/month]	[$/month]	[$/month]	%
GSe	**F1**	50	**-**	**2.37**	**0.08**	**0.10**	**2.55**	1.3	**6.19**	**3.39**	**0.09**	**(0.06)**	**3.42**	7.9	**0.89**	0.62	0.7	**1.092**	1.2	50	-	2.7	5.2	11.8	6.6	128.0%
		75	-	2.37	0.08	0.10	2.55	1.9	6.19	3.39	0.09	(0.06)	3.42	8.8	0.89	0.62	0.7	1.092	1.8	75	-	4.1	7.8	14.6	6.8	88.1%
	F1	100	-	2.37	0.08	0.10	2.55	2.6	6.19	3.39	0.09	(0.06)	3.42	9.6	0.89	0.62	0.7	1.092	2.3	100	-	5.5	10.4	17.4	7.1	68.2%
		125	-	2.37	0.08	0.10	2.55	3.2	6.19	3.39	0.09	(0.06)	3.42	10.5	0.89	0.62	0.7	1.092	2.9	125	-	6.8	12.9	20.2	7.3	56.2%
		150	-	2.37	0.08	0.10	2.55	3.8	6.19	3.39	0.09	(0.06)	3.42	11.3	0.89	0.62	0.7	1.092	3.5	150	-	8.2	15.5	23.0	7.5	48.3%
		200	-	2.37	0.08	0.10	2.55	5.1	6.19	3.39	0.09	(0.06)	3.42	13.0	0.89	0.62	0.7	1.092	4.7	200	-	10.9	20.7	28.7	7.9	38.3%
		400	-	2.37	0.08	0.10	2.55	10.2	6.19	3.39	0.09	(0.06)	3.42	19.9	0.89	0.62	0.7	1.092	9.4	400	-	21.8	41.4	51.1	9.7	23.3%
GSe	**F3**	50	**-**	**3.20**	**0.02**	**0.05**	**3.27**	1.6	**6.19**	**3.39**	**0.09**	**(0.06)**	**3.42**	7.9	**0.85**	0.62	0.7	**1.061**	1.1	50	-	2.7	5.4	11.7	6.3	115.7%
		75	-	3.20	0.02	0.05	3.27	2.5	6.19	3.39	0.09	(0.06)	3.42	8.8	0.85	0.62	0.70	1.061	1.7	75	-	4.0	8.1	14.4	6.3	77.6%
	F3, G3	100	-	3.20	0.02	0.05	3.27	3.3	6.19	3.39	0.09	(0.06)	3.42	9.6	0.85	0.62	0.70	1.061	2.3	100	-	5.3	10.8	17.2	6.3	58.5%
		125	-	3.20	0.02	0.05	3.27	4.1	6.19	3.39	0.09	(0.06)	3.42	10.5	0.85	0.62	0.70	1.061	2.8	125	-	6.6	13.5	19.9	6.4	47.1%
		150	-	3.20	0.02	0.05	3.27	4.9	6.19	3.39	0.09	(0.06)	3.42	11.3	0.85	0.62	0.70	1.061	3.4	150	-	8.0	16.3	22.7	6.4	39.5%
		200	-	3.20	0.02	0.05	3.27	6.5	6.19	3.39	0.09	(0.06)	3.42	13.0	0.85	0.62	0.70	1.061	4.5	200	-	10.6	21.7	28.2	6.5	30.0%
		400	-	3.20	0.02	0.05	3.27	13.1	6.19	3.39	0.09	(0.06)	3.42	19.9	0.85	0.62	0.70	1.061	9.0	400	-	21.2	43.3	50.1	6.8	15.7%
GSe	**G1**	50	**-**	**3.25**	**0.09**	**0.09**	**3.43**	1.7	**6.19**	**3.39**	**0.09**	**(0.06)**	**3.42**	7.9	**0.86**	0.62	0.7	**1.092**	1.2	50	-	2.7	5.6	11.8	6.2	110.5%
		75	-	3.25	0.09	0.09	3.43	2.6	6.19	3.39	0.09	(0.06)	3.42	8.8	0.86	0.62	0.70	1.092	1.7	75	-	4.1	8.4	14.6	6.2	73.6%
	R1,R2,R3	100	-	3.25	0.09	0.09	3.43	3.4	6.19	3.39	0.09	(0.06)	3.42	9.6	0.86	0.62	0.70	1.092	2.3	100	-	5.5	11.2	17.4	6.2	55.2%
	R4,G1	125	-	3.25	0.09	0.09	3.43	4.3	6.19	3.39	0.09	(0.06)	3.42	10.5	0.86	0.62	0.70	1.092	2.9	125	-	6.8	14.0	20.2	6.2	44.1%
		150	-	3.25	0.09	0.09	3.43	5.1	6.19	3.39	0.09	(0.06)	3.42	11.3	0.86	0.62	0.70	1.092	3.5	150	-	8.2	16.8	23.0	6.2	36.8%
		200	-	3.25	0.09	0.09	3.43	6.9	6.19	3.39	0.09	(0.06)	3.42	13.0	0.86	0.62	0.70	1.092	4.6	200	-	10.9	22.4	28.6	6.2	27.5%
		400	-	3.25	0.09	0.09	3.43	13.7	6.19	3.39	0.09	(0.06)	3.42	19.9	0.86	0.62	0.70	1.092	9.3	400	-	21.8	44.8	51.0	6.2	13.7%

New Rate Class: UR

Total Bill Impacts of Proposed Distribution Rates[new RTSR+TLF]: Threshold of 600 kWhs

Classes		Scenario	May 2007 Incl Rate Riders						May 2008 Incl Rate Riders						Non-Dx Compoent				Other Reg	Commodity Bands			Existing	New	$ Incr	% Incr
			Existing Dx Rates					Existing Dx	New Dx Rates					New Dx	RTSR new	WMSC	DRC	TLF new	New	Band 1	Band 2	New	Total Bill	Total Bill	Total Bill	Total Bill
																				600.0						
																				5.0	5.9					
New Class	Old Class	kWh	SrChg	base	Rider1	Rider2	VarChg	[$/month]	SrChg	base	Rider2	Rider3	VarChg	[$/month]	c/kWh	c/kWh	c/kWh		$	kWhs	kWhs	$	[$/month]	[$/month]	[$/month]	%
UR	UR	100	14.32	1.83	0.20	0.05	2.08	16.4	14.00	2.44	0.05	(0.02)	2.47	16.5	0.92	0.62	0.7	1.078	2.4	100	-	5.4	24.3	24.2	(0.0)	-0.2%
		250	14.32	1.83	0.20	0.05	2.08	19.5	14.00	2.44	0.05	(0.02)	2.47	20.2	0.92	0.62	0.7	1.078	5.9	250	-	13.5	39.2	39.5	0.4	0.9%
		500	14.32	1.83	0.20	0.05	2.08	24.7	14.00	2.44	0.05	(0.02)	2.47	26.3	0.92	0.62	0.7	1.078	11.8	500	-	27.0	64.0	65.1	1.0	1.6%
		750	14.32	1.83	0.20	0.05	2.08	29.9	14.00	2.44	0.05	(0.02)	2.47	32.5	0.92	0.62	0.7	1.078	17.7	600	150	42.3	90.9	92.5	1.6	1.8%
		1,000	14.32	1.83	0.20	0.05	2.08	35.1	14.00	2.44	0.05	(0.02)	2.47	38.7	0.92	0.62	0.7	1.078	23.6	600	400	58.2	118.2	120.5	2.3	1.9%
		1,500	14.32	1.83	0.20	0.05	2.08	45.5	14.00	2.44	0.05	(0.02)	2.47	51.0	0.92	0.62	0.7	1.078	35.4	600	900	90.0	172.8	176.4	3.6	2.1%
		2,000	14.32	1.83	0.20	0.05	2.08	55.9	14.00	2.44	0.05	(0.02)	2.47	63.3	0.92	0.62	0.7	1.078	47.2	600	1,400	121.8	227.4	232.3	4.9	2.1%
UR	R1	100	19.04	2.38	0.15	0.07	2.60	21.6	14.00	2.44	0.05	(0.02)	2.47	16.5	0.92	0.62	0.7	1.078	2.4	100	-	5.4	29.5	24.2	(5.3)	-17.9%
		250	19.04	2.38	0.15	0.07	2.60	25.5	14.00	2.44	0.05	(0.02)	2.47	20.2	0.92	0.62	0.70	1.078	5.9	250	-	13.5	45.2	39.5	(5.7)	-12.5%
		500	19.04	2.38	0.15	0.07	2.60	32.0	14.00	2.44	0.05	(0.02)	2.47	26.3	0.92	0.62	0.70	1.078	11.8	500	-	27.0	71.4	65.1	(6.3)	-8.8%
		750	19.04	2.38	0.15	0.07	2.60	38.5	14.00	2.44	0.05	(0.02)	2.47	32.5	0.92	0.62	0.70	1.078	17.7	600	150	42.3	99.5	92.5	(7.0)	-7.0%
		1,000	19.04	2.38	0.15	0.07	2.60	45.0	14.00	2.44	0.05	(0.02)	2.47	38.7	0.92	0.62	0.70	1.078	23.6	600	400	58.2	128.1	120.5	(7.6)	-6.0%
		1,500	19.04	2.38	0.15	0.07	2.60	58.0	14.00	2.44	0.05	(0.02)	2.47	51.0	0.92	0.62	0.70	1.078	35.4	600	900	90.0	185.3	176.4	(8.9)	-4.8%
		2,000	19.04	2.38	0.15	0.07	2.60	71.0	14.00	2.44	0.05	(0.02)	2.47	63.3	0.92	0.62	0.70	1.078	47.2	600	1,400	121.8	242.6	232.3	(10.2)	-4.2%
UR	R2	100	29.22	1.94	0.12	0.13	2.19	31.4	14.00	2.44	0.05	(0.02)	2.47	16.5	0.92	0.62	0.7	1.078	2.4	100	-	5.4	39.3	24.2	(15.1)	-38.3%
		250	29.22	1.94	0.12	0.13	2.19	34.7	14.00	2.44	0.05	(0.02)	2.47	20.2	0.92	0.62	0.70	1.078	5.9	250	-	13.5	54.4	39.5	(14.8)	-27.3%
		500	29.22	1.94	0.12	0.13	2.19	40.2	14.00	2.44	0.05	(0.02)	2.47	26.3	0.92	0.62	0.70	1.078	11.8	500	-	27.0	79.5	65.1	(14.4)	-18.1%
		750	29.22	1.94	0.12	0.13	2.19	45.6	14.00	2.44	0.05	(0.02)	2.47	32.5	0.92	0.62	0.70	1.078	17.7	600	150	42.3	106.6	92.5	(14.1)	-13.2%
		1,000	29.22	1.94	0.12	0.13	2.19	51.1	14.00	2.44	0.05	(0.02)	2.47	38.7	0.92	0.62	0.70	1.078	23.6	600	400	58.2	134.2	120.5	(13.7)	-10.2%
		1,500	29.22	1.94	0.12	0.13	2.19	62.1	14.00	2.44	0.05	(0.02)	2.47	51.0	0.92	0.62	0.70	1.078	35.4	600	900	90.0	189.4	176.4	(13.0)	-6.9%
		2,000	29.22	1.94	0.12	0.13	2.19	73.0	14.00	2.44	0.05	(0.02)	2.47	63.3	0.92	0.62	0.70	1.078	47.2	600	1,400	121.8	244.5	232.3	(12.2)	-5.0%
UR	F1	100	28.61	2.24	0.08	0.10	2.42	31.0	14.00	2.44	0.05	(0.02)	2.47	16.5	0.92	0.62	0.7	1.078	2.4	100	-	5.4	38.8	24.2	(14.6)	-37.7%
		250	28.61	2.24	0.08	0.10	2.42	34.7	14.00	2.44	0.05	(0.02)	2.47	20.2	0.92	0.62	0.70	1.078	5.9	250	-	13.5	54.2	39.5	(14.6)	-27.0%
		500	28.61	2.24	0.08	0.10	2.42	40.7	14.00	2.44	0.05	(0.02)	2.47	26.3	0.92	0.62	0.70	1.078	11.8	500	-	27.0	79.8	65.1	(14.7)	-18.4%
		750	28.61	2.24	0.08	0.10	2.42	46.8	14.00	2.44	0.05	(0.02)	2.47	32.5	0.92	0.62	0.70	1.078	17.7	600	150	42.3	107.3	92.5	(14.8)	-13.8%
		1,000	28.61	2.24	0.08	0.10	2.42	52.8	14.00	2.44	0.05	(0.02)	2.47	38.7	0.92	0.62	0.70	1.078	23.6	600	400	58.2	135.3	120.5	(14.9)	-11.0%
		1,500	28.61	2.24	0.08	0.10	2.42	64.9	14.00	2.44	0.05	(0.02)	2.47	51.0	0.92	0.62	0.70	1.078	35.4	600	900	90.0	191.4	176.4	(15.0)	-7.8%
		2,000	28.61	2.24	0.08	0.10	2.42	77.0	14.00	2.44	0.05	(0.02)	2.47	63.3	0.92	0.62	0.70	1.078	47.2	600	1,400	121.8	247.4	232.3	(15.1)	-6.1%

New Rate Class: UR

Total Bill Impacts of Proposed Distribution Rates[new RTSR+TLF]: Threshold of 600 kWhs

Classes		Scenario	May 2007 Incl Rate Riders						May 2008 Incl Rate Riders						Non-Dx Compoent				Other Reg	Commodity Bands			Existing	New	$ Incr	% Incr
			Existing Dx Rates					Existing Dx	New Dx Rates					New Dx	RTSR new	WMSC	DRC	TLF new	New	Band 1	Band 2	New	Total Bill	Total Bill	Total Bill	Total Bill
																				5.0	5.9					
																				600.0						
New Class	Old Class	kWh	SrChg	base	Rider1	Rider2	VarChg	[$/month]	SrChg	base	Rider2	Rider3	VarChg	[$/month]	c/kWh	c/kWh	c/kWh		$	kWhs	kWhs	$	[$/month]	[$/month]	[$/month]	%
UR	Arnprior	100	**11.54**	**1.47**	**0.49**	**0.18**	**2.14**	13.7	**11.70**	**2.40**	**0.18**	**(0.02)**	**2.55**	14.2	**0.92**	0.62	0.7	**1.078**	2.4	100	-	5.4	21.4	22.0	0.6	2.9%
		250	11.54	1.47	0.49	0.18	2.14	16.9	11.70	2.40	0.18	(0.02)	2.55	18.1	0.92	0.62	0.70	1.078	5.9	250	-	13.5	36.1	37.4	1.3	3.6%
		500	11.54	1.47	0.49	0.18	2.14	22.2	11.70	2.40	0.18	(0.02)	2.55	24.4	0.92	0.62	0.70	1.078	11.8	500	-	27.0	60.7	63.2	2.5	4.0%
		750	11.54	1.47	0.49	0.18	2.14	27.6	11.70	2.40	0.18	(0.02)	2.55	30.8	0.92	0.62	0.70	1.078	17.7	600	150	42.3	87.1	90.8	3.8	4.3%
		1,000	11.54	1.47	0.49	0.18	2.14	32.9	11.70	2.40	0.18	(0.02)	2.55	37.2	0.92	0.62	0.70	1.078	23.6	600	400	58.2	114.0	119.0	5.0	4.3%
		1,500	11.54	1.47	0.49	0.18	2.14	43.6	11.70	2.40	0.18	(0.02)	2.55	50.0	0.92	0.62	0.70	1.078	35.4	600	900	90.0	168.0	175.4	7.4	4.4%
		2,000	11.54	1.47	0.49	0.18	2.14	54.3	11.70	2.40	0.18	(0.02)	2.55	62.7	0.92	0.62	0.70	1.078	47.2	600	1,400	121.8	222.0	231.7	9.8	4.4%
UR	Brockville	100	**12.33**	**0.93**	**0.48**	**0.16**	**1.57**	13.9	**12.50**	**2.40**	**0.16**	**(0.02)**	**2.53**	15.0	**0.92**	0.62	0.7	**1.078**	2.4	100	-	5.4	21.6	22.8	1.2	5.4%
		250	12.33	0.93	0.48	0.16	1.57	16.3	12.50	2.40	0.16	(0.02)	2.53	18.8	0.92	0.62	0.70	1.078	5.9	250	-	13.5	35.5	38.2	2.7	7.6%
		500	12.33	0.93	0.48	0.16	1.57	20.2	12.50	2.40	0.16	(0.02)	2.53	25.2	0.92	0.62	0.70	1.078	11.8	500	-	27.0	58.7	63.9	5.2	8.9%
		750	12.33	0.93	0.48	0.16	1.57	24.1	12.50	2.40	0.16	(0.02)	2.53	31.5	0.92	0.62	0.70	1.078	17.7	600	150	42.3	83.6	91.5	7.9	9.4%
		1,000	12.33	0.93	0.48	0.16	1.57	28.0	12.50	2.40	0.16	(0.02)	2.53	37.8	0.92	0.62	0.70	1.078	23.6	600	400	58.2	109.1	119.6	10.5	9.6%
		1,500	12.33	0.93	0.48	0.16	1.57	35.9	12.50	2.40	0.16	(0.02)	2.53	50.5	0.92	0.62	0.70	1.078	35.4	600	900	90.0	160.2	175.9	15.6	9.7%
		2,000	12.33	0.93	0.48	0.16	1.57	43.7	12.50	2.40	0.16	(0.02)	2.53	63.1	0.92	0.62	0.70	1.078	47.2	600	1,400	121.8	211.3	232.1	20.8	9.8%
UR	Caledon OH 01	100	**18.52**	**0.57**	**0.42**	**0.16**	**1.15**	19.7	**16.95**	**2.15**	**0.16**	**(0.02)**	**2.29**	19.2	**0.92**	0.62	0.7	**1.078**	2.4	100	-	5.4	27.4	27.0	(0.4)	-1.4%
		250	18.52	0.57	0.42	0.16	1.15	21.4	16.95	2.15	0.16	(0.02)	2.29	22.7	0.92	0.62	0.70	1.078	5.9	250	-	13.5	40.6	42.0	1.4	3.4%
		500	18.52	0.57	0.42	0.16	1.15	24.3	16.95	2.15	0.16	(0.02)	2.29	28.4	0.92	0.62	0.70	1.078	11.8	500	-	27.0	62.8	67.1	4.3	6.9%
		750	18.52	0.57	0.42	0.16	1.15	27.1	16.95	2.15	0.16	(0.02)	2.29	34.1	0.92	0.62	0.70	1.078	17.7	600	150	42.3	86.6	94.1	7.5	8.6%
		1,000	18.52	0.57	0.42	0.16	1.15	30.0	16.95	2.15	0.16	(0.02)	2.29	39.8	0.92	0.62	0.70	1.078	23.6	600	400	58.2	111.1	121.6	10.5	9.4%
		1,500	18.52	0.57	0.42	0.16	1.15	35.8	16.95	2.15	0.16	(0.02)	2.29	51.2	0.92	0.62	0.70	1.078	35.4	600	900	90.0	160.1	176.6	16.5	10.3%
		2,000	18.52	0.57	0.42	0.16	1.15	41.5	16.95	2.15	0.16	(0.02)	2.29	62.7	0.92	0.62	0.70	1.078	47.2	600	1,400	121.8	209.1	231.7	22.5	10.8%
UR	Carleton Place	100	**14.17**	**1.79**	**0.38**	**0.15**	**2.32**	16.5	**14.04**	**2.40**	**0.15**	**(0.02)**	**2.52**	16.6	**0.92**	0.62	0.7	**1.078**	2.4	100	-	5.4	24.2	24.3	0.1	0.5%
		250	14.17	1.79	0.38	0.15	2.32	20.0	14.04	2.40	0.15	(0.02)	2.52	20.3	0.92	0.62	0.70	1.078	5.9	250	-	13.5	39.2	39.7	0.5	1.2%
		500	14.17	1.79	0.38	0.15	2.32	25.8	14.04	2.40	0.15	(0.02)	2.52	26.6	0.92	0.62	0.70	1.078	11.8	500	-	27.0	64.3	65.4	1.1	1.7%
		750	14.17	1.79	0.38	0.15	2.32	31.6	14.04	2.40	0.15	(0.02)	2.52	32.9	0.92	0.62	0.70	1.078	17.7	600	150	42.3	91.1	92.9	1.9	2.1%
		1,000	14.17	1.79	0.38	0.15	2.32	37.4	14.04	2.40	0.15	(0.02)	2.52	39.2	0.92	0.62	0.70	1.078	23.6	600	400	58.2	118.5	121.0	2.6	2.2%
		1,500	14.17	1.79	0.38	0.15	2.32	49.0	14.04	2.40	0.15	(0.02)	2.52	51.9	0.92	0.62	0.70	1.078	35.4	600	900	90.0	173.3	177.3	3.9	2.3%
		2,000	14.17	1.79	0.38	0.15	2.32	60.6	14.04	2.40	0.15	(0.02)	2.52	64.5	0.92	0.62	0.70	1.078	47.2	600	1,400	121.8	228.2	233.5	5.3	2.3%

New Rate Class: UR

Total Bill Impacts of Proposed Distribution Rates[new RTSR+TLF]: Threshold of 600 kWhs

Classes		Scenario	May 2007 Incl Rate Riders						May 2008 Incl Rate Riders						Non-Dx Compoent				Other Reg	Commodity Bands			Existing	New	$ Incr	% Incr
			Existing Dx Rates					Existing Dx	New Dx Rates					New Dx	RTSR new	WMSC	DRC	TLF new	New	Band 1	Band 2	New	Total Bill	Total Bill	Total Bill	Total Bill
																				600.0						
																				5.0	5.9					
New Class	Old Class	kWh	SrChg	base	Rider1	Rider2	VarChg	[$/month]	SrChg	base	Rider2	Rider3	VarChg	[$/month]	c/kWh	c/kWh	c/kWh		$	kWhs	kWhs	$	[$/month]	[$/month]	[$/month]	%
UR	**Dryden**	100	**14.28**	**1.65**	**0.43**	**0.18**	**2.26**	16.5	**14.01**	**2.40**	**0.18**	**(0.02)**	**2.55**	16.6	**0.92**	0.62	0.7	**1.078**	2.4	100	-	5.4	24.2	24.3	0.1	0.3%
		250	14.28	1.65	0.43	0.18	2.26	19.9	14.01	2.40	0.18	(0.02)	2.55	20.4	0.92	0.62	0.70	1.078	5.9	250	-	13.5	39.2	39.8	0.6	1.5%
		500	14.28	1.65	0.43	0.18	2.26	25.6	14.01	2.40	0.18	(0.02)	2.55	26.8	0.92	0.62	0.70	1.078	11.8	500	-	27.0	64.1	65.5	1.4	2.2%
		750	14.28	1.65	0.43	0.18	2.26	31.2	14.01	2.40	0.18	(0.02)	2.55	33.1	0.92	0.62	0.70	1.078	17.7	600	150	42.3	90.7	93.1	2.4	2.7%
		1,000	14.28	1.65	0.43	0.18	2.26	36.9	14.01	2.40	0.18	(0.02)	2.55	39.5	0.92	0.62	0.70	1.078	23.6	600	400	58.2	118.0	121.3	3.3	2.8%
		1,500	14.28	1.65	0.43	0.18	2.26	48.2	14.01	2.40	0.18	(0.02)	2.55	52.3	0.92	0.62	0.70	1.078	35.4	600	900	90.0	172.5	177.7	5.1	3.0%
		2,000	14.28	1.65	0.43	0.18	2.26	59.5	14.01	2.40	0.18	(0.02)	2.55	65.0	0.92	0.62	0.70	1.078	47.2	600	1,400	121.8	227.1	234.0	6.9	3.1%
UR	**GBE**	100	**9.68**	**0.95**	**0.46**	**0.13**	**1.54**	11.2	**10.16**	**2.35**	**0.13**	**(0.02)**	**2.46**	12.6	**0.92**	0.62	0.7	**1.078**	2.4	100	-	5.4	18.9	20.4	1.4	7.6%
		250	9.68	0.95	0.46	0.13	1.54	13.5	10.16	2.35	0.13	(0.02)	2.46	16.3	0.92	0.62	0.70	1.078	5.9	250	-	13.5	32.8	35.7	2.9	8.8%
		500	9.68	0.95	0.46	0.13	1.54	17.4	10.16	2.35	0.13	(0.02)	2.46	22.4	0.92	0.62	0.70	1.078	11.8	500	-	27.0	55.9	61.2	5.3	9.5%
		750	9.68	0.95	0.46	0.13	1.54	21.2	10.16	2.35	0.13	(0.02)	2.46	28.6	0.92	0.62	0.70	1.078	17.7	600	150	42.3	80.7	88.6	7.9	9.7%
		1,000	9.68	0.95	0.46	0.13	1.54	25.1	10.16	2.35	0.13	(0.02)	2.46	34.7	0.92	0.62	0.70	1.078	23.6	600	400	58.2	106.2	116.5	10.3	9.7%
		1,500	9.68	0.95	0.46	0.13	1.54	32.8	10.16	2.35	0.13	(0.02)	2.46	47.0	0.92	0.62	0.70	1.078	35.4	600	900	90.0	157.1	172.4	15.2	9.7%
		2,000	9.68	0.95	0.46	0.13	1.54	40.5	10.16	2.35	0.13	(0.02)	2.46	59.3	0.92	0.62	0.70	1.078	47.2	600	1,400	121.8	208.1	228.3	20.2	9.7%
UR	**Lindsay**	100	**15.81**	**1.01**	**0.41**	**0.14**	**1.56**	17.4	**14.63**	**2.40**	**0.14**	**(0.02)**	**2.51**	17.1	**0.92**	0.62	0.7	**1.078**	2.4	100	-	5.4	25.1	24.9	(0.2)	-0.7%
		250	15.81	1.01	0.41	0.14	1.56	19.7	14.63	2.40	0.14	(0.02)	2.51	20.9	0.92	0.62	0.70	1.078	5.9	250	-	13.5	39.0	40.3	1.3	3.4%
		500	15.81	1.01	0.41	0.14	1.56	23.6	14.63	2.40	0.14	(0.02)	2.51	27.2	0.92	0.62	0.70	1.078	11.8	500	-	27.0	62.1	65.9	3.8	6.1%
		750	15.81	1.01	0.41	0.14	1.56	27.5	14.63	2.40	0.14	(0.02)	2.51	33.5	0.92	0.62	0.70	1.078	17.7	600	150	42.3	87.0	93.5	6.5	7.4%
		1,000	15.81	1.01	0.41	0.14	1.56	31.4	14.63	2.40	0.14	(0.02)	2.51	39.7	0.92	0.62	0.70	1.078	23.6	600	400	58.2	112.5	121.5	9.0	8.0%
		1,500	15.81	1.01	0.41	0.14	1.56	39.2	14.63	2.40	0.14	(0.02)	2.51	52.3	0.92	0.62	0.70	1.078	35.4	600	900	90.0	163.6	177.7	14.1	8.6%
		2,000	15.81	1.01	0.41	0.14	1.56	47.0	14.63	2.40	0.14	(0.02)	2.51	64.8	0.92	0.62	0.70	1.078	47.2	600	1,400	121.8	214.6	233.9	19.2	9.0%
UR	**Perth**	100	**14.47**	**1.22**	**0.50**	**0.18**	**1.90**	16.4	**13.96**	**2.40**	**0.18**	**(0.02)**	**2.55**	16.5	**0.92**	0.62	0.7	**1.078**	2.4	100	-	5.4	24.1	24.3	0.2	0.8%
		250	14.47	1.22	0.50	0.18	1.90	19.2	13.96	2.40	0.18	(0.02)	2.55	20.3	0.92	0.62	0.70	1.078	5.9	250	-	13.5	38.5	39.7	1.2	3.2%
		500	14.47	1.22	0.50	0.18	1.90	24.0	13.96	2.40	0.18	(0.02)	2.55	26.7	0.92	0.62	0.70	1.078	11.8	500	-	27.0	62.5	65.5	3.0	4.8%
		750	14.47	1.22	0.50	0.18	1.90	28.7	13.96	2.40	0.18	(0.02)	2.55	33.1	0.92	0.62	0.70	1.078	17.7	600	150	42.3	88.2	93.1	4.9	5.5%
		1,000	14.47	1.22	0.50	0.18	1.90	33.5	13.96	2.40	0.18	(0.02)	2.55	39.5	0.92	0.62	0.70	1.078	23.6	600	400	58.2	114.6	121.3	6.7	5.8%
		1,500	14.47	1.22	0.50	0.18	1.90	43.0	13.96	2.40	0.18	(0.02)	2.55	52.2	0.92	0.62	0.70	1.078	35.4	600	900	90.0	167.3	177.6	10.3	6.2%
		2,000	14.47	1.22	0.50	0.18	1.90	52.5	13.96	2.40	0.18	(0.02)	2.55	65.0	0.92	0.62	0.70	1.078	47.2	600	1,400	121.8	220.1	234.0	13.9	6.3%

New Rate Class: UR

Total Bill Impacts of Proposed Distribution Rates[new RTSR+TLF]: Threshold of 600 kWhs

600.0

Classes		Scenario	May 2007 Incl Rate Riders						May 2008 Incl Rate Riders						Non-Dx Compoent				Other Reg	Commodity Bands			Existing	New	$ Incr	% Incr
			Existing Dx Rates					Existing Dx	New Dx Rates					New Dx	RTSR new	WMSC	DRC	TLF new	New	Band 1	Band 2	New	Total Bill	Total Bill	Total Bill	Total Bill
																				5.0	5.9					
New Class	Old Class	kWh	SrChg	base	Rider1	Rider2	VarChg	[$/month]	SrChg	base	Rider2	Rider3	VarChg	[$/month]	c/kWh	c/kWh	c/kWh		$	kWhs	kWhs	$	[$/month]	[$/month]	[$/month]	%
UR	**Quinte West**	100	**6.58**	**0.92**	**0.39**	**0.11**	**1.42**	8.0	**7.94**	**2.10**	**0.11**	**(0.02)**	**2.19**	10.1	**0.92**	0.62	0.7	**1.078**	2.4	100	-	5.4	15.7	17.9	2.2	13.8%
		250	6.58	0.92	0.39	0.11	1.42	10.1	7.94	2.10	0.11	(0.02)	2.19	13.4	0.92	0.62	0.70	1.078	5.9	250	-	13.5	29.4	32.8	3.4	11.5%
		500	6.58	0.92	0.39	0.11	1.42	13.7	7.94	2.10	0.11	(0.02)	2.19	18.9	0.92	0.62	0.70	1.078	11.8	500	-	27.0	52.2	57.6	5.4	10.4%
		750	6.58	0.92	0.39	0.11	1.42	17.2	7.94	2.10	0.11	(0.02)	2.19	24.3	0.92	0.62	0.70	1.078	17.7	600	150	42.3	76.7	84.3	7.6	9.9%
		1,000	6.58	0.92	0.39	0.11	1.42	20.8	7.94	2.10	0.11	(0.02)	2.19	29.8	0.92	0.62	0.70	1.078	23.6	600	400	58.2	101.9	111.6	9.7	9.5%
		1,500	6.58	0.92	0.39	0.11	1.42	27.9	7.94	2.10	0.11	(0.02)	2.19	40.7	0.92	0.62	0.70	1.078	35.4	600	900	90.0	152.2	166.1	13.9	9.1%
		2,000	6.58	0.92	0.39	0.11	1.42	35.0	7.94	2.10	0.11	(0.02)	2.19	51.6	0.92	0.62	0.70	1.078	47.2	600	1,400	121.8	202.6	220.6	18.0	8.9%
UR	**Smiths Falls**	100	**12.63**	**1.42**	**0.46**	**0.17**	**2.05**	14.7	**12.42**	**2.40**	**0.17**	**(0.02)**	**2.54**	15.0	**0.92**	0.62	0.7	**1.078**	2.4	100	-	5.4	22.4	22.7	0.3	1.5%
		250	12.63	1.42	0.46	0.17	2.05	17.8	12.42	2.40	0.17	(0.02)	2.54	18.8	0.92	0.62	0.70	1.078	5.9	250	-	13.5	37.0	38.2	1.1	3.1%
		500	12.63	1.42	0.46	0.17	2.05	22.9	12.42	2.40	0.17	(0.02)	2.54	25.1	0.92	0.62	0.70	1.078	11.8	500	-	27.0	61.4	63.9	2.5	4.1%
		750	12.63	1.42	0.46	0.17	2.05	28.0	12.42	2.40	0.17	(0.02)	2.54	31.5	0.92	0.62	0.70	1.078	17.7	600	150	42.3	87.5	91.5	4.0	4.6%
		1,000	12.63	1.42	0.46	0.17	2.05	33.1	12.42	2.40	0.17	(0.02)	2.54	37.8	0.92	0.62	0.70	1.078	23.6	600	400	58.2	114.2	119.6	5.4	4.7%
		1,500	12.63	1.42	0.46	0.17	2.05	43.4	12.42	2.40	0.17	(0.02)	2.54	50.5	0.92	0.62	0.70	1.078	35.4	600	900	90.0	167.7	175.9	8.2	4.9%
		2,000	12.63	1.42	0.46	0.17	2.05	53.6	12.42	2.40	0.17	(0.02)	2.54	63.2	0.92	0.62	0.70	1.078	47.2	600	1,400	121.8	221.2	232.2	11.0	5.0%
UR	**Thorold**	100	**13.68**	**1.47**	**0.41**	**0.14**	**2.02**	15.7	**13.16**	**2.40**	**0.14**	**(0.02)**	**2.51**	15.7	**0.92**	0.62	0.7	**1.078**	2.4	100	-	5.4	23.4	23.4	0.0	0.1%
		250	13.68	1.47	0.41	0.14	2.02	18.7	13.16	2.40	0.14	(0.02)	2.51	19.4	0.92	0.62	0.70	1.078	5.9	250	-	13.5	38.0	38.8	0.8	2.2%
		500	13.68	1.47	0.41	0.14	2.02	23.8	13.16	2.40	0.14	(0.02)	2.51	25.7	0.92	0.62	0.70	1.078	11.8	500	-	27.0	62.3	64.5	2.2	3.5%
		750	13.68	1.47	0.41	0.14	2.02	28.8	13.16	2.40	0.14	(0.02)	2.51	32.0	0.92	0.62	0.70	1.078	17.7	600	150	42.3	88.3	92.0	3.7	4.2%
		1,000	13.68	1.47	0.41	0.14	2.02	33.9	13.16	2.40	0.14	(0.02)	2.51	38.3	0.92	0.62	0.70	1.078	23.6	600	400	58.2	115.0	120.1	5.1	4.4%
		1,500	13.68	1.47	0.41	0.14	2.02	44.0	13.16	2.40	0.14	(0.02)	2.51	50.8	0.92	0.62	0.70	1.078	35.4	600	900	90.0	168.3	176.2	7.9	4.7%
		2,000	13.68	1.47	0.41	0.14	2.02	54.1	13.16	2.40	0.14	(0.02)	2.51	63.4	0.92	0.62	0.70	1.078	47.2	600	1,400	121.8	221.7	232.4	10.7	4.8%
UR	**Whitchurch Stouffville**	100	**10.54**	**1.02**	**0.36**	**0.12**	**1.50**	12.0	**10.95**	**2.30**	**0.12**	**(0.02)**	**2.40**	13.3	**0.92**	0.62	0.7	**1.078**	2.4	100	-	5.4	19.7	21.1	1.3	6.8%
		250	10.54	1.02	0.36	0.12	1.50	14.3	10.95	2.30	0.12	(0.02)	2.40	16.9	0.92	0.62	0.70	1.078	5.9	250	-	13.5	33.5	36.3	2.8	8.2%
		500	10.54	1.02	0.36	0.12	1.50	18.0	10.95	2.30	0.12	(0.02)	2.40	22.9	0.92	0.62	0.70	1.078	11.8	500	-	27.0	56.5	61.7	5.1	9.1%
		750	10.54	1.02	0.36	0.12	1.50	21.8	10.95	2.30	0.12	(0.02)	2.40	28.9	0.92	0.62	0.70	1.078	17.7	600	150	42.3	81.3	88.9	7.6	9.4%
		1,000	10.54	1.02	0.36	0.12	1.50	25.5	10.95	2.30	0.12	(0.02)	2.40	34.9	0.92	0.62	0.70	1.078	23.6	600	400	58.2	106.6	116.7	10.0	9.4%
		1,500	10.54	1.02	0.36	0.12	1.50	33.0	10.95	2.30	0.12	(0.02)	2.40	46.9	0.92	0.62	0.70	1.078	35.4	600	900	90.0	157.4	172.3	14.9	9.4%
		2,000	10.54	1.02	0.36	0.12	1.50	40.5	10.95	2.30	0.12	(0.02)	2.40	58.8	0.92	0.62	0.70	1.078	47.2	600	1,400	121.8	208.2	227.9	19.7	9.5%

New Rate Class: R1

Total Bill Impacts of Proposed Distribution Rates [new RTSR+TLF]: Threshold of 600 kWhs

600.0

Classes		Scenario	May 2007 Incl Rate Riders						May 2008 Incl Rate Riders						Non-Dx Compoent				Other Reg	Commodity Bands			Existing	New	$ Incr	% Incr
			Existing Dx Rates					Existing Dx	New Dx Rates					New Dx	RTSR new	WMSC	DRC	TLF new	New	Band 1	Band 2	New	Total Bill	Total Bill	Total Bill	Total Bill
																				5.0	5.9					
New Class	Old Class	kWh	SrChg	base	Rider1	Rider2	VarChg	[$/month]	SrChg	base	Rider2	Rider3	VarChg	[$/month]	c/kWh	c/kWh	c/kWh		$	kWhs	kWhs		[$/month]	[$/month]	[$/month]	%
R1	**R1**	100	**19.04**	**2.38**	**0.15**	**0.07**	**2.60**	21.6	**19.00**	**2.81**	**0.07**	**(0.04)**	**2.84**	21.8	**0.93**	0.62	0.70	**1.085**	2.4	100	-	5.4	29.5	29.6	0.1	0.5%
		250	19.04	2.38	0.15	0.07	2.60	25.5	19.00	2.81	0.07	(0.04)	2.84	26.1	0.93	0.62	0.70	1.085	6.0	250	-	13.6	45.2	45.6	0.4	0.9%
		500	19.04	2.38	0.15	0.07	2.60	32.0	19.00	2.81	0.07	(0.04)	2.84	33.2	0.93	0.62	0.70	1.085	11.9	500	-	27.1	71.4	72.2	0.9	1.2%
		750	19.04	2.38	0.15	0.07	2.60	38.5	19.00	2.81	0.07	(0.04)	2.84	40.3	0.93	0.62	0.70	1.085	17.9	600	150	42.6	99.5	100.8	1.3	1.3%
		1,000	19.04	2.38	0.15	0.07	2.60	45.0	19.00	2.81	0.07	(0.04)	2.84	47.4	0.93	0.62	0.70	1.085	23.8	600	400	58.6	128.1	129.8	1.7	1.3%
		1,500	19.04	2.38	0.15	0.07	2.60	58.0	19.00	2.81	0.07	(0.04)	2.84	61.6	0.93	0.62	0.70	1.085	35.7	600	900	90.6	185.3	187.9	2.6	1.4%
		2,000	19.04	2.38	0.15	0.07	2.60	71.0	19.00	2.81	0.07	(0.04)	2.84	75.8	0.93	0.62	0.70	1.085	47.6	600	1,400	122.6	242.6	246.0	3.5	1.4%
R1	**Ailsa Craig**	100	**10.51**	**0.82**	**0.35**	**0.11**	**1.28**	11.8	**12.13**	**1.85**	**0.11**	**(0.04)**	**1.92**	14.1	**0.93**	0.62	0.70	**1.085**	2.4	100	-	5.4	19.5	21.9	2.4	12.2%
		250	10.51	0.82	0.35	0.11	1.28	13.7	12.13	1.85	0.11	(0.04)	1.92	16.9	0.93	0.62	0.70	1.085	6.0	250	-	13.6	33.0	36.5	3.5	10.6%
		500	10.51	0.82	0.35	0.11	1.28	16.9	12.13	1.85	0.11	(0.04)	1.92	21.7	0.93	0.62	0.70	1.085	11.9	500	-	27.1	55.4	60.8	5.4	9.7%
		750	10.51	0.82	0.35	0.11	1.28	20.1	12.13	1.85	0.11	(0.04)	1.92	26.6	0.93	0.62	0.70	1.085	17.9	600	150	42.6	79.6	87.0	7.4	9.3%
		1,000	10.51	0.82	0.35	0.11	1.28	23.3	12.13	1.85	0.11	(0.04)	1.92	31.4	0.93	0.62	0.70	1.085	23.8	600	400	58.6	104.4	113.8	9.4	9.0%
		1,500	10.51	0.82	0.35	0.11	1.28	29.7	12.13	1.85	0.11	(0.04)	1.92	41.0	0.93	0.62	0.70	1.085	35.7	600	900	90.6	154.1	167.3	13.3	8.6%
		2,000	10.51	0.82	0.35	0.11	1.28	36.1	12.13	1.85	0.11	(0.04)	1.92	50.6	0.93	0.62	0.70	1.085	47.6	600	1,400	122.6	203.7	220.9	17.1	8.4%
R1	**Arkona**	100	**5.84**	**0.26**	**0.68**	**0.33**	**1.27**	7.1	**8.30**	**1.50**	**0.33**	**(0.04)**	**1.79**	10.1	**0.93**	0.62	0.70	**1.085**	2.4	100	-	5.4	14.8	17.9	3.1	20.8%
		250	5.84	0.26	0.68	0.33	1.27	9.0	8.30	1.50	0.33	(0.04)	1.79	12.8	0.93	0.62	0.70	1.085	6.0	250	-	13.6	28.3	32.3	4.0	14.3%
		500	5.84	0.26	0.68	0.33	1.27	12.2	8.30	1.50	0.33	(0.04)	1.79	17.3	0.93	0.62	0.70	1.085	11.9	500	-	27.1	50.7	56.3	5.6	11.0%
		750	5.84	0.26	0.68	0.33	1.27	15.4	8.30	1.50	0.33	(0.04)	1.79	21.7	0.93	0.62	0.70	1.085	17.9	600	150	42.6	74.8	82.2	7.4	9.9%
		1,000	5.84	0.26	0.68	0.33	1.27	18.5	8.30	1.50	0.33	(0.04)	1.79	26.2	0.93	0.62	0.70	1.085	23.8	600	400	58.6	99.6	108.7	9.0	9.0%
		1,500	5.84	0.26	0.68	0.33	1.27	24.9	8.30	1.50	0.33	(0.04)	1.79	35.2	0.93	0.62	0.70	1.085	35.7	600	900	90.6	149.3	161.5	12.3	8.2%
		2,000	5.84	0.26	0.68	0.33	1.27	31.2	8.30	1.50	0.33	(0.04)	1.79	44.2	0.93	0.62	0.70	1.085	47.6	600	1,400	122.6	198.9	214.4	15.6	7.8%
UR	**Arnprior**	100	**11.54**	**1.47**	**0.49**	**0.18**	**2.14**	13.7	**11.70**	**2.40**	**0.18**	**(0.02)**	**2.55**	14.2	**0.92**	0.62	0.70	**1.078**	2.4	100	-	5.4	21.4	22.0	0.6	2.9%
		250	11.54	1.47	0.49	0.18	2.14	16.9	11.70	2.40	0.18	(0.02)	2.55	18.1	0.92	0.62	0.70	1.078	5.9	250	-	13.5	36.1	37.4	1.3	3.6%
		500	11.54	1.47	0.49	0.18	2.14	22.2	11.70	2.40	0.18	(0.02)	2.55	24.4	0.92	0.62	0.70	1.078	11.8	500	-	27.0	60.7	63.2	2.5	4.0%
		750	11.54	1.47	0.49	0.18	2.14	27.6	11.70	2.40	0.18	(0.02)	2.55	30.8	0.92	0.62	0.70	1.078	17.7	600	150	42.3	87.1	90.8	3.8	4.3%
		1,000	11.54	1.47	0.49	0.18	2.14	32.9	11.70	2.40	0.18	(0.02)	2.55	37.2	0.92	0.62	0.70	1.078	23.6	600	400	58.2	114.0	119.0	5.0	4.3%
		1,500	11.54	1.47	0.49	0.18	2.14	43.6	11.70	2.40	0.18	(0.02)	2.55	50.0	0.92	0.62	0.70	1.078	35.4	600	900	90.0	168.0	175.4	7.4	4.4%
		2,000	11.54	1.47	0.49	0.18	2.14	54.3	11.70	2.40	0.18	(0.02)	2.55	62.7	0.92	0.62	0.70	1.078	47.2	600	1,400	121.8	222.0	231.7	9.8	4.4%

New Rate Class: R1

Total Bill Impacts of Proposed Distribution Rates [new RTSR+TLF]: Threshold of 600 kWhs

600.0

Classes		Scenario	May 2007 Incl Rate Riders						May 2008 Incl Rate Riders						Non-Dx Compoent				Other Reg	Commodity Bands			Existing	New	$ Incr	% Incr
			Existing Dx Rates					Existing Dx	New Dx Rates					New Dx	RTSR new	WMSC	DRC	TLF new	New	Band 1	Band 2	New	Total Bill	Total Bill	Total Bill	Total Bill
																				5.0	5.9					
New Class	Old Class	kWh	SrChg	base	Rider1	Rider2	VarChg	[$/month]	SrChg	base	Rider2	Rider3	VarChg	[$/month]	c/kWh	c/kWh	c/kWh		$	kWhs	kWhs		[$/month]	[$/month]	[$/month]	%
R1	Arran-Elders	100	9.02	0.95	0.35	0.15	1.45	10.5	11.51	1.90	0.15	(0.04)	2.01	13.5	0.93	0.62	0.70	1.085	2.4	100	-	5.4	18.2	21.3	3.2	17.3%
		250	9.02	0.95	0.35	0.15	1.45	12.6	11.51	1.90	0.15	(0.04)	2.01	16.5	0.93	0.62	0.70	1.085	6.0	250	-	13.6	31.9	36.1	4.2	13.0%
		500	9.02	0.95	0.35	0.15	1.45	16.3	11.51	1.90	0.15	(0.04)	2.01	21.6	0.93	0.62	0.70	1.085	11.9	500	-	27.1	54.8	60.6	5.8	10.6%
		750	9.02	0.95	0.35	0.15	1.45	19.9	11.51	1.90	0.15	(0.04)	2.01	26.6	0.93	0.62	0.70	1.085	17.9	600	150	42.6	79.4	87.1	7.7	9.7%
		1,000	9.02	0.95	0.35	0.15	1.45	23.5	11.51	1.90	0.15	(0.04)	2.01	31.6	0.93	0.62	0.70	1.085	23.8	600	400	58.6	104.6	114.1	9.4	9.0%
		1,500	9.02	0.95	0.35	0.15	1.45	30.8	11.51	1.90	0.15	(0.04)	2.01	41.7	0.93	0.62	0.70	1.085	35.7	600	900	90.6	155.1	168.0	12.9	8.3%
		2,000	9.02	0.95	0.35	0.15	1.45	38.0	11.51	1.90	0.15	(0.04)	2.01	51.8	0.93	0.62	0.70	1.085	47.6	600	1,400	122.6	205.6	222.0	16.4	8.0%
R1	Artemesia	100	12.73	0.93	0.59	0.34	1.86	14.6	13.58	2.35	0.34	(0.04)	2.65	16.2	0.93	0.62	0.70	1.085	2.4	100	-	5.4	22.3	24.0	1.7	7.8%
		250	12.73	0.93	0.59	0.34	1.86	17.4	13.58	2.35	0.34	(0.04)	2.65	20.2	0.93	0.62	0.70	1.085	6.0	250	-	13.6	36.6	39.7	3.1	8.4%
		500	12.73	0.93	0.59	0.34	1.86	22.0	13.58	2.35	0.34	(0.04)	2.65	26.8	0.93	0.62	0.70	1.085	11.9	500	-	27.1	60.5	65.9	5.3	8.8%
		750	12.73	0.93	0.59	0.34	1.86	26.7	13.58	2.35	0.34	(0.04)	2.65	33.5	0.93	0.62	0.70	1.085	17.9	600	150	42.6	86.2	93.9	7.8	9.0%
		1,000	12.73	0.93	0.59	0.34	1.86	31.3	13.58	2.35	0.34	(0.04)	2.65	40.1	0.93	0.62	0.70	1.085	23.8	600	400	58.6	112.4	122.5	10.1	9.0%
		1,500	12.73	0.93	0.59	0.34	1.86	40.6	13.58	2.35	0.34	(0.04)	2.65	53.4	0.93	0.62	0.70	1.085	35.7	600	900	90.6	165.0	179.7	14.7	8.9%
		2,000	12.73	0.93	0.59	0.34	1.86	49.9	13.58	2.35	0.34	(0.04)	2.65	66.6	0.93	0.62	0.70	1.085	47.6	600	1,400	122.6	217.5	236.9	19.4	8.9%
R1	Bancroft	100	13.48	0.95	0.34	0.12	1.41	14.9	14.39	2.10	0.12	(0.04)	2.18	16.6	0.93	0.62	0.70	1.085	2.4	100	-	5.4	22.6	24.4	1.8	7.9%
		250	13.48	0.95	0.34	0.12	1.41	17.0	14.39	2.10	0.12	(0.04)	2.18	19.8	0.93	0.62	0.70	1.085	6.0	250	-	13.6	36.3	39.4	3.1	8.6%
		500	13.48	0.95	0.34	0.12	1.41	20.5	14.39	2.10	0.12	(0.04)	2.18	25.3	0.93	0.62	0.70	1.085	11.9	500	-	27.1	59.0	64.3	5.3	9.0%
		750	13.48	0.95	0.34	0.12	1.41	24.1	14.39	2.10	0.12	(0.04)	2.18	30.8	0.93	0.62	0.70	1.085	17.9	600	150	42.6	83.5	91.2	7.7	9.2%
		1,000	13.48	0.95	0.34	0.12	1.41	27.6	14.39	2.10	0.12	(0.04)	2.18	36.2	0.93	0.62	0.70	1.085	23.8	600	400	58.6	108.7	118.7	10.0	9.2%
		1,500	13.48	0.95	0.34	0.12	1.41	34.6	14.39	2.10	0.12	(0.04)	2.18	47.1	0.93	0.62	0.70	1.085	35.7	600	900	90.6	159.0	173.5	14.5	9.1%
		2,000	13.48	0.95	0.34	0.12	1.41	41.7	14.39	2.10	0.12	(0.04)	2.18	58.0	0.93	0.62	0.70	1.085	47.6	600	1,400	122.6	209.3	228.3	19.0	9.1%
R1	Bath	100	13.38	0.86	0.68	0.38	1.92	15.3	14.42	2.35	0.38	(0.04)	2.69	17.1	0.93	0.62	0.70	1.085	2.4	100	-	5.4	23.0	24.9	1.9	8.3%
		250	13.38	0.86	0.68	0.38	1.92	18.2	14.42	2.35	0.38	(0.04)	2.69	21.1	0.93	0.62	0.70	1.085	6.0	250	-	13.6	37.4	40.7	3.2	8.6%
		500	13.38	0.86	0.68	0.38	1.92	23.0	14.42	2.35	0.38	(0.04)	2.69	27.9	0.93	0.62	0.70	1.085	11.9	500	-	27.1	61.5	66.9	5.4	8.8%
		750	13.38	0.86	0.68	0.38	1.92	27.8	14.42	2.35	0.38	(0.04)	2.69	34.6	0.93	0.62	0.70	1.085	17.9	600	150	42.6	87.3	95.1	7.8	9.0%
		1,000	13.38	0.86	0.68	0.38	1.92	32.6	14.42	2.35	0.38	(0.04)	2.69	41.3	0.93	0.62	0.70	1.085	23.8	600	400	58.6	113.7	123.8	10.1	8.9%
		1,500	13.38	0.86	0.68	0.38	1.92	42.2	14.42	2.35	0.38	(0.04)	2.69	54.8	0.93	0.62	0.70	1.085	35.7	600	900	90.6	166.5	181.2	14.6	8.8%
		2,000	13.38	0.86	0.68	0.38	1.92	51.8	14.42	2.35	0.38	(0.04)	2.69	68.3	0.93	0.62	0.70	1.085	47.6	600	1,400	122.6	219.4	238.5	19.1	8.7%

New Rate Class: R1

Total Bill Impacts of Proposed Distribution Rates [new RTSR+TLF]: Threshold of 600 kWhs

Classes		Scenario	May 2007 Incl Rate Riders						May 2008 Incl Rate Riders						Non-Dx Compoent				Other Reg	Commodity Bands			Existing	New	$ Incr	% Incr
			Existing Dx Rates					Existing Dx	New Dx Rates					New Dx	RTSR new	WMSC	DRC	TLF new	New	Band 1	Band 2	New	Total Bill	Total Bill	Total Bill	Total Bill
																				600.0						
																				5.0	5.9					
New Class	Old Class	kWh	SrChg	base	Rider1	Rider2	VarChg	[$/month]	SrChg	base	Rider2	Rider3	VarChg	[$/month]	c/kWh	c/kWh	c/kWh		$	kWhs	kWhs		[$/month]	[$/month]	[$/month]	%
R1	Blandford-B	100	11.63	0.90	0.63	0.33	1.86	13.5	12.85	2.30	0.33	(0.04)	2.59	15.4	0.93	0.62	0.70	1.085	2.4	100	-	5.4	21.2	23.3	2.1	9.7%
		250	11.63	0.90	0.63	0.33	1.86	16.3	12.85	2.30	0.33	(0.04)	2.59	19.3	0.93	0.62	0.70	1.085	6.0	250	-	13.6	35.5	38.9	3.3	9.3%
		500	11.63	0.90	0.63	0.33	1.86	20.9	12.85	2.30	0.33	(0.04)	2.59	25.8	0.93	0.62	0.70	1.085	11.9	500	-	27.1	59.4	64.9	5.4	9.1%
		750	11.63	0.90	0.63	0.33	1.86	25.6	12.85	2.30	0.33	(0.04)	2.59	32.3	0.93	0.62	0.70	1.085	17.9	600	150	42.6	85.1	92.8	7.7	9.1%
		1,000	11.63	0.90	0.63	0.33	1.86	30.2	12.85	2.30	0.33	(0.04)	2.59	38.8	0.93	0.62	0.70	1.085	23.8	600	400	58.6	111.3	121.2	9.9	8.9%
		1,500	11.63	0.90	0.63	0.33	1.86	39.5	12.85	2.30	0.33	(0.04)	2.59	51.7	0.93	0.62	0.70	1.085	35.7	600	900	90.6	163.9	178.1	14.2	8.7%
		2,000	11.63	0.90	0.63	0.33	1.86	48.8	12.85	2.30	0.33	(0.04)	2.59	64.7	0.93	0.62	0.70	1.085	47.6	600	1,400	122.6	216.4	235.0	18.5	8.6%
R1	Blyth	100	7.19	0.91	0.54	0.27	1.72	8.9	9.96	2.00	0.27	(0.04)	2.23	12.2	0.93	0.62	0.70	1.085	2.4	100	-	5.4	16.6	20.0	3.4	20.4%
		250	7.19	0.91	0.54	0.27	1.72	11.5	9.96	2.00	0.27	(0.04)	2.23	15.5	0.93	0.62	0.70	1.085	6.0	250	-	13.6	30.7	35.1	4.3	14.0%
		500	7.19	0.91	0.54	0.27	1.72	15.8	9.96	2.00	0.27	(0.04)	2.23	21.1	0.93	0.62	0.70	1.085	11.9	500	-	27.1	54.3	60.2	5.9	10.8%
		750	7.19	0.91	0.54	0.27	1.72	20.1	9.96	2.00	0.27	(0.04)	2.23	26.7	0.93	0.62	0.70	1.085	17.9	600	150	42.6	79.6	87.2	7.6	9.6%
		1,000	7.19	0.91	0.54	0.27	1.72	24.4	9.96	2.00	0.27	(0.04)	2.23	32.3	0.93	0.62	0.70	1.085	23.8	600	400	58.6	105.5	114.7	9.2	8.7%
		1,500	7.19	0.91	0.54	0.27	1.72	33.0	9.96	2.00	0.27	(0.04)	2.23	43.5	0.93	0.62	0.70	1.085	35.7	600	900	90.6	157.4	169.8	12.5	7.9%
		2,000	7.19	0.91	0.54	0.27	1.72	41.6	9.96	2.00	0.27	(0.04)	2.23	54.6	0.93	0.62	0.70	1.085	47.6	600	1,400	122.6	209.2	224.9	15.7	7.5%
R1	Bobcaygeon	100	14.47	0.97	0.28	0.10	1.35	15.8	15.14	2.05	0.10	(0.04)	2.11	17.3	0.93	0.62	0.70	1.085	2.4	100	-	5.4	23.5	25.1	1.5	6.5%
		250	14.47	0.97	0.28	0.10	1.35	17.8	15.14	2.05	0.10	(0.04)	2.11	20.4	0.93	0.62	0.70	1.085	6.0	250	-	13.6	37.1	39.9	2.8	7.7%
		500	14.47	0.97	0.28	0.10	1.35	21.2	15.14	2.05	0.10	(0.04)	2.11	25.7	0.93	0.62	0.70	1.085	11.9	500	-	27.1	59.7	64.7	5.0	8.4%
		750	14.47	0.97	0.28	0.10	1.35	24.6	15.14	2.05	0.10	(0.04)	2.11	31.0	0.93	0.62	0.70	1.085	17.9	600	150	42.6	84.1	91.5	7.4	8.8%
		1,000	14.47	0.97	0.28	0.10	1.35	28.0	15.14	2.05	0.10	(0.04)	2.11	36.3	0.93	0.62	0.70	1.085	23.8	600	400	58.6	109.1	118.7	9.6	8.8%
		1,500	14.47	0.97	0.28	0.10	1.35	34.7	15.14	2.05	0.10	(0.04)	2.11	46.8	0.93	0.62	0.70	1.085	35.7	600	900	90.6	159.1	173.2	14.1	8.9%
		2,000	14.47	0.97	0.28	0.10	1.35	41.5	15.14	2.05	0.10	(0.04)	2.11	57.4	0.93	0.62	0.70	1.085	47.6	600	1,400	122.6	209.1	227.7	18.6	8.9%
R1	Brighton	100	11.61	1.07	0.37	0.11	1.55	13.2	12.86	2.20	0.11	(0.04)	2.27	15.1	0.93	0.62	0.70	1.085	2.4	100	-	5.4	20.9	22.9	2.1	9.9%
		250	11.61	1.07	0.37	0.11	1.55	15.5	12.86	2.20	0.11	(0.04)	2.27	18.5	0.93	0.62	0.70	1.085	6.0	250	-	13.6	34.7	38.1	3.3	9.5%
		500	11.61	1.07	0.37	0.11	1.55	19.4	12.86	2.20	0.11	(0.04)	2.27	24.2	0.93	0.62	0.70	1.085	11.9	500	-	27.1	57.9	63.3	5.4	9.3%
		750	11.61	1.07	0.37	0.11	1.55	23.2	12.86	2.20	0.11	(0.04)	2.27	29.9	0.93	0.62	0.70	1.085	17.9	600	150	42.6	82.7	90.4	7.7	9.3%
		1,000	11.61	1.07	0.37	0.11	1.55	27.1	12.86	2.20	0.11	(0.04)	2.27	35.6	0.93	0.62	0.70	1.085	23.8	600	400	58.6	108.2	118.0	9.8	9.1%
		1,500	11.61	1.07	0.37	0.11	1.55	34.9	12.86	2.20	0.11	(0.04)	2.27	47.0	0.93	0.62	0.70	1.085	35.7	600	900	90.6	159.2	173.3	14.1	8.8%
		2,000	11.61	1.07	0.37	0.11	1.55	42.6	12.86	2.20	0.11	(0.04)	2.27	58.3	0.93	0.62	0.70	1.085	47.6	600	1,400	122.6	210.2	228.6	18.4	8.7%

New Rate Class: R1

Total Bill Impacts of Proposed Distribution Rates [new RTSR+TLF]: Threshold of 600 kWhs

Classes		Scenario	May 2007 Incl Rate Riders						May 2008 Incl Rate Riders						Non-Dx Compoent				Other Reg	Commodity Bands (600.0)			Existing	New	$ Incr	% Incr
			Existing Dx Rates					Existing Dx	New Dx Rates					New Dx	RTSR new	WMSC	DRC	TLF new	New	Band 1	Band 2	New	Total Bill	Total Bill	Total Bill	Total Bill
																				5.0	5.9					
New Class	Old Class	kWh	SrChg	base	Rider1	Rider2	VarChg	[$/month]	SrChg	base	Rider2	Rider3	VarChg	[$/month]	c/kWh	c/kWh	c/kWh		$	kWhs	kWhs		[$/month]	[$/month]	[$/month]	%
UR	Brockville	100	**12.33**	**0.93**	**0.48**	**0.16**	**1.57**	13.9	**12.50**	**2.40**	**0.16**	**(0.02)**	**2.53**	15.0	**0.92**	0.62	0.70	**1.078**	2.4	100	-	5.4	21.6	22.8	1.2	5.4%
		250	12.33	0.93	0.48	0.16	1.57	16.3	12.50	2.40	0.16	(0.02)	2.53	18.8	0.92	0.62	0.70	1.078	5.9	250	-	13.5	35.5	38.2	2.7	7.6%
		500	12.33	0.93	0.48	0.16	1.57	20.2	12.50	2.40	0.16	(0.02)	2.53	25.2	0.92	0.62	0.70	1.078	11.8	500	-	27.0	58.7	63.9	5.2	8.9%
		750	12.33	0.93	0.48	0.16	1.57	24.1	12.50	2.40	0.16	(0.02)	2.53	31.5	0.92	0.62	0.70	1.078	17.7	600	150	42.3	83.6	91.5	7.9	9.4%
		1,000	12.33	0.93	0.48	0.16	1.57	28.0	12.50	2.40	0.16	(0.02)	2.53	37.8	0.92	0.62	0.70	1.078	23.6	600	400	58.2	109.1	119.6	10.5	9.6%
		1,500	12.33	0.93	0.48	0.16	1.57	35.9	12.50	2.40	0.16	(0.02)	2.53	50.5	0.92	0.62	0.70	1.078	35.4	600	900	90.0	160.2	175.9	15.6	9.7%
		2,000	12.33	0.93	0.48	0.16	1.57	43.7	12.50	2.40	0.16	(0.02)	2.53	63.1	0.92	0.62	0.70	1.078	47.2	600	1,400	121.8	211.3	232.1	20.8	9.8%
R1	Caledon CH	100	**15.19**	**1.02**	**0.28**	**0.08**	**1.38**	16.6	**15.96**	**2.10**	**0.08**	**(0.04)**	**2.14**	18.1	**0.93**	0.62	0.70	**1.085**	2.4	100	-	5.4	24.3	25.9	1.6	6.8%
		250	15.19	1.02	0.28	0.08	1.38	18.6	15.96	2.10	0.08	(0.04)	2.14	21.3	0.93	0.62	0.70	1.085	6.0	250	-	13.6	37.9	40.8	2.9	7.8%
		500	15.19	1.02	0.28	0.08	1.38	22.1	15.96	2.10	0.08	(0.04)	2.14	26.7	0.93	0.62	0.70	1.085	11.9	500	-	27.1	60.6	65.7	5.1	8.4%
		750	15.19	1.02	0.28	0.08	1.38	25.5	15.96	2.10	0.08	(0.04)	2.14	32.0	0.93	0.62	0.70	1.085	17.9	600	150	42.6	85.0	92.5	7.5	8.8%
		1,000	15.19	1.02	0.28	0.08	1.38	29.0	15.96	2.10	0.08	(0.04)	2.14	37.4	0.93	0.62	0.70	1.085	23.8	600	400	58.6	110.1	119.8	9.7	8.8%
		1,500	15.19	1.02	0.28	0.08	1.38	35.9	15.96	2.10	0.08	(0.04)	2.14	48.1	0.93	0.62	0.70	1.085	35.7	600	900	90.6	160.3	174.5	14.2	8.9%
		2,000	15.19	1.02	0.28	0.08	1.38	42.8	15.96	2.10	0.08	(0.04)	2.14	58.8	0.93	0.62	0.70	1.085	47.6	600	1,400	122.6	210.4	229.1	18.7	8.9%
R1	Campbellfor	100	**12.30**	**1.07**	**0.41**	**0.12**	**1.60**	13.9	**13.69**	**2.25**	**0.12**	**(0.04)**	**2.33**	16.0	**0.93**	0.62	0.70	**1.085**	2.4	100	-	5.4	21.6	23.8	2.2	10.3%
		250	12.30	1.07	0.41	0.12	1.60	16.3	13.69	2.25	0.12	(0.04)	2.33	19.5	0.93	0.62	0.70	1.085	6.0	250	-	13.6	35.6	39.0	3.5	9.8%
		500	12.30	1.07	0.41	0.12	1.60	20.3	13.69	2.25	0.12	(0.04)	2.33	25.3	0.93	0.62	0.70	1.085	11.9	500	-	27.1	58.8	64.4	5.6	9.5%
		750	12.30	1.07	0.41	0.12	1.60	24.3	13.69	2.25	0.12	(0.04)	2.33	31.2	0.93	0.62	0.70	1.085	17.9	600	150	42.6	83.8	91.7	7.9	9.4%
		1,000	12.30	1.07	0.41	0.12	1.60	28.3	13.69	2.25	0.12	(0.04)	2.33	37.0	0.93	0.62	0.70	1.085	23.8	600	400	58.6	109.4	119.4	10.0	9.2%
		1,500	12.30	1.07	0.41	0.12	1.60	36.3	13.69	2.25	0.12	(0.04)	2.33	48.7	0.93	0.62	0.70	1.085	35.7	600	900	90.6	160.7	175.0	14.4	8.9%
		2,000	12.30	1.07	0.41	0.12	1.60	44.3	13.69	2.25	0.12	(0.04)	2.33	60.3	0.93	0.62	0.70	1.085	47.6	600	1,400	122.6	211.9	230.6	18.7	8.8%
UR	Carleton Pla	100	**14.17**	**1.79**	**0.38**	**0.15**	**2.32**	16.5	**14.04**	**2.40**	**0.15**	**(0.02)**	**2.52**	16.6	**0.92**	0.62	0.70	**1.078**	2.4	100	-	5.4	24.2	24.3	0.1	0.5%
		250	14.17	1.79	0.38	0.15	2.32	20.0	14.04	2.40	0.15	(0.02)	2.52	20.3	0.92	0.62	0.70	1.078	5.9	250	-	13.5	39.2	39.7	0.5	1.2%
		500	14.17	1.79	0.38	0.15	2.32	25.8	14.04	2.40	0.15	(0.02)	2.52	26.6	0.92	0.62	0.70	1.078	11.8	500	-	27.0	64.3	65.4	1.1	1.7%
		750	14.17	1.79	0.38	0.15	2.32	31.6	14.04	2.40	0.15	(0.02)	2.52	32.9	0.92	0.62	0.70	1.078	17.7	600	150	42.3	91.1	92.9	1.9	2.1%
		1,000	14.17	1.79	0.38	0.15	2.32	37.4	14.04	2.40	0.15	(0.02)	2.52	39.2	0.92	0.62	0.70	1.078	23.6	600	400	58.2	118.5	121.0	2.6	2.2%
		1,500	14.17	1.79	0.38	0.15	2.32	49.0	14.04	2.40	0.15	(0.02)	2.52	51.9	0.92	0.62	0.70	1.078	35.4	600	900	90.0	173.3	177.5	3.9	2.3%
		2,000	14.17	1.79	0.38	0.15	2.32	60.6	14.04	2.40	0.15	(0.02)	2.52	64.5	0.92	0.62	0.70	1.078	47.2	600	1,400	121.8	228.2	233.5	5.3	2.3%

New Rate Class: R1

Total Bill Impacts of Proposed Distribution Rates [new RTSR+TLF]: Threshold of 600 kWhs

600.0

Classes		Scenario	May 2007 Incl Rate Riders						May 2008 Incl Rate Riders						Non-Dx Compoent				Other Reg	Commodity Bands			Existing	New	$ Incr	% Incr
			Existing Dx Rates					Existing Dx	New Dx Rates					New Dx	RTSR new	WMSC	DRC	TLF new	New	Band 1	Band 2	New	Total Bill	Total Bill	Total Bill	Total Bill
																				5.0	5.9					
New Class	Old Class	kWh	SrChg	base	Rider1	Rider2	VarChg	[$/month]	SrChg	base	Rider2	Rider3	VarChg	[$/month]	c/kWh	c/kWh	c/kWh		$	kWhs	kWhs		[$/month]	[$/month]	[$/month]	%
R1	Cavan-Millbı	100	15.01	1.34	0.68	0.40	2.42	17.4	16.01	2.71	0.40	(0.04)	3.08	19.1	0.93	0.62	0.70	1.085	2.4	100	-	5.4	25.1	26.9	1.8	7.0%
		250	15.01	1.34	0.68	0.40	2.42	21.1	16.01	2.71	0.40	(0.04)	3.08	23.7	0.93	0.62	0.70	1.085	6.0	250	-	13.6	40.3	43.2	2.9	7.2%
		500	15.01	1.34	0.68	0.40	2.42	27.1	16.01	2.71	0.40	(0.04)	3.08	31.4	0.93	0.62	0.70	1.085	11.9	500	-	27.1	65.6	70.4	4.8	7.3%
		750	15.01	1.34	0.68	0.40	2.42	33.2	16.01	2.71	0.40	(0.04)	3.08	39.1	0.93	0.62	0.70	1.085	17.9	600	150	42.6	92.6	99.6	6.9	7.5%
		1,000	15.01	1.34	0.68	0.40	2.42	39.2	16.01	2.71	0.40	(0.04)	3.08	46.8	0.93	0.62	0.70	1.085	23.8	600	400	58.6	120.3	129.2	8.9	7.4%
		1,500	15.01	1.34	0.68	0.40	2.42	51.3	16.01	2.71	0.40	(0.04)	3.08	62.2	0.93	0.62	0.70	1.085	35.7	600	900	90.6	175.7	188.5	12.8	7.3%
		2,000	15.01	1.34	0.68	0.40	2.42	63.4	16.01	2.71	0.40	(0.04)	3.08	77.5	0.93	0.62	0.70	1.085	47.6	600	1,400	122.6	231.0	247.8	16.8	7.3%
R1	Centre Hasti	100	11.67	0.96	0.29	0.11	1.36	13.0	12.84	2.00	0.11	(0.04)	2.07	14.9	0.93	0.62	0.70	1.085	2.4	100	-	5.4	20.7	22.7	2.0	9.6%
		250	11.67	0.96	0.29	0.11	1.36	15.1	12.84	2.00	0.11	(0.04)	2.07	18.0	0.93	0.62	0.70	1.085	6.0	250	-	13.6	34.3	37.5	3.2	9.4%
		500	11.67	0.96	0.29	0.11	1.36	18.5	12.84	2.00	0.11	(0.04)	2.07	23.2	0.93	0.62	0.70	1.085	11.9	500	-	27.1	57.0	62.2	5.3	9.2%
		750	11.67	0.96	0.29	0.11	1.36	21.9	12.84	2.00	0.11	(0.04)	2.07	28.4	0.93	0.62	0.70	1.085	17.9	600	150	42.6	81.4	88.9	7.5	9.2%
		1,000	11.67	0.96	0.29	0.11	1.36	25.3	12.84	2.00	0.11	(0.04)	2.07	33.6	0.93	0.62	0.70	1.085	23.8	600	400	58.6	106.4	116.0	9.6	9.0%
		1,500	11.67	0.96	0.29	0.11	1.36	32.1	12.84	2.00	0.11	(0.04)	2.07	43.9	0.93	0.62	0.70	1.085	35.7	600	900	90.6	156.4	170.3	13.9	8.9%
		2,000	11.67	0.96	0.29	0.11	1.36	38.9	12.84	2.00	0.11	(0.04)	2.07	54.3	0.93	0.62	0.70	1.085	47.6	600	1,400	122.6	206.5	224.6	18.1	8.8%
R1	Chalk River	100	14.03	1.37	0.61	0.42	2.40	16.4	15.25	2.71	0.42	(0.04)	3.10	18.3	0.93	0.62	0.70	1.085	2.4	100	-	5.4	24.1	26.2	2.0	8.4%
		250	14.03	1.37	0.61	0.42	2.40	20.0	15.25	2.71	0.42	(0.04)	3.10	23.0	0.93	0.62	0.70	1.085	6.0	250	-	13.6	39.3	42.5	3.2	8.2%
		500	14.03	1.37	0.61	0.42	2.40	26.0	15.25	2.71	0.42	(0.04)	3.10	30.7	0.93	0.62	0.70	1.085	11.9	500	-	27.1	64.5	69.8	5.2	8.1%
		750	14.03	1.37	0.61	0.42	2.40	32.0	15.25	2.71	0.42	(0.04)	3.10	38.5	0.93	0.62	0.70	1.085	17.9	600	150	42.6	91.5	98.9	7.4	8.1%
		1,000	14.03	1.37	0.61	0.42	2.40	38.0	15.25	2.71	0.42	(0.04)	3.10	46.2	0.93	0.62	0.70	1.085	23.8	600	400	58.6	119.1	128.6	9.5	8.0%
		1,500	14.03	1.37	0.61	0.42	2.40	50.0	15.25	2.71	0.42	(0.04)	3.10	61.7	0.93	0.62	0.70	1.085	35.7	600	900	90.6	174.4	188.0	13.7	7.8%
		2,000	14.03	1.37	0.61	0.42	2.40	62.0	15.25	2.71	0.42	(0.04)	3.10	77.2	0.93	0.62	0.70	1.085	47.6	600	1,400	122.6	229.6	247.4	17.8	7.7%
R1	Champlain	100	10.36	0.88	0.45	0.23	1.56	11.9	12.17	2.00	0.23	(0.04)	2.19	14.4	0.93	0.62	0.70	1.085	2.4	100	-	5.4	19.6	22.2	2.5	13.0%
		250	10.36	0.88	0.45	0.23	1.56	14.3	12.17	2.00	0.23	(0.04)	2.19	17.7	0.93	0.62	0.70	1.085	6.0	250	-	13.6	33.5	37.2	3.7	10.9%
		500	10.36	0.88	0.45	0.23	1.56	18.2	12.17	2.00	0.23	(0.04)	2.19	23.1	0.93	0.62	0.70	1.085	11.9	500	-	27.1	56.7	62.2	5.5	9.7%
		750	10.36	0.88	0.45	0.23	1.56	22.1	12.17	2.00	0.23	(0.04)	2.19	28.6	0.93	0.62	0.70	1.085	17.9	600	150	42.6	81.5	89.1	7.5	9.3%
		1,000	10.36	0.88	0.45	0.23	1.56	26.0	12.17	2.00	0.23	(0.04)	2.19	34.1	0.93	0.62	0.70	1.085	23.8	600	400	58.6	107.1	116.5	9.5	8.8%
		1,500	10.36	0.88	0.45	0.23	1.56	33.8	12.17	2.00	0.23	(0.04)	2.19	45.1	0.93	0.62	0.70	1.085	35.7	600	900	90.6	158.1	171.4	13.3	8.4%
		2,000	10.36	0.88	0.45	0.23	1.56	41.6	12.17	2.00	0.23	(0.04)	2.19	56.0	0.93	0.62	0.70	1.085	47.6	600	1,400	122.6	209.2	226.3	17.1	8.2%

New Rate Class: R1

Total Bill Impacts of Proposed Distribution Rates [new RTSR+TLF]: Threshold of 600 kWhs

600.0

Classes		Scenario	May 2007 Incl Rate Riders						May 2008 Incl Rate Riders						Non-Dx Compoent				Other Reg	Commodity Bands			Existing	New	$ Incr	% Incr
			Existing Dx Rates					Existing Dx	New Dx Rates					New Dx	RTSR new	WMSC	DRC	TLF new	New	Band 1	Band 2	New	Total Bill	Total Bill	Total Bill	Total Bill
																				5.0	5.9					
New Class	Old Class	kWh	SrChg	base	Rider1	Rider2	VarChg	[$/month]	SrChg	base	Rider2	Rider3	VarChg	[$/month]	c/kWh	c/kWh	c/kWh		$	kWhs	kWhs		[$/month]	[$/month]	[$/month]	%
R1	Cobden	100	13.07	1.76	0.68	0.41	2.85	15.9	14.49	2.71	0.41	(0.04)	3.09	17.6	0.93	0.62	0.70	1.085	2.4	100	-	5.4	23.6	25.4	1.8	7.5%
		250	13.07	1.76	0.68	0.41	2.85	20.2	14.49	2.71	0.41	(0.04)	3.09	22.2	0.93	0.62	0.70	1.085	6.0	250	-	13.6	39.4	41.7	2.3	5.8%
		500	13.07	1.76	0.68	0.41	2.85	27.3	14.49	2.71	0.41	(0.04)	3.09	29.9	0.93	0.62	0.70	1.085	11.9	500	-	27.1	65.8	69.0	3.1	4.8%
		750	13.07	1.76	0.68	0.41	2.85	34.4	14.49	2.71	0.41	(0.04)	3.09	37.6	0.93	0.62	0.70	1.085	17.9	600	150	42.6	93.9	98.1	4.2	4.5%
		1,000	13.07	1.76	0.68	0.41	2.85	41.6	14.49	2.71	0.41	(0.04)	3.09	45.4	0.93	0.62	0.70	1.085	23.8	600	400	58.6	122.7	127.8	5.1	4.2%
		1,500	13.07	1.76	0.68	0.41	2.85	55.8	14.49	2.71	0.41	(0.04)	3.09	60.8	0.93	0.62	0.70	1.085	35.7	600	900	90.6	180.2	187.1	7.0	3.9%
		2,000	13.07	1.76	0.68	0.41	2.85	70.1	14.49	2.71	0.41	(0.04)	3.09	76.2	0.93	0.62	0.70	1.085	47.6	600	1,400	122.6	237.7	246.5	8.8	3.7%
R1	Deep River	100	16.62	2.29	0.38	0.25	2.92	19.5	16.61	2.71	0.25	(0.04)	2.93	19.5	0.93	0.62	0.70	1.085	2.4	100	-	5.4	27.2	27.3	0.1	0.4%
		250	16.62	2.29	0.38	0.25	2.92	23.9	16.61	2.71	0.25	(0.04)	2.93	23.9	0.93	0.62	0.70	1.085	6.0	250	-	13.6	43.2	43.4	0.3	0.6%
		500	16.62	2.29	0.38	0.25	2.92	31.2	16.61	2.71	0.25	(0.04)	2.93	31.2	0.93	0.62	0.70	1.085	11.9	500	-	27.1	69.7	70.3	0.5	0.8%
		750	16.62	2.29	0.38	0.25	2.92	38.5	16.61	2.71	0.25	(0.04)	2.93	38.6	0.93	0.62	0.70	1.085	17.9	600	150	42.6	98.0	99.0	1.0	1.0%
		1,000	16.62	2.29	0.38	0.25	2.92	45.8	16.61	2.71	0.25	(0.04)	2.93	45.9	0.93	0.62	0.70	1.085	23.8	600	400	58.6	126.9	128.3	1.4	1.1%
		1,500	16.62	2.29	0.38	0.25	2.92	60.4	16.61	2.71	0.25	(0.04)	2.93	60.5	0.93	0.62	0.70	1.085	35.7	600	900	90.6	184.8	186.8	2.1	1.1%
		2,000	16.62	2.29	0.38	0.25	2.92	75.0	16.61	2.71	0.25	(0.04)	2.93	75.1	0.93	0.62	0.70	1.085	47.6	600	1,400	122.6	242.6	245.4	2.8	1.1%
R1	Deseronto	100	12.89	1.12	0.37	0.11	1.60	14.5	13.54	2.30	0.11	(0.04)	2.37	15.9	0.93	0.62	0.70	1.085	2.4	100	-	5.4	22.2	23.7	1.5	6.9%
		250	12.89	1.12	0.37	0.11	1.60	16.9	13.54	2.30	0.11	(0.04)	2.37	19.5	0.93	0.62	0.70	1.085	6.0	250	-	13.6	36.1	39.0	2.8	7.9%
		500	12.89	1.12	0.37	0.11	1.60	20.9	13.54	2.30	0.11	(0.04)	2.37	25.4	0.93	0.62	0.70	1.085	11.9	500	-	27.1	59.4	64.4	5.0	8.5%
		750	12.89	1.12	0.37	0.11	1.60	24.9	13.54	2.30	0.11	(0.04)	2.37	31.3	0.93	0.62	0.70	1.085	17.9	600	150	42.6	84.4	91.8	7.4	8.8%
		1,000	12.89	1.12	0.37	0.11	1.60	28.9	13.54	2.30	0.11	(0.04)	2.37	37.3	0.93	0.62	0.70	1.085	23.8	600	400	58.6	110.0	119.7	9.7	8.8%
		1,500	12.89	1.12	0.37	0.11	1.60	36.9	13.54	2.30	0.11	(0.04)	2.37	49.1	0.93	0.62	0.70	1.085	35.7	600	900	90.6	161.3	175.5	14.2	8.8%
		2,000	12.89	1.12	0.37	0.11	1.60	44.9	13.54	2.30	0.11	(0.04)	2.37	61.0	0.93	0.62	0.70	1.085	47.6	600	1,400	122.6	212.5	231.3	18.8	8.8%
UR	Dryden	100	14.28	1.65	0.43	0.18	2.26	16.5	14.01	2.40	0.18	(0.02)	2.55	16.6	0.92	0.62	0.70	1.078	2.4	100	-	5.4	24.2	24.3	0.1	0.3%
		250	14.28	1.65	0.43	0.18	2.26	19.9	14.01	2.40	0.18	(0.02)	2.55	20.4	0.92	0.62	0.70	1.078	5.9	250	-	13.5	39.2	39.8	0.6	1.5%
		500	14.28	1.65	0.43	0.18	2.26	25.6	14.01	2.40	0.18	(0.02)	2.55	26.8	0.92	0.62	0.70	1.078	11.8	500	-	27.0	64.1	65.5	1.4	2.2%
		750	14.28	1.65	0.43	0.18	2.26	31.2	14.01	2.40	0.18	(0.02)	2.55	33.1	0.92	0.62	0.70	1.078	17.7	600	150	42.3	90.7	93.1	2.4	2.7%
		1,000	14.28	1.65	0.43	0.18	2.26	36.9	14.01	2.40	0.18	(0.02)	2.55	39.5	0.92	0.62	0.70	1.078	23.6	600	400	58.2	118.0	121.3	3.3	2.8%
		1,500	14.28	1.65	0.43	0.18	2.26	48.2	14.01	2.40	0.18	(0.02)	2.55	52.3	0.92	0.62	0.70	1.078	35.4	600	900	90.0	172.5	177.7	5.1	3.0%
		2,000	14.28	1.65	0.43	0.18	2.26	59.5	14.01	2.40	0.18	(0.02)	2.55	65.0	0.92	0.62	0.70	1.078	47.2	600	1,400	121.8	227.1	234.0	6.9	3.1%

New Rate Class: R1

Total Bill Impacts of Proposed Distribution Rates [new RTSR+TLF]: Threshold of 600 kWhs

600.0

Classes		Scenario	May 2007 Incl Rate Riders						May 2008 Incl Rate Riders						Non-Dx Compoent				Other Reg	Commodity Bands			Existing	New	$ Incr	% Incr
			Existing Dx Rates					Existing Dx	New Dx Rates					New Dx	RTSR new	WMSC	DRC	TLF new	New	Band 1	Band 2	New	Total Bill	Total Bill	Total Bill	Total Bill
																				5.0	5.9					
New Class	Old Class	kWh	SrChg	base	Rider1	Rider2	VarChg	[$/month]	SrChg	base	Rider2	Rider3	VarChg	[$/month]	c/kWh	c/kWh	c/kWh		$	kWhs	kWhs		[$/month]	[$/month]	[$/month]	%
R1	**Dundalk**	100	**14.47**	**1.08**	**0.39**	**0.13**	**1.60**	16.1	**15.14**	**2.30**	**0.13**	**(0.04)**	**2.39**	17.5	**0.93**	0.62	0.70	**1.085**	2.4	100	-	5.4	23.8	25.3	1.6	6.6%
		250	14.47	1.08	0.39	0.13	1.60	18.5	15.14	2.30	0.13	(0.04)	2.39	21.1	0.93	0.62	0.70	1.085	6.0	250	-	13.6	37.7	40.6	2.9	7.7%
		500	14.47	1.08	0.39	0.13	1.60	22.5	15.14	2.30	0.13	(0.04)	2.39	27.1	0.93	0.62	0.70	1.085	11.9	500	-	27.1	61.0	66.1	5.2	8.5%
		750	14.47	1.08	0.39	0.13	1.60	26.5	15.14	2.30	0.13	(0.04)	2.39	33.1	0.93	0.62	0.70	1.085	17.9	600	150	42.6	86.0	93.6	7.6	8.9%
		1,000	14.47	1.08	0.39	0.13	1.60	30.5	15.14	2.30	0.13	(0.04)	2.39	39.1	0.93	0.62	0.70	1.085	23.8	600	400	58.6	111.6	121.5	9.9	8.9%
		1,500	14.47	1.08	0.39	0.13	1.60	38.5	15.14	2.30	0.13	(0.04)	2.39	51.0	0.93	0.62	0.70	1.085	35.7	600	900	90.6	162.8	177.4	14.6	8.9%
		2,000	14.47	1.08	0.39	0.13	1.60	46.5	15.14	2.30	0.13	(0.04)	2.39	63.0	0.93	0.62	0.70	1.085	47.6	600	1,400	122.6	214.1	233.3	19.2	9.0%
R1	**Durham**	100	**16.35**	**1.24**	**0.46**	**0.16**	**1.86**	18.2	**16.67**	**2.60**	**0.16**	**(0.04)**	**2.72**	19.4	**0.93**	0.62	0.70	**1.085**	2.4	100	-	5.4	25.9	27.2	1.3	5.0%
		250	16.35	1.24	0.46	0.16	1.86	21.0	16.67	2.60	0.16	(0.04)	2.72	23.5	0.93	0.62	0.70	1.085	6.0	250	-	13.6	40.3	43.0	2.7	6.8%
		500	16.35	1.24	0.46	0.16	1.86	25.7	16.67	2.60	0.16	(0.04)	2.72	30.3	0.93	0.62	0.70	1.085	11.9	500	-	27.1	64.2	69.3	5.2	8.0%
		750	16.35	1.24	0.46	0.16	1.86	30.3	16.67	2.60	0.16	(0.04)	2.72	37.1	0.93	0.62	0.70	1.085	17.9	600	150	42.6	89.8	97.6	7.8	8.7%
		1,000	16.35	1.24	0.46	0.16	1.86	35.0	16.67	2.60	0.16	(0.04)	2.72	43.9	0.93	0.62	0.70	1.085	23.8	600	400	58.6	116.1	126.3	10.3	8.9%
		1,500	16.35	1.24	0.46	0.16	1.86	44.3	16.67	2.60	0.16	(0.04)	2.72	57.5	0.93	0.62	0.70	1.085	35.7	600	900	90.6	168.6	183.9	15.3	9.0%
		2,000	16.35	1.24	0.46	0.16	1.86	53.6	16.67	2.60	0.16	(0.04)	2.72	71.1	0.93	0.62	0.70	1.085	47.6	600	1,400	122.6	221.2	241.4	20.2	9.1%
R1	**Eganville**	100	**13.86**	**1.53**	**0.29**	**0.12**	**1.94**	15.8	**14.30**	**2.71**	**0.12**	**(0.04)**	**2.80**	17.1	**0.93**	0.62	0.70	**1.085**	2.4	100	-	5.4	23.5	24.9	1.4	5.9%
		250	13.86	1.53	0.29	0.12	1.94	18.7	14.30	2.71	0.12	(0.04)	2.80	21.3	0.93	0.62	0.70	1.085	6.0	250	-	13.6	38.0	40.8	2.8	7.5%
		500	13.86	1.53	0.29	0.12	1.94	23.6	14.30	2.71	0.12	(0.04)	2.80	28.3	0.93	0.62	0.70	1.085	11.9	500	-	27.1	62.1	67.3	5.2	8.4%
		750	13.86	1.53	0.29	0.12	1.94	28.4	14.30	2.71	0.12	(0.04)	2.80	35.3	0.93	0.62	0.70	1.085	17.9	600	150	42.6	87.9	95.7	7.8	8.9%
		1,000	13.86	1.53	0.29	0.12	1.94	33.3	14.30	2.71	0.12	(0.04)	2.80	42.3	0.93	0.62	0.70	1.085	23.8	600	400	58.6	114.4	124.7	10.3	9.0%
		1,500	13.86	1.53	0.29	0.12	1.94	43.0	14.30	2.71	0.12	(0.04)	2.80	56.2	0.93	0.62	0.70	1.085	35.7	600	900	90.6	167.3	182.6	15.3	9.1%
		2,000	13.86	1.53	0.29	0.12	1.94	52.7	14.30	2.71	0.12	(0.04)	2.80	70.2	0.93	0.62	0.70	1.085	47.6	600	1,400	122.6	220.3	240.5	20.2	9.2%
R1	**Erin**	100	**13.13**	**1.90**	**0.83**	**0.40**	**3.13**	16.3	**14.48**	**2.71**	**0.40**	**(0.04)**	**3.08**	17.6	**0.93**	0.62	0.70	**1.085**	2.4	100	-	5.4	24.0	25.4	1.4	5.8%
		250	13.13	1.90	0.83	0.40	3.13	21.0	14.48	2.71	0.40	(0.04)	3.08	22.2	0.93	0.62	0.70	1.085	6.0	250	-	13.6	40.2	41.7	1.5	3.7%
		500	13.13	1.90	0.83	0.40	3.13	28.8	14.48	2.71	0.40	(0.04)	3.08	29.9	0.93	0.62	0.70	1.085	11.9	500	-	27.1	67.3	68.9	1.6	2.4%
		750	13.13	1.90	0.83	0.40	3.13	36.6	14.48	2.71	0.40	(0.04)	3.08	37.5	0.93	0.62	0.70	1.085	17.9	600	150	42.6	96.1	98.0	1.9	2.0%
		1,000	13.13	1.90	0.83	0.40	3.13	44.4	14.48	2.71	0.40	(0.04)	3.08	45.2	0.93	0.62	0.70	1.085	23.8	600	400	58.6	125.5	127.7	2.1	1.7%
		1,500	13.13	1.90	0.83	0.40	3.13	60.1	14.48	2.71	0.40	(0.04)	3.08	60.6	0.93	0.62	0.70	1.085	35.7	600	900	90.6	184.4	187.0	2.5	1.4%
		2,000	13.13	1.90	0.83	0.40	3.13	75.7	14.48	2.71	0.40	(0.04)	3.08	76.0	0.93	0.62	0.70	1.085	47.6	600	1,400	122.6	243.3	246.3	2.9	1.2%

New Rate Class: R1

Total Bill Impacts of Proposed Distribution Rates [new RTSR+TLF]: Threshold of 600 kWhs

Classes		Scenario	May 2007 Incl Rate Riders						May 2008 Incl Rate Riders						Non-Dx Compoent				Other Reg	Commodity Bands			Existing	New	$ Incr	% Incr
			Existing Dx Rates					Existing Dx	New Dx Rates					New Dx	RTSR new	WMSC	DRC	TLF new	New	Band 1	Band 2	New	Total Bill	Total Bill	Total Bill	Total Bill
																				600.0						
																				5.0	5.9					
New Class	Old Class	kWh	SrChg	base	Rider1	Rider2	VarChg	[$/month]	SrChg	base	Rider2	Rider3	VarChg	[$/month]	c/kWh	c/kWh	c/kWh		$	kWhs	kWhs		[$/month]	[$/month]	[$/month]	%
R1	**Exeter**	100	**15.10**	**0.96**	**0.45**	**0.15**	**1.56**	16.7	**15.99**	**2.25**	**0.15**	**(0.04)**	**2.36**	18.3	**0.93**	0.62	0.70	**1.085**	2.4	100	-	5.4	24.4	26.2	1.8	7.4%
		250	15.10	0.96	0.45	0.15	1.56	19.0	15.99	2.25	0.15	(0.04)	2.36	21.9	0.93	0.62	0.70	1.085	6.0	250	-	13.6	38.3	41.4	3.2	8.2%
		500	15.10	0.96	0.45	0.15	1.56	22.9	15.99	2.25	0.15	(0.04)	2.36	27.8	0.93	0.62	0.70	1.085	11.9	500	-	27.1	61.4	66.8	5.4	8.8%
		750	15.10	0.96	0.45	0.15	1.56	26.8	15.99	2.25	0.15	(0.04)	2.36	33.7	0.93	0.62	0.70	1.085	17.9	600	150	42.6	86.3	94.2	7.9	9.2%
		1,000	15.10	0.96	0.45	0.15	1.56	30.7	15.99	2.25	0.15	(0.04)	2.36	39.6	0.93	0.62	0.70	1.085	23.8	600	400	58.6	111.8	122.0	10.2	9.2%
		1,500	15.10	0.96	0.45	0.15	1.56	38.5	15.99	2.25	0.15	(0.04)	2.36	51.4	0.93	0.62	0.70	1.085	35.7	600	900	90.6	162.9	177.8	14.9	9.2%
		2,000	15.10	0.96	0.45	0.15	1.56	46.3	15.99	2.25	0.15	(0.04)	2.36	63.2	0.93	0.62	0.70	1.085	47.6	600	1,400	122.6	213.9	233.5	19.6	9.2%
R1	**Fenelon Fall**	100	**6.09**	**0.96**	**0.25**	**0.08**	**1.29**	7.4	**9.24**	**1.70**	**0.08**	**(0.04)**	**1.74**	11.0	**0.93**	0.62	0.70	**1.085**	2.4	100	-	5.4	15.1	18.8	3.7	24.6%
		250	6.09	0.96	0.25	0.08	1.29	9.3	9.24	1.70	0.08	(0.04)	1.74	13.6	0.93	0.62	0.70	1.085	6.0	250	-	13.6	28.6	33.1	4.5	15.9%
		500	6.09	0.96	0.25	0.08	1.29	12.5	9.24	1.70	0.08	(0.04)	1.74	18.0	0.93	0.62	0.70	1.085	11.9	500	-	27.1	51.0	57.0	5.9	11.6%
		750	6.09	0.96	0.25	0.08	1.29	15.8	9.24	1.70	0.08	(0.04)	1.74	22.3	0.93	0.62	0.70	1.085	17.9	600	150	42.6	75.2	82.8	7.5	10.0%
		1,000	6.09	0.96	0.25	0.08	1.29	19.0	9.24	1.70	0.08	(0.04)	1.74	26.7	0.93	0.62	0.70	1.085	23.8	600	400	58.6	100.1	109.1	9.0	9.0%
		1,500	6.09	0.96	0.25	0.08	1.29	25.4	9.24	1.70	0.08	(0.04)	1.74	35.4	0.93	0.62	0.70	1.085	35.7	600	900	90.6	149.8	161.7	11.9	8.0%
		2,000	6.09	0.96	0.25	0.08	1.29	31.9	9.24	1.70	0.08	(0.04)	1.74	44.1	0.93	0.62	0.70	1.085	47.6	600	1,400	122.6	199.5	214.4	14.9	7.4%
R1	**Forest**	100	**15.26**	**0.95**	**0.41**	**0.15**	**1.51**	16.8	**15.95**	**2.20**	**0.15**	**(0.04)**	**2.31**	18.3	**0.93**	0.62	0.70	**1.085**	2.4	100	-	5.4	24.5	26.1	1.6	6.5%
		250	15.26	0.95	0.41	0.15	1.51	19.0	15.95	2.20	0.15	(0.04)	2.31	21.7	0.93	0.62	0.70	1.085	6.0	250	-	13.6	38.3	41.2	3.0	7.7%
		500	15.26	0.95	0.41	0.15	1.51	22.8	15.95	2.20	0.15	(0.04)	2.31	27.5	0.93	0.62	0.70	1.085	11.9	500	-	27.1	61.3	66.5	5.2	8.5%
		750	15.26	0.95	0.41	0.15	1.51	26.6	15.95	2.20	0.15	(0.04)	2.31	33.3	0.93	0.62	0.70	1.085	17.9	600	150	42.6	86.1	93.8	7.7	8.9%
		1,000	15.26	0.95	0.41	0.15	1.51	30.4	15.95	2.20	0.15	(0.04)	2.31	39.1	0.93	0.62	0.70	1.085	23.8	600	400	58.6	111.5	121.5	10.0	9.0%
		1,500	15.26	0.95	0.41	0.15	1.51	37.9	15.95	2.20	0.15	(0.04)	2.31	50.6	0.93	0.62	0.70	1.085	35.7	600	900	90.6	162.3	177.0	14.7	9.1%
		2,000	15.26	0.95	0.41	0.15	1.51	45.5	15.95	2.20	0.15	(0.04)	2.31	62.2	0.93	0.62	0.70	1.085	47.6	600	1,400	122.6	213.1	232.5	19.4	9.1%
UR	**GBE**	100	**9.68**	**0.95**	**0.46**	**0.13**	**1.54**	11.2	**10.16**	**2.35**	**0.13**	**(0.02)**	**2.46**	12.6	**0.92**	0.62	0.70	**1.078**	2.4	100	-	5.4	18.9	20.4	1.4	7.6%
		250	9.68	0.95	0.46	0.13	1.54	13.5	10.16	2.35	0.13	(0.02)	2.46	16.3	0.92	0.62	0.70	1.078	5.9	250	-	13.5	32.8	35.7	2.9	8.8%
		500	9.68	0.95	0.46	0.13	1.54	17.4	10.16	2.35	0.13	(0.02)	2.46	22.4	0.92	0.62	0.70	1.078	11.8	500	-	27.0	55.9	61.2	5.3	9.5%
		750	9.68	0.95	0.46	0.13	1.54	21.2	10.16	2.35	0.13	(0.02)	2.46	28.6	0.92	0.62	0.70	1.078	17.7	600	150	42.3	80.7	88.6	7.9	9.7%
		1,000	9.68	0.95	0.46	0.13	1.54	25.1	10.16	2.35	0.13	(0.02)	2.46	34.7	0.92	0.62	0.70	1.078	23.6	600	400	58.2	106.2	116.5	10.3	9.7%
		1,500	9.68	0.95	0.46	0.13	1.54	32.8	10.16	2.35	0.13	(0.02)	2.46	47.0	0.92	0.62	0.70	1.078	35.4	600	900	90.0	157.1	172.4	15.2	9.7%
		2,000	9.68	0.95	0.46	0.13	1.54	40.5	10.16	2.35	0.13	(0.02)	2.46	59.3	0.92	0.62	0.70	1.078	47.2	600	1,400	121.8	208.1	228.3	20.2	9.7%

New Rate Class: R1

Total Bill Impacts of Proposed Distribution Rates [new RTSR+TLF]: Threshold of 600 kWhs

600.0

Classes		Scenario	May 2007 Incl Rate Riders						May 2008 Incl Rate Riders						Non-Dx Compoent				Other Reg	Commodity Bands			Existing	New	$ Incr	% Incr
			Existing Dx Rates					Existing Dx	New Dx Rates					New Dx	RTSR new	WMSC	DRC	TLF new	New	Band 1	Band 2	New	Total Bill	Total Bill	Total Bill	Total Bill
																				5.0	5.9					
New Class	Old Class	kWh	SrChg	base	Rider1	Rider2	VarChg	[$/month]	SrChg	base	Rider2	Rider3	VarChg	[$/month]	c/kWh	c/kWh	c/kWh		$	kWhs	kWhs		[$/month]	[$/month]	[$/month]	%
R1	**Georgina**	100	**11.72**	**0.98**	**0.31**	**0.09**	**1.38**	13.1	**12.83**	**2.05**	**0.09**	**(0.04)**	**2.10**	14.9	**0.93**	0.62	0.70	**1.085**	2.4	100	-	5.4	20.8	22.7	1.9	9.3%
		250	11.72	0.98	0.31	0.09	1.38	15.2	12.83	2.05	0.09	(0.04)	2.10	18.1	0.93	0.62	0.70	1.085	6.0	250	-	13.6	34.4	37.6	3.2	9.2%
		500	11.72	0.98	0.31	0.09	1.38	18.6	12.83	2.05	0.09	(0.04)	2.10	23.3	0.93	0.62	0.70	1.085	11.9	500	-	27.1	57.1	62.4	5.2	9.2%
		750	11.72	0.98	0.31	0.09	1.38	22.1	12.83	2.05	0.09	(0.04)	2.10	28.6	0.93	0.62	0.70	1.085	17.9	600	150	42.6	81.6	89.1	7.5	9.2%
		1,000	11.72	0.98	0.31	0.09	1.38	25.5	12.83	2.05	0.09	(0.04)	2.10	33.9	0.93	0.62	0.70	1.085	23.8	600	400	58.6	106.6	116.3	9.7	9.1%
		1,500	11.72	0.98	0.31	0.09	1.38	32.4	12.83	2.05	0.09	(0.04)	2.10	44.4	0.93	0.62	0.70	1.085	35.7	600	900	90.6	156.8	170.7	13.9	8.9%
		2,000	11.72	0.98	0.31	0.09	1.38	39.3	12.83	2.05	0.09	(0.04)	2.10	54.9	0.93	0.62	0.70	1.085	47.6	600	1,400	122.6	206.9	225.2	18.2	8.8%
R1	**Glencoe**	100	**12.90**	**0.77**	**0.89**	**0.43**	**2.09**	15.0	**13.54**	**2.55**	**0.43**	**(0.04)**	**2.94**	16.5	**0.93**	0.62	0.70	**1.085**	2.4	100	-	5.4	22.7	24.3	1.6	7.0%
		250	12.90	0.77	0.89	0.43	2.09	18.1	13.54	2.55	0.43	(0.04)	2.94	20.9	0.93	0.62	0.70	1.085	6.0	250	-	13.6	37.4	40.4	3.0	8.1%
		500	12.90	0.77	0.89	0.43	2.09	23.4	13.54	2.55	0.43	(0.04)	2.94	28.2	0.93	0.62	0.70	1.085	11.9	500	-	27.1	61.9	67.3	5.4	8.8%
		750	12.90	0.77	0.89	0.43	2.09	28.6	13.54	2.55	0.43	(0.04)	2.94	35.6	0.93	0.62	0.70	1.085	17.9	600	150	42.6	88.1	96.1	8.0	9.1%
		1,000	12.90	0.77	0.89	0.43	2.09	33.8	13.54	2.55	0.43	(0.04)	2.94	43.0	0.93	0.62	0.70	1.085	23.8	600	400	58.6	114.9	125.4	10.5	9.1%
		1,500	12.90	0.77	0.89	0.43	2.09	44.3	13.54	2.55	0.43	(0.04)	2.94	57.7	0.93	0.62	0.70	1.085	35.7	600	900	90.6	168.6	184.0	15.4	9.1%
		2,000	12.90	0.77	0.89	0.43	2.09	54.7	13.54	2.55	0.43	(0.04)	2.94	72.4	0.93	0.62	0.70	1.085	47.6	600	1,400	122.6	222.3	242.7	20.3	9.1%
R1	**Grand Bend**	100	**13.58**	**0.87**	**0.42**	**0.13**	**1.42**	15.0	**14.37**	**2.10**	**0.13**	**(0.04)**	**2.19**	16.6	**0.93**	0.62	0.70	**1.085**	2.4	100	-	5.4	22.7	24.4	1.7	7.3%
		250	13.58	0.87	0.42	0.13	1.42	17.1	14.37	2.10	0.13	(0.04)	2.19	19.8	0.93	0.62	0.70	1.085	6.0	250	-	13.6	36.4	39.4	3.0	8.2%
		500	13.58	0.87	0.42	0.13	1.42	20.7	14.37	2.10	0.13	(0.04)	2.19	25.3	0.93	0.62	0.70	1.085	11.9	500	-	27.1	59.2	64.4	5.2	8.7%
		750	13.58	0.87	0.42	0.13	1.42	24.2	14.37	2.10	0.13	(0.04)	2.19	30.8	0.93	0.62	0.70	1.085	17.9	600	150	42.6	83.7	91.3	7.6	9.0%
		1,000	13.58	0.87	0.42	0.13	1.42	27.8	14.37	2.10	0.13	(0.04)	2.19	36.3	0.93	0.62	0.70	1.085	23.8	600	400	58.6	108.9	118.7	9.8	9.0%
		1,500	13.58	0.87	0.42	0.13	1.42	34.9	14.37	2.10	0.13	(0.04)	2.19	47.3	0.93	0.62	0.70	1.085	35.7	600	900	90.6	159.2	173.6	14.4	9.0%
		2,000	13.58	0.87	0.42	0.13	1.42	42.0	14.37	2.10	0.13	(0.04)	2.19	58.2	0.93	0.62	0.70	1.085	47.6	600	1,400	122.6	209.6	228.5	18.9	9.0%
R1	**Hastings**	100	**16.44**	**1.35**	**0.37**	**0.12**	**1.84**	18.3	**16.65**	**2.65**	**0.12**	**(0.04)**	**2.73**	19.4	**0.93**	0.62	0.70	**1.085**	2.4	100	-	5.4	26.0	27.2	1.2	4.6%
		250	16.44	1.35	0.37	0.12	1.84	21.0	16.65	2.65	0.12	(0.04)	2.73	23.5	0.93	0.62	0.70	1.085	6.0	250	-	13.6	40.3	43.0	2.7	6.7%
		500	16.44	1.35	0.37	0.12	1.84	25.6	16.65	2.65	0.12	(0.04)	2.73	30.3	0.93	0.62	0.70	1.085	11.9	500	-	27.1	64.1	69.3	5.2	8.1%
		750	16.44	1.35	0.37	0.12	1.84	30.2	16.65	2.65	0.12	(0.04)	2.73	37.1	0.93	0.62	0.70	1.085	17.9	600	150	42.6	89.7	97.6	7.9	8.8%
		1,000	16.44	1.35	0.37	0.12	1.84	34.8	16.65	2.65	0.12	(0.04)	2.73	44.0	0.93	0.62	0.70	1.085	23.8	600	400	58.6	115.9	126.4	10.5	9.0%
		1,500	16.44	1.35	0.37	0.12	1.84	44.0	16.65	2.65	0.12	(0.04)	2.73	57.6	0.93	0.62	0.70	1.085	35.7	600	900	90.6	168.4	184.0	15.6	9.3%
		2,000	16.44	1.35	0.37	0.12	1.84	53.2	16.65	2.65	0.12	(0.04)	2.73	71.3	0.93	0.62	0.70	1.085	47.6	600	1,400	122.6	220.9	241.6	20.7	9.4%

New Rate Class: R1

Total Bill Impacts of Proposed Distribution Rates [new RTSR+TLF]: Threshold of 600 kWhs

Classes		Scenario	May 2007 Incl Rate Riders						May 2008 Incl Rate Riders						Non-Dx Compoent				Other Reg	Commodity Bands (600.0)			Existing	New	$ Incr	% Incr
			Existing Dx Rates					Existing Dx	New Dx Rates					New Dx	RTSR new	WMSC	DRC	TLF new	New	Band 1	Band 2	New	Total Bill	Total Bill	Total Bill	Total Bill
																				5.0	5.9					
New Class	Old Class	kWh	SrChg	base	Rider1	Rider2	VarChg	[$/month]	SrChg	base	Rider2	Rider3	VarChg	[$/month]	c/kWh	c/kWh	c/kWh		$	kWhs	kWhs		[$/month]	[$/month]	[$/month]	%
R1	**Havelock**	100	**15.17**	**1.14**	**0.32**	**0.13**	**1.59**	16.8	**15.97**	**2.30**	**0.13**	**(0.04)**	**2.39**	18.4	**0.93**	0.62	0.70	**1.085**	2.4	100	-	5.4	24.5	26.2	1.7	7.0%
		250	15.17	1.14	0.32	0.13	1.59	19.1	15.97	2.30	0.13	(0.04)	2.39	21.9	0.93	0.62	0.70	1.085	6.0	250	-	13.6	38.4	41.5	3.1	8.0%
		500	15.17	1.14	0.32	0.13	1.59	23.1	15.97	2.30	0.13	(0.04)	2.39	27.9	0.93	0.62	0.70	1.085	11.9	500	-	27.1	61.6	67.0	5.3	8.7%
		750	15.17	1.14	0.32	0.13	1.59	27.1	15.97	2.30	0.13	(0.04)	2.39	33.9	0.93	0.62	0.70	1.085	17.9	600	150	42.6	86.6	94.4	7.8	9.0%
		1,000	15.17	1.14	0.32	0.13	1.59	31.1	15.97	2.30	0.13	(0.04)	2.39	39.9	0.93	0.62	0.70	1.085	23.8	600	400	58.6	112.2	122.3	10.1	9.0%
		1,500	15.17	1.14	0.32	0.13	1.59	39.0	15.97	2.30	0.13	(0.04)	2.39	51.9	0.93	0.62	0.70	1.085	35.7	600	900	90.6	163.4	178.2	14.8	9.1%
		2,000	15.17	1.14	0.32	0.13	1.59	47.0	15.97	2.30	0.13	(0.04)	2.39	63.8	0.93	0.62	0.70	1.085	47.6	600	1,400	122.6	214.6	234.1	19.5	9.1%
R1	**Kirkfield**	100	**5.34**	**1.00**	**0.48**	**0.26**	**1.74**	7.1	**8.43**	**2.00**	**0.26**	**(0.04)**	**2.22**	10.6	**0.93**	0.62	0.70	**1.085**	2.4	100	-	5.4	14.8	18.5	3.7	24.8%
		250	5.34	1.00	0.48	0.26	1.74	9.7	8.43	2.00	0.26	(0.04)	2.22	14.0	0.93	0.62	0.70	1.085	6.0	250	-	13.6	28.9	33.5	4.6	15.7%
		500	5.34	1.00	0.48	0.26	1.74	14.0	8.43	2.00	0.26	(0.04)	2.22	19.5	0.93	0.62	0.70	1.085	11.9	500	-	27.1	52.5	58.6	6.0	11.5%
		750	5.34	1.00	0.48	0.26	1.74	18.4	8.43	2.00	0.26	(0.04)	2.22	25.1	0.93	0.62	0.70	1.085	17.9	600	150	42.6	77.9	85.6	7.7	9.9%
		1,000	5.34	1.00	0.48	0.26	1.74	22.7	8.43	2.00	0.26	(0.04)	2.22	30.7	0.93	0.62	0.70	1.085	23.8	600	400	58.6	103.8	113.1	9.2	8.9%
		1,500	5.34	1.00	0.48	0.26	1.74	31.4	8.43	2.00	0.26	(0.04)	2.22	41.8	0.93	0.62	0.70	1.085	35.7	600	900	90.6	155.8	168.1	12.3	7.9%
		2,000	5.34	1.00	0.48	0.26	1.74	40.1	8.43	2.00	0.26	(0.04)	2.22	52.9	0.93	0.62	0.70	1.085	47.6	600	1,400	122.6	207.8	223.1	15.4	7.4%
R1	**Lanark High**	100	**11.31**	**1.02**	**0.56**	**0.40**	**1.98**	13.3	**12.93**	**2.35**	**0.40**	**(0.04)**	**2.71**	15.6	**0.93**	0.62	0.70	**1.085**	2.4	100	-	5.4	21.0	23.5	2.5	11.7%
		250	11.31	1.02	0.56	0.40	1.98	16.3	12.93	2.35	0.40	(0.04)	2.71	19.7	0.93	0.62	0.70	1.085	6.0	250	-	13.6	35.5	39.2	3.7	10.5%
		500	11.31	1.02	0.56	0.40	1.98	21.2	12.93	2.35	0.40	(0.04)	2.71	26.5	0.93	0.62	0.70	1.085	11.9	500	-	27.1	59.7	65.5	5.8	9.7%
		750	11.31	1.02	0.56	0.40	1.98	26.2	12.93	2.35	0.40	(0.04)	2.71	33.3	0.93	0.62	0.70	1.085	17.9	600	150	42.6	85.6	93.8	8.1	9.5%
		1,000	11.31	1.02	0.56	0.40	1.98	31.1	12.93	2.35	0.40	(0.04)	2.71	40.1	0.93	0.62	0.70	1.085	23.8	600	400	58.6	112.2	122.5	10.3	9.2%
		1,500	11.31	1.02	0.56	0.40	1.98	41.0	12.93	2.35	0.40	(0.04)	2.71	53.6	0.93	0.62	0.70	1.085	35.7	600	900	90.6	165.4	180.0	14.6	8.8%
		2,000	11.31	1.02	0.56	0.40	1.98	50.9	12.93	2.35	0.40	(0.04)	2.71	67.2	0.93	0.62	0.70	1.085	47.6	600	1,400	122.6	218.5	237.5	18.9	8.7%
R1	**Larder Lake**	100	**15.84**	**1.01**	**0.68**	**0.43**	**2.12**	18.0	**15.80**	**2.70**	**0.43**	**(0.04)**	**3.09**	18.9	**0.93**	0.62	0.70	**1.085**	2.4	100	-	5.4	25.7	26.7	1.0	4.0%
		250	15.84	1.01	0.68	0.43	2.12	21.1	15.80	2.70	0.43	(0.04)	3.09	23.5	0.93	0.62	0.70	1.085	6.0	250	-	13.6	40.4	43.0	2.7	6.6%
		500	15.84	1.01	0.68	0.43	2.12	26.4	15.80	2.70	0.43	(0.04)	3.09	31.3	0.93	0.62	0.70	1.085	11.9	500	-	27.1	64.9	70.3	5.3	8.2%
		750	15.84	1.01	0.68	0.43	2.12	31.7	15.80	2.70	0.43	(0.04)	3.09	39.0	0.93	0.62	0.70	1.085	17.9	600	150	42.6	91.2	99.5	8.2	9.0%
		1,000	15.84	1.01	0.68	0.43	2.12	37.0	15.80	2.70	0.43	(0.04)	3.09	46.7	0.93	0.62	0.70	1.085	23.8	600	400	58.6	118.1	129.2	11.0	9.3%
		1,500	15.84	1.01	0.68	0.43	2.12	47.6	15.80	2.70	0.43	(0.04)	3.09	62.2	0.93	0.62	0.70	1.085	35.7	600	900	90.6	172.0	188.5	16.5	9.6%
		2,000	15.84	1.01	0.68	0.43	2.12	58.2	15.80	2.70	0.43	(0.04)	3.09	77.7	0.93	0.62	0.70	1.085	47.6	600	1,400	122.6	225.9	247.9	22.1	9.8%

New Rate Class: R1

Total Bill Impacts of Proposed Distribution Rates [new RTSR+TLF]: Threshold of 600 kWhs

Classes		Scenario	May 2007 Incl Rate Riders						May 2008 Incl Rate Riders						Non-Dx Compoent				Other Reg	Commodity Bands			Existing	New	$ Incr	% Incr
			Existing Dx Rates					Existing Dx	New Dx Rates					New Dx	RTSR new	WMSC	DRC	TLF new	New	Band 1	Band 2	New	Total Bill	Total Bill	Total Bill	Total Bill
																				600.0						
																				5.0	5.9					
New Class	Old Class	kWh	SrChg	base	Rider1	Rider2	VarChg	[$/month]	SrChg	base	Rider2	Rider3	VarChg	[$/month]	c/kWh	c/kWh	c/kWh		$	kWhs	kWhs		[$/month]	[$/month]	[$/month]	%
R1	**Latchford**	100	**13.31**	**0.88**	**1.04**	**0.45**	**2.37**	15.7	**14.43**	**2.71**	**0.45**	**(0.04)**	**3.13**	17.6	**0.93**	0.62	0.70	**1.085**	2.4	100	-	5.4	23.4	25.4	2.0	8.5%
		250	13.31	0.88	1.04	0.45	2.37	19.2	14.43	2.71	0.45	(0.04)	3.13	22.2	0.93	0.62	0.70	1.085	6.0	250	-	13.6	38.5	41.8	3.3	8.5%
		500	13.31	0.88	1.04	0.45	2.37	25.2	14.43	2.71	0.45	(0.04)	3.13	30.1	0.93	0.62	0.70	1.085	11.9	500	-	27.1	63.7	69.1	5.4	8.5%
		750	13.31	0.88	1.04	0.45	2.37	31.1	14.43	2.71	0.45	(0.04)	3.13	37.9	0.93	0.62	0.70	1.085	17.9	600	150	42.6	90.6	98.4	7.8	8.6%
		1,000	13.31	0.88	1.04	0.45	2.37	37.0	14.43	2.71	0.45	(0.04)	3.13	45.7	0.93	0.62	0.70	1.085	23.8	600	400	58.6	118.1	128.1	10.0	8.5%
		1,500	13.31	0.88	1.04	0.45	2.37	48.9	14.43	2.71	0.45	(0.04)	3.13	61.3	0.93	0.62	0.70	1.085	35.7	600	900	90.6	173.2	187.7	14.5	8.3%
		2,000	13.31	0.88	1.04	0.45	2.37	60.7	14.43	2.71	0.45	(0.04)	3.13	77.0	0.93	0.62	0.70	1.085	47.6	600	1,400	122.6	228.3	247.2	18.9	8.3%
UR	**Lindsay**	100	**15.81**	**1.01**	**0.41**	**0.14**	**1.56**	17.4	**14.63**	**2.40**	**0.14**	**(0.02)**	**2.51**	17.1	**0.92**	0.62	0.70	**1.078**	2.4	100	-	5.4	25.1	24.9	(0.2)	-0.7%
		250	15.81	1.01	0.41	0.14	1.56	19.7	14.63	2.40	0.14	(0.02)	2.51	20.9	0.92	0.62	0.70	1.078	5.9	250	-	13.5	39.0	40.3	1.3	3.4%
		500	15.81	1.01	0.41	0.14	1.56	23.6	14.63	2.40	0.14	(0.02)	2.51	27.2	0.92	0.62	0.70	1.078	11.8	500	-	27.0	62.1	65.9	3.8	6.1%
		750	15.81	1.01	0.41	0.14	1.56	27.5	14.63	2.40	0.14	(0.02)	2.51	33.5	0.92	0.62	0.70	1.078	17.7	600	150	42.3	87.0	93.5	6.5	7.4%
		1,000	15.81	1.01	0.41	0.14	1.56	31.4	14.63	2.40	0.14	(0.02)	2.51	39.7	0.92	0.62	0.70	1.078	23.6	600	400	58.2	112.5	121.5	9.0	8.0%
		1,500	15.81	1.01	0.41	0.14	1.56	39.2	14.63	2.40	0.14	(0.02)	2.51	52.3	0.92	0.62	0.70	1.078	35.4	600	900	90.0	163.6	177.7	14.1	8.6%
		2,000	15.81	1.01	0.41	0.14	1.56	47.0	14.63	2.40	0.14	(0.02)	2.51	64.8	0.92	0.62	0.70	1.078	47.2	600	1,400	121.8	214.6	233.9	19.2	9.0%
R1	**Lucan Grant**	100	**11.72**	**1.42**	**0.37**	**0.17**	**1.96**	13.7	**12.83**	**2.60**	**0.17**	**(0.04)**	**2.73**	15.6	**0.93**	0.62	0.70	**1.085**	2.4	100	-	5.4	21.4	23.4	2.0	9.3%
		250	11.72	1.42	0.37	0.17	1.96	16.6	12.83	2.60	0.17	(0.04)	2.73	19.7	0.93	0.62	0.70	1.085	6.0	250	-	13.6	35.9	39.2	3.3	9.2%
		500	11.72	1.42	0.37	0.17	1.96	21.5	12.83	2.60	0.17	(0.04)	2.73	26.5	0.93	0.62	0.70	1.085	11.9	500	-	27.1	60.0	65.5	5.5	9.2%
		750	11.72	1.42	0.37	0.17	1.96	26.4	12.83	2.60	0.17	(0.04)	2.73	33.3	0.93	0.62	0.70	1.085	17.9	600	150	42.6	85.9	93.8	7.9	9.2%
		1,000	11.72	1.42	0.37	0.17	1.96	31.3	12.83	2.60	0.17	(0.04)	2.73	40.2	0.93	0.62	0.70	1.085	23.8	600	400	58.6	112.4	122.6	10.2	9.0%
		1,500	11.72	1.42	0.37	0.17	1.96	41.1	12.83	2.60	0.17	(0.04)	2.73	53.8	0.93	0.62	0.70	1.085	35.7	600	900	90.6	165.5	180.2	14.7	8.9%
		2,000	11.72	1.42	0.37	0.17	1.96	50.9	12.83	2.60	0.17	(0.04)	2.73	67.5	0.93	0.62	0.70	1.085	47.6	600	1,400	122.6	218.5	237.8	19.2	8.8%
R1	**Malahide**	100	**11.17**	**0.87**	**0.78**	**0.34**	**1.99**	13.2	**12.97**	**2.40**	**0.34**	**(0.04)**	**2.70**	15.7	**0.93**	0.62	0.70	**1.085**	2.4	100	-	5.4	20.9	23.5	2.6	12.5%
		250	11.17	0.87	0.78	0.34	1.99	16.1	12.97	2.40	0.34	(0.04)	2.70	19.7	0.93	0.62	0.70	1.085	6.0	250	-	13.6	35.4	39.2	3.8	10.9%
		500	11.17	0.87	0.78	0.34	1.99	21.1	12.97	2.40	0.34	(0.04)	2.70	26.5	0.93	0.62	0.70	1.085	11.9	500	-	27.1	59.6	65.5	5.9	9.9%
		750	11.17	0.87	0.78	0.34	1.99	26.1	12.97	2.40	0.34	(0.04)	2.70	33.2	0.93	0.62	0.70	1.085	17.9	600	150	42.6	85.6	93.7	8.1	9.5%
		1,000	11.17	0.87	0.78	0.34	1.99	31.1	12.97	2.40	0.34	(0.04)	2.70	40.0	0.93	0.62	0.70	1.085	23.8	600	400	58.6	112.2	122.4	10.2	9.1%
		1,500	11.17	0.87	0.78	0.34	1.99	41.0	12.97	2.40	0.34	(0.04)	2.70	53.5	0.93	0.62	0.70	1.085	35.7	600	900	90.6	165.4	179.9	14.5	8.8%
		2,000	11.17	0.87	0.78	0.34	1.99	51.0	12.97	2.40	0.34	(0.04)	2.70	67.0	0.93	0.62	0.70	1.085	47.6	600	1,400	122.6	218.6	237.3	18.7	8.6%

New Rate Class: R1

Total Bill Impacts of Proposed Distribution Rates [new RTSR+TLF]: Threshold of 600 kWhs

Classes		Scenario	May 2007 Incl Rate Riders						May 2008 Incl Rate Riders						Non-Dx Compoent				Other Reg	Commodity Bands	600.0		Existing	New	$ Incr	% Incr
			Existing Dx Rates					Existing Dx	New Dx Rates					New Dx	RTSR new	WMSC	DRC	TLF new	New	Band 1	Band 2	New	Total Bill	Total Bill	Total Bill	Total Bill
																				5.0	5.9					
New Class	Old Class	kWh	SrChg	base	Rider1	Rider2	VarChg	[$/month]	SrChg	base	Rider2	Rider3	VarChg	[$/month]	c/kWh	c/kWh	c/kWh		$	kWhs	kWhs		[$/month]	[$/month]	[$/month]	%
R1	Mapleton	100	13.47	0.92	0.65	0.39	1.96	15.4	14.39	2.40	0.39	(0.04)	2.75	17.1	0.93	0.62	0.70	1.085	2.4	100	-	5.4	23.1	25.0	1.8	7.9%
		250	13.47	0.92	0.65	0.39	1.96	18.4	14.39	2.40	0.39	(0.04)	2.75	21.3	0.93	0.62	0.70	1.085	6.0	250	-	13.6	37.6	40.8	3.2	8.4%
		500	13.47	0.92	0.65	0.39	1.96	23.3	14.39	2.40	0.39	(0.04)	2.75	28.2	0.93	0.62	0.70	1.085	11.9	500	-	27.1	61.8	67.2	5.4	8.8%
		750	13.47	0.92	0.65	0.39	1.96	28.2	14.39	2.40	0.39	(0.04)	2.75	35.0	0.93	0.62	0.70	1.085	17.9	600	150	42.6	87.7	95.5	7.9	9.0%
		1,000	13.47	0.92	0.65	0.39	1.96	33.1	14.39	2.40	0.39	(0.04)	2.75	41.9	0.93	0.62	0.70	1.085	23.8	600	400	58.6	114.2	124.4	10.2	8.9%
		1,500	13.47	0.92	0.65	0.39	1.96	42.9	14.39	2.40	0.39	(0.04)	2.75	55.7	0.93	0.62	0.70	1.085	35.7	600	900	90.6	167.2	182.0	14.8	8.8%
		2,000	13.47	0.92	0.65	0.39	1.96	52.7	14.39	2.40	0.39	(0.04)	2.75	69.4	0.93	0.62	0.70	1.085	47.6	600	1,400	122.6	220.3	239.7	19.4	8.8%
R1	Markdale	100	14.30	0.86	0.44	0.16	1.46	15.8	15.19	2.10	0.16	(0.04)	2.22	17.4	0.93	0.62	0.70	1.085	2.4	100	-	5.4	23.5	25.2	1.8	7.5%
		250	14.30	0.86	0.44	0.16	1.46	18.0	15.19	2.10	0.16	(0.04)	2.22	20.7	0.93	0.62	0.70	1.085	6.0	250	-	13.6	37.2	40.3	3.1	8.2%
		500	14.30	0.86	0.44	0.16	1.46	21.6	15.19	2.10	0.16	(0.04)	2.22	26.3	0.93	0.62	0.70	1.085	11.9	500	-	27.1	60.1	65.3	5.2	8.7%
		750	14.30	0.86	0.44	0.16	1.46	25.3	15.19	2.10	0.16	(0.04)	2.22	31.9	0.93	0.62	0.70	1.085	17.9	600	150	42.6	84.7	92.3	7.6	9.0%
		1,000	14.30	0.86	0.44	0.16	1.46	28.9	15.19	2.10	0.16	(0.04)	2.22	37.4	0.93	0.62	0.70	1.085	23.8	600	400	58.6	110.0	119.8	9.8	8.9%
		1,500	14.30	0.86	0.44	0.16	1.46	36.2	15.19	2.10	0.16	(0.04)	2.22	48.5	0.93	0.62	0.70	1.085	35.7	600	900	90.6	160.6	174.9	14.3	8.9%
		2,000	14.30	0.86	0.44	0.16	1.46	43.5	15.19	2.10	0.16	(0.04)	2.22	59.6	0.93	0.62	0.70	1.085	47.6	600	1,400	122.6	211.1	229.9	18.8	8.9%
R1	Marmora	100	11.59	0.92	0.33	0.11	1.36	13.0	12.86	2.00	0.11	(0.04)	2.07	14.9	0.93	0.62	0.70	1.085	2.4	100	-	5.4	20.7	22.7	2.1	10.1%
		250	11.59	0.92	0.33	0.11	1.36	15.0	12.86	2.00	0.11	(0.04)	2.07	18.0	0.93	0.62	0.70	1.085	6.0	250	-	13.6	34.2	37.6	3.3	9.7%
		500	11.59	0.92	0.33	0.11	1.36	18.4	12.86	2.00	0.11	(0.04)	2.07	23.2	0.93	0.62	0.70	1.085	11.9	500	-	27.1	56.9	62.3	5.4	9.4%
		750	11.59	0.92	0.33	0.11	1.36	21.8	12.86	2.00	0.11	(0.04)	2.07	28.4	0.93	0.62	0.70	1.085	17.9	600	150	42.6	81.3	88.9	7.6	9.4%
		1,000	11.59	0.92	0.33	0.11	1.36	25.2	12.86	2.00	0.11	(0.04)	2.07	33.6	0.93	0.62	0.70	1.085	23.8	600	400	58.6	106.3	116.0	9.7	9.1%
		1,500	11.59	0.92	0.33	0.11	1.36	32.0	12.86	2.00	0.11	(0.04)	2.07	44.0	0.93	0.62	0.70	1.085	35.7	600	900	90.6	156.4	170.3	14.0	8.9%
		2,000	11.59	0.92	0.33	0.11	1.36	38.8	12.86	2.00	0.11	(0.04)	2.07	54.3	0.93	0.62	0.70	1.085	47.6	600	1,400	122.6	206.4	224.6	18.2	8.8%
R1	McGarry	100	12.85	0.93	0.71	0.45	2.09	14.9	13.55	2.50	0.45	(0.04)	2.91	16.5	0.93	0.62	0.70	1.085	2.4	100	-	5.4	22.6	24.3	1.6	7.2%
		250	12.85	0.93	0.71	0.45	2.09	18.1	13.55	2.50	0.45	(0.04)	2.91	20.8	0.93	0.62	0.70	1.085	6.0	250	-	13.6	37.3	40.3	3.0	8.1%
		500	12.85	0.93	0.71	0.45	2.09	23.3	13.55	2.50	0.45	(0.04)	2.91	28.1	0.93	0.62	0.70	1.085	11.9	500	-	27.1	61.8	67.1	5.3	8.6%
		750	12.85	0.93	0.71	0.45	2.09	28.5	13.55	2.50	0.45	(0.04)	2.91	35.4	0.93	0.62	0.70	1.085	17.9	600	150	42.6	88.0	95.9	7.9	8.9%
		1,000	12.85	0.93	0.71	0.45	2.09	33.8	13.55	2.50	0.45	(0.04)	2.91	42.7	0.93	0.62	0.70	1.085	23.8	600	400	58.6	114.9	125.1	10.2	8.9%
		1,500	12.85	0.93	0.71	0.45	2.09	44.2	13.55	2.50	0.45	(0.04)	2.91	57.2	0.93	0.62	0.70	1.085	35.7	600	900	90.6	168.6	183.6	15.0	8.9%
		2,000	12.85	0.93	0.71	0.45	2.09	54.7	13.55	2.50	0.45	(0.04)	2.91	71.8	0.93	0.62	0.70	1.085	47.6	600	1,400	122.6	222.3	242.1	19.8	8.9%

New Rate Class: R1

Total Bill Impacts of Proposed Distribution Rates [new RTSR+TLF]: Threshold of 600 kWhs

Classes		Scenario	May 2007 Incl Rate Riders						May 2008 Incl Rate Riders						Non-Dx Compoent				Other Reg	Commodity Bands			Existing	New	$ Incr	% Incr
			Existing Dx Rates					Existing Dx	New Dx Rates					New Dx	RTSR new	WMSC	DRC	TLF new	New	Band 1	Band 2	New	Total Bill	Total Bill	Total Bill	Total Bill
																				600.0						
																				5.0	5.9					
New Class	Old Class	kWh	SrChg	base	Rider1	Rider2	VarChg	[$/month]	SrChg	base	Rider2	Rider3	VarChg	[$/month]	c/kWh	c/kWh	c/kWh		$	kWhs	kWhs		[$/month]	[$/month]	[$/month]	%
R1	**Meaford**	100	**12.75**	**0.97**	**0.40**	**0.12**	**1.49**	14.2	**13.57**	**2.20**	**0.12**	**(0.04)**	**2.28**	15.9	**0.93**	0.62	0.70	**1.085**	2.4	100	-	5.4	21.9	23.7	1.7	7.8%
		250	12.75	0.97	0.40	0.12	1.49	16.5	13.57	2.20	0.12	(0.04)	2.28	19.3	0.93	0.62	0.70	1.085	6.0	250	-	13.6	35.7	38.8	3.1	8.6%
		500	12.75	0.97	0.40	0.12	1.49	20.2	13.57	2.20	0.12	(0.04)	2.28	25.0	0.93	0.62	0.70	1.085	11.9	500	-	27.1	58.7	64.0	5.3	9.0%
		750	12.75	0.97	0.40	0.12	1.49	23.9	13.57	2.20	0.12	(0.04)	2.28	30.7	0.93	0.62	0.70	1.085	17.9	600	150	42.6	83.4	91.2	7.8	9.3%
		1,000	12.75	0.97	0.40	0.12	1.49	27.7	13.57	2.20	0.12	(0.04)	2.28	36.4	0.93	0.62	0.70	1.085	23.8	600	400	58.6	108.8	118.8	10.1	9.3%
		1,500	12.75	0.97	0.40	0.12	1.49	35.1	13.57	2.20	0.12	(0.04)	2.28	47.8	0.93	0.62	0.70	1.085	35.7	600	900	90.6	159.5	174.2	14.7	9.2%
		2,000	12.75	0.97	0.40	0.12	1.49	42.6	13.57	2.20	0.12	(0.04)	2.28	59.2	0.93	0.62	0.70	1.085	47.6	600	1,400	122.6	210.2	229.5	19.3	9.2%
R1	**Middlesex C**	100	**14.19**	**0.78**	**0.65**	**0.40**	**1.83**	16.0	**15.21**	**2.25**	**0.40**	**(0.04)**	**2.61**	17.8	**0.93**	0.62	0.70	**1.085**	2.4	100	-	5.4	23.7	25.6	1.9	8.1%
		250	14.19	0.78	0.65	0.40	1.83	18.8	15.21	2.25	0.40	(0.04)	2.61	21.7	0.93	0.62	0.70	1.085	6.0	250	-	13.6	38.0	41.3	3.2	8.5%
		500	14.19	0.78	0.65	0.40	1.83	23.3	15.21	2.25	0.40	(0.04)	2.61	28.3	0.93	0.62	0.70	1.085	11.9	500	-	27.1	61.8	67.3	5.5	8.8%
		750	14.19	0.78	0.65	0.40	1.83	27.9	15.21	2.25	0.40	(0.04)	2.61	34.8	0.93	0.62	0.70	1.085	17.9	600	150	42.6	87.4	95.3	7.9	9.0%
		1,000	14.19	0.78	0.65	0.40	1.83	32.5	15.21	2.25	0.40	(0.04)	2.61	41.3	0.93	0.62	0.70	1.085	23.8	600	400	58.6	113.6	123.8	10.2	9.0%
		1,500	14.19	0.78	0.65	0.40	1.83	41.6	15.21	2.25	0.40	(0.04)	2.61	54.4	0.93	0.62	0.70	1.085	35.7	600	900	90.6	166.0	180.8	14.8	8.9%
		2,000	14.19	0.78	0.65	0.40	1.83	50.8	15.21	2.25	0.40	(0.04)	2.61	67.5	0.93	0.62	0.70	1.085	47.6	600	1,400	122.6	218.4	237.7	19.3	8.8%
R1	**Napanee**	100	**14.70**	**1.02**	**0.43**	**0.14**	**1.59**	16.3	**15.09**	**2.35**	**0.14**	**(0.04)**	**2.45**	17.5	**0.93**	0.62	0.70	**1.085**	2.4	100	-	5.4	24.0	25.3	1.4	5.6%
		250	14.70	1.02	0.43	0.14	1.59	18.7	15.09	2.35	0.14	(0.04)	2.45	21.2	0.93	0.62	0.70	1.085	6.0	250	-	13.6	37.9	40.7	2.8	7.4%
		500	14.70	1.02	0.43	0.14	1.59	22.7	15.09	2.35	0.14	(0.04)	2.45	27.3	0.93	0.62	0.70	1.085	11.9	500	-	27.1	61.2	66.4	5.2	8.5%
		750	14.70	1.02	0.43	0.14	1.59	26.6	15.09	2.35	0.14	(0.04)	2.45	33.5	0.93	0.62	0.70	1.085	17.9	600	150	42.6	86.1	94.0	7.8	9.1%
		1,000	14.70	1.02	0.43	0.14	1.59	30.6	15.09	2.35	0.14	(0.04)	2.45	39.6	0.93	0.62	0.70	1.085	23.8	600	400	58.6	111.7	122.0	10.3	9.3%
		1,500	14.70	1.02	0.43	0.14	1.59	38.6	15.09	2.35	0.14	(0.04)	2.45	51.9	0.93	0.62	0.70	1.085	35.7	600	900	90.6	162.9	178.2	15.3	9.4%
		2,000	14.70	1.02	0.43	0.14	1.59	46.5	15.09	2.35	0.14	(0.04)	2.45	64.1	0.93	0.62	0.70	1.085	47.6	600	1,400	122.6	214.1	234.4	20.3	9.5%
R1	**Nipigon**	100	**14.23**	**1.42**	**1.27**	**0.72**	**3.41**	17.6	**15.20**	**2.71**	**0.72**	**(0.04)**	**3.40**	18.6	**0.93**	0.62	0.70	**1.085**	2.4	100	-	5.4	25.3	26.4	1.1	4.2%
		250	14.23	1.42	1.27	0.72	3.41	22.8	15.20	2.71	0.72	(0.04)	3.40	23.7	0.93	0.62	0.70	1.085	6.0	250	-	13.6	42.0	43.2	1.2	2.9%
		500	14.23	1.42	1.27	0.72	3.41	31.3	15.20	2.71	0.72	(0.04)	3.40	32.2	0.93	0.62	0.70	1.085	11.9	500	-	27.1	69.8	71.2	1.4	2.0%
		750	14.23	1.42	1.27	0.72	3.41	39.8	15.20	2.71	0.72	(0.04)	3.40	40.7	0.93	0.62	0.70	1.085	17.9	600	150	42.6	99.3	101.1	1.9	1.9%
		1,000	14.23	1.42	1.27	0.72	3.41	48.3	15.20	2.71	0.72	(0.04)	3.40	49.2	0.93	0.62	0.70	1.085	23.8	600	400	58.6	129.4	131.6	2.2	1.7%
		1,500	14.23	1.42	1.27	0.72	3.41	65.4	15.20	2.71	0.72	(0.04)	3.40	66.1	0.93	0.62	0.70	1.085	35.7	600	900	90.6	189.7	192.5	2.8	1.5%
		2,000	14.23	1.42	1.27	0.72	3.41	82.4	15.20	2.71	0.72	(0.04)	3.40	83.1	0.93	0.62	0.70	1.085	47.6	600	1,400	122.6	250.0	253.4	3.3	1.3%

New Rate Class: R1

Total Bill Impacts of Proposed Distribution Rates [new RTSR+TLF]: Threshold of 600 kWhs

600.0

Classes		Scenario	May 2007 Incl Rate Riders						May 2008 Incl Rate Riders						Non-Dx Compoent				Other Reg	Commodity Bands			Existing	New	$ Incr	% Incr
			Existing Dx Rates					Existing Dx	New Dx Rates					New Dx	RTSR new	WMSC	DRC	TLF new	New	Band 1	Band 2	New	Total Bill	Total Bill	Total Bill	Total Bill
																				5.0	5.9					
New Class	**Old Class**	kWh	SrChg	base	Rider1	Rider2	VarChg	[$/month]	SrChg	base	Rider2	Rider3	VarChg	[$/month]	c/kWh	c/kWh	c/kWh		$	kWhs	kWhs		[$/month]	[$/month]	[$/month]	%
R1	**North Dorch**	100	**8.97**	**0.86**	**0.67**	**0.40**	**1.93**	10.9	**10.52**	**2.25**	**0.40**	**(0.04)**	**2.61**	13.1	**0.93**	0.62	0.70	**1.085**	2.4	100	-	5.4	18.6	20.9	2.3	12.6%
		250	8.97	0.86	0.67	0.40	1.93	13.8	10.52	2.25	0.40	(0.04)	2.61	17.0	0.93	0.62	0.70	1.085	6.0	250	-	13.6	33.0	36.6	3.5	10.6%
		500	8.97	0.86	0.67	0.40	1.93	18.6	10.52	2.25	0.40	(0.04)	2.61	23.6	0.93	0.62	0.70	1.085	11.9	500	-	27.1	57.1	62.6	5.5	9.6%
		750	8.97	0.86	0.67	0.40	1.93	23.4	10.52	2.25	0.40	(0.04)	2.61	30.1	0.93	0.62	0.70	1.085	17.9	600	150	42.6	82.9	90.6	7.7	9.2%
		1,000	8.97	0.86	0.67	0.40	1.93	28.3	10.52	2.25	0.40	(0.04)	2.61	36.6	0.93	0.62	0.70	1.085	23.8	600	400	58.6	109.4	119.1	9.7	8.9%
		1,500	8.97	0.86	0.67	0.40	1.93	37.9	10.52	2.25	0.40	(0.04)	2.61	49.7	0.93	0.62	0.70	1.085	35.7	600	900	90.6	162.3	176.1	13.8	8.5%
		2,000	8.97	0.86	0.67	0.40	1.93	47.6	10.52	2.25	0.40	(0.04)	2.61	62.8	0.93	0.62	0.70	1.085	47.6	600	1,400	122.6	215.2	233.0	17.9	8.3%
R1	**North Dunda**	100	**11.17**	**0.97**	**0.55**	**0.14**	**1.66**	12.8	**12.97**	**2.25**	**0.14**	**(0.04)**	**2.35**	15.3	**0.93**	0.62	0.70	**1.085**	2.4	100	-	5.4	20.5	23.1	2.6	12.6%
		250	11.17	0.97	0.55	0.14	1.66	15.3	12.97	2.25	0.14	(0.04)	2.35	18.8	0.93	0.62	0.70	1.085	6.0	250	-	13.6	34.6	38.4	3.8	11.0%
		500	11.17	0.97	0.55	0.14	1.66	19.5	12.97	2.25	0.14	(0.04)	2.35	24.7	0.93	0.62	0.70	1.085	11.9	500	-	27.1	58.0	63.8	5.8	10.0%
		750	11.17	0.97	0.55	0.14	1.66	23.6	12.97	2.25	0.14	(0.04)	2.35	30.6	0.93	0.62	0.70	1.085	17.9	600	150	42.6	83.1	91.1	8.0	9.6%
		1,000	11.17	0.97	0.55	0.14	1.66	27.8	12.97	2.25	0.14	(0.04)	2.35	36.5	0.93	0.62	0.70	1.085	23.8	600	400	58.6	108.9	118.9	10.0	9.2%
		1,500	11.17	0.97	0.55	0.14	1.66	36.1	12.97	2.25	0.14	(0.04)	2.35	48.3	0.93	0.62	0.70	1.085	35.7	600	900	90.6	160.4	174.6	14.2	8.8%
		2,000	11.17	0.97	0.55	0.14	1.66	44.4	12.97	2.25	0.14	(0.04)	2.35	60.0	0.93	0.62	0.70	1.085	47.6	600	1,400	122.6	212.0	230.3	18.3	8.6%
R1	**North Gleng**	100	**7.74**	**1.02**	**0.52**	**0.22**	**1.76**	9.5	**9.83**	**2.20**	**0.22**	**(0.04)**	**2.38**	12.2	**0.93**	0.62	0.70	**1.085**	2.4	100	-	5.4	17.2	20.0	2.8	16.4%
		250	7.74	1.02	0.52	0.22	1.76	12.1	9.83	2.20	0.22	(0.04)	2.38	15.8	0.93	0.62	0.70	1.085	6.0	250	-	13.6	31.4	35.3	3.9	12.4%
		500	7.74	1.02	0.52	0.22	1.76	16.5	9.83	2.20	0.22	(0.04)	2.38	21.7	0.93	0.62	0.70	1.085	11.9	500	-	27.1	55.0	60.8	5.7	10.4%
		750	7.74	1.02	0.52	0.22	1.76	20.9	9.83	2.20	0.22	(0.04)	2.38	27.7	0.93	0.62	0.70	1.085	17.9	600	150	42.6	80.4	88.2	7.7	9.6%
		1,000	7.74	1.02	0.52	0.22	1.76	25.3	9.83	2.20	0.22	(0.04)	2.38	33.7	0.93	0.62	0.70	1.085	23.8	600	400	58.6	106.4	116.1	9.6	9.1%
		1,500	7.74	1.02	0.52	0.22	1.76	34.1	9.83	2.20	0.22	(0.04)	2.38	45.6	0.93	0.62	0.70	1.085	35.7	600	900	90.6	158.5	171.9	13.4	8.5%
		2,000	7.74	1.02	0.52	0.22	1.76	42.9	9.83	2.20	0.22	(0.04)	2.38	57.5	0.93	0.62	0.70	1.085	47.6	600	1,400	122.6	210.6	227.7	17.2	8.2%
R1	**North Grenv**	100	**14.40**	**1.65**	**0.37**	**0.16**	**2.18**	16.6	**15.16**	**2.71**	**0.16**	**(0.04)**	**2.84**	18.0	**0.93**	0.62	0.70	**1.085**	2.4	100	-	5.4	24.3	25.8	1.5	6.3%
		250	14.40	1.65	0.37	0.16	2.18	19.9	15.16	2.71	0.16	(0.04)	2.84	22.3	0.93	0.62	0.70	1.085	6.0	250	-	13.6	39.1	41.8	2.7	6.8%
		500	14.40	1.65	0.37	0.16	2.18	25.3	15.16	2.71	0.16	(0.04)	2.84	29.3	0.93	0.62	0.70	1.085	11.9	500	-	27.1	63.8	68.4	4.6	7.2%
		750	14.40	1.65	0.37	0.16	2.18	30.8	15.16	2.71	0.16	(0.04)	2.84	36.4	0.93	0.62	0.70	1.085	17.9	600	150	42.6	90.2	96.9	6.7	7.4%
		1,000	14.40	1.65	0.37	0.16	2.18	36.2	15.16	2.71	0.16	(0.04)	2.84	43.5	0.93	0.62	0.70	1.085	23.8	600	400	58.6	117.3	126.0	8.6	7.4%
		1,500	14.40	1.65	0.37	0.16	2.18	47.1	15.16	2.71	0.16	(0.04)	2.84	57.7	0.93	0.62	0.70	1.085	35.7	600	900	90.6	171.5	184.1	12.6	7.3%
		2,000	14.40	1.65	0.37	0.16	2.18	58.0	15.16	2.71	0.16	(0.04)	2.84	71.9	0.93	0.62	0.70	1.085	47.6	600	1,400	122.6	225.6	242.2	16.5	7.3%

New Rate Class: R1

Total Bill Impacts of Proposed Distribution Rates [new RTSR+TLF]: Threshold of 600 kWhs

600.0

Classes		Scenario	May 2007 Incl Rate Riders						May 2008 Incl Rate Riders						Non-Dx Compoent				Other Reg	Commodity Bands			Existing	New	$ Incr	% Incr
			Existing Dx Rates					Existing Dx	New Dx Rates					New Dx	RTSR new	WMSC	DRC	TLF new	New	Band 1	Band 2	New	Total Bill	Total Bill	Total Bill	Total Bill
																				5.0	5.9					
New Class	Old Class	kWh	SrChg	base	Rider1	Rider2	VarChg	[$/month]	SrChg	base	Rider2	Rider3	VarChg	[$/month]	c/kWh	c/kWh	c/kWh		$	kWhs	kWhs		[$/month]	[$/month]	[$/month]	%
R1	North Perth	100	14.73	1.05	0.47	0.16	1.68	16.4	15.08	2.40	0.16	(0.04)	2.52	17.6	0.93	0.62	0.70	1.085	2.4	100	-	5.4	24.1	25.4	1.3	5.4%
		250	14.73	1.05	0.47	0.16	1.68	18.9	15.08	2.40	0.16	(0.04)	2.52	21.4	0.93	0.62	0.70	1.085	6.0	250	-	13.6	38.2	40.9	2.7	7.1%
		500	14.73	1.05	0.47	0.16	1.68	23.1	15.08	2.40	0.16	(0.04)	2.52	27.7	0.93	0.62	0.70	1.085	11.9	500	-	27.1	61.6	66.7	5.1	8.3%
		750	14.73	1.05	0.47	0.16	1.68	27.3	15.08	2.40	0.16	(0.04)	2.52	34.0	0.93	0.62	0.70	1.085	17.9	600	150	42.6	86.8	94.5	7.7	8.8%
		1,000	14.73	1.05	0.47	0.16	1.68	31.5	15.08	2.40	0.16	(0.04)	2.52	40.3	0.93	0.62	0.70	1.085	23.8	600	400	58.6	112.6	122.7	10.1	9.0%
		1,500	14.73	1.05	0.47	0.16	1.68	39.9	15.08	2.40	0.16	(0.04)	2.52	52.9	0.93	0.62	0.70	1.085	35.7	600	900	90.6	164.3	179.3	15.0	9.1%
		2,000	14.73	1.05	0.47	0.16	1.68	48.3	15.08	2.40	0.16	(0.04)	2.52	65.5	0.93	0.62	0.70	1.085	47.6	600	1,400	122.6	215.9	235.8	19.9	9.2%
R1	North Storm	100	5.42	0.92	0.62	0.36	1.90	7.3	8.41	2.10	0.36	(0.04)	2.42	10.8	0.93	0.62	0.70	1.085	2.4	100	-	5.4	15.0	18.6	3.6	24.0%
		250	5.42	0.92	0.62	0.36	1.90	10.2	8.41	2.10	0.36	(0.04)	2.42	14.5	0.93	0.62	0.70	1.085	6.0	250	-	13.6	29.4	34.0	4.6	15.5%
		500	5.42	0.92	0.62	0.36	1.90	14.9	8.41	2.10	0.36	(0.04)	2.42	20.5	0.93	0.62	0.70	1.085	11.9	500	-	27.1	53.4	59.6	6.1	11.5%
		750	5.42	0.92	0.62	0.36	1.90	19.7	8.41	2.10	0.36	(0.04)	2.42	26.6	0.93	0.62	0.70	1.085	17.9	600	150	42.6	79.2	87.1	7.9	10.0%
		1,000	5.42	0.92	0.62	0.36	1.90	24.4	8.41	2.10	0.36	(0.04)	2.42	32.6	0.93	0.62	0.70	1.085	23.8	600	400	58.6	105.5	115.1	9.5	9.0%
		1,500	5.42	0.92	0.62	0.36	1.90	33.9	8.41	2.10	0.36	(0.04)	2.42	44.7	0.93	0.62	0.70	1.085	35.7	600	900	90.6	158.3	171.1	12.8	8.1%
		2,000	5.42	0.92	0.62	0.36	1.90	43.4	8.41	2.10	0.36	(0.04)	2.42	56.9	0.93	0.62	0.70	1.085	47.6	600	1,400	122.6	211.0	227.1	16.1	7.6%
R1	Omemee	100	14.99	1.50	0.36	0.14	2.00	17.0	15.01	2.71	0.14	(0.04)	2.82	17.8	0.93	0.62	0.70	1.085	2.4	100	-	5.4	24.7	25.6	0.9	3.8%
		250	14.99	1.50	0.36	0.14	2.00	20.0	15.01	2.71	0.14	(0.04)	2.82	22.1	0.93	0.62	0.70	1.085	6.0	250	-	13.6	39.2	41.6	2.3	5.9%
		500	14.99	1.50	0.36	0.14	2.00	25.0	15.01	2.71	0.14	(0.04)	2.82	29.1	0.93	0.62	0.70	1.085	11.9	500	-	27.1	63.5	68.1	4.6	7.3%
		750	14.99	1.50	0.36	0.14	2.00	30.0	15.01	2.71	0.14	(0.04)	2.82	36.1	0.93	0.62	0.70	1.085	17.9	600	150	42.6	89.5	96.6	7.1	8.0%
		1,000	14.99	1.50	0.36	0.14	2.00	35.0	15.01	2.71	0.14	(0.04)	2.82	43.2	0.93	0.62	0.70	1.085	23.8	600	400	58.6	116.1	125.6	9.5	8.2%
		1,500	14.99	1.50	0.36	0.14	2.00	45.0	15.01	2.71	0.14	(0.04)	2.82	57.3	0.93	0.62	0.70	1.085	35.7	600	900	90.6	169.4	183.6	14.3	8.4%
		2,000	14.99	1.50	0.36	0.14	2.00	55.0	15.01	2.71	0.14	(0.04)	2.82	71.3	0.93	0.62	0.70	1.085	47.6	600	1,400	122.6	222.6	241.6	19.0	8.5%
UR	Perth	100	14.47	1.22	0.50	0.18	1.90	16.4	13.96	2.40	0.18	(0.02)	2.55	16.5	0.92	0.62	0.70	1.078	2.4	100	-	5.4	24.1	24.3	0.2	0.8%
		250	14.47	1.22	0.50	0.18	1.90	19.2	13.96	2.40	0.18	(0.02)	2.55	20.3	0.92	0.62	0.70	1.078	5.9	250	-	13.5	38.5	39.7	1.2	3.2%
		500	14.47	1.22	0.50	0.18	1.90	24.0	13.96	2.40	0.18	(0.02)	2.55	26.7	0.92	0.62	0.70	1.078	11.8	500	-	27.0	62.5	65.5	3.0	4.8%
		750	14.47	1.22	0.50	0.18	1.90	28.7	13.96	2.40	0.18	(0.02)	2.55	33.1	0.92	0.62	0.70	1.078	17.7	600	150	42.3	88.2	93.1	4.9	5.5%
		1,000	14.47	1.22	0.50	0.18	1.90	33.5	13.96	2.40	0.18	(0.02)	2.55	39.5	0.92	0.62	0.70	1.078	23.6	600	400	58.2	114.6	121.3	6.7	5.8%
		1,500	14.47	1.22	0.50	0.18	1.90	43.0	13.96	2.40	0.18	(0.02)	2.55	52.2	0.92	0.62	0.70	1.078	35.4	600	900	90.0	167.3	177.6	10.3	6.2%
		2,000	14.47	1.22	0.50	0.18	1.90	52.5	13.96	2.40	0.18	(0.02)	2.55	65.0	0.92	0.62	0.70	1.078	47.2	600	1,400	121.8	220.1	234.0	13.9	6.3%

New Rate Class: R1

Total Bill Impacts of Proposed Distribution Rates [new RTSR+TLF]: Threshold of 600 kWhs

600.0

Classes		Scenario	May 2007 Incl Rate Riders						May 2008 Incl Rate Riders						Non-Dx Compoent				Other Reg	Commodity Bands			Existing	New	$ Incr	% Incr
			Existing Dx Rates					Existing Dx	New Dx Rates					New Dx	RTSR new	WMSC	DRC	TLF new	New	Band 1	Band 2	New	Total Bill	Total Bill	Total Bill	Total Bill
																				5.0	5.9					
New Class	Old Class	kWh	SrChg	base	Rider1	Rider2	VarChg	[$/month]	SrChg	base	Rider2	Rider3	VarChg	[$/month]	c/kWh	c/kWh	c/kWh		$	kWhs	kWhs		[$/month]	[$/month]	[$/month]	%
R1	**Perth East**	100	**5.95**	**0.78**	**0.26**	**0.06**	**1.10**	7.1	**8.27**	**1.60**	**0.06**	**(0.04)**	**1.62**	9.9	**0.93**	0.62	0.70	**1.085**	2.4	100	-	5.4	14.8	17.7	3.0	20.0%
		250	5.95	0.78	0.26	0.06	1.10	8.7	8.27	1.60	0.06	(0.04)	1.62	12.3	0.93	0.62	0.70	1.085	6.0	250	-	13.6	28.0	31.8	3.9	13.9%
		500	5.95	0.78	0.26	0.06	1.10	11.5	8.27	1.60	0.06	(0.04)	1.62	16.4	0.93	0.62	0.70	1.085	11.9	500	-	27.1	50.0	55.4	5.5	10.9%
		750	5.95	0.78	0.26	0.06	1.10	14.2	8.27	1.60	0.06	(0.04)	1.62	20.4	0.93	0.62	0.70	1.085	17.9	600	150	42.6	73.7	80.9	7.2	9.8%
		1,000	5.95	0.78	0.26	0.06	1.10	17.0	8.27	1.60	0.06	(0.04)	1.62	24.5	0.93	0.62	0.70	1.085	23.8	600	400	58.6	98.1	106.9	8.9	9.0%
		1,500	5.95	0.78	0.26	0.06	1.10	22.5	8.27	1.60	0.06	(0.04)	1.62	32.6	0.93	0.62	0.70	1.085	35.7	600	900	90.6	146.8	159.0	12.2	8.3%
		2,000	5.95	0.78	0.26	0.06	1.10	28.0	8.27	1.60	0.06	(0.04)	1.62	40.7	0.93	0.62	0.70	1.085	47.6	600	1,400	122.6	195.6	211.0	15.4	7.9%
R1	**Prince Edwa**	100	**14.25**	**1.05**	**0.39**	**0.13**	**1.57**	15.8	**15.20**	**2.25**	**0.13**	**(0.04)**	**2.34**	17.5	**0.93**	0.62	0.70	**1.085**	2.4	100	-	5.4	23.5	25.3	1.8	7.8%
		250	14.25	1.05	0.39	0.13	1.57	18.2	15.20	2.25	0.13	(0.04)	2.34	21.1	0.93	0.62	0.70	1.085	6.0	250	-	13.6	37.4	40.6	3.1	8.4%
		500	14.25	1.05	0.39	0.13	1.57	22.1	15.20	2.25	0.13	(0.04)	2.34	26.9	0.93	0.62	0.70	1.085	11.9	500	-	27.1	60.6	65.9	5.3	8.8%
		750	14.25	1.05	0.39	0.13	1.57	26.0	15.20	2.25	0.13	(0.04)	2.34	32.8	0.93	0.62	0.70	1.085	17.9	600	150	42.6	85.5	93.2	7.7	9.0%
		1,000	14.25	1.05	0.39	0.13	1.57	30.0	15.20	2.25	0.13	(0.04)	2.34	38.6	0.93	0.62	0.70	1.085	23.8	600	400	58.6	111.1	121.1	10.0	9.0%
		1,500	14.25	1.05	0.39	0.13	1.57	37.8	15.20	2.25	0.13	(0.04)	2.34	50.3	0.93	0.62	0.70	1.085	35.7	600	900	90.6	162.2	176.7	14.5	9.0%
		2,000	14.25	1.05	0.39	0.13	1.57	45.7	15.20	2.25	0.13	(0.04)	2.34	62.1	0.93	0.62	0.70	1.085	47.6	600	1,400	122.6	213.3	232.3	19.1	8.9%
UR	**Quinte West**	100	**6.58**	**0.92**	**0.39**	**0.11**	**1.42**	8.0	**7.94**	**2.10**	**0.11**	**(0.02)**	**2.19**	10.1	**0.92**	0.62	0.70	**1.078**	2.4	100	-	5.4	15.7	17.9	2.2	13.8%
		250	6.58	0.92	0.39	0.11	1.42	10.1	7.94	2.10	0.11	(0.02)	2.19	13.4	0.92	0.62	0.70	1.078	5.9	250	-	13.5	29.4	32.8	3.4	11.5%
		500	6.58	0.92	0.39	0.11	1.42	13.7	7.94	2.10	0.11	(0.02)	2.19	18.9	0.92	0.62	0.70	1.078	11.8	500	-	27.0	52.2	57.6	5.4	10.4%
		750	6.58	0.92	0.39	0.11	1.42	17.2	7.94	2.10	0.11	(0.02)	2.19	24.3	0.92	0.62	0.70	1.078	17.7	600	150	42.3	76.7	84.3	7.6	9.9%
		1,000	6.58	0.92	0.39	0.11	1.42	20.8	7.94	2.10	0.11	(0.02)	2.19	29.8	0.92	0.62	0.70	1.078	23.6	600	400	58.2	101.9	111.6	9.7	9.5%
		1,500	6.58	0.92	0.39	0.11	1.42	27.9	7.94	2.10	0.11	(0.02)	2.19	40.7	0.92	0.62	0.70	1.078	35.4	600	900	90.0	152.2	166.1	13.9	9.1%
		2,000	6.58	0.92	0.39	0.11	1.42	35.0	7.94	2.10	0.11	(0.02)	2.19	51.6	0.92	0.62	0.70	1.078	47.2	600	1,400	121.8	202.6	220.6	18.0	8.9%
R1	**Rainy River**	100	**15.04**	**1.02**	**0.75**	**0.50**	**2.27**	17.3	**16.00**	**2.65**	**0.50**	**(0.04)**	**3.11**	19.1	**0.93**	0.62	0.70	**1.085**	2.4	100	-	5.4	25.0	26.9	1.9	7.6%
		250	15.04	1.02	0.75	0.50	2.27	20.7	16.00	2.65	0.50	(0.04)	3.11	23.8	0.93	0.62	0.70	1.085	6.0	250	-	13.6	40.0	43.3	3.3	8.3%
		500	15.04	1.02	0.75	0.50	2.27	26.4	16.00	2.65	0.50	(0.04)	3.11	31.6	0.93	0.62	0.70	1.085	11.9	500	-	27.1	64.9	70.6	5.7	8.8%
		750	15.04	1.02	0.75	0.50	2.27	32.1	16.00	2.65	0.50	(0.04)	3.11	39.3	0.93	0.62	0.70	1.085	17.9	600	150	42.6	91.5	99.8	8.3	9.0%
		1,000	15.04	1.02	0.75	0.50	2.27	37.7	16.00	2.65	0.50	(0.04)	3.11	47.1	0.93	0.62	0.70	1.085	23.8	600	400	58.6	118.8	129.6	10.7	9.0%
		1,500	15.04	1.02	0.75	0.50	2.27	49.1	16.00	2.65	0.50	(0.04)	3.11	62.7	0.93	0.62	0.70	1.085	35.7	600	900	90.6	173.5	189.0	15.6	9.0%
		2,000	15.04	1.02	0.75	0.50	2.27	60.4	16.00	2.65	0.50	(0.04)	3.11	78.3	0.93	0.62	0.70	1.085	47.6	600	1,400	122.6	228.1	248.5	20.5	9.0%

New Rate Class: R1

Total Bill Impacts of Proposed Distribution Rates [new RTSR+TLF]: Threshold of 600 kWhs

600.0

Classes		Scenario	May 2007 Incl Rate Riders						May 2008 Incl Rate Riders						Non-Dx Compoent				Other Reg	Commodity Bands			Existing	New	$ Incr	% Incr
			Existing Dx Rates					Existing Dx	New Dx Rates					New Dx	RTSR new	WMSC	DRC	TLF new	New	Band 1	Band 2	New	Total Bill	Total Bill	Total Bill	Total Bill
																				5.0	5.9					
New Class	Old Class	kWh	SrChg	base	Rider1	Rider2	VarChg	[$/month]	SrChg	base	Rider2	Rider3	VarChg	[$/month]	c/kWh	c/kWh	c/kWh		$	kWhs	kWhs		[$/month]	[$/month]	[$/month]	%
R1	Ramara	100	6.52	0.95	0.55	0.35	1.85	8.4	9.13	2.10	0.35	(0.04)	2.41	11.5	0.93	0.62	0.70	1.085	2.4	100	-	5.4	16.1	19.3	3.3	20.4%
		250	6.52	0.95	0.55	0.35	1.85	11.1	9.13	2.10	0.35	(0.04)	2.41	15.2	0.93	0.62	0.70	1.085	6.0	250	-	13.6	30.4	34.7	4.3	14.1%
		500	6.52	0.95	0.55	0.35	1.85	15.8	9.13	2.10	0.35	(0.04)	2.41	21.2	0.93	0.62	0.70	1.085	11.9	500	-	27.1	54.3	60.2	5.9	11.0%
		750	6.52	0.95	0.55	0.35	1.85	20.4	9.13	2.10	0.35	(0.04)	2.41	27.2	0.93	0.62	0.70	1.085	17.9	600	150	42.6	79.9	87.7	7.8	9.8%
		1,000	6.52	0.95	0.55	0.35	1.85	25.0	9.13	2.10	0.35	(0.04)	2.41	33.3	0.93	0.62	0.70	1.085	23.8	600	400	58.6	106.1	115.7	9.6	9.0%
		1,500	6.52	0.95	0.55	0.35	1.85	34.3	9.13	2.10	0.35	(0.04)	2.41	45.3	0.93	0.62	0.70	1.085	35.7	600	900	90.6	158.6	171.7	13.0	8.2%
		2,000	6.52	0.95	0.55	0.35	1.85	43.5	9.13	2.10	0.35	(0.04)	2.41	57.4	0.93	0.62	0.70	1.085	47.6	600	1,400	122.6	211.1	227.7	16.5	7.8%
R1	Red Rock	100	15.21	2.07	0.77	0.54	3.38	18.6	15.96	2.71	0.54	(0.04)	3.22	19.2	0.93	0.62	0.70	1.085	2.4	100	-	5.4	26.3	27.0	0.7	2.6%
		250	15.21	2.07	0.77	0.54	3.38	23.7	15.96	2.71	0.54	(0.04)	3.22	24.0	0.93	0.62	0.70	1.085	6.0	250	-	13.6	42.9	43.5	0.6	1.4%
		500	15.21	2.07	0.77	0.54	3.38	32.1	15.96	2.71	0.54	(0.04)	3.22	32.0	0.93	0.62	0.70	1.085	11.9	500	-	27.1	70.6	71.1	0.5	0.6%
		750	15.21	2.07	0.77	0.54	3.38	40.6	15.96	2.71	0.54	(0.04)	3.22	40.1	0.93	0.62	0.70	1.085	17.9	600	150	42.6	100.0	100.6	0.5	0.5%
		1,000	15.21	2.07	0.77	0.54	3.38	49.0	15.96	2.71	0.54	(0.04)	3.22	48.1	0.93	0.62	0.70	1.085	23.8	600	400	58.6	130.1	130.6	0.4	0.3%
		1,500	15.21	2.07	0.77	0.54	3.38	65.9	15.96	2.71	0.54	(0.04)	3.22	64.2	0.93	0.62	0.70	1.085	35.7	600	900	90.6	190.3	190.6	0.3	0.1%
		2,000	15.21	2.07	0.77	0.54	3.38	82.8	15.96	2.71	0.54	(0.04)	3.22	80.3	0.93	0.62	0.70	1.085	47.6	600	1,400	122.6	250.4	250.5	0.1	0.0%
R1	Rockland	100	9.41	0.92	0.65	0.37	1.94	11.4	11.41	2.30	0.37	(0.04)	2.63	14.0	0.93	0.62	0.70	1.085	2.4	100	-	5.4	19.1	21.8	2.8	14.7%
		250	9.41	0.92	0.65	0.37	1.94	14.3	11.41	2.30	0.37	(0.04)	2.63	18.0	0.93	0.62	0.70	1.085	6.0	250	-	13.6	33.5	37.5	4.0	11.9%
		500	9.41	0.92	0.65	0.37	1.94	19.1	11.41	2.30	0.37	(0.04)	2.63	24.6	0.93	0.62	0.70	1.085	11.9	500	-	27.1	57.6	63.6	6.0	10.4%
		750	9.41	0.92	0.65	0.37	1.94	24.0	11.41	2.30	0.37	(0.04)	2.63	31.2	0.93	0.62	0.70	1.085	17.9	600	150	42.6	83.4	91.6	8.2	9.8%
		1,000	9.41	0.92	0.65	0.37	1.94	28.8	11.41	2.30	0.37	(0.04)	2.63	37.7	0.93	0.62	0.70	1.085	23.8	600	400	58.6	109.9	120.2	10.2	9.3%
		1,500	9.41	0.92	0.65	0.37	1.94	38.5	11.41	2.30	0.37	(0.04)	2.63	50.9	0.93	0.62	0.70	1.085	35.7	600	900	90.6	162.9	177.2	14.4	8.8%
		2,000	9.41	0.92	0.65	0.37	1.94	48.2	11.41	2.30	0.37	(0.04)	2.63	64.1	0.93	0.62	0.70	1.085	47.6	600	1,400	122.6	215.8	234.3	18.5	8.6%
R1	Russell	100	13.11	1.44	0.28	0.11	1.83	14.9	14.48	2.50	0.11	(0.04)	2.57	17.1	0.93	0.62	0.70	1.085	2.4	100	-	5.4	22.6	24.9	2.2	9.8%
		250	13.11	1.44	0.28	0.11	1.83	17.7	14.48	2.50	0.11	(0.04)	2.57	20.9	0.93	0.62	0.70	1.085	6.0	250	-	13.6	36.9	40.4	3.5	9.5%
		500	13.11	1.44	0.28	0.11	1.83	22.3	14.48	2.50	0.11	(0.04)	2.57	27.3	0.93	0.62	0.70	1.085	11.9	500	-	27.1	60.8	66.4	5.6	9.2%
		750	13.11	1.44	0.28	0.11	1.83	26.8	14.48	2.50	0.11	(0.04)	2.57	33.8	0.93	0.62	0.70	1.085	17.9	600	150	42.6	86.3	94.3	7.9	9.2%
		1,000	13.11	1.44	0.28	0.11	1.83	31.4	14.48	2.50	0.11	(0.04)	2.57	40.2	0.93	0.62	0.70	1.085	23.8	600	400	58.6	112.5	122.6	10.1	9.0%
		1,500	13.11	1.44	0.28	0.11	1.83	40.6	14.48	2.50	0.11	(0.04)	2.57	53.1	0.93	0.62	0.70	1.085	35.7	600	900	90.6	164.9	179.4	14.5	8.8%
		2,000	13.11	1.44	0.28	0.11	1.83	49.7	14.48	2.50	0.11	(0.04)	2.57	65.9	0.93	0.62	0.70	1.085	47.6	600	1,400	122.6	217.3	236.2	18.9	8.7%

New Rate Class: R1

Total Bill Impacts of Proposed Distribution Rates [new RTSR+TLF]: Threshold of 600 kWhs

600.0

Classes		Scenario	May 2007 Incl Rate Riders						May 2008 Incl Rate Riders						Non-Dx Compoent				Other Reg	Commodity Bands			Existing	New	$ Incr	% Incr
			Existing Dx Rates					Existing Dx	New Dx Rates					New Dx	RTSR new	WMSC	DRC	TLF new	New	Band 1	Band 2	New	Total Bill	Total Bill	Total Bill	Total Bill
																				5.0	5.9					
New Class	**Old Class**	kWh	SrChg	base	Rider1	Rider2	VarChg	[$/month]	SrChg	base	Rider2	Rider3	VarChg	[$/month]	c/kWh	c/kWh	c/kWh		$	kWhs	kWhs		[$/month]	[$/month]	[$/month]	%
R1	**Schreiber**	100	**16.32**	**1.84**	**0.68**	**0.44**	**2.96**	19.3	**16.68**	**2.71**	**0.44**	**(0.04)**	**3.12**	19.8	**0.93**	0.62	0.70	**1.085**	2.4	100	-	5.4	27.0	27.6	0.6	2.3%
		250	16.32	1.84	0.68	0.44	2.96	23.7	16.68	2.71	0.44	(0.04)	3.12	24.5	0.93	0.62	0.70	1.085	6.0	250	-	13.6	43.0	44.0	1.0	2.4%
		500	16.32	1.84	0.68	0.44	2.96	31.1	16.68	2.71	0.44	(0.04)	3.12	32.3	0.93	0.62	0.70	1.085	11.9	500	-	27.1	69.6	71.3	1.7	2.4%
		750	16.32	1.84	0.68	0.44	2.96	38.5	16.68	2.71	0.44	(0.04)	3.12	40.1	0.93	0.62	0.70	1.085	17.9	600	150	42.6	98.0	100.5	2.5	2.6%
		1,000	16.32	1.84	0.68	0.44	2.96	45.9	16.68	2.71	0.44	(0.04)	3.12	47.8	0.93	0.62	0.70	1.085	23.8	600	400	58.6	127.0	130.3	3.2	2.6%
		1,500	16.32	1.84	0.68	0.44	2.96	60.7	16.68	2.71	0.44	(0.04)	3.12	63.4	0.93	0.62	0.70	1.085	35.7	600	900	90.6	185.1	189.8	4.7	2.5%
		2,000	16.32	1.84	0.68	0.44	2.96	75.5	16.68	2.71	0.44	(0.04)	3.12	79.0	0.93	0.62	0.70	1.085	47.6	600	1,400	122.6	243.1	249.3	6.1	2.5%
R1	**Severn**	100	**10.60**	**0.90**	**0.59**	**0.32**	**1.81**	12.4	**12.11**	**2.25**	**0.32**	**(0.04)**	**2.53**	14.6	**0.93**	0.62	0.70	**1.085**	2.4	100	-	5.4	20.1	22.4	2.3	11.6%
		250	10.60	0.90	0.59	0.32	1.81	15.1	12.11	2.25	0.32	(0.04)	2.53	18.4	0.93	0.62	0.70	1.085	6.0	250	-	13.6	34.4	38.0	3.6	10.4%
		500	10.60	0.90	0.59	0.32	1.81	19.7	12.11	2.25	0.32	(0.04)	2.53	24.8	0.93	0.62	0.70	1.085	11.9	500	-	27.1	58.2	63.8	5.6	9.7%
		750	10.60	0.90	0.59	0.32	1.81	24.2	12.11	2.25	0.32	(0.04)	2.53	31.1	0.93	0.62	0.70	1.085	17.9	600	150	42.6	83.7	91.6	7.9	9.5%
		1,000	10.60	0.90	0.59	0.32	1.81	28.7	12.11	2.25	0.32	(0.04)	2.53	37.4	0.93	0.62	0.70	1.085	23.8	600	400	58.6	109.8	119.9	10.1	9.2%
		1,500	10.60	0.90	0.59	0.32	1.81	37.8	12.11	2.25	0.32	(0.04)	2.53	50.1	0.93	0.62	0.70	1.085	35.7	600	900	90.6	162.1	176.5	14.3	8.8%
		2,000	10.60	0.90	0.59	0.32	1.81	46.8	12.11	2.25	0.32	(0.04)	2.53	62.8	0.93	0.62	0.70	1.085	47.6	600	1,400	122.6	214.4	233.0	18.6	8.7%
R1	**Shelburne**	100	**14.14**	**1.33**	**0.39**	**0.14**	**1.86**	16.0	**15.23**	**2.55**	**0.14**	**(0.04)**	**2.65**	17.9	**0.93**	0.62	0.70	**1.085**	2.4	100	-	5.4	23.7	25.7	2.0	8.4%
		250	14.14	1.33	0.39	0.14	1.86	18.8	15.23	2.55	0.14	(0.04)	2.65	21.9	0.93	0.62	0.70	1.085	6.0	250	-	13.6	38.0	41.4	3.3	8.8%
		500	14.14	1.33	0.39	0.14	1.86	23.4	15.23	2.55	0.14	(0.04)	2.65	28.5	0.93	0.62	0.70	1.085	11.9	500	-	27.1	61.9	67.5	5.6	9.0%
		750	14.14	1.33	0.39	0.14	1.86	28.1	15.23	2.55	0.14	(0.04)	2.65	35.1	0.93	0.62	0.70	1.085	17.9	600	150	42.6	87.6	95.6	8.0	9.2%
		1,000	14.14	1.33	0.39	0.14	1.86	32.7	15.23	2.55	0.14	(0.04)	2.65	41.8	0.93	0.62	0.70	1.085	23.8	600	400	58.6	113.8	124.2	10.3	9.1%
		1,500	14.14	1.33	0.39	0.14	1.86	42.0	15.23	2.55	0.14	(0.04)	2.65	55.0	0.93	0.62	0.70	1.085	35.7	600	900	90.6	166.4	181.4	15.0	9.0%
		2,000	14.14	1.33	0.39	0.14	1.86	51.3	15.23	2.55	0.14	(0.04)	2.65	68.3	0.93	0.62	0.70	1.085	47.6	600	1,400	122.6	219.0	238.5	19.6	8.9%
UR	**Smiths Falls**	100	**12.63**	**1.42**	**0.46**	**0.17**	**2.05**	14.7	**12.42**	**2.40**	**0.17**	**(0.02)**	**2.54**	15.0	**0.92**	0.62	0.70	**1.078**	2.4	100	-	5.4	22.4	22.7	0.3	1.5%
		250	12.63	1.42	0.46	0.17	2.05	17.8	12.42	2.40	0.17	(0.02)	2.54	18.8	0.92	0.62	0.70	1.078	5.9	250	-	13.5	37.0	38.2	1.1	3.1%
		500	12.63	1.42	0.46	0.17	2.05	22.9	12.42	2.40	0.17	(0.02)	2.54	25.1	0.92	0.62	0.70	1.078	11.8	500	-	27.0	61.4	63.9	2.5	4.1%
		750	12.63	1.42	0.46	0.17	2.05	28.0	12.42	2.40	0.17	(0.02)	2.54	31.5	0.92	0.62	0.70	1.078	17.7	600	150	42.3	87.5	91.5	4.0	4.6%
		1,000	12.63	1.42	0.46	0.17	2.05	33.1	12.42	2.40	0.17	(0.02)	2.54	37.8	0.92	0.62	0.70	1.078	23.6	600	400	58.2	114.2	119.6	5.4	4.7%
		1,500	12.63	1.42	0.46	0.17	2.05	43.4	12.42	2.40	0.17	(0.02)	2.54	50.5	0.92	0.62	0.70	1.078	35.4	600	900	90.0	167.7	175.9	8.2	4.9%
		2,000	12.63	1.42	0.46	0.17	2.05	53.6	12.42	2.40	0.17	(0.02)	2.54	63.2	0.92	0.62	0.70	1.078	47.2	600	1,400	121.8	221.2	232.2	11.0	5.0%

New Rate Class: R1

Total Bill Impacts of Proposed Distribution Rates [new RTSR+TLF]: Threshold of 600 kWhs

600.0

Classes		Scenario	May 2007 Incl Rate Riders						May 2008 Incl Rate Riders						Non-Dx Compoent				Other Reg	Commodity Bands			Existing	New	$ Incr	% Incr
			Existing Dx Rates					Existing Dx	New Dx Rates					New Dx	RTSR new	WMSC	DRC	TLF new	New	Band 1	Band 2	New	Total Bill	Total Bill	Total Bill	Total Bill
																				5.0	5.9					
New Class	Old Class	kWh	SrChg	base	Rider1	Rider2	VarChg	[$/month]	SrChg	base	Rider2	Rider3	VarChg	[$/month]	c/kWh	c/kWh	c/kWh		$	kWhs	kWhs		[$/month]	[$/month]	[$/month]	%
R1	**South Glenç**	100	**9.46**	**0.75**	**0.52**	**0.36**	**1.63**	11.1	**11.40**	**1.95**	**0.36**	**(0.04)**	**2.27**	13.7	**0.93**	0.62	0.70	**1.085**	2.4	100	-	5.4	18.8	21.5	2.7	14.3%
		250	9.46	0.75	0.52	0.36	1.63	13.5	11.40	1.95	0.36	(0.04)	2.27	17.1	0.93	0.62	0.70	1.085	6.0	250	-	13.6	32.8	36.6	3.8	11.6%
		500	9.46	0.75	0.52	0.36	1.63	17.6	11.40	1.95	0.36	(0.04)	2.27	22.8	0.93	0.62	0.70	1.085	11.9	500	-	27.1	56.1	61.8	5.7	10.1%
		750	9.46	0.75	0.52	0.36	1.63	21.7	11.40	1.95	0.36	(0.04)	2.27	28.4	0.93	0.62	0.70	1.085	17.9	600	150	42.6	81.2	88.9	7.7	9.5%
		1,000	9.46	0.75	0.52	0.36	1.63	25.8	11.40	1.95	0.36	(0.04)	2.27	34.1	0.93	0.62	0.70	1.085	23.8	600	400	58.6	106.9	116.6	9.7	9.1%
		1,500	9.46	0.75	0.52	0.36	1.63	33.9	11.40	1.95	0.36	(0.04)	2.27	45.5	0.93	0.62	0.70	1.085	35.7	600	900	90.6	158.3	171.8	13.6	8.6%
		2,000	9.46	0.75	0.52	0.36	1.63	42.1	11.40	1.95	0.36	(0.04)	2.27	56.9	0.93	0.62	0.70	1.085	47.6	600	1,400	122.6	209.7	227.1	17.4	8.3%
R1	**South River**	100	**14.22**	**1.25**	**0.63**	**0.41**	**2.29**	16.5	**15.21**	**2.71**	**0.41**	**(0.04)**	**3.09**	18.3	**0.93**	0.62	0.70	**1.085**	2.4	100	-	5.4	24.2	26.1	1.9	7.8%
		250	14.22	1.25	0.63	0.41	2.29	19.9	15.21	2.71	0.41	(0.04)	3.09	22.9	0.93	0.62	0.70	1.085	6.0	250	-	13.6	39.2	42.4	3.2	8.3%
		500	14.22	1.25	0.63	0.41	2.29	25.7	15.21	2.71	0.41	(0.04)	3.09	30.6	0.93	0.62	0.70	1.085	11.9	500	-	27.1	64.2	69.7	5.5	8.6%
		750	14.22	1.25	0.63	0.41	2.29	31.4	15.21	2.71	0.41	(0.04)	3.09	38.4	0.93	0.62	0.70	1.085	17.9	600	150	42.6	90.9	98.8	7.9	8.7%
		1,000	14.22	1.25	0.63	0.41	2.29	37.1	15.21	2.71	0.41	(0.04)	3.09	46.1	0.93	0.62	0.70	1.085	23.8	600	400	58.6	118.2	128.5	10.3	8.7%
		1,500	14.22	1.25	0.63	0.41	2.29	48.6	15.21	2.71	0.41	(0.04)	3.09	61.5	0.93	0.62	0.70	1.085	35.7	600	900	90.6	172.9	187.8	14.9	8.6%
		2,000	14.22	1.25	0.63	0.41	2.29	60.0	15.21	2.71	0.41	(0.04)	3.09	76.9	0.93	0.62	0.70	1.085	47.6	600	1,400	122.6	227.6	247.2	19.6	8.6%
R1	**Springwater**	100	**11.79**	**0.82**	**0.61**	**0.31**	**1.74**	13.5	**12.81**	**2.25**	**0.31**	**(0.04)**	**2.52**	15.3	**0.93**	0.62	0.70	**1.085**	2.4	100	-	5.4	21.2	23.1	1.9	9.0%
		250	11.79	0.82	0.61	0.31	1.74	16.1	12.81	2.25	0.31	(0.04)	2.52	19.1	0.93	0.62	0.70	1.085	6.0	250	-	13.6	35.4	38.6	3.2	9.2%
		500	11.79	0.82	0.61	0.31	1.74	20.5	12.81	2.25	0.31	(0.04)	2.52	25.4	0.93	0.62	0.70	1.085	11.9	500	-	27.1	59.0	64.5	5.5	9.3%
		750	11.79	0.82	0.61	0.31	1.74	24.8	12.81	2.25	0.31	(0.04)	2.52	31.7	0.93	0.62	0.70	1.085	17.9	600	150	42.6	84.3	92.2	7.9	9.4%
		1,000	11.79	0.82	0.61	0.31	1.74	29.2	12.81	2.25	0.31	(0.04)	2.52	38.0	0.93	0.62	0.70	1.085	23.8	600	400	58.6	110.3	120.5	10.2	9.2%
		1,500	11.79	0.82	0.61	0.31	1.74	37.9	12.81	2.25	0.31	(0.04)	2.52	50.7	0.93	0.62	0.70	1.085	35.7	600	900	90.6	162.3	177.0	14.8	9.1%
		2,000	11.79	0.82	0.61	0.31	1.74	46.6	12.81	2.25	0.31	(0.04)	2.52	63.3	0.93	0.62	0.70	1.085	47.6	600	1,400	122.6	214.2	233.5	19.3	9.0%
R1	**Stirling-Raw**	100	**12.55**	**1.03**	**0.38**	**0.12**	**1.53**	14.1	**13.62**	**2.20**	**0.12**	**(0.04)**	**2.28**	15.9	**0.93**	0.62	0.70	**1.085**	2.4	100	-	5.4	21.8	23.7	1.9	8.9%
		250	12.55	1.03	0.38	0.12	1.53	16.4	13.62	2.20	0.12	(0.04)	2.28	19.3	0.93	0.62	0.70	1.085	6.0	250	-	13.6	35.6	38.8	3.2	9.0%
		500	12.55	1.03	0.38	0.12	1.53	20.2	13.62	2.20	0.12	(0.04)	2.28	25.0	0.93	0.62	0.70	1.085	11.9	500	-	27.1	58.7	64.1	5.4	9.1%
		750	12.55	1.03	0.38	0.12	1.53	24.0	13.62	2.20	0.12	(0.04)	2.28	30.7	0.93	0.62	0.70	1.085	17.9	600	150	42.6	83.5	91.2	7.7	9.2%
		1,000	12.55	1.03	0.38	0.12	1.53	27.9	13.62	2.20	0.12	(0.04)	2.28	36.5	0.93	0.62	0.70	1.085	23.8	600	400	58.6	109.0	118.9	9.9	9.1%
		1,500	12.55	1.03	0.38	0.12	1.53	35.5	13.62	2.20	0.12	(0.04)	2.28	47.9	0.93	0.62	0.70	1.085	35.7	600	900	90.6	159.9	174.2	14.4	9.0%
		2,000	12.55	1.03	0.38	0.12	1.53	43.2	13.62	2.20	0.12	(0.04)	2.28	59.3	0.93	0.62	0.70	1.085	47.6	600	1,400	122.6	210.8	229.5	18.8	8.9%

New Rate Class: R1

Total Bill Impacts of Proposed Distribution Rates [new RTSR+TLF]: Threshold of 600 kWhs

600.0

Classes		Scenario	May 2007 Incl Rate Riders						May 2008 Incl Rate Riders						Non-Dx Compoent				Other Reg	Commodity Bands			Existing	New	$ Incr	% Incr
			Existing Dx Rates					Existing Dx	New Dx Rates					New Dx	RTSR new	WMSC	DRC	TLF new	New	Band 1	Band 2	New	Total Bill	Total Bill	Total Bill	Total Bill
																				5.0	5.9					
New Class	**Old Class**	kWh	SrChg	base	Rider1	Rider2	VarChg	[$/month]	SrChg	base	Rider2	Rider3	VarChg	[$/month]	c/kWh	c/kWh	c/kWh		$	kWhs	kWhs		[$/month]	[$/month]	[$/month]	%
R1	**Thedford**	100	**12.75**	**0.81**	**0.82**	**0.52**	**2.15**	14.9	**13.57**	**2.50**	**0.52**	**(0.04)**	**2.98**	16.6	**0.93**	0.62	0.70	**1.085**	2.4	100	-	5.4	22.6	24.4	1.8	7.8%
		250	12.75	0.81	0.82	0.52	2.15	18.1	13.57	2.50	0.52	(0.04)	2.98	21.0	0.93	0.62	0.70	1.085	6.0	250	-	13.6	37.4	40.5	3.2	8.5%
		500	12.75	0.81	0.82	0.52	2.15	23.5	13.57	2.50	0.52	(0.04)	2.98	28.5	0.93	0.62	0.70	1.085	11.9	500	-	27.1	62.0	67.5	5.5	8.9%
		750	12.75	0.81	0.82	0.52	2.15	28.9	13.57	2.50	0.52	(0.04)	2.98	35.9	0.93	0.62	0.70	1.085	17.9	600	150	42.6	88.4	96.4	8.1	9.1%
		1,000	12.75	0.81	0.82	0.52	2.15	34.3	13.57	2.50	0.52	(0.04)	2.98	43.4	0.93	0.62	0.70	1.085	23.8	600	400	58.6	115.4	125.8	10.5	9.1%
		1,500	12.75	0.81	0.82	0.52	2.15	45.0	13.57	2.50	0.52	(0.04)	2.98	58.3	0.93	0.62	0.70	1.085	35.7	600	900	90.6	169.4	184.7	15.3	9.0%
		2,000	12.75	0.81	0.82	0.52	2.15	55.8	13.57	2.50	0.52	(0.04)	2.98	73.2	0.93	0.62	0.70	1.085	47.6	600	1,400	122.6	223.4	243.5	20.1	9.0%
R1	**Thessalon**	100	**15.56**	**1.05**	**0.28**	**0.12**	**1.45**	17.0	**15.87**	**2.20**	**0.12**	**(0.04)**	**2.28**	18.2	**0.93**	0.62	0.70	**1.085**	2.4	100	-	5.4	24.7	26.0	1.2	5.0%
		250	15.56	1.05	0.28	0.12	1.45	19.2	15.87	2.20	0.12	(0.04)	2.28	21.6	0.93	0.62	0.70	1.085	6.0	250	-	13.6	38.4	41.1	2.7	6.9%
		500	15.56	1.05	0.28	0.12	1.45	22.8	15.87	2.20	0.12	(0.04)	2.28	27.3	0.93	0.62	0.70	1.085	11.9	500	-	27.1	61.3	66.3	5.0	8.2%
		750	15.56	1.05	0.28	0.12	1.45	26.4	15.87	2.20	0.12	(0.04)	2.28	33.0	0.93	0.62	0.70	1.085	17.9	600	150	42.6	85.9	93.5	7.5	8.8%
		1,000	15.56	1.05	0.28	0.12	1.45	30.1	15.87	2.20	0.12	(0.04)	2.28	38.7	0.93	0.62	0.70	1.085	23.8	600	400	58.6	111.2	121.1	10.0	9.0%
		1,500	15.56	1.05	0.28	0.12	1.45	37.3	15.87	2.20	0.12	(0.04)	2.28	50.1	0.93	0.62	0.70	1.085	35.7	600	900	90.6	161.7	176.5	14.8	9.1%
		2,000	15.56	1.05	0.28	0.12	1.45	44.6	15.87	2.20	0.12	(0.04)	2.28	61.5	0.93	0.62	0.70	1.085	47.6	600	1,400	122.6	212.2	231.8	19.6	9.2%
R1	**Thorndale**	100	**4.32**	**0.88**	**0.62**	**0.32**	**1.82**	6.1	**7.68**	**2.00**	**0.32**	**(0.04)**	**2.28**	10.0	**0.93**	0.62	0.70	**1.085**	2.4	100	-	5.4	13.8	17.8	3.9	28.4%
		250	4.32	0.88	0.62	0.32	1.82	8.9	7.68	2.00	0.32	(0.04)	2.28	13.4	0.93	0.62	0.70	1.085	6.0	250	-	13.6	28.1	32.9	4.8	17.0%
		500	4.32	0.88	0.62	0.32	1.82	13.4	7.68	2.00	0.32	(0.04)	2.28	19.1	0.93	0.62	0.70	1.085	11.9	500	-	27.1	51.9	58.1	6.2	11.9%
		750	4.32	0.88	0.62	0.32	1.82	18.0	7.68	2.00	0.32	(0.04)	2.28	24.8	0.93	0.62	0.70	1.085	17.9	600	150	42.6	77.5	85.3	7.8	10.1%
		1,000	4.32	0.88	0.62	0.32	1.82	22.5	7.68	2.00	0.32	(0.04)	2.28	30.5	0.93	0.62	0.70	1.085	23.8	600	400	58.6	103.6	112.9	9.3	9.0%
		1,500	4.32	0.88	0.62	0.32	1.82	31.6	7.68	2.00	0.32	(0.04)	2.28	41.9	0.93	0.62	0.70	1.085	35.7	600	900	90.6	156.0	168.3	12.3	7.9%
		2,000	4.32	0.88	0.62	0.32	1.82	40.7	7.68	2.00	0.32	(0.04)	2.28	53.3	0.93	0.62	0.70	1.085	47.6	600	1,400	122.6	208.3	223.6	15.3	7.3%
UR	**Thorold**	100	**13.68**	**1.47**	**0.41**	**0.14**	**2.02**	15.7	**13.16**	**2.40**	**0.14**	**(0.02)**	**2.51**	15.7	**0.92**	0.62	0.70	**1.078**	2.4	100	-	5.4	23.4	23.4	0.0	0.1%
		250	13.68	1.47	0.41	0.14	2.02	18.7	13.16	2.40	0.14	(0.02)	2.51	19.4	0.92	0.62	0.70	1.078	5.9	250	-	13.5	38.0	38.8	0.8	2.2%
		500	13.68	1.47	0.41	0.14	2.02	23.8	13.16	2.40	0.14	(0.02)	2.51	25.7	0.92	0.62	0.70	1.078	11.8	500	-	27.0	62.3	64.5	2.2	3.5%
		750	13.68	1.47	0.41	0.14	2.02	28.8	13.16	2.40	0.14	(0.02)	2.51	32.0	0.92	0.62	0.70	1.078	17.7	600	150	42.3	88.3	92.0	3.7	4.2%
		1,000	13.68	1.47	0.41	0.14	2.02	33.9	13.16	2.40	0.14	(0.02)	2.51	38.3	0.92	0.62	0.70	1.078	23.6	600	400	58.2	115.0	120.1	5.1	4.4%
		1,500	13.68	1.47	0.41	0.14	2.02	44.0	13.16	2.40	0.14	(0.02)	2.51	50.8	0.92	0.62	0.70	1.078	35.4	600	900	90.0	168.3	176.2	7.9	4.7%
		2,000	13.68	1.47	0.41	0.14	2.02	54.1	13.16	2.40	0.14	(0.02)	2.51	63.4	0.92	0.62	0.70	1.078	47.2	600	1,400	121.8	221.7	232.4	10.7	4.8%

New Rate Class: R1

Total Bill Impacts of Proposed Distribution Rates [new RTSR+TLF]: Threshold of 600 kWhs

Classes		Scenario	May 2007 Incl Rate Riders						May 2008 Incl Rate Riders						Non-Dx Compoent				Other Reg	Commodity Bands			Existing	New	$ Incr	% Incr
			Existing Dx Rates					Existing Dx	New Dx Rates					New Dx	RTSR new	WMSC	DRC	TLF new	New	Band 1	Band 2	New	Total Bill	Total Bill	Total Bill	Total Bill
																				600.0						
																				5.0	5.9					
New Class	Old Class	kWh	SrChg	base	Rider1	Rider2	VarChg	[$/month]	SrChg	base	Rider2	Rider3	VarChg	[$/month]	c/kWh	c/kWh	c/kWh		$	kWhs	kWhs		[$/month]	[$/month]	[$/month]	%
R1	**Tweed**	100	**4.48**	**0.95**	**0.61**	**0.37**	**1.93**	6.4	**7.64**	**2.10**	**0.37**	**(0.04)**	**2.43**	10.1	**0.93**	0.62	0.70	**1.085**	2.4	100	-	5.4	14.1	17.9	3.8	26.7%
		250	4.48	0.95	0.61	0.37	1.93	9.3	7.64	2.10	0.37	(0.04)	2.43	13.7	0.93	0.62	0.70	1.085	6.0	250	-	13.6	28.6	33.2	4.7	16.4%
		500	4.48	0.95	0.61	0.37	1.93	14.1	7.64	2.10	0.37	(0.04)	2.43	19.8	0.93	0.62	0.70	1.085	11.9	500	-	27.1	52.6	58.8	6.2	11.8%
		750	4.48	0.95	0.61	0.37	1.93	19.0	7.64	2.10	0.37	(0.04)	2.43	25.9	0.93	0.62	0.70	1.085	17.9	600	150	42.6	78.4	86.4	7.9	10.1%
		1,000	4.48	0.95	0.61	0.37	1.93	23.8	7.64	2.10	0.37	(0.04)	2.43	32.0	0.93	0.62	0.70	1.085	23.8	600	400	58.6	104.9	114.4	9.5	9.1%
		1,500	4.48	0.95	0.61	0.37	1.93	33.4	7.64	2.10	0.37	(0.04)	2.43	44.1	0.93	0.62	0.70	1.085	35.7	600	900	90.6	157.8	170.5	12.7	8.0%
		2,000	4.48	0.95	0.61	0.37	1.93	43.1	7.64	2.10	0.37	(0.04)	2.43	56.3	0.93	0.62	0.70	1.085	47.6	600	1,400	122.6	210.7	226.6	15.9	7.5%
R1	**Wardsville**	100	**9.64**	**0.97**	**0.36**	**0.10**	**1.43**	11.1	**11.35**	**2.00**	**0.10**	**(0.04)**	**2.06**	13.4	**0.93**	0.62	0.70	**1.085**	2.4	100	-	5.4	18.8	21.2	2.4	13.0%
		250	9.64	0.97	0.36	0.10	1.43	13.2	11.35	2.00	0.10	(0.04)	2.06	16.5	0.93	0.62	0.70	1.085	6.0	250	-	13.6	32.5	36.0	3.6	10.9%
		500	9.64	0.97	0.36	0.10	1.43	16.8	11.35	2.00	0.10	(0.04)	2.06	21.7	0.93	0.62	0.70	1.085	11.9	500	-	27.1	55.3	60.7	5.4	9.8%
		750	9.64	0.97	0.36	0.10	1.43	20.4	11.35	2.00	0.10	(0.04)	2.06	26.8	0.93	0.62	0.70	1.085	17.9	600	150	42.6	79.8	87.3	7.4	9.3%
		1,000	9.64	0.97	0.36	0.10	1.43	23.9	11.35	2.00	0.10	(0.04)	2.06	32.0	0.93	0.62	0.70	1.085	23.8	600	400	58.6	105.0	114.4	9.4	8.9%
		1,500	9.64	0.97	0.36	0.10	1.43	31.1	11.35	2.00	0.10	(0.04)	2.06	42.3	0.93	0.62	0.70	1.085	35.7	600	900	90.6	155.5	168.6	13.2	8.5%
		2,000	9.64	0.97	0.36	0.10	1.43	38.2	11.35	2.00	0.10	(0.04)	2.06	52.6	0.93	0.62	0.70	1.085	47.6	600	1,400	122.6	205.9	222.9	17.0	8.3%
R1	**Warkworth**	100	**15.25**	**1.18**	**0.66**	**0.43**	**2.27**	17.5	**15.95**	**2.71**	**0.43**	**(0.04)**	**3.11**	19.1	**0.93**	0.62	0.70	**1.085**	2.4	100	-	5.4	25.2	26.9	1.6	6.5%
		250	15.25	1.18	0.66	0.43	2.27	20.9	15.95	2.71	0.43	(0.04)	3.11	23.7	0.93	0.62	0.70	1.085	6.0	250	-	13.6	40.2	43.2	3.1	7.6%
		500	15.25	1.18	0.66	0.43	2.27	26.6	15.95	2.71	0.43	(0.04)	3.11	31.5	0.93	0.62	0.70	1.085	11.9	500	-	27.1	65.1	70.5	5.4	8.3%
		750	15.25	1.18	0.66	0.43	2.27	32.3	15.95	2.71	0.43	(0.04)	3.11	39.2	0.93	0.62	0.70	1.085	17.9	600	150	42.6	91.8	99.7	8.0	8.7%
		1,000	15.25	1.18	0.66	0.43	2.27	38.0	15.95	2.71	0.43	(0.04)	3.11	47.0	0.93	0.62	0.70	1.085	23.8	600	400	58.6	119.1	129.4	10.4	8.7%
		1,500	15.25	1.18	0.66	0.43	2.27	49.3	15.95	2.71	0.43	(0.04)	3.11	62.5	0.93	0.62	0.70	1.085	35.7	600	900	90.6	173.7	188.9	15.2	8.8%
		2,000	15.25	1.18	0.66	0.43	2.27	60.7	15.95	2.71	0.43	(0.04)	3.11	78.1	0.93	0.62	0.70	1.085	47.6	600	1,400	122.6	228.3	248.3	20.1	8.8%
R1	**West Elgin**	100	**13.30**	**1.42**	**0.63**	**0.35**	**2.40**	15.7	**14.44**	**2.71**	**0.35**	**(0.04)**	**3.03**	17.5	**0.93**	0.62	0.70	**1.085**	2.4	100	-	5.4	23.4	25.3	1.9	8.0%
		250	13.30	1.42	0.63	0.35	2.40	19.3	14.44	2.71	0.35	(0.04)	3.03	22.0	0.93	0.62	0.70	1.085	6.0	250	-	13.6	38.6	41.5	3.0	7.7%
		500	13.30	1.42	0.63	0.35	2.40	25.3	14.44	2.71	0.35	(0.04)	3.03	29.6	0.93	0.62	0.70	1.085	11.9	500	-	27.1	63.8	68.6	4.8	7.5%
		750	13.30	1.42	0.63	0.35	2.40	31.3	14.44	2.71	0.35	(0.04)	3.03	37.1	0.93	0.62	0.70	1.085	17.9	600	150	42.6	90.8	97.6	6.8	7.5%
		1,000	13.30	1.42	0.63	0.35	2.40	37.3	14.44	2.71	0.35	(0.04)	3.03	44.7	0.93	0.62	0.70	1.085	23.8	600	400	58.6	118.4	127.1	8.7	7.4%
		1,500	13.30	1.42	0.63	0.35	2.40	49.3	14.44	2.71	0.35	(0.04)	3.03	59.8	0.93	0.62	0.70	1.085	35.7	600	900	90.6	173.7	186.2	12.5	7.2%
		2,000	13.30	1.42	0.63	0.35	2.40	61.3	14.44	2.71	0.35	(0.04)	3.03	75.0	0.93	0.62	0.70	1.085	47.6	600	1,400	122.6	228.9	245.2	16.3	7.1%

New Rate Class: R1

Total Bill Impacts of Proposed Distribution Rates [new RTSR+TLF]: Threshold of 600 kWhs

Classes		Scenario	May 2007 Incl Rate Riders						May 2008 Incl Rate Riders						Non-Dx Compoent				Other Reg	Commodity Bands (600.0)			Existing	New	$ Incr	% Incr
			Existing Dx Rates					Existing Dx	New Dx Rates					New Dx	RTSR new	WMSC	DRC	TLF new	New	Band 1	Band 2	New	Total Bill	Total Bill	Total Bill	Total Bill
																				5.0	5.9					
New Class	Old Class	kWh	SrChg	base	Rider1	Rider2	VarChg	[$/month]	SrChg	base	Rider2	Rider3	VarChg	[$/month]	c/kWh	c/kWh	c/kWh		$	kWhs	kWhs		[$/month]	[$/month]	[$/month]	%
UR	**Whitchurch**	100	**10.54**	**1.02**	**0.36**	**0.12**	**1.50**	12.0	**10.95**	**2.30**	**0.12**	**(0.02)**	**2.40**	13.3	**0.92**	0.62	0.70	**1.078**	2.4	100	-	5.4	19.7	21.1	1.3	6.8%
		250	10.54	1.02	0.36	0.12	1.50	14.3	10.95	2.30	0.12	(0.02)	2.40	16.9	0.92	0.62	0.70	1.078	5.9	250	-	13.5	33.5	36.3	2.8	8.2%
		500	10.54	1.02	0.36	0.12	1.50	18.0	10.95	2.30	0.12	(0.02)	2.40	22.9	0.92	0.62	0.70	1.078	11.8	500	-	27.0	56.5	61.7	5.1	9.1%
		750	10.54	1.02	0.36	0.12	1.50	21.8	10.95	2.30	0.12	(0.02)	2.40	28.9	0.92	0.62	0.70	1.078	17.7	600	150	42.3	81.3	88.9	7.6	9.4%
		1,000	10.54	1.02	0.36	0.12	1.50	25.5	10.95	2.30	0.12	(0.02)	2.40	34.9	0.92	0.62	0.70	1.078	23.6	600	400	58.2	106.6	116.7	10.0	9.4%
		1,500	10.54	1.02	0.36	0.12	1.50	33.0	10.95	2.30	0.12	(0.02)	2.40	46.9	0.92	0.62	0.70	1.078	35.4	600	900	90.0	157.4	172.3	14.9	9.4%
		2,000	10.54	1.02	0.36	0.12	1.50	40.5	10.95	2.30	0.12	(0.02)	2.40	58.8	0.92	0.62	0.70	1.078	47.2	600	1,400	121.8	208.2	227.9	19.7	9.5%
R1	**Wiarton**	100	**15.83**	**1.55**	**0.37**	**0.14**	**2.06**	17.9	**15.80**	**2.71**	**0.14**	**(0.04)**	**2.82**	18.6	**0.93**	0.62	0.70	**1.085**	2.4	100	-	5.4	25.6	26.4	0.8	3.3%
		250	15.83	1.55	0.37	0.14	2.06	21.0	15.80	2.71	0.14	(0.04)	2.82	22.8	0.93	0.62	0.70	1.085	6.0	250	-	13.6	40.2	42.4	2.1	5.3%
		500	15.83	1.55	0.37	0.14	2.06	26.1	15.80	2.71	0.14	(0.04)	2.82	29.9	0.93	0.62	0.70	1.085	11.9	500	-	27.1	64.6	68.9	4.3	6.6%
		750	15.83	1.55	0.37	0.14	2.06	31.3	15.80	2.71	0.14	(0.04)	2.82	36.9	0.93	0.62	0.70	1.085	17.9	600	150	42.6	90.8	97.4	6.6	7.3%
		1,000	15.83	1.55	0.37	0.14	2.06	36.4	15.80	2.71	0.14	(0.04)	2.82	44.0	0.93	0.62	0.70	1.085	23.8	600	400	58.6	117.5	126.4	8.9	7.5%
		1,500	15.83	1.55	0.37	0.14	2.06	46.7	15.80	2.71	0.14	(0.04)	2.82	58.0	0.93	0.62	0.70	1.085	35.7	600	900	90.6	171.1	184.4	13.3	7.8%
		2,000	15.83	1.55	0.37	0.14	2.06	57.0	15.80	2.71	0.14	(0.04)	2.82	72.1	0.93	0.62	0.70	1.085	47.6	600	1,400	122.6	224.6	242.4	17.7	7.9%
R1	**Woodville**	100	**3.78**	**0.95**	**0.51**	**0.26**	**1.72**	5.5	**6.82**	**2.00**	**0.26**	**(0.04)**	**2.22**	9.0	**0.93**	0.62	0.70	**1.085**	2.4	100	-	5.4	13.2	16.8	3.6	27.6%
		250	3.78	0.95	0.51	0.26	1.72	8.1	6.82	2.00	0.26	(0.04)	2.22	12.4	0.93	0.62	0.70	1.085	6.0	250	-	13.6	27.3	31.9	4.6	16.7%
		500	3.78	0.95	0.51	0.26	1.72	12.4	6.82	2.00	0.26	(0.04)	2.22	17.9	0.93	0.62	0.70	1.085	11.9	500	-	27.1	50.9	57.0	6.1	11.9%
		750	3.78	0.95	0.51	0.26	1.72	16.7	6.82	2.00	0.26	(0.04)	2.22	23.5	0.93	0.62	0.70	1.085	17.9	600	150	42.6	76.2	84.0	7.8	10.2%
		1,000	3.78	0.95	0.51	0.26	1.72	21.0	6.82	2.00	0.26	(0.04)	2.22	29.0	0.93	0.62	0.70	1.085	23.8	600	400	58.6	102.1	111.5	9.4	9.2%
		1,500	3.78	0.95	0.51	0.26	1.72	29.6	6.82	2.00	0.26	(0.04)	2.22	40.2	0.93	0.62	0.70	1.085	35.7	600	900	90.6	153.9	166.5	12.6	8.2%
		2,000	3.78	0.95	0.51	0.26	1.72	38.2	6.82	2.00	0.26	(0.04)	2.22	51.3	0.93	0.62	0.70	1.085	47.6	600	1,400	122.6	205.8	221.5	15.7	7.6%
R1	**Wyoming**	100	**11.52**	**0.81**	**0.36**	**0.11**	**1.28**	12.8	**12.88**	**1.90**	**0.11**	**(0.04)**	**1.97**	14.9	**0.93**	0.62	0.70	**1.085**	2.4	100	-	5.4	20.5	22.7	2.2	10.5%
		250	11.52	0.81	0.36	0.11	1.28	14.7	12.88	1.90	0.11	(0.04)	1.97	17.8	0.93	0.62	0.70	1.085	6.0	250	-	13.6	34.0	37.3	3.4	9.9%
		500	11.52	0.81	0.36	0.11	1.28	17.9	12.88	1.90	0.11	(0.04)	1.97	22.7	0.93	0.62	0.70	1.085	11.9	500	-	27.1	56.4	61.8	5.3	9.5%
		750	11.52	0.81	0.36	0.11	1.28	21.1	12.88	1.90	0.11	(0.04)	1.97	27.7	0.93	0.62	0.70	1.085	17.9	600	150	42.6	80.6	88.2	7.5	9.4%
		1,000	11.52	0.81	0.36	0.11	1.28	24.3	12.88	1.90	0.11	(0.04)	1.97	32.6	0.93	0.62	0.70	1.085	23.8	600	400	58.6	105.4	115.0	9.6	9.1%
		1,500	11.52	0.81	0.36	0.11	1.28	30.7	12.88	1.90	0.11	(0.04)	1.97	42.5	0.93	0.62	0.70	1.085	35.7	600	900	90.6	155.1	168.8	13.7	8.9%
		2,000	11.52	0.81	0.36	0.11	1.28	37.1	12.88	1.90	0.11	(0.04)	1.97	52.3	0.93	0.62	0.70	1.085	47.6	600	1,400	122.6	204.7	222.6	17.9	8.7%

New Rate Class: R1

Total Bill Impacts of Proposed Distribution Rates [new RTSR+TLF]: Threshold of 600 kWhs

Classes		Scenario	May 2007 Incl Rate Riders						May 2008 Incl Rate Riders						Non-Dx Compoent				Other Reg	Commodity Bands (600.0)			Existing	New	$ Incr	% Incr
			Existing Dx Rates					Existing Dx	New Dx Rates					New Dx	RTSR new	WMSC	DRC	TLF new	New	Band 1	Band 2	New	Total Bill	Total Bill	Total Bill	Total Bill
																				5.0	5.9					
New Class	Old Class	kWh	SrChg	base	Rider1	Rider2	VarChg	[$/month]	SrChg	base	Rider2	Rider3	VarChg	[$/month]	c/kWh	c/kWh	c/kWh		$	kWhs	kWhs		[$/month]	[$/month]	[$/month]	%
R1	**Terrace Bay**	100	**20.81**	**1.45**	**0.97**	**-**	**2.42**	23.2	**19.56**	**2.71**	**-**	**(0.04)**	**2.68**	22.2	**0.93**	0.62	0.70	**1.085**	2.4	100	-	5.4	30.3	30.0	(0.3)	-0.9%
		250	20.81	1.45	0.97	-	2.42	26.9	19.56	2.71	-	(0.04)	2.68	26.2	0.93	0.62	0.70	1.085	6.0	250	-	13.6	44.6	45.8	1.2	2.6%
		500	20.81	1.45	0.97	-	2.42	32.9	19.56	2.71	-	(0.04)	2.68	32.9	0.93	0.62	0.70	1.085	11.9	500	-	27.1	68.4	72.0	3.6	5.3%
		750	20.81	1.45	0.97	-	2.42	39.0	19.56	2.71	-	(0.04)	2.68	39.6	0.93	0.62	0.70	1.085	17.9	600	150	42.6	93.8	100.1	6.3	6.7%
		1,000	20.81	1.45	0.97	-	2.42	45.0	19.56	2.71	-	(0.04)	2.68	46.3	0.93	0.62	0.70	1.085	23.8	600	400	58.6	119.9	128.8	8.8	7.4%
		1,500	20.81	1.45	0.97	-	2.42	57.1	19.56	2.71	-	(0.04)	2.68	59.7	0.93	0.62	0.70	1.085	35.7	600	900	90.6	172.2	186.1	13.9	8.1%
		2,000	20.81	1.45	0.97	-	2.42	69.2	19.56	2.71	-	(0.04)	2.68	73.1	0.93	0.62	0.70	1.085	47.6	600	1,400	122.6	224.4	243.3	18.9	8.4%

New Rate Class: R2

Total Bill Impacts of Proposed Distribution Rates [new RTSR+TLF]: Threshold of 600 kWhs

600.0

Classes		Scenario	May 2007 Incl Rate Riders						May 2008 Incl Rate Riders						Non-Dx Compoent				Other Reg	Commodity Bands			Existing	New	$ Incr	% Incr
			Existing Dx Rates					Existing Dx	New Dx Rates					New Dx	RTSR new	WMSC	DRC	TLF new	New	Band 1	Band 2	New	Total Bill	Total Bill	Total Bill	Total Bill
																				5.0	5.9					
New Class	Old Class	kWh	SrChg [$/cust]	base [c/kWh]	Rider1 [c/kWh]	Rider2 [c/kWh]	VarChg [c/kWh]	[$/month]	SrChg [$/cust]	base [c/kWh]	Rider2 [c/kWh]	Rider3 [c/kWh]	VarChg [c/kWh]	[$/month]	c/kWh	c/kWh	c/kWh		$	kWhs	kWhs		[$/month]	[$/month]	[$/month]	%
R2	**R2**	100	**29.22**	**1.94**	**0.12**	**0.13**	**2.19**	31.4	**27.05**	**2.68**	**0.13**	**(0.05)**	**2.76**	29.8	**0.89**	0.62	0.7	**1.092**	2.3	100	-	5.5	39.3	37.6	(1.7)	-4.2%
		250	29.22	1.94	0.12	0.13	2.19	34.7	27.05	2.68	0.13	(0.05)	2.76	33.9	0.89	0.62	0.7	1.09	5.9	250	-	13.7	54.4	53.5	(0.9)	-1.6%
		500	29.22	1.94	0.12	0.13	2.19	40.2	27.05	2.68	0.13	(0.05)	2.76	40.8	0.89	0.62	0.7	1.09	11.7	500	-	27.3	79.5	79.9	0.4	0.5%
		750	29.22	1.94	0.12	0.13	2.19	45.6	27.05	2.68	0.13	(0.05)	2.76	47.7	0.89	0.62	0.7	1.09	17.6	600	150	42.9	106.6	108.3	1.7	1.6%
		1,000	29.22	1.94	0.12	0.13	2.19	51.1	27.05	2.68	0.13	(0.05)	2.76	54.6	0.89	0.62	0.7	1.09	23.5	600	400	59.0	134.2	137.1	3.0	2.2%
		1,500	29.22	1.94	0.12	0.13	2.19	62.1	27.05	2.68	0.13	(0.05)	2.76	68.4	0.89	0.62	0.7	1.09	35.2	600	900	91.2	189.4	194.9	5.5	2.9%
		2,000	29.22	1.94	0.12	0.13	2.19	73.0	27.05	2.68	0.13	(0.05)	2.76	82.2	0.89	0.62	0.7	1.09	47.0	600	1,400	123.5	244.5	252.6	8.1	3.3%
R2	**F1**	100	**28.61**	**2.24**	**0.08**	**0.10**	**2.42**	31.0	**26.20**	**2.68**	**0.10**	**(0.05)**	**2.73**	28.9	**0.89**	0.62	0.7	**1.092**	2.3	100	-	5.5	38.8	36.7	(2.1)	-5.4%
		250	28.61	2.24	0.08	0.10	2.42	34.7	26.20	2.68	0.10	(0.05)	2.73	33.0	0.89	0.62	0.70	1.09	5.9	250	-	13.7	54.2	52.5	(1.6)	-3.0%
		500	28.61	2.24	0.08	0.10	2.42	40.7	26.20	2.68	0.10	(0.05)	2.73	39.8	0.89	0.62	0.70	1.09	11.7	500	-	27.3	79.8	78.9	(0.9)	-1.1%
		750	28.61	2.24	0.08	0.10	2.42	46.8	26.20	2.68	0.10	(0.05)	2.73	46.7	0.89	0.62	0.70	1.09	17.6	600	150	42.9	107.3	107.2	(0.1)	-0.1%
		1,000	28.61	2.24	0.08	0.10	2.42	52.8	26.20	2.68	0.10	(0.05)	2.73	53.5	0.89	0.62	0.70	1.09	23.5	600	400	59.0	135.3	136.0	0.7	0.5%
		1,500	28.61	2.24	0.08	0.10	2.42	64.9	26.20	2.68	0.10	(0.05)	2.73	67.1	0.89	0.62	0.70	1.09	35.2	600	900	91.2	191.4	193.6	2.2	1.2%
		2,000	28.61	2.24	0.08	0.10	2.42	77.0	26.20	2.68	0.10	(0.05)	2.73	80.8	0.89	0.62	0.70	1.09	47.0	600	1,400	123.5	247.4	251.2	3.7	1.5%
R2	**F3**	100	**30.16**	**2.89**	**0.03**	**0.04**	**2.96**	33.1	**27.81**	**2.68**	**0.04**	**(0.05)**	**2.67**	30.5	**0.89**	0.62	0.7	**1.092**	2.3	100	-	5.5	40.7	38.3	(2.4)	-5.9%
		250	30.16	2.89	0.03	0.04	2.96	37.6	27.81	2.68	0.04	(0.05)	2.67	34.5	0.89	0.62	0.70	1.09	5.9	250	-	13.7	56.4	54.0	(2.4)	-4.3%
		500	30.16	2.89	0.03	0.04	2.96	45.0	27.81	2.68	0.04	(0.05)	2.67	41.2	0.89	0.62	0.70	1.09	11.7	500	-	27.3	82.7	80.2	(2.5)	-3.1%
		750	30.16	2.89	0.03	0.04	2.96	52.4	27.81	2.68	0.04	(0.05)	2.67	47.8	0.89	0.62	0.70	1.09	17.6	600	150	42.9	110.8	108.4	(2.4)	-2.2%
		1,000	30.16	2.89	0.03	0.04	2.96	59.8	27.81	2.68	0.04	(0.05)	2.67	54.5	0.89	0.62	0.70	1.09	23.5	600	400	59.0	139.4	137.0	(2.4)	-1.8%
		1,500	30.16	2.89	0.03	0.04	2.96	74.6	27.81	2.68	0.04	(0.05)	2.67	67.8	0.89	0.62	0.70	1.09	35.2	600	900	91.2	196.8	194.3	(2.5)	-1.3%
		2,000	30.16	2.89	0.03	0.04	2.96	89.4	27.81	2.68	0.04	(0.05)	2.67	81.2	0.89	0.62	0.70	1.09	47.0	600	1,400	123.5	254.1	251.6	(2.5)	-1.0%
R2	**Caledon OH 06**	100	**34.85**	**0.50**	**0.25**	**0.11**	**0.86**	35.7	**30.64**	**2.20**	**0.11**	**(0.05)**	**2.26**	32.9	**0.89**	0.62	0.7	**1.092**	2.3	100	-	5.5	43.4	40.7	(2.7)	-6.2%
		250	34.85	0.50	0.25	0.11	0.86	37.0	30.64	2.20	0.11	(0.05)	2.26	36.3	0.89	0.62	0.70	1.09	5.9	250	-	13.7	56.3	55.8	(0.4)	-0.8%
		500	34.85	0.50	0.25	0.11	0.86	39.2	30.64	2.20	0.11	(0.05)	2.26	41.9	0.89	0.62	0.70	1.09	11.7	500	-	27.3	77.7	81.0	3.3	4.3%
		750	34.85	0.50	0.25	0.11	0.86	41.3	30.64	2.20	0.11	(0.05)	2.26	47.6	0.89	0.62	0.70	1.09	17.6	600	150	42.9	100.8	108.1	7.4	7.3%
		1,000	34.85	0.50	0.25	0.11	0.86	43.5	30.64	2.20	0.11	(0.05)	2.26	53.3	0.89	0.62	0.70	1.09	23.5	600	400	59.0	124.6	135.8	11.2	9.0%
		1,500	34.85	0.50	0.25	0.11	0.86	47.8	30.64	2.20	0.11	(0.05)	2.26	64.6	0.89	0.62	0.70	1.09	35.2	600	900	91.2	172.1	191.0	18.9	11.0%
		2,000	34.85	0.50	0.25	0.11	0.86	52.1	30.64	2.20	0.11	(0.05)	2.26	75.9	0.89	0.62	0.70	1.09	47.0	600	1,400	123.5	219.7	246.3	26.6	12.1%

New Rate Class: Seasonal

Total Bill Impacts of Proposed Distribution Rates [new RTSR+TLF]: Threshold of 600 kWhs

600.0

Classes		Scenario	May 2007 Incl Rate Riders						May 2008 Incl Rate Riders						Non-Dx Compoent				Other Reg	Commodity Bands			Existing	New	$ Incr	% Incr
			Existing Dx Rates					Existing Dx	New Dx Rates					New Dx	RTSR new	WMSC	DRC	TLF new	New	Band 1	Band 2	New	Total Bill	Total Bill	Total Bill	Total Bill
																				5.0	5.9					
Seasonal Residential		kWh	SrChg	base	Rider1	Rider2	VarChg	[$/month]	SrChg	base	Rider2	Rider3	VarChg	[$/month]	c/kWh	c/kWh	c/kWh		$	kWhs	kWhs		[$/month]	[$/month]	[$/month]	%
			[$/cust]	[c/kWh]	[c/kWh]	[c/kWh]	[c/kWh]		[$/cust]	[c/kWh]	[c/kWh]	[c/kWh]	[c/kWh]													
Seasonal	R3	100	**19.51**	**2.74**	**0.35**	**0.15**	**3.24**	22.8	**19.00**	**4.69**	**0.15**	**0.02**	**4.86**	23.9	**0.87**	0.62	0.7	**1.092**	2.3	100	-	5.5	30.5	31.6	1.2	3.8%
		250	19.51	2.74	0.35	0.15	3.24	27.6	19.00	4.69	0.15	0.02	4.86	31.1	0.87	0.62	0.7	1.09	5.8	250	-	13.7	46.9	50.6	3.7	7.9%
		500	19.51	2.74	0.35	0.15	3.24	35.7	19.00	4.69	0.15	0.02	4.86	43.3	0.87	0.62	0.7	1.09	11.6	500	-	27.3	74.3	82.2	7.9	10.6%
		750	19.51	2.74	0.35	0.15	3.24	43.8	19.00	4.69	0.15	0.02	4.86	55.4	0.87	0.62	0.7	1.09	17.5	600	150	42.9	103.7	115.8	12.1	11.7%
		1,000	19.51	2.74	0.35	0.15	3.24	51.9	19.00	4.69	0.15	0.02	4.86	67.6	0.87	0.62	0.7	1.09	23.3	600	400	59.0	133.6	149.9	16.3	12.2%
		1,500	19.51	2.74	0.35	0.15	3.24	68.1	19.00	4.69	0.15	0.02	4.86	91.8	0.87	0.62	0.7	1.09	34.9	600	900	91.2	193.3	218.0	24.7	12.8%
		2,000	19.51	2.74	0.35	0.15	3.24	84.3	19.00	4.69	0.15	0.02	4.86	116.1	0.87	0.62	0.7	1.09	46.5	600	1,400	123.5	253.0	286.1	33.1	13.1%
Seasonal	R4	100	**36.36**	**1.92**	**0.36**	**0.24**	**2.52**	38.9	**31.79**	**4.70**	**0.24**	**0.02**	**4.95**	36.7	**0.87**	0.62	0.7	**1.092**	2.3	100	-	5.5	46.6	44.5	(2.1)	-4.4%
		250	36.36	1.92	0.36	0.24	2.52	42.7	31.79	4.70	0.24	0.02	4.95	44.2	0.87	0.62	0.70	1.09	5.8	250	-	13.7	62.0	63.6	1.7	2.7%
		500	36.36	1.92	0.36	0.24	2.52	49.0	31.79	4.70	0.24	0.02	4.95	56.6	0.87	0.62	0.70	1.09	11.6	500	-	27.3	87.6	95.5	7.9	9.1%
		750	36.36	1.92	0.36	0.24	2.52	55.3	31.79	4.70	0.24	0.02	4.95	68.9	0.87	0.62	0.70	1.09	17.5	600	150	42.9	115.1	129.3	14.2	12.3%
		1,000	36.36	1.92	0.36	0.24	2.52	61.6	31.79	4.70	0.24	0.02	4.95	81.3	0.87	0.62	0.70	1.09	23.3	600	400	59.0	143.2	163.6	20.4	14.3%
		1,500	36.36	1.92	0.36	0.24	2.52	74.2	31.79	4.70	0.24	0.02	4.95	106.1	0.87	0.62	0.70	1.09	34.9	600	900	91.2	199.3	232.2	32.9	16.5%
		2,000	36.36	1.92	0.36	0.24	2.52	86.8	31.79	4.70	0.24	0.02	4.95	130.9	0.87	0.62	0.70	1.09	46.5	600	1,400	123.5	255.4	300.9	45.4	17.8%
Seasonal	Caledon OH 07	100	**38.78**	**1.04**	**0.43**	**0.25**	**1.72**	40.5	**33.18**	**3.20**	**0.25**	**0.02**	**3.47**	36.6	**0.87**	0.62	0.7	**1.092**	2.3	100	-	5.5	48.2	44.4	(3.8)	-7.8%
		250	38.78	1.04	0.43	0.25	1.72	43.1	33.18	3.20	0.25	0.02	3.47	41.8	0.87	0.62	0.70	1.09	5.8	250	-	13.7	62.3	61.3	(1.0)	-1.6%
		500	38.78	1.04	0.43	0.25	1.72	47.4	33.18	3.20	0.25	0.02	3.47	50.5	0.87	0.62	0.70	1.09	11.6	500	-	27.3	85.9	89.5	3.6	4.1%
		750	38.78	1.04	0.43	0.25	1.72	51.7	33.18	3.20	0.25	0.02	3.47	59.2	0.87	0.62	0.70	1.09	17.5	600	150	42.9	111.2	119.6	8.4	7.6%
		1,000	38.78	1.04	0.43	0.25	1.72	56.0	33.18	3.20	0.25	0.02	3.47	67.9	0.87	0.62	0.70	1.09	23.3	600	400	59.0	137.1	150.1	13.1	9.5%
		1,500	38.78	1.04	0.43	0.25	1.72	64.6	33.18	3.20	0.25	0.02	3.47	85.2	0.87	0.62	0.70	1.09	34.9	600	900	91.2	188.9	211.3	22.4	11.8%
		2,000	38.78	1.04	0.43	0.25	1.72	73.2	33.18	3.20	0.25	0.02	3.47	102.5	0.87	0.62	0.70	1.09	46.5	600	1,400	123.5	240.8	272.5	31.7	13.2%

New Rate Class: UGe

Total Bill Impacts of Proposed Distribution Rates [new RTSR+TLF]: Threshold of 750 kWhs

750.0

Classes		Scenario	May 2007 Incl Rate Riders						May 2008 Incl Rate Riders						Non-Dx Compoent				Other Reg	Commodity Bands			Existing	New	$ Incr	% Incr
			Existing Dx Rates					Existing Dx	New Dx Rates					New Dx	RTSR new	WMSC	DRC	TLF new	New	Band 1	Band 2	New	Total Bill	Total Bill	Total Bill	Total Bill
																				5.0	5.9					
New Class	Old Class	kWh	SrChg [$/cust]	base [c/kWh]	Rider1 [c/kWh]	Rider2 [c/kWh]	VarChg [c/kWh]	[$/month]	SrChg [$/cust]	base [c/kWh]	Rider2 [c/kWh]	Rider3 [c/kWh]	VarChg [c/kWh]	[$/month]	c/kWh	c/kWh	c/kWh		$	kWhs	kWhs		[$/month]	[$/month]	[$/month]	%
UGe	UG	1,000	15.79	2.74	0.03	0.03	2.80	43.8	14.27	2.00	0.03	(0.06)	1.98	34.0	0.69	0.62	0.7	1.092	21.3	750	250	57.7	124.5	113.0	(11.5)	-9.2%
		2,000	15.79	2.74	0.03	0.03	2.80	71.8	14.27	2.00	0.03	(0.06)	1.98	53.8	0.69	0.62	0.7	1.092	42.6	750	1,250	122.1	240.0	218.5	(21.5)	-9.0%
		5,000	15.79	2.74	0.03	0.03	2.80	155.8	14.27	2.00	0.03	(0.06)	1.98	113.0	0.69	0.62	0.7	1.092	106.5	750	4,250	315.4	586.4	535.0	(51.5)	-8.8%
		10,000	15.79	2.74	0.03	0.03	2.80	295.8	14.27	2.00	0.03	(0.06)	1.98	211.8	0.69	0.62	0.7	1.092	213.1	750	9,250	637.5	1,163.8	1,062.4	(101.4)	-8.7%
		15,000	15.79	2.74	0.03	0.03	2.80	435.8	14.27	2.00	0.03	(0.06)	1.98	310.6	0.69	0.62	0.7	1.092	319.6	750	14,250	959.7	1,741.2	1,589.8	(151.4)	-8.7%
UGe	F1	1,000	60.71	2.24	0.08	0.10	2.42	84.9	14.27	2.00	0.03	(0.06)	1.98	34.0	0.69	0.62	0.7	1.092	21.3	750	250	57.7	166.1	113.0	(53.1)	-32.0%
		2,000	60.71	2.24	0.08	0.10	2.42	109.1	14.27	2.00	0.03	(0.06)	1.98	53.8	0.69	0.62	0.70	1.092	42.6	750	1,250	122.1	278.2	218.5	(59.7)	-21.5%
		5,000	60.71	2.24	0.08	0.10	2.42	181.7	14.27	2.00	0.03	(0.06)	1.98	113.0	0.69	0.62	0.70	1.092	106.5	750	4,250	315.4	614.5	535.0	(79.6)	-13.0%
		10,000	60.71	2.24	0.08	0.10	2.42	302.7	14.27	2.00	0.03	(0.06)	1.98	211.8	0.69	0.62	0.70	1.092	213.1	750	9,250	637.5	1,175.1	1,062.4	(112.7)	-9.6%
		15,000	60.71	2.24	0.08	0.10	2.42	423.7	14.27	2.00	0.03	(0.06)	1.98	310.6	0.69	0.62	0.70	1.092	319.6	750	14,250	959.7	1,735.7	1,589.8	(145.9)	-8.4%
UGe	G1	1,000	36.93	3.12	0.09	0.09	3.30	69.9	14.27	2.00	0.03	(0.06)	1.98	34.0	0.69	0.62	0.7	1.092	21.3	750	250	57.7	150.8	113.0	(37.8)	-25.0%
		2,000	36.93	3.12	0.09	0.09	3.30	102.9	14.27	2.00	0.03	(0.06)	1.98	53.8	0.69	0.62	0.70	1.092	42.6	750	1,250	122.1	271.4	218.5	(52.9)	-19.5%
		5,000	36.93	3.12	0.09	0.09	3.30	201.9	14.27	2.00	0.03	(0.06)	1.98	113.0	0.69	0.62	0.70	1.092	106.5	750	4,250	315.4	633.1	535.0	(98.2)	-15.5%
		10,000	36.93	3.12	0.09	0.09	3.30	366.9	14.27	2.00	0.03	(0.06)	1.98	211.8	0.69	0.62	0.70	1.092	213.1	750	9,250	637.5	1,236.1	1,062.4	(173.7)	-14.1%
		15,000	36.93	3.12	0.09	0.09	3.30	531.9	14.27	2.00	0.03	(0.06)	1.98	310.6	0.69	0.62	0.70	1.092	319.6	750	14,250	959.7	1,839.0	1,589.8	(249.2)	-13.6%
UGe	G3	1,000	46.78	3.07	0.02	0.05	3.14	78.2	14.27	2.00	0.03	(0.06)	1.98	34.0	0.69	0.62	0.7	1.092	21.3	750	250	57.7	156.6	113.0	(43.6)	-27.8%
		2,000	46.78	3.07	0.02	0.05	3.14	109.6	14.27	2.00	0.03	(0.06)	1.98	53.8	0.69	0.62	0.70	1.092	42.6	750	1,250	122.1	273.2	218.5	(54.7)	-20.0%
		5,000	46.78	3.07	0.02	0.05	3.14	203.8	14.27	2.00	0.03	(0.06)	1.98	113.0	0.69	0.62	0.70	1.092	106.5	750	4,250	315.4	623.0	535.0	(88.0)	-14.1%
		10,000	46.78	3.07	0.02	0.05	3.14	360.8	14.27	2.00	0.03	(0.06)	1.98	211.8	0.69	0.62	0.70	1.092	213.1	750	9,250	637.5	1,206.0	1,062.4	(143.6)	-11.9%
		15,000	46.78	3.07	0.02	0.05	3.14	517.8	14.27	2.00	0.03	(0.06)	1.98	310.6	0.69	0.62	0.70	1.092	319.6	750	14,250	959.7	1,789.0	1,589.8	(199.1)	-11.1%

New Rate Class: UGe

Total Bill Impacts of Proposed Distribution Rates [new RTSR+TLF]: Threshold of 750 kWhs

Classes		Scenario	May 2007 Incl Rate Riders						May 2008 Incl Rate Riders						Non-Dx Compoent				Other Reg	Commodity Bands			Existing	New	$ Incr	% Incr
			Existing Dx Rates					Existing Dx	New Dx Rates					New Dx	RTSR new	WMSC	DRC	TLF new	New	Band 1	Band 2	New	Total Bill	Total Bill	Total Bill	Total Bill
																				750.0						
																				5.0	5.9					
New Class	Old Class	kWh	SrChg [$/cust]	base [c/kWh]	Rider1 [c/kWh]	Rider2 [c/kWh]	VarChg [c/kWh]	[$/month]	SrChg [$/cust]	base [c/kWh]	Rider2 [c/kWh]	Rider3 [c/kWh]	VarChg [c/kWh]	[$/month]	c/kWh	c/kWh	c/kWh		$	kWhs	kWhs		[$/month]	[$/month]	[$/month]	%
UGe	Arnprior	1,000	**21.38**	**1.17**	**0.16**	**0.06**	**1.39**	35.3	**18.74**	**2.00**	**0.06**	**(0.06)**	**2.01**	38.8	**0.69**	0.62	0.7	**1.092**	21.3	750	250	57.7	114.1	117.8	3.7	3.2%
		2,000	21.38	1.17	0.16	0.06	1.39	49.2	18.74	2.00	0.06	(0.06)	2.01	58.8	0.69	0.62	0.70	1.09	42.6	750	1,250	122.1	213.6	223.6	10.0	4.7%
		5,000	21.38	1.17	0.16	0.06	1.39	90.9	18.74	2.00	0.06	(0.06)	2.01	119.0	0.69	0.62	0.70	1.09	106.5	750	4,250	315.4	511.9	540.9	29.0	5.7%
		10,000	21.38	1.17	0.16	0.06	1.39	160.4	18.74	2.00	0.06	(0.06)	2.01	219.3	0.69	0.62	0.70	1.09	213.1	750	9,250	637.5	1,009.2	1,069.9	60.6	6.0%
		15,000	21.38	1.17	0.16	0.06	1.39	229.9	18.74	2.00	0.06	(0.06)	2.01	319.5	0.69	0.62	0.70	1.09	319.6	750	14,250	959.7	1,506.5	1,598.8	92.3	6.1%
UGe	Brockville	1,000	**21.65**	**0.78**	**0.13**	**0.04**	**0.95**	31.2	**18.67**	**2.00**	**0.04**	**(0.06)**	**1.99**	38.5	**0.69**	0.62	0.7	**1.092**	21.3	750	250	57.7	110.0	117.5	7.5	6.9%
		2,000	21.65	0.78	0.13	0.04	0.95	40.7	18.67	2.00	0.04	(0.06)	1.99	58.4	0.69	0.62	0.70	1.09	42.6	750	1,250	122.1	205.0	223.1	18.1	8.8%
		5,000	21.65	0.78	0.13	0.04	0.95	69.2	18.67	2.00	0.04	(0.06)	1.99	117.9	0.69	0.62	0.70	1.09	106.5	750	4,250	315.4	490.2	539.9	49.7	10.1%
		10,000	21.65	0.78	0.13	0.04	0.95	116.7	18.67	2.00	0.04	(0.06)	1.99	217.2	0.69	0.62	0.70	1.09	213.1	750	9,250	637.5	965.5	1,067.8	102.3	10.6%
		15,000	21.65	0.78	0.13	0.04	0.95	164.2	18.67	2.00	0.04	(0.06)	1.99	316.5	0.69	0.62	0.70	1.09	319.6	750	14,250	959.7	1,440.8	1,595.7	154.9	10.8%
UGe	Carleton Place	1,000	**23.65**	**1.68**	**0.13**	**0.07**	**1.88**	42.5	**20.17**	**2.00**	**0.07**	**(0.06)**	**2.02**	40.3	**0.69**	0.62	0.7	**1.092**	21.3	750	250	57.7	121.3	119.3	(2.0)	-1.6%
		2,000	23.65	1.68	0.13	0.07	1.88	61.3	20.17	2.00	0.07	(0.06)	2.02	60.5	0.69	0.62	0.70	1.09	42.6	750	1,250	122.1	225.6	225.2	(0.4)	-0.2%
		5,000	23.65	1.68	0.13	0.07	1.88	117.7	20.17	2.00	0.07	(0.06)	2.02	120.9	0.69	0.62	0.70	1.09	106.5	750	4,250	315.4	538.7	542.9	4.2	0.8%
		10,000	23.65	1.68	0.13	0.07	1.88	211.7	20.17	2.00	0.07	(0.06)	2.02	221.7	0.69	0.62	0.70	1.09	213.1	750	9,250	637.5	1,060.5	1,072.3	11.8	1.1%
		15,000	23.65	1.68	0.13	0.07	1.88	305.7	20.17	2.00	0.07	(0.06)	2.02	322.5	0.69	0.62	0.70	1.09	319.6	750	14,250	959.7	1,582.3	1,601.7	19.4	1.2%
UGe	Dryden	1,000	**19.11**	**1.03**	**0.12**	**0.04**	**1.19**	31.0	**17.31**	**2.00**	**0.04**	**(0.06)**	**1.99**	37.2	**0.69**	0.62	0.7	**1.092**	21.3	750	250	57.7	109.8	116.1	6.3	5.8%
		2,000	19.11	1.03	0.12	0.04	1.19	42.9	17.31	2.00	0.04	(0.06)	1.99	57.0	0.69	0.62	0.70	1.09	42.6	750	1,250	122.1	207.3	221.7	14.4	7.0%
		5,000	19.11	1.03	0.12	0.04	1.19	78.6	17.31	2.00	0.04	(0.06)	1.99	116.6	0.69	0.62	0.70	1.09	106.5	750	4,250	315.4	499.7	538.5	38.8	7.8%
		10,000	19.11	1.03	0.12	0.04	1.19	138.1	17.31	2.00	0.04	(0.06)	1.99	215.8	0.69	0.62	0.70	1.09	213.1	750	9,250	637.5	987.0	1,066.4	79.5	8.1%
		15,000	19.11	1.03	0.12	0.04	1.19	197.6	17.31	2.00	0.04	(0.06)	1.99	315.1	0.69	0.62	0.70	1.09	319.6	750	14,250	959.7	1,474.3	1,594.4	120.1	8.1%

New Rate Class: UGe

Total Bill Impacts of Proposed Distribution Rates [new RTSR+TLF]: Threshold of 750 kWhs

Classes		Scenario	May 2007 Incl Rate Riders						May 2008 Incl Rate Riders						Non-Dx Compoent				Other Reg	Commodity Bands			Existing	New	$ Incr	% Incr
			Existing Dx Rates					Existing Dx	New Dx Rates					New Dx	RTSR new	WMSC	DRC	TLF new	New	Band 1	Band 2	New	Total Bill	Total Bill	Total Bill	Total Bill
																				750.0						
																				5.0	5.9					
New Class	Old Class	kWh	SrChg [$/cust]	base [c/kWh]	Rider1 [c/kWh]	Rider2 [c/kWh]	VarChg [c/kWh]	[$/month]	SrChg [$/cust]	base [c/kWh]	Rider2 [c/kWh]	Rider3 [c/kWh]	VarChg [c/kWh]	[$/month]	c/kWh	c/kWh	c/kWh		$	kWhs	kWhs		[$/month]	[$/month]	[$/month]	%
UGe	**GBE**	1,000	**10.77**	**1.14**	**0.16**	**0.06**	**1.36**	24.4	**10.39**	**2.00**	**0.06**	**(0.06)**	**2.01**	30.4	**0.69**	0.62	0.7	**1.092**	21.3	750	250	57.7	103.2	109.4	6.2	6.1%
		2,000	10.77	1.14	0.16	0.06	1.36	38.0	10.39	2.00	0.06	(0.06)	2.01	50.5	0.69	0.62	0.70	1.09	42.6	750	1,250	122.1	202.3	215.2	12.9	6.4%
		5,000	10.77	1.14	0.16	0.06	1.36	78.8	10.39	2.00	0.06	(0.06)	2.01	110.7	0.69	0.62	0.70	1.09	106.5	750	4,250	315.4	499.8	532.6	32.8	6.6%
		10,000	10.77	1.14	0.16	0.06	1.36	146.8	10.39	2.00	0.06	(0.06)	2.01	210.9	0.69	0.62	0.70	1.09	213.1	750	9,250	637.5	995.6	1,061.5	65.9	6.6%
		15,000	10.77	1.14	0.16	0.06	1.36	214.8	10.39	2.00	0.06	(0.06)	2.01	311.2	0.69	0.62	0.70	1.09	319.6	750	14,250	959.7	1,491.4	1,590.4	99.0	6.6%
UGe	**Lindsay**	1,000	**23.94**	**1.38**	**0.15**	**0.06**	**1.59**	39.8	**20.10**	**2.00**	**0.06**	**(0.06)**	**2.01**	40.2	**0.69**	0.62	0.7	**1.092**	21.3	750	250	57.7	118.7	119.1	0.5	0.4%
		2,000	23.94	1.38	0.15	0.06	1.59	55.7	20.10	2.00	0.06	(0.06)	2.01	60.2	0.69	0.62	0.70	1.09	42.6	750	1,250	122.1	220.1	224.9	4.8	2.2%
		5,000	23.94	1.38	0.15	0.06	1.59	103.4	20.10	2.00	0.06	(0.06)	2.01	120.4	0.69	0.62	0.70	1.09	106.5	750	4,250	315.4	524.5	542.3	17.8	3.4%
		10,000	23.94	1.38	0.15	0.06	1.59	182.9	20.10	2.00	0.06	(0.06)	2.01	220.6	0.69	0.62	0.70	1.09	213.1	750	9,250	637.5	1,031.8	1,071.2	39.4	3.8%
		15,000	23.94	1.38	0.15	0.06	1.59	262.4	20.10	2.00	0.06	(0.06)	2.01	320.9	0.69	0.62	0.70	1.09	319.6	750	14,250	959.7	1,539.1	1,600.2	61.1	4.0%
UGe	**Perth**	1,000	**19.92**	**0.92**	**0.13**	**0.04**	**1.09**	30.8	**17.10**	**2.00**	**0.04**	**(0.06)**	**1.99**	37.0	**0.69**	0.62	0.7	**1.092**	21.3	750	250	57.7	109.6	115.9	6.3	5.8%
		2,000	19.92	0.92	0.13	0.04	1.09	41.7	17.10	2.00	0.04	(0.06)	1.99	56.8	0.69	0.62	0.70	1.09	42.6	750	1,250	122.1	206.1	221.5	15.4	7.5%
		5,000	19.92	0.92	0.13	0.04	1.09	74.4	17.10	2.00	0.04	(0.06)	1.99	116.4	0.69	0.62	0.70	1.09	106.5	750	4,250	315.4	495.5	538.3	42.8	8.6%
		10,000	19.92	0.92	0.13	0.04	1.09	128.9	17.10	2.00	0.04	(0.06)	1.99	215.6	0.69	0.62	0.70	1.09	213.1	750	9,250	637.5	977.8	1,066.2	88.5	9.0%
		15,000	19.92	0.92	0.13	0.04	1.09	183.4	17.10	2.00	0.04	(0.06)	1.99	314.9	0.69	0.62	0.70	1.09	319.6	750	14,250	959.7	1,460.1	1,594.2	134.1	9.2%
UGe	**Quinte West**	1,000	**3.74**	**1.05**	**0.14**	**0.06**	**1.25**	16.2	**5.15**	**2.00**	**0.06**	**(0.06)**	**2.01**	25.2	**0.69**	0.62	0.7	**1.092**	21.3	750	250	57.7	95.1	104.2	9.1	9.6%
		2,000	3.74	1.05	0.14	0.06	1.25	28.7	5.15	2.00	0.06	(0.06)	2.01	45.3	0.69	0.62	0.70	1.09	42.6	750	1,250	122.1	193.1	210.0	16.9	8.7%
		5,000	3.74	1.05	0.14	0.06	1.25	66.2	5.15	2.00	0.06	(0.06)	2.01	105.4	0.69	0.62	0.70	1.09	106.5	750	4,250	315.4	487.3	527.3	40.0	8.2%
		10,000	3.74	1.05	0.14	0.06	1.25	128.7	5.15	2.00	0.06	(0.06)	2.01	205.7	0.69	0.62	0.70	1.09	213.1	750	9,250	637.5	977.6	1,056.3	78.7	8.0%
		15,000	3.74	1.05	0.14	0.06	1.25	191.2	5.15	2.00	0.06	(0.06)	2.01	306.0	0.69	0.62	0.70	1.09	319.6	750	14,250	959.7	1,467.9	1,585.2	117.3	8.0%

New Rate Class: UGe

Total Bill Impacts of Proposed Distribution Rates [new RTSR+TLF]: Threshold of 750 kWhs

Classes		Scenario	May 2007 Incl Rate Riders						May 2008 Incl Rate Riders						Non-Dx Compoent				Other Reg	Commodity Bands			Existing	New	$ Incr	% Incr
			Existing Dx Rates					Existing Dx	New Dx Rates					New Dx	RTSR new	WMSC	DRC	TLF new	New	Band 1	Band 2	New	Total Bill	Total Bill	Total Bill	Total Bill
																				750.0						
																				5.0	5.9					
New Class	Old Class	kWh	SrChg [$/cust]	base [c/kWh]	Rider1 [c/kWh]	Rider2 [c/kWh]	VarChg [c/kWh]	[$/month]	SrChg [$/cust]	base [c/kWh]	Rider2 [c/kWh]	Rider3 [c/kWh]	VarChg [c/kWh]	[$/month]	c/kWh	c/kWh	c/kWh		$	kWhs	kWhs		[$/month]	[$/month]	[$/month]	%
UGe	**Smiths Falls**	1,000	**9.84**	**1.05**	**0.12**	**0.04**	**1.21**	21.9	**9.62**	**2.00**	**0.04**	**(0.06)**	**1.99**	29.5	**0.69**	0.62	0.7	**1.092**	21.3	750	250	57.7	100.8	108.5	7.7	7.7%
		2,000	9.84	1.05	0.12	0.04	1.21	34.0	9.62	2.00	0.04	(0.06)	1.99	49.3	0.69	0.62	0.70	1.09	42.6	750	1,250	122.1	198.4	214.0	15.6	7.9%
		5,000	9.84	1.05	0.12	0.04	1.21	70.3	9.62	2.00	0.04	(0.06)	1.99	108.9	0.69	0.62	0.70	1.09	106.5	750	4,250	315.4	491.4	530.8	39.4	8.0%
		10,000	9.84	1.05	0.12	0.04	1.21	130.8	9.62	2.00	0.04	(0.06)	1.99	208.2	0.69	0.62	0.70	1.09	213.1	750	9,250	637.5	979.7	1,058.7	79.1	8.1%
		15,000	9.84	1.05	0.12	0.04	1.21	191.3	9.62	2.00	0.04	(0.06)	1.99	307.4	0.69	0.62	0.70	1.09	319.6	750	14,250	959.7	1,468.0	1,586.7	118.7	8.1%
UGe	**Thorold**	1,000	**22.63**	**1.50**	**0.15**	**0.06**	**1.71**	39.7	**19.43**	**2.00**	**0.06**	**(0.06)**	**2.01**	39.5	**0.69**	0.62	0.7	**1.092**	21.3	750	250	57.7	118.5	118.5	(0.1)	-0.1%
		2,000	22.63	1.50	0.15	0.06	1.71	56.8	19.43	2.00	0.06	(0.06)	2.01	59.5	0.69	0.62	0.70	1.09	42.6	750	1,250	122.1	221.2	224.2	3.0	1.4%
		5,000	22.63	1.50	0.15	0.06	1.71	108.1	19.43	2.00	0.06	(0.06)	2.01	119.7	0.69	0.62	0.70	1.09	106.5	750	4,250	315.4	529.2	541.6	12.4	2.3%
		10,000	22.63	1.50	0.15	0.06	1.71	193.6	19.43	2.00	0.06	(0.06)	2.01	220.0	0.69	0.62	0.70	1.09	213.1	750	9,250	637.5	1,042.5	1,070.5	28.1	2.7%
		15,000	22.63	1.50	0.15	0.06	1.71	279.1	19.43	2.00	0.06	(0.06)	2.01	320.2	0.69	0.62	0.70	1.09	319.6	750	14,250	959.7	1,555.8	1,599.5	43.7	2.8%
UGe	**Whitchurch Stouffville**	1,000	**21.85**	**0.93**	**0.11**	**0.04**	**1.08**	32.7	**18.62**	**2.00**	**0.04**	**(0.06)**	**1.99**	38.5	**0.69**	0.62	0.7	**1.092**	21.3	750	250	57.7	111.5	117.5	6.0	5.4%
		2,000	21.85	0.93	0.11	0.04	1.08	43.5	18.62	2.00	0.04	(0.06)	1.99	58.3	0.69	0.62	0.70	1.09	42.6	750	1,250	122.1	207.8	223.0	15.2	7.3%
		5,000	21.85	0.93	0.11	0.04	1.08	75.9	18.62	2.00	0.04	(0.06)	1.99	117.9	0.69	0.62	0.70	1.09	106.5	750	4,250	315.4	496.9	539.8	42.9	8.6%
		10,000	21.85	0.93	0.11	0.04	1.08	129.9	18.62	2.00	0.04	(0.06)	1.99	217.2	0.69	0.62	0.70	1.09	213.1	750	9,250	637.5	978.7	1,067.7	89.0	9.1%
		15,000	21.85	0.93	0.11	0.04	1.08	183.9	18.62	2.00	0.04	(0.06)	1.99	316.4	0.69	0.62	0.70	1.09	319.6	750	14,250	959.7	1,460.5	1,595.7	135.2	9.3%

New Rate Class: UGd

Total Bill Impacts of Proposed Distribution Rates [new RTSR+TLF]: Threshold of 750 kWhs

Classes		Scenario			May 2007 Incl Rate Riders						May 2008 Incl Rate Riders						Non-Dx Compoent				Other Reg	Commodity Bands			Existing	New	$ Incr	% Incr
					Existing Dx Rates					Existing Dx	New Dx Rates					New Dx	RTSR new	WMSC	DRC	TLF new	New	Band 1	Band 2	New	Total Bill	Total Bill	Total Bill	Total Bill
																						-	5.2					
New Class	Old Class	kWh	kW	LF	SrChg	base	Rider1	Rider2	VarChg	[$/month]	SrChg	base	Rider2	Rider3	VarChg	[$/month]	$/kW	c/kWh	c/kWh		$	kWhs	kWhs		[$/month]	[$/month]	[$/month]	%
					[$/cust]	[$/kW]	[$/kW]	[$/kW]	[$/kW]		[$/cust]	[$/kW]	[$/kW]	[$/kW]	[$/kW]													
UGd	**UG**	15,000	60	35%	**15.79**	**8.44**	**0.10**	**0.11**	**8.65**	534.8	**18.49**	**7.42**	**0.11**	**(0.27)**	**7.26**	454.2	**2.68**	0.62	0.7	**1.061**	374.3	-	15,000	827.6	1,762.3	1,656.1	(106.2)	-6.0%
		43,164	133	45%	15.79	8.44	0.10	0.11	8.65	1,166.2	18.49	7.42	0.11	(0.27)	7.26	984.3	2.68	0.62	0.7	1.061	964.3	-	43,164	2,381.4	4,586.6	4,330.0	(256.6)	-5.6%
		100,000	500	28%	15.79	8.44	0.10	0.11	8.65	4,340.8	18.49	7.42	0.11	(0.27)	7.26	3,649.3	2.68	0.62	0.7	1.061	2,779.6	-	100,000	5,517.2	12,806.0	11,946.1	(859.9)	-6.7%
		400,000	1000	56%	15.79	8.44	0.10	0.11	8.65	8,665.8	18.49	7.42	0.11	(0.27)	7.26	7,280.2	2.68	0.62	0.7	1.061	8,274.8	-	400,000	22,068.8	39,707.1	37,623.8	(2,083.3)	-5.2%
		1,000,000	3000	46%	15.79	8.44	0.10	0.11	8.65	25,965.8	18.49	7.42	0.11	(0.27)	7.26	21,803.6	2.68	0.62	0.7	1.061	22,108.6	-	1,000,000	55,172.0	104,978.8	99,084.2	(5,894.6)	-5.6%
		1,500,000	4000	52%	15.79	8.44	0.10	0.11	8.65	34,615.8	18.49	7.42	0.11	(0.27)	7.26	29,065.3	2.68	0.62	0.7	1.061	31,741.2	-	1,500,000	82,758.0	151,725.6	143,564.5	(8,161.0)	-5.4%
UGd	**G1**	15,000	60	35%	**36.93**	**9.59**	**0.26**	**0.29**	**10.14**	645.3	**18.49**	**7.42**	**0.11**	**(0.27)**	**7.26**	454.2	**2.68**	0.62	0.7	**1.061**	374.3	-	15,000	827.6	1,875.2	1,656.1	(219.2)	-11.7%
		43,164	133	45%	36.93	9.59	0.26	0.29	10.14	1,385.6	18.49	7.42	0.11	(0.27)	7.26	984.3	2.68	0.62	0.70	1.061	964.3	-	43,164	2,381.4	4,811.3	4,330.0	(481.3)	-10.0%
		100,000	500	28%	36.93	9.59	0.26	0.29	10.14	5,106.9	18.49	7.42	0.11	(0.27)	7.26	3,649.3	2.68	0.62	0.70	1.061	2,779.6	-	100,000	5,517.2	13,592.3	11,946.1	(1,646.2)	-12.1%
		400,000	1000	56%	36.93	9.59	0.26	0.29	10.14	10,176.9	18.49	7.42	0.11	(0.27)	7.26	7,280.2	2.68	0.62	0.70	1.061	8,274.8	-	400,000	22,068.8	41,258.6	37,623.8	(3,634.9)	-8.8%
		1,000,000	3000	46%	36.93	9.59	0.26	0.29	10.14	30,456.9	18.49	7.42	0.11	(0.27)	7.26	21,803.6	2.68	0.62	0.70	1.061	22,108.6	-	1,000,000	55,172.0	109,591.2	99,084.2	(10,506.9)	-9.6%
		1,500,000	4000	52%	36.93	9.59	0.26	0.29	10.14	40,596.9	18.49	7.42	0.11	(0.27)	7.26	29,065.3	2.68	0.62	0.70	1.061	31,741.2	-	1,500,000	82,758.0	157,868.3	143,564.5	(14,303.8)	-9.1%
UGd	**G3**	15,000	60	35%	**46.78**	**9.91**	**0.08**	**0.15**	**10.14**	655.2	**18.49**	**7.42**	**0.11**	**(0.27)**	**7.26**	454.2	**2.68**	0.62	0.7	**1.061**	374.3	-	15,000	827.6	1,861.6	1,656.1	(205.6)	-11.0%
		43,164	133	45%	46.78	9.91	0.08	0.15	10.14	1,395.4	18.49	7.42	0.11	(0.27)	7.26	984.3	2.68	0.62	0.70	1.061	964.3	-	43,164	2,381.4	4,751.3	4,330.0	(421.3)	-8.9%
		100,000	500	28%	46.78	9.91	0.08	0.15	10.14	5,116.8	18.49	7.42	0.11	(0.27)	7.26	3,649.3	2.68	0.62	0.70	1.061	2,779.6	-	100,000	5,517.2	13,451.7	11,946.1	(1,505.6)	-11.2%
		400,000	1000	56%	46.78	9.91	0.08	0.15	10.14	10,186.8	18.49	7.42	0.11	(0.27)	7.26	7,280.2	2.68	0.62	0.70	1.061	8,274.8	-	400,000	22,068.8	40,606.7	37,623.8	(2,983.0)	-7.3%
		1,000,000	3000	46%	46.78	9.91	0.08	0.15	10.14	30,466.8	18.49	7.42	0.11	(0.27)	7.26	21,803.6	2.68	0.62	0.70	1.061	22,108.6	-	1,000,000	55,172.0	107,976.6	99,084.2	(8,892.4)	-8.2%
		1,500,000	4000	52%	46.78	9.91	0.08	0.15	10.14	40,606.8	18.49	7.42	0.11	(0.27)	7.26	29,065.3	2.68	0.62	0.70	1.061	31,741.2	-	1,500,000	82,758.0	155,411.6	143,564.5	(11,847.0)	-7.6%
UGd	**Arnprior**	15,000	60	35%	**21.38**	**3.70**	**0.50**	**0.20**	**4.40**	285.4	**22.95**	**7.33**	**0.20**	**(0.27)**	**7.26**	458.6	**2.68**	0.62	0.7	**1.061**	374.3	-	15,000	827.6	1,534.8	1,660.4	125.6	8.2%
		43,164	133	45%	21.38	3.70	0.50	0.20	4.40	606.6	22.95	7.33	0.20	(0.27)	7.26	988.6	2.68	0.62	0.70	1.06	964.3	-	43,164	2,381.4	4,054.0	4,334.3	280.3	6.9%
		100,000	500	28%	21.38	3.70	0.50	0.20	4.40	2,221.4	22.95	7.33	0.20	(0.27)	7.26	3,653.1	2.68	0.62	0.70	1.06	2,779.6	-	100,000	5,517.2	10,924.0	11,949.8	1,025.8	9.4%
		400,000	1000	56%	21.38	3.70	0.50	0.20	4.40	4,421.4	22.95	7.33	0.20	(0.27)	7.26	7,283.2	2.68	0.62	0.70	1.06	8,274.8	-	400,000	22,068.8	35,501.0	37,626.7	2,125.8	6.0%
		1,000,000	3000	46%	21.38	3.70	0.50	0.20	4.40	13,221.4	22.95	7.33	0.20	(0.27)	7.26	21,803.6	2.68	0.62	0.70	1.06	22,108.6	-	1,000,000	55,172.0	92,785.7	99,084.2	6,298.5	6.8%
		1,500,000	4000	52%	21.38	3.70	0.50	0.20	4.40	17,621.4	22.95	7.33	0.20	(0.27)	7.26	29,063.8	2.68	0.62	0.70	1.06	31,741.2	-	1,500,000	82,758.0	135,102.5	143,563.0	8,460.5	6.3%

New Rate Class: UGd

Total Bill Impacts of Proposed Distribution Rates [new RTSR+TLF]: Threshold of 750 kWhs

Classes		Scenario			May 2007 Incl Rate Riders						May 2008 Incl Rate Riders						Non-Dx Compoent				Other Reg	Commodity Bands			Existing	New	$ Incr	% Incr
					Existing Dx Rates					Existing Dx	New Dx Rates					New Dx	RTSR new	WMSC	DRC	TLF new	New	Band 1	Band 2	New	Total Bill	Total Bill	Total Bill	Total Bill
																						-	5.2					
New Class	Old Class	kWh	kW	LF	SrChg [$/cust]	base [$/kW]	Rider1 [$/kW]	Rider2 [$/kW]	VarChg [$/kW]	[$/month]	SrChg [$/cust]	base [$/kW]	Rider2 [$/kW]	Rider3 [$/kW]	VarChg [$/kW]	[$/month]	$/kW	c/kWh	c/kWh		$	kWhs	kWhs		[$/month]	[$/month]	[$/month]	%
UGd	Brockville	15,000	60	35%	21.65	2.49	0.41	0.12	3.02	202.9	22.89	6.70	0.12	(0.27)	6.55	415.7	2.68	0.62	0.7	1.061	374.3	-	15,000	827.6	1,452.3	1,617.6	165.3	11.4%
		43,164	133	45%	21.65	2.49	0.41	0.12	3.02	423.3	22.89	6.70	0.12	(0.27)	6.55	893.7	2.68	0.62	0.70	1.06	964.3	-	43,164	2,381.4	3,870.7	4,239.4	368.7	9.5%
		100,000	500	28%	21.65	2.49	0.41	0.12	3.02	1,531.7	22.89	6.70	0.12	(0.27)	6.55	3,296.4	2.68	0.62	0.70	1.06	2,779.6	-	100,000	5,517.2	10,234.3	11,593.2	1,359.0	13.3%
		400,000	1000	56%	21.65	2.49	0.41	0.12	3.02	3,041.7	22.89	6.70	0.12	(0.27)	6.55	6,570.0	2.68	0.62	0.70	1.06	8,274.8	-	400,000	22,068.8	34,121.2	36,913.6	2,792.3	8.2%
		1,000,000	3000	46%	21.65	2.49	0.41	0.12	3.02	9,081.7	22.89	6.70	0.12	(0.27)	6.55	19,664.3	2.68	0.62	0.70	1.06	22,108.6	-	1,000,000	55,172.0	88,646.0	96,944.9	8,298.9	9.4%
		1,500,000	4000	52%	21.65	2.49	0.41	0.12	3.02	12,101.7	22.89	6.70	0.12	(0.27)	6.55	26,211.4	2.68	0.62	0.70	1.06	31,741.2	-	1,500,000	82,758.0	129,582.8	140,710.6	11,127.8	8.6%
UGd	Carleton Pla	15,000	60	35%	23.65	5.31	0.42	0.22	5.95	380.7	24.39	7.33	0.22	(0.27)	7.28	461.2	2.68	0.62	0.7	1.061	374.3	-	15,000	827.6	1,630.1	1,663.1	33.0	2.0%
		43,164	133	45%	23.65	5.31	0.42	0.22	5.95	815.0	24.39	7.33	0.22	(0.27)	7.28	992.7	2.68	0.62	0.70	1.06	964.3	-	43,164	2,381.4	4,262.4	4,338.4	76.0	1.8%
		100,000	500	28%	23.65	5.31	0.42	0.22	5.95	2,998.7	24.39	7.33	0.22	(0.27)	7.28	3,664.5	2.68	0.62	0.70	1.06	2,779.6	-	100,000	5,517.2	11,701.3	11,961.2	260.0	2.2%
		400,000	1000	56%	23.65	5.31	0.42	0.22	5.95	5,973.7	24.39	7.33	0.22	(0.27)	7.28	7,304.6	2.68	0.62	0.70	1.06	8,274.8	-	400,000	22,068.8	37,053.2	37,648.1	594.9	1.6%
		1,000,000	3000	46%	23.65	5.31	0.42	0.22	5.95	17,873.7	24.39	7.33	0.22	(0.27)	7.28	21,865.0	2.68	0.62	0.70	1.06	22,108.6	-	1,000,000	55,172.0	97,438.0	99,145.6	1,707.6	1.8%
		1,500,000	4000	52%	23.65	5.31	0.42	0.22	5.95	23,823.7	24.39	7.33	0.22	(0.27)	7.28	29,145.2	2.68	0.62	0.70	1.06	31,741.2	-	1,500,000	82,758.0	141,304.8	143,644.4	2,339.6	1.7%
UGd	Dryden	15,000	60	35%	19.11	3.29	0.38	0.13	3.80	247.1	21.52	7.33	0.13	(0.27)	7.19	452.9	2.68	0.62	0.7	1.061	374.3	-	15,000	827.6	1,496.5	1,654.8	158.3	10.6%
		43,164	133	45%	19.11	3.29	0.38	0.13	3.80	524.5	21.52	7.33	0.13	(0.27)	7.19	977.8	2.68	0.62	0.70	1.06	964.3	-	43,164	2,381.4	3,971.9	4,323.5	351.6	8.9%
		100,000	500	28%	19.11	3.29	0.38	0.13	3.80	1,919.1	21.52	7.33	0.13	(0.27)	7.19	3,616.6	2.68	0.62	0.70	1.06	2,779.6	-	100,000	5,517.2	10,621.7	11,913.4	1,291.7	12.2%
		400,000	1000	56%	19.11	3.29	0.38	0.13	3.80	3,819.1	21.52	7.33	0.13	(0.27)	7.19	7,211.7	2.68	0.62	0.70	1.06	8,274.8	-	400,000	22,068.8	34,898.7	37,555.3	2,656.6	7.6%
		1,000,000	3000	46%	19.11	3.29	0.38	0.13	3.80	11,419.1	21.52	7.33	0.13	(0.27)	7.19	21,592.1	2.68	0.62	0.70	1.06	22,108.6	-	1,000,000	55,172.0	90,983.5	98,872.8	7,889.3	8.7%
		1,500,000	4000	52%	19.11	3.29	0.38	0.13	3.80	15,219.1	21.52	7.33	0.13	(0.27)	7.19	28,782.3	2.68	0.62	0.70	1.06	31,741.2	-	1,500,000	82,758.0	132,700.2	143,281.6	10,581.3	8.0%
UGd	GBE	15,000	60	35%	10.77	3.64	0.49	0.19	4.32	270.0	14.61	7.33	0.19	(0.27)	7.25	449.6	2.68	0.62	0.7	1.061	374.3	-	15,000	827.6	1,519.4	1,651.5	132.1	8.7%
		43,164	133	45%	10.77	3.64	0.49	0.19	4.32	585.3	14.61	7.33	0.19	(0.27)	7.25	978.9	2.68	0.62	0.70	1.06	964.3	-	43,164	2,381.4	4,032.7	4,324.6	291.9	7.2%
		100,000	500	28%	10.77	3.64	0.49	0.19	4.32	2,170.8	14.61	7.33	0.19	(0.27)	7.25	3,639.7	2.68	0.62	0.70	1.06	2,779.6	-	100,000	5,517.2	10,873.4	11,936.5	1,063.1	9.8%
		400,000	1000	56%	10.77	3.64	0.49	0.19	4.32	4,330.8	14.61	7.33	0.19	(0.27)	7.25	7,264.8	2.68	0.62	0.70	1.06	8,274.8	-	400,000	22,068.8	35,410.4	37,608.4	2,198.0	6.2%
		1,000,000	3000	46%	10.77	3.64	0.49	0.19	4.32	12,970.8	14.61	7.33	0.19	(0.27)	7.25	21,765.2	2.68	0.62	0.70	1.06	22,108.6	-	1,000,000	55,172.0	92,535.1	99,045.9	6,510.7	7.0%
		1,500,000	4000	52%	10.77	3.64	0.49	0.19	4.32	17,290.8	14.61	7.33	0.19	(0.27)	7.25	29,015.4	2.68	0.62	0.70	1.06	31,741.2	-	1,500,000	82,758.0	134,771.9	143,514.6	8,742.7	6.5%

New Rate Class: UGd

Total Bill Impacts of Proposed Distribution Rates [new RTSR+TLF]: Threshold of 750 kWhs

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Classes		Scenario			May 2007 Incl Rate Riders						May 2008 Incl Rate Riders						Non-Dx Compoent				Other Reg	Commodity Bands			Existing	New	$ Incr	% Incr
					Existing Dx Rates					Existing Dx	New Dx Rates					New Dx	RTSR new	WMSC	DRC	TLF new	New	Band 1	Band 2	New	Total Bill	Total Bill	Total Bill	Total Bill
																						-	5.2					
New Class	Old Class	kWh	kW	LF	SrChg	base	Rider1	Rider2	VarChg	[$/month]	SrChg	base	Rider2	Rider3	VarChg	[$/month]	$/kW	c/kWh	c/kWh		$	kWhs	kWhs		[$/month]	[$/month]	[$/month]	%
					[$/cust]	[$/kW]	[$/kW]	[$/kW]	[$/kW]		[$/cust]	[$/kW]	[$/kW]	[$/kW]	[$/kW]													
UGd	**Lindsay**	15,000	60	35%	**23.94**	**4.36**	**0.49**	**0.19**	**5.04**	326.3	**24.31**	**7.33**	**0.19**	**(0.27)**	**7.25**	459.3	**2.68**	0.62	0.7	**1.061**	374.3	-	15,000	827.6	1,575.8	1,661.2	85.4	5.4%
		43,164	133	45%	23.94	4.36	0.49	0.19	5.04	694.3	24.31	7.33	0.19	(0.27)	7.25	988.6	2.68	0.62	0.70	1.06	964.3	-	43,164	2,381.4	4,141.7	4,334.3	192.6	4.7%
		100,000	500	28%	23.94	4.36	0.49	0.19	5.04	2,543.9	24.31	7.33	0.19	(0.27)	7.25	3,649.4	2.68	0.62	0.70	1.06	2,779.6	-	100,000	5,517.2	11,246.5	11,946.2	699.6	6.2%
		400,000	1000	56%	23.94	4.36	0.49	0.19	5.04	5,063.9	24.31	7.33	0.19	(0.27)	7.25	7,274.5	2.68	0.62	0.70	1.06	8,274.8	-	400,000	22,068.8	36,143.5	37,618.1	1,474.6	4.1%
		1,000,000	3000	46%	23.94	4.36	0.49	0.19	5.04	15,143.9	24.31	7.33	0.19	(0.27)	7.25	21,774.9	2.68	0.62	0.70	1.06	22,108.6	-	1,000,000	55,172.0	94,708.3	99,055.6	4,347.3	4.6%
		1,500,000	4000	52%	23.94	4.36	0.49	0.19	5.04	20,183.9	24.31	7.33	0.19	(0.27)	7.25	29,025.1	2.68	0.62	0.70	1.06	31,741.2	-	1,500,000	82,758.0	137,665.1	143,524.4	5,859.3	4.3%
UGd	**Perth**	15,000	60	35%	**19.92**	**2.87**	**0.42**	**0.12**	**3.41**	224.5	**21.32**	**7.15**	**0.12**	**(0.27)**	**7.00**	441.1	**2.68**	0.62	0.7	**1.061**	374.3	-	15,000	827.6	1,473.9	1,643.0	169.1	11.5%
		43,164	133	45%	19.92	2.87	0.42	0.12	3.41	473.5	21.32	7.15	0.12	(0.27)	7.00	951.9	2.68	0.62	0.70	1.06	964.3	-	43,164	2,381.4	3,920.9	4,297.7	376.8	9.6%
		100,000	500	28%	19.92	2.87	0.42	0.12	3.41	1,724.9	21.32	7.15	0.12	(0.27)	7.00	3,519.9	2.68	0.62	0.70	1.06	2,779.6	-	100,000	5,517.2	10,427.5	11,816.6	1,389.1	13.3%
		400,000	1000	56%	19.92	2.87	0.42	0.12	3.41	3,429.9	21.32	7.15	0.12	(0.27)	7.00	7,018.4	2.68	0.62	0.70	1.06	8,274.8	-	400,000	22,068.8	34,509.5	37,362.0	2,852.5	8.3%
		1,000,000	3000	46%	19.92	2.87	0.42	0.12	3.41	10,249.9	21.32	7.15	0.12	(0.27)	7.00	21,012.7	2.68	0.62	0.70	1.06	22,108.6	-	1,000,000	55,172.0	89,814.3	98,293.3	8,479.1	9.4%
		1,500,000	4000	52%	19.92	2.87	0.42	0.12	3.41	13,659.9	21.32	7.15	0.12	(0.27)	7.00	28,009.8	2.68	0.62	0.70	1.06	31,741.2	-	1,500,000	82,758.0	131,141.1	142,509.0	11,368.0	8.7%
UGd	**Quinte West**	15,000	60	35%	**3.74**	**3.32**	**0.46**	**0.18**	**3.96**	241.3	**9.36**	**7.33**	**0.18**	**(0.27)**	**7.24**	443.8	**2.68**	0.62	0.7	**1.061**	374.3	-	15,000	827.6	1,490.8	1,645.6	154.9	10.4%
		43,164	133	45%	3.74	3.32	0.46	0.18	3.96	530.4	9.36	7.33	0.18	(0.27)	7.24	972.3	2.68	0.62	0.70	1.06	964.3	-	43,164	2,381.4	3,977.8	4,318.0	340.2	8.6%
		100,000	500	28%	3.74	3.32	0.46	0.18	3.96	1,983.7	9.36	7.33	0.18	(0.27)	7.24	3,629.5	2.68	0.62	0.70	1.06	2,779.6	-	100,000	5,517.2	10,686.3	11,926.2	1,239.9	11.6%
		400,000	1000	56%	3.74	3.32	0.46	0.18	3.96	3,963.7	9.36	7.33	0.18	(0.27)	7.24	7,249.6	2.68	0.62	0.70	1.06	8,274.8	-	400,000	22,068.8	35,043.3	37,593.1	2,549.8	7.3%
		1,000,000	3000	46%	3.74	3.32	0.46	0.18	3.96	11,883.7	9.36	7.33	0.18	(0.27)	7.24	21,730.0	2.68	0.62	0.70	1.06	22,108.6	-	1,000,000	55,172.0	91,448.1	99,010.6	7,562.5	8.3%
		1,500,000	4000	52%	3.74	3.32	0.46	0.18	3.96	15,843.7	9.36	7.33	0.18	(0.27)	7.24	28,970.2	2.68	0.62	0.70	1.06	31,741.2	-	1,500,000	82,758.0	133,324.9	143,469.4	10,144.5	7.6%
UGd	**Smiths Falls**	15,000	60	35%	**9.84**	**3.33**	**0.39**	**0.13**	**3.85**	240.8	**13.84**	**7.33**	**0.13**	**(0.27)**	**7.19**	445.2	**2.68**	0.62	0.7	**1.061**	374.3	-	15,000	827.6	1,490.3	1,647.1	156.8	10.5%
		43,164	133	45%	9.84	3.33	0.39	0.13	3.85	521.9	13.84	7.33	0.13	(0.27)	7.19	970.1	2.68	0.62	0.70	1.06	964.3	-	43,164	2,381.4	3,969.3	4,315.9	346.6	8.7%
		100,000	500	28%	9.84	3.33	0.39	0.13	3.85	1,934.8	13.84	7.33	0.13	(0.27)	7.19	3,608.9	2.68	0.62	0.70	1.06	2,779.6	-	100,000	5,517.2	10,637.4	11,905.7	1,268.3	11.9%
		400,000	1000	56%	9.84	3.33	0.39	0.13	3.85	3,859.8	13.84	7.33	0.13	(0.27)	7.19	7,204.0	2.68	0.62	0.70	1.06	8,274.8	-	400,000	22,068.8	34,939.4	37,547.6	2,608.2	7.5%
		1,000,000	3000	46%	9.84	3.33	0.39	0.13	3.85	11,559.8	13.84	7.33	0.13	(0.27)	7.19	21,584.5	2.68	0.62	0.70	1.06	22,108.6	-	1,000,000	55,172.0	91,124.2	98,865.1	7,740.9	8.5%
		1,500,000	4000	52%	9.84	3.33	0.39	0.13	3.85	15,409.8	13.84	7.33	0.13	(0.27)	7.19	28,774.7	2.68	0.62	0.70	1.06	31,741.2	-	1,500,000	82,758.0	132,891.0	143,273.9	10,382.9	7.8%

New Rate Class: UGd

Total Bill Impacts of Proposed Distribution Rates [new RTSR+TLF]: Threshold of 750 kWhs

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Classes		Scenario			May 2007 Incl Rate Riders						May 2008 Incl Rate Riders						Non-Dx Compoent				Other Reg	Commodity Bands			Existing	New	$ Incr	% Incr
					Existing Dx Rates					Existing Dx	New Dx Rates					New Dx	RTSR new	WMSC	DRC	TLF new	New	Band 1	Band 2	New	Total Bill	Total Bill	Total Bill	Total Bill
																						-	5.2					
New Class	Old Class	kWh	kW	LF	SrChg [$/cust]	base [$/kW]	Rider1 [$/kW]	Rider2 [$/kW]	VarChg [$/kW]	[$/month]	SrChg [$/cust]	base [$/kW]	Rider2 [$/kW]	Rider3 [$/kW]	VarChg [$/kW]	[$/month]	$/kW	c/kWh	c/kWh		$	kWhs	kWhs		[$/month]	[$/month]	[$/month]	%
UGd	**Thorold**	15,000	60	35%	**22.63**	**4.76**	**0.46**	**0.20**	**5.42**	347.8	**23.64**	**7.33**	**0.20**	**(0.27)**	**7.26**	459.3	**2.68**	0.62	0.7	**1.061**	374.3	-	15,000	827.6	1,597.3	1,661.1	63.9	4.0%
		43,164	133	45%	22.63	4.76	0.46	0.20	5.42	743.5	23.64	7.33	0.20	(0.27)	7.26	989.2	2.68	0.62	0.70	1.06	964.3	-	43,164	2,381.4	4,190.9	4,335.0	144.1	3.4%
		100,000	500	28%	22.63	4.76	0.46	0.20	5.42	2,732.6	23.64	7.33	0.20	(0.27)	7.26	3,653.7	2.68	0.62	0.70	1.06	2,779.6	-	100,000	5,517.2	11,435.2	11,950.5	515.3	4.5%
		400,000	1000	56%	22.63	4.76	0.46	0.20	5.42	5,442.6	23.64	7.33	0.20	(0.27)	7.26	7,283.8	2.68	0.62	0.70	1.06	8,274.8	-	400,000	22,068.8	36,522.2	37,627.4	1,105.2	3.0%
		1,000,000	3000	46%	22.63	4.76	0.46	0.20	5.42	16,282.6	23.64	7.33	0.20	(0.27)	7.26	21,804.3	2.68	0.62	0.70	1.06	22,108.6	-	1,000,000	55,172.0	95,847.0	99,084.9	3,237.9	3.4%
		1,500,000	4000	52%	22.63	4.76	0.46	0.20	5.42	21,702.6	23.64	7.33	0.20	(0.27)	7.26	29,064.5	2.68	0.62	0.70	1.06	31,741.2	-	1,500,000	82,758.0	139,183.8	143,563.7	4,379.9	3.1%
UGd	**Whitchurch**	15,000	60	35%	**21.85**	**2.93**	**0.35**	**0.13**	**3.41**	226.5	**22.84**	**7.15**	**0.13**	**(0.27)**	**7.01**	443.3	**2.68**	0.62	0.7	**1.061**	374.3	-	15,000	827.6	1,475.9	1,645.1	169.2	11.5%
		43,164	133	45%	21.85	2.93	0.35	0.13	3.41	475.4	22.84	7.15	0.13	(0.27)	7.01	954.8	2.68	0.62	0.70	1.06	964.3	-	43,164	2,381.4	3,922.8	4,300.5	377.7	9.6%
		100,000	500	28%	21.85	2.93	0.35	0.13	3.41	1,726.9	22.84	7.15	0.13	(0.27)	7.01	3,526.4	2.68	0.62	0.70	1.06	2,779.6	-	100,000	5,517.2	10,429.5	11,823.2	1,393.7	13.4%
		400,000	1000	56%	21.85	2.93	0.35	0.13	3.41	3,431.9	22.84	7.15	0.13	(0.27)	7.01	7,030.0	2.68	0.62	0.70	1.06	8,274.8	-	400,000	22,068.8	34,511.4	37,373.5	2,862.1	8.3%
		1,000,000	3000	46%	21.85	2.93	0.35	0.13	3.41	10,251.9	22.84	7.15	0.13	(0.27)	7.01	21,044.2	2.68	0.62	0.70	1.06	22,108.6	-	1,000,000	55,172.0	89,816.2	98,324.9	8,508.6	9.5%
		1,500,000	4000	52%	21.85	2.93	0.35	0.13	3.41	13,661.9	22.84	7.15	0.13	(0.27)	7.01	28,051.3	2.68	0.62	0.70	1.06	31,741.2	-	1,500,000	82,758.0	131,143.0	142,550.6	11,407.6	8.7%

New Rate Class: GSe - Metered

Total Bill Impacts of Proposed Distribution Rates [new RTSR+TLF]: Threshold of 750 kWhs

750.0

Classes		Scenario	May 2007 Incl Rate Riders						May 2008 Incl Rate Riders						Non-Dx Compoent				Other Reg	Commodity Bands			Existing	New	$ Incr	% Incr
			Existing Dx Rates					Existing Dx	New Dx Rates					New Dx	RTSR new	WMSC	DRC	TLF new	New	Band 1	Band 2	New	Total Bill	Total Bill	Total Bill	Total Bill
																				5.0	5.9					
New Class	Old Class	kWh	SrChg	base	Rider1	Rider2	VarChg	[$/month]	SrChg	base	Rider2	Rider3	VarChg	[$/month]	c/kWh	c/kWh	c/kWh		$	kWhs	kWhs		[$/month]	[$/month]	[$/month]	%
			[$/cust]	[c/kWh]	[c/kWh]	[c/kWh]	[c/kWh]		[$/cust]	[c/kWh]	[c/kWh]	[c/kWh]	[c/kWh]													
GSe	**F1**	1,000	**60.71**	**2.24**	**0.08**	**0.10**	**2.42**	84.9	**52.91**	**3.38**	**0.10**	**(0.06)**	**3.42**	87.1	**0.67**	0.62	0.7	**1.092**	21.1	750	250	57.7	166.1	165.9	(0.2)	-0.1%
		2,000	60.71	2.24	0.08	0.10	2.42	109.1	52.91	3.38	0.10	(0.06)	3.42	121.3	0.67	0.62	0.7	1.092	42.2	750	1,250	122.1	278.2	285.6	7.4	2.7%
		5,000	60.71	2.24	0.08	0.10	2.42	181.7	52.91	3.38	0.10	(0.06)	3.42	223.9	0.67	0.62	0.7	1.092	105.4	750	4,250	315.4	614.5	644.7	30.2	4.9%
		10,000	60.71	2.24	0.08	0.10	2.42	302.7	52.91	3.38	0.10	(0.06)	3.42	394.9	0.67	0.62	0.7	1.092	210.9	750	9,250	637.5	1,175.1	1,243.3	68.2	5.8%
		15,000	60.71	2.24	0.08	0.10	2.42	423.7	52.91	3.38	0.10	(0.06)	3.42	565.9	0.67	0.62	0.7	1.092	316.3	750	14,250	959.7	1,735.7	1,841.9	106.2	6.1%
GSe	**F3**	1,000	**53.91**	**2.89**	**0.03**	**0.04**	**2.96**	83.5	**47.61**	**3.38**	**0.04**	**(0.06)**	**3.36**	81.2	**0.67**	0.62	0.7	**1.092**	21.1	750	250	57.7	161.8	160.0	(1.9)	-1.2%
		2,000	53.91	2.89	0.03	0.04	2.96	113.1	47.61	3.38	0.04	(0.06)	3.36	114.8	0.67	0.62	0.70	1.092	42.2	750	1,250	122.1	276.5	279.1	2.6	0.9%
		5,000	53.91	2.89	0.03	0.04	2.96	201.9	47.61	3.38	0.04	(0.06)	3.36	215.6	0.67	0.62	0.70	1.092	105.4	750	4,250	315.4	620.6	636.4	15.8	2.6%
		10,000	53.91	2.89	0.03	0.04	2.96	349.9	47.61	3.38	0.04	(0.06)	3.36	383.6	0.67	0.62	0.70	1.092	210.9	750	9,250	637.5	1,194.1	1,232.0	38.0	3.2%
		15,000	53.91	2.89	0.03	0.04	2.96	497.9	47.61	3.38	0.04	(0.06)	3.36	551.6	0.67	0.62	0.70	1.092	316.3	750	14,250	959.7	1,767.5	1,827.6	60.1	3.4%
GSe	**G1**	1,000	**36.93**	**3.12**	**0.09**	**0.09**	**3.30**	69.9	**35.09**	**3.38**	**0.09**	**(0.06)**	**3.41**	69.2	**0.67**	0.62	0.7	**1.092**	21.1	750	250	57.7	150.8	148.0	(2.8)	-1.9%
		2,000	36.93	3.12	0.09	0.09	3.30	102.9	35.09	3.38	0.09	(0.06)	3.41	103.3	0.67	0.62	0.70	1.092	42.2	750	1,250	122.1	271.4	267.6	(3.8)	-1.4%
		5,000	36.93	3.12	0.09	0.09	3.30	201.9	35.09	3.38	0.09	(0.06)	3.41	205.6	0.67	0.62	0.70	1.092	105.4	750	4,250	315.4	633.1	626.4	(6.7)	-1.1%
		10,000	36.93	3.12	0.09	0.09	3.30	366.9	35.09	3.38	0.09	(0.06)	3.41	376.1	0.67	0.62	0.70	1.092	210.9	750	9,250	637.5	1,236.1	1,224.5	(11.6)	-0.9%
		15,000	36.93	3.12	0.09	0.09	3.30	531.9	35.09	3.38	0.09	(0.06)	3.41	546.6	0.67	0.62	0.70	1.092	316.3	750	14,250	959.7	1,839.0	1,822.6	(16.4)	-0.9%
GSe	**G3**	1,000	**46.78**	**3.07**	**0.02**	**0.05**	**3.14**	78.2	**42.40**	**3.38**	**0.05**	**(0.06)**	**3.37**	76.1	**0.67**	0.62	0.7	**1.092**	21.1	750	250	57.7	156.6	154.9	(1.8)	-1.1%
		2,000	46.78	3.07	0.02	0.05	3.14	109.6	42.40	3.38	0.05	(0.06)	3.37	109.8	0.67	0.62	0.70	1.092	42.2	750	1,250	122.1	273.2	274.1	0.9	0.3%
		5,000	46.78	3.07	0.02	0.05	3.14	203.8	42.40	3.38	0.05	(0.06)	3.37	210.9	0.67	0.62	0.70	1.092	105.4	750	4,250	315.4	623.0	631.7	8.7	1.4%
		10,000	46.78	3.07	0.02	0.05	3.14	360.8	42.40	3.38	0.05	(0.06)	3.37	379.4	0.67	0.62	0.70	1.092	210.9	750	9,250	637.5	1,206.0	1,227.8	21.8	1.8%
		15,000	46.78	3.07	0.02	0.05	3.14	517.8	42.40	3.38	0.05	(0.06)	3.37	547.9	0.67	0.62	0.70	1.092	316.3	750	14,250	959.7	1,789.0	1,823.9	34.9	2.0%
GSe	**T**	1,000	**261.54**	**2.43**	**0.01**	**0.03**	**2.47**	286.2	**203.71**	**3.38**	**0.03**	**(0.06)**	**3.35**	237.2	**0.67**	0.62	0.7	**1.092**	21.1	750	250	57.7	364.6	316.0	(48.6)	-13.3%
		2,000	261.54	2.43	0.01	0.03	2.47	310.9	203.71	3.38	0.03	(0.06)	3.35	270.7	0.67	0.62	0.70	1.092	42.2	750	1,250	122.1	474.4	435.0	(39.4)	-8.3%
		5,000	261.54	2.43	0.01	0.03	2.47	385.0	203.71	3.38	0.03	(0.06)	3.35	371.2	0.67	0.62	0.70	1.092	105.4	750	4,250	315.4	803.7	792.0	(11.7)	-1.5%
		10,000	261.54	2.43	0.01	0.03	2.47	508.5	203.71	3.38	0.03	(0.06)	3.35	538.7	0.67	0.62	0.70	1.092	210.9	750	9,250	637.5	1,352.7	1,387.1	34.4	2.5%
		15,000	261.54	2.43	0.01	0.03	2.47	632.0	203.71	3.38	0.03	(0.06)	3.35	706.2	0.67	0.62	0.70	1.092	316.3	750	14,250	959.7	1,901.6	1,982.2	80.6	4.2%

New Rate Class: GSe - Metered

Total Bill Impacts of Proposed Distribution Rates [new RTSR+TLF]: Threshold of 750 kWhs

Classes		Scenario	May 2007 Incl Rate Riders						May 2008 Incl Rate Riders						Non-Dx Compoent				Other Reg	Commodity Bands 750.0			Existing	New	$ Incr	% Incr
			Existing Dx Rates					Existing Dx	New Dx Rates					New Dx	RTSR new	WMSC	DRC	TLF new	New	Band 1 5.0	Band 2 5.9	New	Total Bill	Total Bill	Total Bill	Total Bill
New Class	Old Class	kWh	SrChg [$/cust]	base [c/kWh]	Rider1 [c/kWh]	Rider2 [c/kWh]	VarChg [c/kWh]	[$/month]	SrChg [$/cust]	base [c/kWh]	Rider2 [c/kWh]	Rider3 [c/kWh]	VarChg [c/kWh]	[$/month]	c/kWh	c/kWh	c/kWh		$	kWhs	kWhs		[$/month]	[$/month]	[$/month]	%
GSe	**Ailsa Craig**	1,000	**17.31**	**1.32**	**0.17**	**0.09**	**1.58**	33.1	**20.76**	**2.34**	**0.09**	**(0.06)**	**2.37**	44.5	**0.67**	0.62	0.7	**1.092**	21.1	750	250	57.7	111.9	123.3	11.3	10.1%
		2,000	17.31	1.32	0.17	0.09	1.58	48.9	20.76	2.34	0.09	(0.06)	2.37	68.2	0.67	0.62	0.70	1.09	42.2	750	1,250	122.1	213.3	232.5	19.2	9.0%
		5,000	17.31	1.32	0.17	0.09	1.58	96.3	20.76	2.34	0.09	(0.06)	2.37	139.4	0.67	0.62	0.70	1.09	105.4	750	4,250	315.4	517.4	560.3	42.9	8.3%
		10,000	17.31	1.32	0.17	0.09	1.58	175.3	20.76	2.34	0.09	(0.06)	2.37	258.1	0.67	0.62	0.70	1.09	210.9	750	9,250	637.5	1,024.2	1,106.5	82.3	8.0%
		15,000	17.31	1.32	0.17	0.09	1.58	254.3	20.76	2.34	0.09	(0.06)	2.37	376.8	0.67	0.62	0.70	1.09	316.3	750	14,250	959.7	1,531.0	1,652.7	121.8	8.0%
GSe	**Arkona**	1,000	**3.20**	**0.86**	**0.51**	**0.36**	**1.73**	20.5	**10.29**	**1.98**	**0.36**	**(0.06)**	**2.28**	33.1	**0.67**	0.62	0.7	**1.092**	21.1	750	250	57.7	99.3	111.9	12.6	12.7%
		2,000	3.20	0.86	0.51	0.36	1.73	37.8	10.29	1.98	0.36	(0.06)	2.28	56.0	0.67	0.62	0.70	1.09	42.2	750	1,250	122.1	202.2	220.2	18.1	8.9%
		5,000	3.20	0.86	0.51	0.36	1.73	89.7	10.29	1.98	0.36	(0.06)	2.28	124.5	0.67	0.62	0.70	1.09	105.4	750	4,250	315.4	510.8	545.3	34.5	6.8%
		10,000	3.20	0.86	0.51	0.36	1.73	176.2	10.29	1.98	0.36	(0.06)	2.28	238.6	0.67	0.62	0.70	1.09	210.9	750	9,250	637.5	1,025.1	1,087.0	62.0	6.0%
		15,000	3.20	0.86	0.51	0.36	1.73	262.7	10.29	1.98	0.36	(0.06)	2.28	352.8	0.67	0.62	0.70	1.09	316.3	750	14,250	959.7	1,539.4	1,628.8	89.4	5.8%
UGe	**Arnprior**	1,000	**21.38**	**1.17**	**0.16**	**0.06**	**1.39**	35.3	**18.74**	**2.00**	**0.06**	**(0.06)**	**2.01**	38.8	**0.69**	0.62	0.7	**1.092**	21.3	750	250	57.7	114.1	117.8	3.7	3.2%
		2,000	21.38	1.17	0.16	0.06	1.39	49.2	18.74	2.00	0.06	(0.06)	2.01	58.8	0.69	0.62	0.70	1.09	42.6	750	1,250	122.1	213.6	223.6	10.0	4.7%
		5,000	21.38	1.17	0.16	0.06	1.39	90.9	18.74	2.00	0.06	(0.06)	2.01	119.0	0.69	0.62	0.70	1.09	106.5	750	4,250	315.4	511.9	540.9	29.0	5.7%
		10,000	21.38	1.17	0.16	0.06	1.39	160.4	18.74	2.00	0.06	(0.06)	2.01	219.3	0.69	0.62	0.70	1.09	213.1	750	9,250	637.5	1,009.2	1,069.9	60.6	6.0%
		15,000	21.38	1.17	0.16	0.06	1.39	229.9	18.74	2.00	0.06	(0.06)	2.01	319.5	0.69	0.62	0.70	1.09	319.6	750	14,250	959.7	1,506.5	1,598.8	92.3	6.1%
GSe	**Arran-Elderslie**	1,000	**8.83**	**1.03**	**0.17**	**0.09**	**1.29**	21.7	**13.88**	**1.90**	**0.09**	**(0.06)**	**1.93**	33.2	**0.67**	0.62	0.7	**1.092**	21.1	750	250	57.7	100.5	112.0	11.4	11.4%
		2,000	8.83	1.03	0.17	0.09	1.29	34.6	13.88	1.90	0.09	(0.06)	1.93	52.5	0.67	0.62	0.70	1.09	42.2	750	1,250	122.1	199.0	216.8	17.8	9.0%
		5,000	8.83	1.03	0.17	0.09	1.29	73.3	13.88	1.90	0.09	(0.06)	1.93	110.5	0.67	0.62	0.70	1.09	105.4	750	4,250	315.4	494.4	531.4	37.0	7.5%
		10,000	8.83	1.03	0.17	0.09	1.29	137.8	13.88	1.90	0.09	(0.06)	1.93	207.2	0.67	0.62	0.70	1.09	210.9	750	9,250	637.5	986.7	1,055.6	68.9	7.0%
		15,000	8.83	1.03	0.17	0.09	1.29	202.3	13.88	1.90	0.09	(0.06)	1.93	303.9	0.67	0.62	0.70	1.09	316.3	750	14,250	959.7	1,479.0	1,579.8	100.9	6.8%
GSe	**Artemesia**	1,000	**19.62**	**1.74**	**0.49**	**0.34**	**2.57**	45.3	**22.19**	**3.21**	**0.34**	**(0.06)**	**3.49**	57.1	**0.67**	0.62	0.7	**1.092**	21.1	750	250	57.7	124.1	135.9	11.8	9.5%
		2,000	19.62	1.74	0.49	0.34	2.57	71.0	22.19	3.21	0.34	(0.06)	3.49	92.1	0.67	0.62	0.70	1.09	42.2	750	1,250	122.1	235.4	256.3	21.0	8.9%
		5,000	19.62	1.74	0.49	0.34	2.57	148.1	22.19	3.21	0.34	(0.06)	3.49	196.9	0.67	0.62	0.70	1.09	105.4	750	4,250	315.4	569.2	617.7	48.5	8.5%
		10,000	19.62	1.74	0.49	0.34	2.57	276.6	22.19	3.21	0.34	(0.06)	3.49	371.6	0.67	0.62	0.70	1.09	210.9	750	9,250	637.5	1,125.5	1,220.0	94.5	8.4%
		15,000	19.62	1.74	0.49	0.34	2.57	405.1	22.19	3.21	0.34	(0.06)	3.49	546.2	0.67	0.62	0.70	1.09	316.3	750	14,250	959.7	1,681.8	1,822.2	140.4	8.4%

New Rate Class: GSe - Metered

Total Bill Impacts of Proposed Distribution Rates [new RTSR+TLF]: Threshold of 750 kWhs

750.0

Classes		Scenario	May 2007 Incl Rate Riders						May 2008 Incl Rate Riders						Non-Dx Compoent				Other Reg	Commodity Bands			Existing	New	$ Incr	% Incr
			Existing Dx Rates					Existing Dx	New Dx Rates					New Dx	RTSR new	WMSC	DRC	TLF new	New	Band 1	Band 2	New	Total Bill	Total Bill	Total Bill	Total Bill
																				5.0	5.9					
New Class	Old Class	kWh	SrChg [$/cust]	base [c/kWh]	Rider1 [c/kWh]	Rider2 [c/kWh]	VarChg [c/kWh]	[$/month]	SrChg [$/cust]	base [c/kWh]	Rider2 [c/kWh]	Rider3 [c/kWh]	VarChg [c/kWh]	[$/month]	c/kWh	c/kWh	c/kWh		$	kWhs	kWhs		[$/month]	[$/month]	[$/month]	%
GSe	Bancroft	1,000	**24.41**	**1.18**	**0.17**	**0.08**	**1.43**	38.7	**25.99**	**2.30**	**0.08**	**(0.06)**	**2.32**	49.2	**0.67**	0.62	0.7	**1.092**	21.1	750	250	57.7	117.5	128.0	10.5	8.9%
		2,000	24.41	1.18	0.17	0.08	1.43	53.0	25.99	2.30	0.08	(0.06)	2.32	72.5	0.67	0.62	0.70	1.09	42.2	750	1,250	122.1	217.4	236.7	19.4	8.9%
		5,000	24.41	1.18	0.17	0.08	1.43	95.9	25.99	2.30	0.08	(0.06)	2.32	142.2	0.67	0.62	0.70	1.09	105.4	750	4,250	315.4	517.0	563.0	46.0	8.9%
		10,000	24.41	1.18	0.17	0.08	1.43	167.4	25.99	2.30	0.08	(0.06)	2.32	258.3	0.67	0.62	0.70	1.09	210.9	750	9,250	637.5	1,016.3	1,106.7	90.5	8.9%
		15,000	24.41	1.18	0.17	0.08	1.43	238.9	25.99	2.30	0.08	(0.06)	2.32	374.5	0.67	0.62	0.70	1.09	316.3	750	14,250	959.7	1,515.6	1,650.5	134.9	8.9%
GSe	Bath	1,000	**10.65**	**1.47**	**0.29**	**0.24**	**2.00**	30.7	**15.43**	**2.55**	**0.24**	**(0.06)**	**2.73**	42.8	**0.67**	0.62	0.7	**1.092**	21.1	750	250	57.7	109.5	121.5	12.1	11.0%
		2,000	10.65	1.47	0.29	0.24	2.00	50.7	15.43	2.55	0.24	(0.06)	2.73	70.1	0.67	0.62	0.70	1.09	42.2	750	1,250	122.1	215.0	234.4	19.4	9.0%
		5,000	10.65	1.47	0.29	0.24	2.00	110.7	15.43	2.55	0.24	(0.06)	2.73	152.1	0.67	0.62	0.70	1.09	105.4	750	4,250	315.4	531.7	572.9	41.2	7.8%
		10,000	10.65	1.47	0.29	0.24	2.00	210.7	15.43	2.55	0.24	(0.06)	2.73	288.8	0.67	0.62	0.70	1.09	210.9	750	9,250	637.5	1,059.5	1,137.2	77.7	7.3%
		15,000	10.65	1.47	0.29	0.24	2.00	310.7	15.43	2.55	0.24	(0.06)	2.73	425.4	0.67	0.62	0.70	1.09	316.3	750	14,250	959.7	1,587.3	1,701.4	114.1	7.2%
GSe	Blandford-Ble	1,000	**23.85**	**1.14**	**0.28**	**0.20**	**1.62**	40.1	**25.13**	**2.40**	**0.20**	**(0.06)**	**2.54**	50.6	**0.67**	0.62	0.7	**1.092**	21.1	750	250	57.7	118.9	129.3	10.5	8.8%
		2,000	23.85	1.14	0.28	0.20	1.62	56.3	25.13	2.40	0.20	(0.06)	2.54	76.0	0.67	0.62	0.70	1.09	42.2	750	1,250	122.1	220.6	240.3	19.7	8.9%
		5,000	23.85	1.14	0.28	0.20	1.62	104.9	25.13	2.40	0.20	(0.06)	2.54	152.3	0.67	0.62	0.70	1.09	105.4	750	4,250	315.4	525.9	573.1	47.2	9.0%
		10,000	23.85	1.14	0.28	0.20	1.62	185.9	25.13	2.40	0.20	(0.06)	2.54	279.5	0.67	0.62	0.70	1.09	210.9	750	9,250	637.5	1,034.7	1,127.9	93.2	9.0%
		15,000	23.85	1.14	0.28	0.20	1.62	266.9	25.13	2.40	0.20	(0.06)	2.54	406.6	0.67	0.62	0.70	1.09	316.3	750	14,250	959.7	1,543.5	1,682.6	139.1	9.0%
GSe	Blyth	1,000	**21.63**	**1.05**	**0.26**	**0.20**	**1.51**	36.7	**23.68**	**2.20**	**0.20**	**(0.06)**	**2.34**	47.1	**0.67**	0.62	0.7	**1.092**	21.1	750	250	57.7	115.5	125.9	10.3	9.0%
		2,000	21.63	1.05	0.26	0.20	1.51	51.8	23.68	2.20	0.20	(0.06)	2.34	70.5	0.67	0.62	0.70	1.09	42.2	750	1,250	122.1	216.2	234.8	18.6	8.6%
		5,000	21.63	1.05	0.26	0.20	1.51	97.1	23.68	2.20	0.20	(0.06)	2.34	140.8	0.67	0.62	0.70	1.09	105.4	750	4,250	315.4	518.2	561.7	43.5	8.4%
		10,000	21.63	1.05	0.26	0.20	1.51	172.6	23.68	2.20	0.20	(0.06)	2.34	258.0	0.67	0.62	0.70	1.09	210.9	750	9,250	637.5	1,021.5	1,106.4	84.9	8.3%
		15,000	21.63	1.05	0.26	0.20	1.51	248.1	23.68	2.20	0.20	(0.06)	2.34	375.2	0.67	0.62	0.70	1.09	316.3	750	14,250	959.7	1,524.8	1,651.1	126.4	8.3%
GSe	Bobcaygeon	1,000	**23.20**	**1.38**	**0.18**	**0.09**	**1.65**	39.7	**25.29**	**2.50**	**0.09**	**(0.06)**	**2.53**	50.6	**0.67**	0.62	0.7	**1.092**	21.1	750	250	57.7	118.5	129.4	10.9	9.2%
		2,000	23.20	1.38	0.18	0.09	1.65	56.2	25.29	2.50	0.09	(0.06)	2.53	76.0	0.67	0.62	0.70	1.09	42.2	750	1,250	122.1	220.6	240.2	19.7	8.9%
		5,000	23.20	1.38	0.18	0.09	1.65	105.7	25.29	2.50	0.09	(0.06)	2.53	152.0	0.67	0.62	0.70	1.09	105.4	750	4,250	315.4	526.8	572.8	46.0	8.7%
		10,000	23.20	1.38	0.18	0.09	1.65	188.2	25.29	2.50	0.09	(0.06)	2.53	278.6	0.67	0.62	0.70	1.09	210.9	750	9,250	637.5	1,037.1	1,127.0	90.0	8.7%
		15,000	23.20	1.38	0.18	0.09	1.65	270.7	25.29	2.50	0.09	(0.06)	2.53	405.3	0.67	0.62	0.70	1.09	316.3	750	14,250	959.7	1,547.4	1,681.3	133.9	8.7%

New Rate Class: GSe - Metered

Total Bill Impacts of Proposed Distribution Rates [new RTSR+TLF]: Threshold of 750 kWhs

750.0

Classes		Scenario	May 2007 Incl Rate Riders						May 2008 Incl Rate Riders						Non-Dx Compoent				Other Reg	Commodity Bands			Existing	New	$ Incr	% Incr
			Existing Dx Rates					Existing Dx	New Dx Rates					New Dx	RTSR new	WMSC	DRC	TLF new	New	Band 1	Band 2	New	Total Bill	Total Bill	Total Bill	Total Bill
																				5.0	5.9					
New Class	Old Class	kWh	SrChg	base	Rider1	Rider2	VarChg	[$/month]	SrChg	base	Rider2	Rider3	VarChg	[$/month]	c/kWh	c/kWh	c/kWh		$	kWhs	kWhs		[$/month]	[$/month]	[$/month]	%
			[$/cust]	[c/kWh]	[c/kWh]	[c/kWh]	[c/kWh]		[$/cust]	[c/kWh]	[c/kWh]	[c/kWh]	[c/kWh]													
GSe	**Brighton**	1,000	**22.90**	**1.35**	**0.20**	**0.08**	**1.63**	39.2	**24.37**	**2.50**	**0.08**	**(0.06)**	**2.52**	49.6	**0.67**	0.62	0.7	**1.092**	21.1	750	250	57.7	118.0	128.4	10.4	8.8%
		2,000	22.90	1.35	0.20	0.08	1.63	55.5	24.37	2.50	0.08	(0.06)	2.52	74.8	0.67	0.62	0.70	1.09	42.2	750	1,250	122.1	219.9	239.1	19.2	8.8%
		5,000	22.90	1.35	0.20	0.08	1.63	104.4	24.37	2.50	0.08	(0.06)	2.52	150.5	0.67	0.62	0.70	1.09	105.4	750	4,250	315.4	525.5	571.4	45.9	8.7%
		10,000	22.90	1.35	0.20	0.08	1.63	185.9	24.37	2.50	0.08	(0.06)	2.52	276.7	0.67	0.62	0.70	1.09	210.9	750	9,250	637.5	1,034.8	1,125.1	90.3	8.7%
		15,000	22.90	1.35	0.20	0.08	1.63	267.4	24.37	2.50	0.08	(0.06)	2.52	402.9	0.67	0.62	0.70	1.09	316.3	750	14,250	959.7	1,544.1	1,678.8	134.8	8.7%
UGe	**Brockville**	1,000	**21.65**	**0.78**	**0.13**	**0.04**	**0.95**	31.2	**18.67**	**2.00**	**0.04**	**(0.06)**	**1.99**	38.5	**0.69**	0.62	0.7	**1.092**	21.3	750	250	57.7	110.0	117.5	7.5	6.9%
		2,000	21.65	0.78	0.13	0.04	0.95	40.7	18.67	2.00	0.04	(0.06)	1.99	58.4	0.69	0.62	0.70	1.09	42.6	750	1,250	122.1	205.0	223.1	18.1	8.8%
		5,000	21.65	0.78	0.13	0.04	0.95	69.2	18.67	2.00	0.04	(0.06)	1.99	117.9	0.69	0.62	0.70	1.09	106.5	750	4,250	315.4	490.2	539.9	49.7	10.1%
		10,000	21.65	0.78	0.13	0.04	0.95	116.7	18.67	2.00	0.04	(0.06)	1.99	217.2	0.69	0.62	0.70	1.09	213.1	750	9,250	637.5	965.5	1,067.8	102.3	10.6%
		15,000	21.65	0.78	0.13	0.04	0.95	164.2	18.67	2.00	0.04	(0.06)	1.99	316.5	0.69	0.62	0.70	1.09	319.6	750	14,250	959.7	1,440.8	1,595.7	154.9	10.8%
GSe	**Caledon CH**	1,000	**24.21**	**1.80**	**0.14**	**0.08**	**2.02**	44.4	**26.04**	**2.90**	**0.08**	**(0.06)**	**2.92**	55.3	**0.67**	0.62	0.7	**1.092**	21.1	750	250	57.7	123.2	134.0	10.8	8.8%
		2,000	24.21	1.80	0.14	0.08	2.02	64.6	26.04	2.90	0.08	(0.06)	2.92	84.5	0.67	0.62	0.70	1.09	42.2	750	1,250	122.1	229.0	248.8	19.8	8.6%
		5,000	24.21	1.80	0.14	0.08	2.02	125.2	26.04	2.90	0.08	(0.06)	2.92	172.2	0.67	0.62	0.70	1.09	105.4	750	4,250	315.4	546.3	593.0	46.8	8.6%
		10,000	24.21	1.80	0.14	0.08	2.02	226.2	26.04	2.90	0.08	(0.06)	2.92	318.4	0.67	0.62	0.70	1.09	210.9	750	9,250	637.5	1,075.1	1,166.8	91.7	8.5%
		15,000	24.21	1.80	0.14	0.08	2.02	327.2	26.04	2.90	0.08	(0.06)	2.92	464.5	0.67	0.62	0.70	1.09	316.3	750	14,250	959.7	1,603.9	1,740.5	136.6	8.5%
GSe	**Caledon OH**	1,000	**25.56**	**1.70**	**0.16**	**0.07**	**1.93**	44.9	**26.70**	**2.90**	**0.07**	**(0.06)**	**2.91**	55.8	**0.67**	0.62	0.7	**1.092**	21.1	750	250	57.7	123.7	134.6	10.9	8.8%
		2,000	25.56	1.70	0.16	0.07	1.93	64.2	26.70	2.90	0.07	(0.06)	2.91	85.0	0.67	0.62	0.70	1.09	42.2	750	1,250	122.1	228.5	249.2	20.7	9.1%
		5,000	25.56	1.70	0.16	0.07	1.93	122.1	26.70	2.90	0.07	(0.06)	2.91	172.4	0.67	0.62	0.70	1.09	105.4	750	4,250	315.4	543.1	593.2	50.1	9.2%
		10,000	25.56	1.70	0.16	0.07	1.93	218.6	26.70	2.90	0.07	(0.06)	2.91	318.0	0.67	0.62	0.70	1.09	210.9	750	9,250	637.5	1,067.4	1,166.4	99.0	9.3%
		15,000	25.56	1.70	0.16	0.07	1.93	315.1	26.70	2.90	0.07	(0.06)	2.91	463.7	0.67	0.62	0.70	1.09	316.3	750	14,250	959.7	1,591.7	1,739.7	147.9	9.3%
GSe	**Campbellford-**	1,000	**16.19**	**1.19**	**0.17**	**0.05**	**1.41**	30.3	**20.04**	**2.15**	**0.05**	**(0.06)**	**2.14**	41.5	**0.67**	0.62	0.7	**1.092**	21.1	750	250	57.7	109.1	120.2	11.1	10.2%
		2,000	16.19	1.19	0.17	0.05	1.41	44.4	20.04	2.15	0.05	(0.06)	2.14	62.9	0.67	0.62	0.70	1.09	42.2	750	1,250	122.1	208.8	227.2	18.4	8.8%
		5,000	16.19	1.19	0.17	0.05	1.41	86.7	20.04	2.15	0.05	(0.06)	2.14	127.2	0.67	0.62	0.70	1.09	105.4	750	4,250	315.4	507.7	548.0	40.3	7.9%
		10,000	16.19	1.19	0.17	0.05	1.41	157.2	20.04	2.15	0.05	(0.06)	2.14	234.4	0.67	0.62	0.70	1.09	210.9	750	9,250	637.5	1,006.0	1,082.8	76.7	7.6%
		15,000	16.19	1.19	0.17	0.05	1.41	227.7	20.04	2.15	0.05	(0.06)	2.14	341.5	0.67	0.62	0.70	1.09	316.3	750	14,250	959.7	1,504.3	1,617.5	113.2	7.5%

New Rate Class: GSe - Metered

Total Bill Impacts of Proposed Distribution Rates [new RTSR+TLF]: Threshold of 750 kWhs

750.0

Classes		Scenario	May 2007 Incl Rate Riders						May 2008 Incl Rate Riders						Non-Dx Compoent				Other Reg	Commodity Bands			Existing	New	$ Incr	% Incr
			Existing Dx Rates					Existing Dx	New Dx Rates					New Dx	RTSR new	WMSC	DRC	TLF new	New	Band 1	Band 2	New	Total Bill	Total Bill	Total Bill	Total Bill
																				5.0	5.9					
New Class	Old Class	kWh	SrChg [$/cust]	base [c/kWh]	Rider1 [c/kWh]	Rider2 [c/kWh]	VarChg [c/kWh]	[$/month]	SrChg [$/cust]	base [c/kWh]	Rider2 [c/kWh]	Rider3 [c/kWh]	VarChg [c/kWh]	[$/month]	c/kWh	c/kWh	c/kWh		$	kWhs	kWhs		[$/month]	[$/month]	[$/month]	%
UGe	Carleton Place	1,000	**23.65**	**1.68**	**0.13**	**0.07**	**1.88**	42.5	**20.17**	**2.00**	**0.07**	**(0.06)**	**2.02**	40.3	**0.69**	0.62	0.7	**1.092**	21.3	750	250	57.7	121.3	119.3	(2.0)	-1.6%
		2,000	23.65	1.68	0.13	0.07	1.88	61.3	20.17	2.00	0.07	(0.06)	2.02	60.5	0.69	0.62	0.70	1.09	42.6	750	1,250	122.1	225.6	225.2	(0.4)	-0.2%
		5,000	23.65	1.68	0.13	0.07	1.88	117.7	20.17	2.00	0.07	(0.06)	2.02	120.9	0.69	0.62	0.70	1.09	106.5	750	4,250	315.4	538.7	542.9	4.2	0.8%
		10,000	23.65	1.68	0.13	0.07	1.88	211.7	20.17	2.00	0.07	(0.06)	2.02	221.7	0.69	0.62	0.70	1.09	213.1	750	9,250	637.5	1,060.5	1,072.3	11.8	1.1%
		15,000	23.65	1.68	0.13	0.07	1.88	305.7	20.17	2.00	0.07	(0.06)	2.02	322.5	0.69	0.62	0.70	1.09	319.6	750	14,250	959.7	1,582.3	1,601.7	19.4	1.2%
GSe	Cavan-Millbro	1,000	**22.28**	**1.50**	**0.33**	**0.26**	**2.09**	43.2	**24.52**	**2.80**	**0.26**	**(0.06)**	**3.00**	54.6	**0.67**	0.62	0.7	**1.092**	21.1	750	250	57.7	122.0	133.3	11.3	9.3%
		2,000	22.28	1.50	0.33	0.26	2.09	64.1	24.52	2.80	0.26	(0.06)	3.00	84.6	0.67	0.62	0.70	1.09	42.2	750	1,250	122.1	228.5	248.9	20.4	8.9%
		5,000	22.28	1.50	0.33	0.26	2.09	126.8	24.52	2.80	0.26	(0.06)	3.00	174.7	0.67	0.62	0.70	1.09	105.4	750	4,250	315.4	547.8	595.5	47.7	8.7%
		10,000	22.28	1.50	0.33	0.26	2.09	231.3	24.52	2.80	0.26	(0.06)	3.00	324.8	0.67	0.62	0.70	1.09	210.9	750	9,250	637.5	1,080.1	1,173.2	93.1	8.6%
		15,000	22.28	1.50	0.33	0.26	2.09	335.8	24.52	2.80	0.26	(0.06)	3.00	475.0	0.67	0.62	0.70	1.09	316.3	750	14,250	959.7	1,612.4	1,751.0	138.5	8.6%
GSe	Centre Hasting	1,000	**18.38**	**0.97**	**0.14**	**0.06**	**1.17**	30.1	**21.50**	**1.94**	**0.06**	**(0.06)**	**1.94**	40.9	**0.67**	0.62	0.7	**1.092**	21.1	750	250	57.7	108.9	119.7	10.8	9.9%
		2,000	18.38	0.97	0.14	0.06	1.17	41.8	21.50	1.94	0.06	(0.06)	1.94	60.4	0.67	0.62	0.70	1.09	42.2	750	1,250	122.1	206.2	224.6	18.5	9.0%
		5,000	18.38	0.97	0.14	0.06	1.17	76.9	21.50	1.94	0.06	(0.06)	1.94	118.7	0.67	0.62	0.70	1.09	105.4	750	4,250	315.4	497.9	539.5	41.6	8.3%
		10,000	18.38	0.97	0.14	0.06	1.17	135.4	21.50	1.94	0.06	(0.06)	1.94	215.8	0.67	0.62	0.70	1.09	210.9	750	9,250	637.5	984.2	1,064.2	80.0	8.1%
		15,000	18.38	0.97	0.14	0.06	1.17	193.9	21.50	1.94	0.06	(0.06)	1.94	313.0	0.67	0.62	0.70	1.09	316.3	750	14,250	959.7	1,470.5	1,589.0	118.4	8.1%
GSe	Chalk River	1,000	**21.33**	**1.79**	**0.39**	**0.34**	**2.52**	46.5	**23.76**	**3.18**	**0.34**	**(0.06)**	**3.46**	58.4	**0.67**	0.62	0.7	**1.092**	21.1	750	250	57.7	125.3	137.2	11.8	9.4%
		2,000	21.33	1.79	0.39	0.34	2.52	71.7	23.76	3.18	0.34	(0.06)	3.46	93.0	0.67	0.62	0.70	1.09	42.2	750	1,250	122.1	236.1	257.3	21.2	9.0%
		5,000	21.33	1.79	0.39	0.34	2.52	147.3	23.76	3.18	0.34	(0.06)	3.46	196.9	0.67	0.62	0.70	1.09	105.4	750	4,250	315.4	568.4	617.7	49.4	8.7%
		10,000	21.33	1.79	0.39	0.34	2.52	273.3	23.76	3.18	0.34	(0.06)	3.46	370.1	0.67	0.62	0.70	1.09	210.9	750	9,250	637.5	1,122.2	1,218.5	96.3	8.6%
		15,000	21.33	1.79	0.39	0.34	2.52	399.3	23.76	3.18	0.34	(0.06)	3.46	543.2	0.67	0.62	0.70	1.09	316.3	750	14,250	959.7	1,676.0	1,819.2	143.2	8.5%
GSe	Champlain	1,000	**20.59**	**0.91**	**0.26**	**0.15**	**1.32**	33.8	**22.94**	**2.05**	**0.15**	**(0.06)**	**2.14**	44.4	**0.67**	0.62	0.7	**1.092**	21.1	750	250	57.7	112.6	123.1	10.5	9.4%
		2,000	20.59	0.91	0.26	0.15	1.32	47.0	22.94	2.05	0.15	(0.06)	2.14	65.8	0.67	0.62	0.70	1.09	42.2	750	1,250	122.1	211.4	230.1	18.7	8.9%
		5,000	20.59	0.91	0.26	0.15	1.32	86.6	22.94	2.05	0.15	(0.06)	2.14	130.1	0.67	0.62	0.70	1.09	105.4	750	4,250	315.4	507.6	550.9	43.3	8.5%
		10,000	20.59	0.91	0.26	0.15	1.32	152.6	22.94	2.05	0.15	(0.06)	2.14	237.3	0.67	0.62	0.70	1.09	210.9	750	9,250	637.5	1,001.4	1,085.7	84.2	8.4%
		15,000	20.59	0.91	0.26	0.15	1.32	218.6	22.94	2.05	0.15	(0.06)	2.14	344.4	0.67	0.62	0.70	1.09	316.3	750	14,250	959.7	1,495.2	1,620.4	125.2	8.4%

New Rate Class: GSe - Metered

Total Bill Impacts of Proposed Distribution Rates [new RTSR+TLF]: Threshold of 750 kWhs

750.0

Classes		Scenario	May 2007 Incl Rate Riders						May 2008 Incl Rate Riders						Non-Dx Compoent				Other Reg	Commodity Bands			Existing	New	$ Incr	% Incr
			Existing Dx Rates					Existing Dx	New Dx Rates					New Dx	RTSR new	WMSC	DRC	TLF new	New	Band 1	Band 2	New	Total Bill	Total Bill	Total Bill	Total Bill
																				5.0	5.9					
New Class	Old Class	kWh	SrChg [$/cust]	base [c/kWh]	Rider1 [c/kWh]	Rider2 [c/kWh]	VarChg [c/kWh]	[$/month]	SrChg [$/cust]	base [c/kWh]	Rider2 [c/kWh]	Rider3 [c/kWh]	VarChg [c/kWh]	[$/month]	c/kWh	c/kWh	c/kWh		$	kWhs	kWhs		[$/month]	[$/month]	[$/month]	%
GSe	**Cobden**	1,000	**21.93**	**2.13**	**0.36**	**0.30**	**2.79**	49.8	**23.61**	**3.21**	**0.30**	**(0.06)**	**3.45**	58.1	**0.67**	0.62	0.7	**1.092**	21.1	750	250	57.7	128.6	136.9	8.3	6.4%
		2,000	21.93	2.13	0.36	0.30	2.79	77.7	23.61	3.21	0.30	(0.06)	3.45	92.7	0.67	0.62	0.70	1.09	42.2	750	1,250	122.1	242.1	257.0	14.9	6.1%
		5,000	21.93	2.13	0.36	0.30	2.79	161.4	23.61	3.21	0.30	(0.06)	3.45	196.3	0.67	0.62	0.70	1.09	105.4	750	4,250	315.4	582.5	617.1	34.6	5.9%
		10,000	21.93	2.13	0.36	0.30	2.79	300.9	23.61	3.21	0.30	(0.06)	3.45	369.0	0.67	0.62	0.70	1.09	210.9	750	9,250	637.5	1,149.8	1,217.4	67.6	5.9%
		15,000	21.93	2.13	0.36	0.30	2.79	440.4	23.61	3.21	0.30	(0.06)	3.45	541.7	0.67	0.62	0.70	1.09	316.3	750	14,250	959.7	1,717.1	1,817.6	100.6	5.9%
GSe	**Deep River**	1,000	**23.94**	**2.26**	**0.15**	**0.14**	**2.55**	49.4	**25.11**	**3.21**	**0.14**	**(0.06)**	**3.29**	58.0	**0.67**	0.62	0.7	**1.092**	21.1	750	250	57.7	128.3	136.8	8.6	6.7%
		2,000	23.94	2.26	0.15	0.14	2.55	74.9	25.11	3.21	0.14	(0.06)	3.29	91.0	0.67	0.62	0.70	1.09	42.2	750	1,250	122.1	239.3	255.3	16.0	6.7%
		5,000	23.94	2.26	0.15	0.14	2.55	151.4	25.11	3.21	0.14	(0.06)	3.29	189.8	0.67	0.62	0.70	1.09	105.4	750	4,250	315.4	572.5	610.6	38.1	6.7%
		10,000	23.94	2.26	0.15	0.14	2.55	278.9	25.11	3.21	0.14	(0.06)	3.29	354.5	0.67	0.62	0.70	1.09	210.9	750	9,250	637.5	1,127.8	1,202.9	75.1	6.7%
		15,000	23.94	2.26	0.15	0.14	2.55	406.4	25.11	3.21	0.14	(0.06)	3.29	519.2	0.67	0.62	0.70	1.09	316.3	750	14,250	959.7	1,683.1	1,795.1	112.0	6.7%
GSe	**Deseronto**	1,000	**10.14**	**1.35**	**0.13**	**0.05**	**1.53**	25.4	**15.56**	**2.18**	**0.05**	**(0.06)**	**2.17**	37.3	**0.67**	0.62	0.7	**1.092**	21.1	750	250	57.7	104.3	116.1	11.8	11.3%
		2,000	10.14	1.35	0.13	0.05	1.53	40.7	15.56	2.18	0.05	(0.06)	2.17	59.0	0.67	0.62	0.70	1.09	42.2	750	1,250	122.1	205.1	223.3	18.2	8.9%
		5,000	10.14	1.35	0.13	0.05	1.53	86.6	15.56	2.18	0.05	(0.06)	2.17	124.2	0.67	0.62	0.70	1.09	105.4	750	4,250	315.4	507.7	545.0	37.4	7.4%
		10,000	10.14	1.35	0.13	0.05	1.53	163.1	15.56	2.18	0.05	(0.06)	2.17	232.9	0.67	0.62	0.70	1.09	210.9	750	9,250	637.5	1,012.0	1,081.3	69.3	6.8%
		15,000	10.14	1.35	0.13	0.05	1.53	239.6	15.56	2.18	0.05	(0.06)	2.17	341.5	0.67	0.62	0.70	1.09	316.3	750	14,250	959.7	1,516.3	1,617.5	101.2	6.7%
UGe	**Dryden**	1,000	**19.11**	**1.03**	**0.12**	**0.04**	**1.19**	31.0	**17.31**	**2.00**	**0.04**	**(0.06)**	**1.99**	37.2	**0.69**	0.62	0.7	**1.092**	21.3	750	250	57.7	109.8	116.1	6.3	5.8%
		2,000	19.11	1.03	0.12	0.04	1.19	42.9	17.31	2.00	0.04	(0.06)	1.99	57.0	0.69	0.62	0.70	1.09	42.6	750	1,250	122.1	207.3	221.7	14.4	7.0%
		5,000	19.11	1.03	0.12	0.04	1.19	78.6	17.31	2.00	0.04	(0.06)	1.99	116.6	0.69	0.62	0.70	1.09	106.5	750	4,250	315.4	499.7	538.5	38.8	7.8%
		10,000	19.11	1.03	0.12	0.04	1.19	138.1	17.31	2.00	0.04	(0.06)	1.99	215.8	0.69	0.62	0.70	1.09	213.1	750	9,250	637.5	987.0	1,066.4	79.5	8.1%
		15,000	19.11	1.03	0.12	0.04	1.19	197.6	17.31	2.00	0.04	(0.06)	1.99	315.1	0.69	0.62	0.70	1.09	319.6	750	14,250	959.7	1,474.3	1,594.4	120.1	8.1%
GSe	**Dundalk**	1,000	**23.56**	**1.64**	**0.23**	**0.09**	**1.96**	43.2	**25.20**	**2.85**	**0.09**	**(0.06)**	**2.88**	54.0	**0.67**	0.62	0.7	**1.092**	21.1	750	250	57.7	122.0	132.8	10.8	8.9%
		2,000	23.56	1.64	0.23	0.09	1.96	62.8	25.20	2.85	0.09	(0.06)	2.88	82.9	0.67	0.62	0.70	1.09	42.2	750	1,250	122.1	227.1	247.1	20.0	8.8%
		5,000	23.56	1.64	0.23	0.09	1.96	121.6	25.20	2.85	0.09	(0.06)	2.88	169.4	0.67	0.62	0.70	1.09	105.4	750	4,250	315.4	542.6	590.2	47.6	8.8%
		10,000	23.56	1.64	0.23	0.09	1.96	219.6	25.20	2.85	0.09	(0.06)	2.88	313.5	0.67	0.62	0.70	1.09	210.9	750	9,250	637.5	1,068.4	1,161.9	93.5	8.8%
		15,000	23.56	1.64	0.23	0.09	1.96	317.6	25.20	2.85	0.09	(0.06)	2.88	457.7	0.67	0.62	0.70	1.09	316.3	750	14,250	959.7	1,594.2	1,733.7	139.4	8.7%

New Rate Class: GSe - Metered

Total Bill Impacts of Proposed Distribution Rates [new RTSR+TLF]: Threshold of 750 kWhs

750.0

Classes		Scenario	May 2007 Incl Rate Riders						May 2008 Incl Rate Riders						Non-Dx Compoent				Other Reg	Commodity Bands			Existing	New	$ Incr	% Incr
			Existing Dx Rates					Existing Dx	New Dx Rates					New Dx	RTSR new	WMSC	DRC	TLF new	New	Band 1	Band 2	New	Total Bill	Total Bill	Total Bill	Total Bill
																				5.0	5.9					
New Class	Old Class	kWh	SrChg [$/cust]	base [c/kWh]	Rider1 [c/kWh]	Rider2 [c/kWh]	VarChg [c/kWh]	[$/month]	SrChg [$/cust]	base [c/kWh]	Rider2 [c/kWh]	Rider3 [c/kWh]	VarChg [c/kWh]	[$/month]	c/kWh	c/kWh	c/kWh		$	kWhs	kWhs		[$/month]	[$/month]	[$/month]	%
GSe	Durham	1,000	**24.12**	**1.37**	**0.15**	**0.06**	**1.58**	39.9	**26.06**	**2.48**	**0.06**	**(0.06)**	**2.48**	50.9	**0.67**	0.62	0.7	**1.092**	21.1	750	250	57.7	118.7	129.7	10.9	9.2%
		2,000	24.12	1.37	0.15	0.06	1.58	55.7	26.06	2.48	0.06	(0.06)	2.48	75.7	0.67	0.62	0.70	1.09	42.2	750	1,250	122.1	220.1	240.0	19.9	9.0%
		5,000	24.12	1.37	0.15	0.06	1.58	103.1	26.06	2.48	0.06	(0.06)	2.48	150.2	0.67	0.62	0.70	1.09	105.4	750	4,250	315.4	524.2	571.0	46.9	8.9%
		10,000	24.12	1.37	0.15	0.06	1.58	182.1	26.06	2.48	0.06	(0.06)	2.48	274.4	0.67	0.62	0.70	1.09	210.9	750	9,250	637.5	1,031.0	1,122.8	91.8	8.9%
		15,000	24.12	1.37	0.15	0.06	1.58	261.1	26.06	2.48	0.06	(0.06)	2.48	398.6	0.67	0.62	0.70	1.09	316.3	750	14,250	959.7	1,537.8	1,674.5	136.7	8.9%
GSe	Eganville	1,000	**21.35**	**2.32**	**0.17**	**0.12**	**2.61**	47.5	**23.75**	**3.21**	**0.12**	**(0.06)**	**3.27**	56.5	**0.67**	0.62	0.7	**1.092**	21.1	750	250	57.7	126.3	135.3	9.0	7.1%
		2,000	21.35	2.32	0.17	0.12	2.61	73.6	23.75	3.21	0.12	(0.06)	3.27	89.2	0.67	0.62	0.70	1.09	42.2	750	1,250	122.1	237.9	253.5	15.6	6.6%
		5,000	21.35	2.32	0.17	0.12	2.61	151.9	23.75	3.21	0.12	(0.06)	3.27	187.4	0.67	0.62	0.70	1.09	105.4	750	4,250	315.4	572.9	608.3	35.4	6.2%
		10,000	21.35	2.32	0.17	0.12	2.61	282.4	23.75	3.21	0.12	(0.06)	3.27	351.1	0.67	0.62	0.70	1.09	210.9	750	9,250	637.5	1,131.2	1,199.5	68.3	6.0%
		15,000	21.35	2.32	0.17	0.12	2.61	412.9	23.75	3.21	0.12	(0.06)	3.27	514.8	0.67	0.62	0.70	1.09	316.3	750	14,250	959.7	1,689.5	1,790.8	101.3	6.0%
GSe	Erin	1,000	**40.38**	**0.73**	**0.19**	**0.08**	**1.00**	50.4	**38.00**	**2.10**	**0.08**	**(0.06)**	**2.12**	59.2	**0.67**	0.62	0.7	**1.092**	21.1	750	250	57.7	129.2	138.0	8.8	6.8%
		2,000	40.38	0.73	0.19	0.08	1.00	60.4	38.00	2.10	0.08	(0.06)	2.12	80.5	0.67	0.62	0.70	1.09	42.2	750	1,250	122.1	224.8	244.7	20.0	8.9%
		5,000	40.38	0.73	0.19	0.08	1.00	90.4	38.00	2.10	0.08	(0.06)	2.12	144.2	0.67	0.62	0.70	1.09	105.4	750	4,250	315.4	511.4	565.0	53.6	10.5%
		10,000	40.38	0.73	0.19	0.08	1.00	140.4	38.00	2.10	0.08	(0.06)	2.12	250.3	0.67	0.62	0.70	1.09	210.9	750	9,250	637.5	989.2	1,098.7	109.5	11.1%
		15,000	40.38	0.73	0.19	0.08	1.00	190.4	38.00	2.10	0.08	(0.06)	2.12	356.5	0.67	0.62	0.70	1.09	316.3	750	14,250	959.7	1,467.0	1,632.5	165.4	11.3%
GSe	Exeter	1,000	**11.36**	**1.30**	**0.15**	**0.06**	**1.51**	26.5	**16.25**	**2.18**	**0.06**	**(0.06)**	**2.18**	38.1	**0.67**	0.62	0.7	**1.092**	21.1	750	250	57.7	105.3	116.8	11.6	11.0%
		2,000	11.36	1.30	0.15	0.06	1.51	41.6	16.25	2.18	0.06	(0.06)	2.18	59.9	0.67	0.62	0.70	1.09	42.2	750	1,250	122.1	205.9	224.2	18.3	8.9%
		5,000	11.36	1.30	0.15	0.06	1.51	86.9	16.25	2.18	0.06	(0.06)	2.18	125.4	0.67	0.62	0.70	1.09	105.4	750	4,250	315.4	507.9	546.2	38.3	7.5%
		10,000	11.36	1.30	0.15	0.06	1.51	162.4	16.25	2.18	0.06	(0.06)	2.18	234.6	0.67	0.62	0.70	1.09	210.9	750	9,250	637.5	1,011.2	1,083.0	71.8	7.1%
		15,000	11.36	1.30	0.15	0.06	1.51	237.9	16.25	2.18	0.06	(0.06)	2.18	343.7	0.67	0.62	0.70	1.09	316.3	750	14,250	959.7	1,514.5	1,619.7	105.2	6.9%
GSe	Fenelon Falls	1,000	**19.81**	**0.95**	**0.15**	**0.08**	**1.18**	31.6	**22.14**	**1.98**	**0.08**	**(0.06)**	**2.00**	42.2	**0.67**	0.62	0.7	**1.092**	21.1	750	250	57.7	110.4	120.9	10.5	9.5%
		2,000	19.81	0.95	0.15	0.08	1.18	43.4	22.14	1.98	0.08	(0.06)	2.00	62.2	0.67	0.62	0.70	1.09	42.2	750	1,250	122.1	207.8	226.5	18.7	9.0%
		5,000	19.81	0.95	0.15	0.08	1.18	78.8	22.14	1.98	0.08	(0.06)	2.00	122.3	0.67	0.62	0.70	1.09	105.4	750	4,250	315.4	499.9	543.1	43.3	8.7%
		10,000	19.81	0.95	0.15	0.08	1.18	137.8	22.14	1.98	0.08	(0.06)	2.00	222.5	0.67	0.62	0.70	1.09	210.9	750	9,250	637.5	986.7	1,070.9	84.2	8.5%
		15,000	19.81	0.95	0.15	0.08	1.18	196.8	22.14	1.98	0.08	(0.06)	2.00	322.6	0.67	0.62	0.70	1.09	316.3	750	14,250	959.7	1,473.5	1,598.6	125.1	8.5%

New Rate Class: GSe - Metered

Total Bill Impacts of Proposed Distribution Rates [new RTSR+TLF]: Threshold of 750 kWhs

Classes		Scenario	May 2007 Incl Rate Riders						May 2008 Incl Rate Riders						Non-Dx Compoent				Other Reg	Commodity Bands			Existing	New	$ Incr	% Incr
			Existing Dx Rates					Existing Dx	New Dx Rates					New Dx	RTSR new	WMSC	DRC	TLF new	New	Band 1	Band 2	New	Total Bill	Total Bill	Total Bill	Total Bill
																				750.0						
																				5.0	5.9					
New Class	Old Class	kWh	SrChg [$/cust]	base [c/kWh]	Rider1 [c/kWh]	Rider2 [c/kWh]	VarChg [c/kWh]	[$/month]	SrChg [$/cust]	base [c/kWh]	Rider2 [c/kWh]	Rider3 [c/kWh]	VarChg [c/kWh]	[$/month]	c/kWh	c/kWh	c/kWh		$	kWhs	kWhs		[$/month]	[$/month]	[$/month]	%
GSe	**Forest**	1,000	**24.91**	**1.18**	**0.16**	**0.06**	**1.40**	38.9	**25.86**	**2.32**	**0.06**	**(0.06)**	**2.32**	49.1	**0.67**	0.62	0.7	**1.092**	21.1	750	250	57.7	117.7	127.9	10.1	8.6%
		2,000	24.91	1.18	0.16	0.06	1.40	52.9	25.86	2.32	0.06	(0.06)	2.32	72.3	0.67	0.62	0.70	1.09	42.2	750	1,250	122.1	217.3	236.6	19.3	8.9%
		5,000	24.91	1.18	0.16	0.06	1.40	94.9	25.86	2.32	0.06	(0.06)	2.32	142.0	0.67	0.62	0.70	1.09	105.4	750	4,250	315.4	516.0	562.9	46.9	9.1%
		10,000	24.91	1.18	0.16	0.06	1.40	164.9	25.86	2.32	0.06	(0.06)	2.32	258.2	0.67	0.62	0.70	1.09	210.9	750	9,250	637.5	1,013.8	1,106.6	92.8	9.2%
		15,000	24.91	1.18	0.16	0.06	1.40	234.9	25.86	2.32	0.06	(0.06)	2.32	374.4	0.67	0.62	0.70	1.09	316.3	750	14,250	959.7	1,511.6	1,650.3	138.8	9.2%
UGe	**GBE**	1,000	**10.77**	**1.14**	**0.16**	**0.06**	**1.36**	24.4	**10.39**	**2.00**	**0.06**	**(0.06)**	**2.01**	30.4	**0.69**	0.62	0.7	**1.092**	21.3	750	250	57.7	103.2	109.4	6.2	6.1%
		2,000	10.77	1.14	0.16	0.06	1.36	38.0	10.39	2.00	0.06	(0.06)	2.01	50.5	0.69	0.62	0.70	1.09	42.6	750	1,250	122.1	202.3	215.2	12.9	6.4%
		5,000	10.77	1.14	0.16	0.06	1.36	78.8	10.39	2.00	0.06	(0.06)	2.01	110.7	0.69	0.62	0.70	1.09	106.5	750	4,250	315.4	499.8	532.6	32.8	6.6%
		10,000	10.77	1.14	0.16	0.06	1.36	146.8	10.39	2.00	0.06	(0.06)	2.01	210.9	0.69	0.62	0.70	1.09	213.1	750	9,250	637.5	995.6	1,061.5	65.9	6.6%
		15,000	10.77	1.14	0.16	0.06	1.36	214.8	10.39	2.00	0.06	(0.06)	2.01	311.2	0.69	0.62	0.70	1.09	319.6	750	14,250	959.7	1,491.4	1,590.4	99.0	6.6%
GSe	**Georgina**	1,000	**17.40**	**1.62**	**0.16**	**0.08**	**1.86**	36.0	**20.74**	**2.65**	**0.08**	**(0.06)**	**2.67**	47.5	**0.67**	0.62	0.7	**1.092**	21.1	750	250	57.7	114.8	126.2	11.4	10.0%
		2,000	17.40	1.62	0.16	0.08	1.86	54.6	20.74	2.65	0.08	(0.06)	2.67	74.2	0.67	0.62	0.70	1.09	42.2	750	1,250	122.1	219.0	238.5	19.5	8.9%
		5,000	17.40	1.62	0.16	0.08	1.86	110.4	20.74	2.65	0.08	(0.06)	2.67	154.4	0.67	0.62	0.70	1.09	105.4	750	4,250	315.4	531.5	575.2	43.8	8.2%
		10,000	17.40	1.62	0.16	0.08	1.86	203.4	20.74	2.65	0.08	(0.06)	2.67	288.1	0.67	0.62	0.70	1.09	210.9	750	9,250	637.5	1,052.3	1,136.5	84.2	8.0%
		15,000	17.40	1.62	0.16	0.08	1.86	296.4	20.74	2.65	0.08	(0.06)	2.67	421.7	0.67	0.62	0.70	1.09	316.3	750	14,250	959.7	1,573.1	1,697.7	124.6	7.9%
GSe	**Glencoe**	1,000	**11.37**	**0.81**	**0.22**	**0.14**	**1.17**	23.1	**16.25**	**1.74**	**0.14**	**(0.06)**	**1.82**	34.5	**0.67**	0.62	0.7	**1.092**	21.1	750	250	57.7	101.9	113.2	11.4	11.2%
		2,000	11.37	0.81	0.22	0.14	1.17	34.8	16.25	1.74	0.14	(0.06)	1.82	52.7	0.67	0.62	0.70	1.09	42.2	750	1,250	122.1	199.1	217.0	17.9	9.0%
		5,000	11.37	0.81	0.22	0.14	1.17	69.9	16.25	1.74	0.14	(0.06)	1.82	107.4	0.67	0.62	0.70	1.09	105.4	750	4,250	315.4	490.9	528.2	37.3	7.6%
		10,000	11.37	0.81	0.22	0.14	1.17	128.4	16.25	1.74	0.14	(0.06)	1.82	198.6	0.67	0.62	0.70	1.09	210.9	750	9,250	637.5	977.2	1,047.0	69.8	7.1%
		15,000	11.37	0.81	0.22	0.14	1.17	186.9	16.25	1.74	0.14	(0.06)	1.82	289.7	0.67	0.62	0.70	1.09	316.3	750	14,250	959.7	1,463.5	1,565.7	102.2	7.0%
GSe	**Grand Bend**	1,000	**22.20**	**1.23**	**0.19**	**0.07**	**1.49**	37.1	**24.54**	**2.34**	**0.07**	**(0.06)**	**2.35**	48.1	**0.67**	0.62	0.7	**1.092**	21.1	750	250	57.7	115.9	126.8	10.9	9.4%
		2,000	22.20	1.23	0.19	0.07	1.49	52.0	24.54	2.34	0.07	(0.06)	2.35	71.6	0.67	0.62	0.70	1.09	42.2	750	1,250	122.1	216.4	235.9	19.5	9.0%
		5,000	22.20	1.23	0.19	0.07	1.49	96.7	24.54	2.34	0.07	(0.06)	2.35	142.2	0.67	0.62	0.70	1.09	105.4	750	4,250	315.4	517.8	563.0	45.3	8.7%
		10,000	22.20	1.23	0.19	0.07	1.49	171.2	24.54	2.34	0.07	(0.06)	2.35	259.9	0.67	0.62	0.70	1.09	210.9	750	9,250	637.5	1,020.1	1,108.3	88.2	8.6%
		15,000	22.20	1.23	0.19	0.07	1.49	245.7	24.54	2.34	0.07	(0.06)	2.35	377.5	0.67	0.62	0.70	1.09	316.3	750	14,250	959.7	1,522.4	1,653.5	131.1	8.6%

New Rate Class: GSe - Metered

Total Bill Impacts of Proposed Distribution Rates [new RTSR+TLF]: Threshold of 750 kWhs

750.0

Classes		Scenario	May 2007 Incl Rate Riders						May 2008 Incl Rate Riders						Non-Dx Compoent				Other Reg	Commodity Bands			Existing	New	$ Incr	% Incr
			Existing Dx Rates					Existing Dx	New Dx Rates					New Dx	RTSR new	WMSC	DRC	TLF new	New	Band 1	Band 2	New	Total Bill	Total Bill	Total Bill	Total Bill
																				5.0	5.9					
New Class	Old Class	kWh	SrChg [$/cust]	base [c/kWh]	Rider1 [c/kWh]	Rider2 [c/kWh]	VarChg [c/kWh]	[$/month]	SrChg [$/cust]	base [c/kWh]	Rider2 [c/kWh]	Rider3 [c/kWh]	VarChg [c/kWh]	[$/month]	c/kWh	c/kWh	c/kWh		$	kWhs	kWhs		[$/month]	[$/month]	[$/month]	%
GSe	Hastings	1,000	**22.89**	**1.69**	**0.23**	**0.09**	**2.01**	43.0	**24.37**	**2.93**	**0.09**	**(0.06)**	**2.96**	54.0	**0.67**	0.62	0.7	**1.092**	21.1	750	250	57.7	121.8	132.8	11.0	9.0%
		2,000	22.89	1.69	0.23	0.09	2.01	63.1	24.37	2.93	0.09	(0.06)	2.96	83.6	0.67	0.62	0.70	1.09	42.2	750	1,250	122.1	227.5	247.9	20.5	9.0%
		5,000	22.89	1.69	0.23	0.09	2.01	123.4	24.37	2.93	0.09	(0.06)	2.96	172.5	0.67	0.62	0.70	1.09	105.4	750	4,250	315.4	544.4	593.4	48.9	9.0%
		10,000	22.89	1.69	0.23	0.09	2.01	223.9	24.37	2.93	0.09	(0.06)	2.96	320.7	0.67	0.62	0.70	1.09	210.9	750	9,250	637.5	1,072.7	1,169.1	96.4	9.0%
		15,000	22.89	1.69	0.23	0.09	2.01	324.4	24.37	2.93	0.09	(0.06)	2.96	468.9	0.67	0.62	0.70	1.09	316.3	750	14,250	959.7	1,601.0	1,744.8	143.8	9.0%
GSe	Havelock	1,000	**22.18**	**1.52**	**0.16**	**0.09**	**1.77**	39.9	**24.55**	**2.60**	**0.09**	**(0.06)**	**2.63**	50.9	**0.67**	0.62	0.7	**1.092**	21.1	750	250	57.7	118.7	129.6	11.0	9.2%
		2,000	22.18	1.52	0.16	0.09	1.77	57.6	24.55	2.60	0.09	(0.06)	2.63	77.2	0.67	0.62	0.70	1.09	42.2	750	1,250	122.1	222.0	241.5	19.5	8.8%
		5,000	22.18	1.52	0.16	0.09	1.77	110.7	24.55	2.60	0.09	(0.06)	2.63	156.2	0.67	0.62	0.70	1.09	105.4	750	4,250	315.4	531.7	577.0	45.3	8.5%
		10,000	22.18	1.52	0.16	0.09	1.77	199.2	24.55	2.60	0.09	(0.06)	2.63	287.9	0.67	0.62	0.70	1.09	210.9	750	9,250	637.5	1,048.0	1,136.3	88.2	8.4%
		15,000	22.18	1.52	0.16	0.09	1.77	287.7	24.55	2.60	0.09	(0.06)	2.63	419.5	0.67	0.62	0.70	1.09	316.3	750	14,250	959.7	1,564.3	1,695.5	131.2	8.4%
GSe	Kirkfield	1,000	**14.69**	**1.95**	**0.61**	**0.44**	**3.00**	44.7	**18.42**	**3.21**	**0.44**	**(0.06)**	**3.59**	54.4	**0.67**	0.62	0.7	**1.092**	21.1	750	250	57.7	123.5	133.1	9.6	7.8%
		2,000	14.69	1.95	0.61	0.44	3.00	74.7	18.42	3.21	0.44	(0.06)	3.59	90.3	0.67	0.62	0.70	1.09	42.2	750	1,250	122.1	239.1	254.6	15.5	6.5%
		5,000	14.69	1.95	0.61	0.44	3.00	164.7	18.42	3.21	0.44	(0.06)	3.59	198.1	0.67	0.62	0.70	1.09	105.4	750	4,250	315.4	585.7	618.9	33.2	5.7%
		10,000	14.69	1.95	0.61	0.44	3.00	314.7	18.42	3.21	0.44	(0.06)	3.59	377.8	0.67	0.62	0.70	1.09	210.9	750	9,250	637.5	1,163.5	1,226.2	62.6	5.4%
		15,000	14.69	1.95	0.61	0.44	3.00	464.7	18.42	3.21	0.44	(0.06)	3.59	557.5	0.67	0.62	0.70	1.09	316.3	750	14,250	959.7	1,741.3	1,833.5	92.1	5.3%
GSe	Lanark Highla	1,000	**18.43**	**1.99**	**0.63**	**0.50**	**3.12**	49.6	**21.48**	**3.21**	**0.50**	**(0.06)**	**3.65**	58.0	**0.67**	0.62	0.7	**1.092**	21.1	750	250	57.7	128.4	136.8	8.3	6.5%
		2,000	18.43	1.99	0.63	0.50	3.12	80.8	21.48	3.21	0.50	(0.06)	3.65	94.6	0.67	0.62	0.70	1.09	42.2	750	1,250	122.1	245.2	258.8	13.6	5.6%
		5,000	18.43	1.99	0.63	0.50	3.12	174.4	21.48	3.21	0.50	(0.06)	3.65	204.2	0.67	0.62	0.70	1.09	105.4	750	4,250	315.4	595.5	625.0	29.5	5.0%
		10,000	18.43	1.99	0.63	0.50	3.12	330.4	21.48	3.21	0.50	(0.06)	3.65	386.9	0.67	0.62	0.70	1.09	210.9	750	9,250	637.5	1,179.3	1,235.3	56.0	4.7%
		15,000	18.43	1.99	0.63	0.50	3.12	486.4	21.48	3.21	0.50	(0.06)	3.65	569.5	0.67	0.62	0.70	1.09	316.3	750	14,250	959.7	1,763.1	1,845.5	82.4	4.7%
GSe	Larder Lake	1,000	**20.18**	**1.58**	**0.51**	**0.36**	**2.45**	44.7	**23.05**	**3.05**	**0.36**	**(0.06)**	**3.35**	56.6	**0.67**	0.62	0.7	**1.092**	21.1	750	250	57.7	123.5	135.3	11.9	9.6%
		2,000	20.18	1.58	0.51	0.36	2.45	69.2	23.05	3.05	0.36	(0.06)	3.35	90.1	0.67	0.62	0.70	1.09	42.2	750	1,250	122.1	233.6	254.4	20.8	8.9%
		5,000	20.18	1.58	0.51	0.36	2.45	142.7	23.05	3.05	0.36	(0.06)	3.35	190.7	0.67	0.62	0.70	1.09	105.4	750	4,250	315.4	563.7	611.5	47.8	8.5%
		10,000	20.18	1.58	0.51	0.36	2.45	265.2	23.05	3.05	0.36	(0.06)	3.35	358.4	0.67	0.62	0.70	1.09	210.9	750	9,250	637.5	1,114.0	1,206.8	92.7	8.3%
		15,000	20.18	1.58	0.51	0.36	2.45	387.7	23.05	3.05	0.36	(0.06)	3.35	526.0	0.67	0.62	0.70	1.09	316.3	750	14,250	959.7	1,664.3	1,802.0	137.7	8.3%

New Rate Class: GSe - Metered

Total Bill Impacts of Proposed Distribution Rates [new RTSR+TLF]: Threshold of 750 kWhs

750.0

Classes		Scenario	May 2007 Incl Rate Riders						May 2008 Incl Rate Riders						Non-Dx Compoent				Other Reg	Commodity Bands			Existing	New	$ Incr	% Incr
			Existing Dx Rates					Existing Dx	New Dx Rates					New Dx	RTSR new	WMSC	DRC	TLF new	New	Band 1	Band 2	New	Total Bill	Total Bill	Total Bill	Total Bill
																				5.0	5.9					
New Class	Old Class	kWh	SrChg [$/cust]	base [c/kWh]	Rider1 [c/kWh]	Rider2 [c/kWh]	VarChg [c/kWh]	[$/month]	SrChg [$/cust]	base [c/kWh]	Rider2 [c/kWh]	Rider3 [c/kWh]	VarChg [c/kWh]	[$/month]	c/kWh	c/kWh	c/kWh		$	kWhs	kWhs		[$/month]	[$/month]	[$/month]	%
GSe	Latchford	1,000	**2.88**	**1.02**	**0.65**	**0.20**	**1.87**	21.6	**9.37**	**2.32**	**0.20**	**(0.06)**	**2.46**	34.0	**0.67**	0.62	0.7	**1.092**	21.1	750	250	57.7	100.4	112.8	12.4	12.3%
		2,000	2.88	1.02	0.65	0.20	1.87	40.3	9.37	2.32	0.20	(0.06)	2.46	58.6	0.67	0.62	0.70	1.09	42.2	750	1,250	122.1	204.7	222.9	18.3	8.9%
		5,000	2.88	1.02	0.65	0.20	1.87	96.4	9.37	2.32	0.20	(0.06)	2.46	132.5	0.67	0.62	0.70	1.09	105.4	750	4,250	315.4	517.4	553.4	35.9	6.9%
		10,000	2.88	1.02	0.65	0.20	1.87	189.9	9.37	2.32	0.20	(0.06)	2.46	255.7	0.67	0.62	0.70	1.09	210.9	750	9,250	637.5	1,038.7	1,104.1	65.4	6.3%
		15,000	2.88	1.02	0.65	0.20	1.87	283.4	9.37	2.32	0.20	(0.06)	2.46	378.9	0.67	0.62	0.70	1.09	316.3	750	14,250	959.7	1,560.0	1,654.8	94.8	6.1%
UGe	Lindsay	1,000	**23.94**	**1.38**	**0.15**	**0.06**	**1.59**	39.8	**20.10**	**2.00**	**0.06**	**(0.06)**	**2.01**	40.2	**0.69**	0.62	0.7	**1.092**	21.3	750	250	57.7	118.7	119.1	0.5	0.4%
		2,000	23.94	1.38	0.15	0.06	1.59	55.7	20.10	2.00	0.06	(0.06)	2.01	60.2	0.69	0.62	0.70	1.09	42.6	750	1,250	122.1	220.1	224.9	4.8	2.2%
		5,000	23.94	1.38	0.15	0.06	1.59	103.4	20.10	2.00	0.06	(0.06)	2.01	120.4	0.69	0.62	0.70	1.09	106.5	750	4,250	315.4	524.5	542.3	17.8	3.4%
		10,000	23.94	1.38	0.15	0.06	1.59	182.9	20.10	2.00	0.06	(0.06)	2.01	220.6	0.69	0.62	0.70	1.09	213.1	750	9,250	637.5	1,031.8	1,071.2	39.4	3.8%
		15,000	23.94	1.38	0.15	0.06	1.59	262.4	20.10	2.00	0.06	(0.06)	2.01	320.9	0.69	0.62	0.70	1.09	319.6	750	14,250	959.7	1,539.1	1,600.2	61.1	4.0%
GSe	Lucan Grantor	1,000	**16.99**	**1.47**	**0.17**	**0.10**	**1.74**	34.4	**19.84**	**2.53**	**0.10**	**(0.06)**	**2.57**	45.6	**0.67**	0.62	0.7	**1.092**	21.1	750	250	57.7	113.2	124.3	11.1	9.8%
		2,000	16.99	1.47	0.17	0.10	1.74	51.8	19.84	2.53	0.10	(0.06)	2.57	71.3	0.67	0.62	0.70	1.09	42.2	750	1,250	122.1	216.2	235.6	19.4	9.0%
		5,000	16.99	1.47	0.17	0.10	1.74	104.0	19.84	2.53	0.10	(0.06)	2.57	148.5	0.67	0.62	0.70	1.09	105.4	750	4,250	315.4	525.0	569.3	44.3	8.4%
		10,000	16.99	1.47	0.17	0.10	1.74	191.0	19.84	2.53	0.10	(0.06)	2.57	277.2	0.67	0.62	0.70	1.09	210.9	750	9,250	637.5	1,039.8	1,125.6	85.7	8.2%
		15,000	16.99	1.47	0.17	0.10	1.74	278.0	19.84	2.53	0.10	(0.06)	2.57	405.8	0.67	0.62	0.70	1.09	316.3	750	14,250	959.7	1,554.6	1,681.8	127.2	8.2%
GSe	Malahide	1,000	**15.84**	**1.98**	**0.81**	**0.49**	**3.28**	48.6	**19.13**	**3.21**	**0.49**	**(0.06)**	**3.64**	55.6	**0.67**	0.62	0.7	**1.092**	21.1	750	250	57.7	127.5	134.3	6.9	5.4%
		2,000	15.84	1.98	0.81	0.49	3.28	81.4	19.13	3.21	0.49	(0.06)	3.64	92.0	0.67	0.62	0.70	1.09	42.2	750	1,250	122.1	245.8	256.3	10.5	4.3%
		5,000	15.84	1.98	0.81	0.49	3.28	179.8	19.13	3.21	0.49	(0.06)	3.64	201.3	0.67	0.62	0.70	1.09	105.4	750	4,250	315.4	600.9	622.1	21.3	3.5%
		10,000	15.84	1.98	0.81	0.49	3.28	343.8	19.13	3.21	0.49	(0.06)	3.64	383.5	0.67	0.62	0.70	1.09	210.9	750	9,250	637.5	1,192.7	1,231.9	39.2	3.3%
		15,000	15.84	1.98	0.81	0.49	3.28	507.8	19.13	3.21	0.49	(0.06)	3.64	565.7	0.67	0.62	0.70	1.09	316.3	750	14,250	959.7	1,784.5	1,841.7	57.2	3.2%
GSe	Mapleton	1,000	**21.55**	**1.71**	**0.40**	**0.29**	**2.40**	45.6	**23.70**	**3.11**	**0.29**	**(0.06)**	**3.34**	57.1	**0.67**	0.62	0.7	**1.092**	21.1	750	250	57.7	124.4	135.9	11.5	9.3%
		2,000	21.55	1.71	0.40	0.29	2.40	69.6	23.70	3.11	0.29	(0.06)	3.34	90.6	0.67	0.62	0.70	1.09	42.2	750	1,250	122.1	233.9	254.8	20.9	8.9%
		5,000	21.55	1.71	0.40	0.29	2.40	141.6	23.70	3.11	0.29	(0.06)	3.34	190.9	0.67	0.62	0.70	1.09	105.4	750	4,250	315.4	562.6	611.7	49.1	8.7%
		10,000	21.55	1.71	0.40	0.29	2.40	261.6	23.70	3.11	0.29	(0.06)	3.34	358.0	0.67	0.62	0.70	1.09	210.9	750	9,250	637.5	1,110.4	1,206.4	96.0	8.6%
		15,000	21.55	1.71	0.40	0.29	2.40	381.6	23.70	3.11	0.29	(0.06)	3.34	525.2	0.67	0.62	0.70	1.09	316.3	750	14,250	959.7	1,658.2	1,801.2	143.0	8.6%

New Rate Class: GSe - Metered

Total Bill Impacts of Proposed Distribution Rates [new RTSR+TLF]: Threshold of 750 kWhs

750.0

Classes		Scenario	May 2007 Incl Rate Riders						May 2008 Incl Rate Riders						Non-Dx Compoent				Other Reg	Commodity Bands			Existing	New	$ Incr	% Incr
			Existing Dx Rates					Existing Dx	New Dx Rates					New Dx	RTSR new	WMSC	DRC	TLF new	New	Band 1	Band 2	New	Total Bill	Total Bill	Total Bill	Total Bill
																				5.0	5.9					
New Class	Old Class	kWh	SrChg	base	Rider1	Rider2	VarChg	[$/month]	SrChg	base	Rider2	Rider3	VarChg	[$/month]	c/kWh	c/kWh	c/kWh		$	kWhs	kWhs		[$/month]	[$/month]	[$/month]	%
			[$/cust]	[c/kWh]	[c/kWh]	[c/kWh]	[c/kWh]		[$/cust]	[c/kWh]	[c/kWh]	[c/kWh]	[c/kWh]													
GSe	**Markdale**	1,000	**23.00**	**0.80**	**0.15**	**0.04**	**0.99**	32.9	**25.34**	**1.82**	**0.04**	**(0.06)**	**1.80**	43.4	**0.67**	0.62	0.7	**1.092**	21.1	750	250	57.7	111.7	122.1	10.4	9.3%
		2,000	23.00	0.80	0.15	0.04	0.99	42.8	25.34	1.82	0.04	(0.06)	1.80	61.4	0.67	0.62	0.70	1.09	42.2	750	1,250	122.1	207.2	225.7	18.5	8.9%
		5,000	23.00	0.80	0.15	0.04	0.99	72.5	25.34	1.82	0.04	(0.06)	1.80	115.5	0.67	0.62	0.70	1.09	105.4	750	4,250	315.4	493.6	536.3	42.8	8.7%
		10,000	23.00	0.80	0.15	0.04	0.99	122.0	25.34	1.82	0.04	(0.06)	1.80	205.7	0.67	0.62	0.70	1.09	210.9	750	9,250	637.5	970.9	1,054.1	83.2	8.6%
		15,000	23.00	0.80	0.15	0.04	0.99	171.5	25.34	1.82	0.04	(0.06)	1.80	295.8	0.67	0.62	0.70	1.09	316.3	750	14,250	959.7	1,448.2	1,571.8	123.6	8.5%
GSe	**Marmora**	1,000	**10.02**	**1.05**	**0.15**	**0.05**	**1.25**	22.5	**15.59**	**1.88**	**0.05**	**(0.06)**	**1.87**	34.3	**0.67**	0.62	0.7	**1.092**	21.1	750	250	57.7	101.3	113.1	11.8	11.6%
		2,000	10.02	1.05	0.15	0.05	1.25	35.0	15.59	1.88	0.05	(0.06)	1.87	53.1	0.67	0.62	0.70	1.09	42.2	750	1,250	122.1	199.4	217.3	17.9	9.0%
		5,000	10.02	1.05	0.15	0.05	1.25	72.5	15.59	1.88	0.05	(0.06)	1.87	109.3	0.67	0.62	0.70	1.09	105.4	750	4,250	315.4	493.6	530.1	36.5	7.4%
		10,000	10.02	1.05	0.15	0.05	1.25	135.0	15.59	1.88	0.05	(0.06)	1.87	202.9	0.67	0.62	0.70	1.09	210.9	750	9,250	637.5	983.9	1,051.3	67.4	6.9%
		15,000	10.02	1.05	0.15	0.05	1.25	197.5	15.59	1.88	0.05	(0.06)	1.87	296.6	0.67	0.62	0.70	1.09	316.3	750	14,250	959.7	1,474.2	1,572.5	98.4	6.7%
GSe	**McGarry**	1,000	**19.99**	**2.00**	**0.57**	**0.50**	**3.07**	50.7	**22.09**	**3.21**	**0.50**	**(0.06)**	**3.65**	58.6	**0.67**	0.62	0.7	**1.092**	21.1	750	250	57.7	129.5	137.4	7.9	6.1%
		2,000	19.99	2.00	0.57	0.50	3.07	81.4	22.09	3.21	0.50	(0.06)	3.65	95.2	0.67	0.62	0.70	1.09	42.2	750	1,250	122.1	245.8	259.4	13.7	5.6%
		5,000	19.99	2.00	0.57	0.50	3.07	173.5	22.09	3.21	0.50	(0.06)	3.65	204.8	0.67	0.62	0.70	1.09	105.4	750	4,250	315.4	594.5	625.6	31.1	5.2%
		10,000	19.99	2.00	0.57	0.50	3.07	327.0	22.09	3.21	0.50	(0.06)	3.65	387.5	0.67	0.62	0.70	1.09	210.9	750	9,250	637.5	1,175.8	1,235.9	60.0	5.1%
		15,000	19.99	2.00	0.57	0.50	3.07	480.5	22.09	3.21	0.50	(0.06)	3.65	570.2	0.67	0.62	0.70	1.09	316.3	750	14,250	959.7	1,757.1	1,846.1	89.0	5.1%
GSe	**Meaford**	1,000	**24.05**	**1.23**	**0.16**	**0.07**	**1.46**	38.7	**26.08**	**2.32**	**0.07**	**(0.06)**	**2.33**	49.4	**0.67**	0.62	0.7	**1.092**	21.1	750	250	57.7	117.5	128.2	10.7	9.1%
		2,000	24.05	1.23	0.16	0.07	1.46	53.3	26.08	2.32	0.07	(0.06)	2.33	72.7	0.67	0.62	0.70	1.09	42.2	750	1,250	122.1	217.6	237.0	19.4	8.9%
		5,000	24.05	1.23	0.16	0.07	1.46	97.1	26.08	2.32	0.07	(0.06)	2.33	142.7	0.67	0.62	0.70	1.09	105.4	750	4,250	315.4	518.1	563.6	45.5	8.8%
		10,000	24.05	1.23	0.16	0.07	1.46	170.1	26.08	2.32	0.07	(0.06)	2.33	259.4	0.67	0.62	0.70	1.09	210.9	750	9,250	637.5	1,018.9	1,107.8	88.9	8.7%
		15,000	24.05	1.23	0.16	0.07	1.46	243.1	26.08	2.32	0.07	(0.06)	2.33	376.1	0.67	0.62	0.70	1.09	316.3	750	14,250	959.7	1,519.7	1,652.0	132.3	8.7%
GSe	**Middlesex Cer**	1,000	**17.35**	**1.37**	**0.44**	**0.35**	**2.16**	39.0	**20.75**	**2.70**	**0.35**	**(0.06)**	**2.99**	50.7	**0.67**	0.62	0.7	**1.092**	21.1	750	250	57.7	117.8	129.5	11.7	9.9%
		2,000	17.35	1.37	0.44	0.35	2.16	60.6	20.75	2.70	0.35	(0.06)	2.99	80.6	0.67	0.62	0.70	1.09	42.2	750	1,250	122.1	224.9	244.9	20.0	8.9%
		5,000	17.35	1.37	0.44	0.35	2.16	125.4	20.75	2.70	0.35	(0.06)	2.99	170.4	0.67	0.62	0.70	1.09	105.4	750	4,250	315.4	546.4	591.2	44.8	8.2%
		10,000	17.35	1.37	0.44	0.35	2.16	233.4	20.75	2.70	0.35	(0.06)	2.99	320.1	0.67	0.62	0.70	1.09	210.9	750	9,250	637.5	1,082.2	1,168.5	86.3	8.0%
		15,000	17.35	1.37	0.44	0.35	2.16	341.4	20.75	2.70	0.35	(0.06)	2.99	469.7	0.67	0.62	0.70	1.09	316.3	750	14,250	959.7	1,618.0	1,745.7	127.7	7.9%

New Rate Class: GSe - Metered

Total Bill Impacts of Proposed Distribution Rates [new RTSR+TLF]: Threshold of 750 kWhs

750.0

Classes		Scenario	May 2007 Incl Rate Riders						May 2008 Incl Rate Riders						Non-Dx Compoent				Other Reg	Commodity Bands			Existing	New	$ Incr	% Incr
			Existing Dx Rates					Existing Dx	New Dx Rates					New Dx	RTSR new	WMSC	DRC	TLF new	New	Band 1	Band 2	New	Total Bill	Total Bill	Total Bill	Total Bill
																				5.0	5.9					
New Class	Old Class	kWh	SrChg [$/cust]	base [c/kWh]	Rider1 [c/kWh]	Rider2 [c/kWh]	VarChg [c/kWh]	[$/month]	SrChg [$/cust]	base [c/kWh]	Rider2 [c/kWh]	Rider3 [c/kWh]	VarChg [c/kWh]	[$/month]	c/kWh	c/kWh	c/kWh		$	kWhs	kWhs		[$/month]	[$/month]	[$/month]	%
GSe	Napanee	1,000	22.17	1.28	0.16	0.06	1.50	37.2	24.55	2.35	0.06	(0.06)	2.35	48.1	0.67	0.62	0.7	1.092	21.1	750	250	57.7	116.0	126.8	10.9	9.4%
		2,000	22.17	1.28	0.16	0.06	1.50	52.2	24.55	2.35	0.06	(0.06)	2.35	71.6	0.67	0.62	0.70	1.09	42.2	750	1,250	122.1	216.5	235.9	19.4	8.9%
		5,000	22.17	1.28	0.16	0.06	1.50	97.2	24.55	2.35	0.06	(0.06)	2.35	142.2	0.67	0.62	0.70	1.09	105.4	750	4,250	315.4	518.2	563.0	44.8	8.6%
		10,000	22.17	1.28	0.16	0.06	1.50	172.2	24.55	2.35	0.06	(0.06)	2.35	259.9	0.67	0.62	0.70	1.09	210.9	750	9,250	637.5	1,021.0	1,108.3	87.3	8.5%
		15,000	22.17	1.28	0.16	0.06	1.50	247.2	24.55	2.35	0.06	(0.06)	2.35	377.5	0.67	0.62	0.70	1.09	316.3	750	14,250	959.7	1,523.8	1,653.5	129.7	8.5%
GSe	Nipigon	1,000	23.32	1.05	0.34	0.21	1.60	39.3	25.26	2.34	0.21	(0.06)	2.49	50.2	0.67	0.62	0.7	1.092	21.1	750	250	57.7	118.1	129.0	10.8	9.2%
		2,000	23.32	1.05	0.34	0.21	1.60	55.3	25.26	2.34	0.21	(0.06)	2.49	75.1	0.67	0.62	0.70	1.09	42.2	750	1,250	122.1	219.7	239.4	19.7	9.0%
		5,000	23.32	1.05	0.34	0.21	1.60	103.3	25.26	2.34	0.21	(0.06)	2.49	149.9	0.67	0.62	0.70	1.09	105.4	750	4,250	315.4	524.4	570.7	46.4	8.8%
		10,000	23.32	1.05	0.34	0.21	1.60	183.3	25.26	2.34	0.21	(0.06)	2.49	274.6	0.67	0.62	0.70	1.09	210.9	750	9,250	637.5	1,032.2	1,123.0	90.8	8.8%
		15,000	23.32	1.05	0.34	0.21	1.60	263.3	25.26	2.34	0.21	(0.06)	2.49	399.3	0.67	0.62	0.70	1.09	316.3	750	14,250	959.7	1,540.0	1,675.2	135.2	8.8%
GSe	North Dorches	1,000	15.88	0.90	0.35	0.26	1.51	31.0	19.12	2.08	0.26	(0.06)	2.28	42.0	0.67	0.62	0.7	1.092	21.1	750	250	57.7	109.8	120.7	10.9	10.0%
		2,000	15.88	0.90	0.35	0.26	1.51	46.1	19.12	2.08	0.26	(0.06)	2.28	64.8	0.67	0.62	0.70	1.09	42.2	750	1,250	122.1	210.5	229.1	18.6	8.8%
		5,000	15.88	0.90	0.35	0.26	1.51	91.4	19.12	2.08	0.26	(0.06)	2.28	133.3	0.67	0.62	0.70	1.09	105.4	750	4,250	315.4	512.4	554.1	41.7	8.1%
		10,000	15.88	0.90	0.35	0.26	1.51	166.9	19.12	2.08	0.26	(0.06)	2.28	247.4	0.67	0.62	0.70	1.09	210.9	750	9,250	637.5	1,015.7	1,095.8	80.1	7.9%
		15,000	15.88	0.90	0.35	0.26	1.51	242.4	19.12	2.08	0.26	(0.06)	2.28	361.6	0.67	0.62	0.70	1.09	316.3	750	14,250	959.7	1,519.0	1,637.6	118.5	7.8%
GSe	North Dundas	1,000	13.52	0.83	0.16	0.04	1.03	23.8	17.71	1.72	0.04	(0.06)	1.70	34.7	0.67	0.62	0.7	1.092	21.1	750	250	57.7	102.6	113.5	10.9	10.6%
		2,000	13.52	0.83	0.16	0.04	1.03	34.1	17.71	1.72	0.04	(0.06)	1.70	51.8	0.67	0.62	0.70	1.09	42.2	750	1,250	122.1	198.5	216.1	17.6	8.9%
		5,000	13.52	0.83	0.16	0.04	1.03	65.0	17.71	1.72	0.04	(0.06)	1.70	102.9	0.67	0.62	0.70	1.09	105.4	750	4,250	315.4	486.1	523.7	37.6	7.7%
		10,000	13.52	0.83	0.16	0.04	1.03	116.5	17.71	1.72	0.04	(0.06)	1.70	188.0	0.67	0.62	0.70	1.09	210.9	750	9,250	637.5	965.4	1,036.4	71.1	7.4%
		15,000	13.52	0.83	0.16	0.04	1.03	168.0	17.71	1.72	0.04	(0.06)	1.70	273.2	0.67	0.62	0.70	1.09	316.3	750	14,250	959.7	1,444.7	1,549.2	104.5	7.2%
GSe	North Glengar	1,000	17.72	0.90	0.21	0.12	1.23	30.0	20.66	1.95	0.12	(0.06)	2.01	40.8	0.67	0.62	0.7	1.092	21.1	750	250	57.7	108.8	119.6	10.7	9.9%
		2,000	17.72	0.90	0.21	0.12	1.23	42.3	20.66	1.95	0.12	(0.06)	2.01	60.9	0.67	0.62	0.70	1.09	42.2	750	1,250	122.1	206.7	225.2	18.5	9.0%
		5,000	17.72	0.90	0.21	0.12	1.23	79.2	20.66	1.95	0.12	(0.06)	2.01	121.3	0.67	0.62	0.70	1.09	105.4	750	4,250	315.4	500.3	542.1	41.9	8.4%
		10,000	17.72	0.90	0.21	0.12	1.23	140.7	20.66	1.95	0.12	(0.06)	2.01	222.0	0.67	0.62	0.70	1.09	210.9	750	9,250	637.5	989.6	1,070.4	80.8	8.2%
		15,000	17.72	0.90	0.21	0.12	1.23	202.2	20.66	1.95	0.12	(0.06)	2.01	322.7	0.67	0.62	0.70	1.09	316.3	750	14,250	959.7	1,478.9	1,598.6	119.7	8.1%

New Rate Class: GSe - Metered

Total Bill Impacts of Proposed Distribution Rates [new RTSR+TLF]: Threshold of 750 kWhs

750.0

Classes		Scenario	May 2007 Incl Rate Riders						May 2008 Incl Rate Riders						Non-Dx Compoent				Other Reg	Commodity Bands			Existing	New	$ Incr	% Incr
			Existing Dx Rates					Existing Dx	New Dx Rates					New Dx	RTSR new	WMSC	DRC	TLF new	New	Band 1	Band 2	New	Total Bill	Total Bill	Total Bill	Total Bill
																				5.0	5.9					
New Class	Old Class	kWh	SrChg [$/cust]	base [c/kWh]	Rider1 [c/kWh]	Rider2 [c/kWh]	VarChg [c/kWh]	[$/month]	SrChg [$/cust]	base [c/kWh]	Rider2 [c/kWh]	Rider3 [c/kWh]	VarChg [c/kWh]	[$/month]	c/kWh	c/kWh	c/kWh		$	kWhs	kWhs		[$/month]	[$/month]	[$/month]	%
GSe	North Grenvill	1,000	**20.42**	**1.71**	**0.14**	**0.08**	**1.93**	39.7	**22.99**	**2.79**	**0.08**	**(0.06)**	**2.81**	51.1	**0.67**	0.62	0.7	**1.092**	21.1	750	250	57.7	118.5	129.9	11.4	9.6%
		2,000	20.42	1.71	0.14	0.08	1.93	59.0	22.99	2.79	0.08	(0.06)	2.81	79.3	0.67	0.62	0.70	1.09	42.2	750	1,250	122.1	223.4	243.5	20.1	9.0%
		5,000	20.42	1.71	0.14	0.08	1.93	116.9	22.99	2.79	0.08	(0.06)	2.81	163.7	0.67	0.62	0.70	1.09	105.4	750	4,250	315.4	538.0	584.5	46.5	8.6%
		10,000	20.42	1.71	0.14	0.08	1.93	213.4	22.99	2.79	0.08	(0.06)	2.81	304.3	0.67	0.62	0.70	1.09	210.9	750	9,250	637.5	1,062.3	1,152.7	90.4	8.5%
		15,000	20.42	1.71	0.14	0.08	1.93	309.9	22.99	2.79	0.08	(0.06)	2.81	445.0	0.67	0.62	0.70	1.09	316.3	750	14,250	959.7	1,586.6	1,720.9	134.4	8.5%
GSe	North Perth	1,000	**29.52**	**1.00**	**0.12**	**0.04**	**1.16**	41.1	**29.71**	**2.15**	**0.04**	**(0.06)**	**2.13**	51.0	**0.67**	0.62	0.7	**1.092**	21.1	750	250	57.7	119.9	129.8	9.9	8.2%
		2,000	29.52	1.00	0.12	0.04	1.16	52.7	29.71	2.15	0.04	(0.06)	2.13	72.4	0.67	0.62	0.70	1.09	42.2	750	1,250	122.1	217.1	236.7	19.6	9.0%
		5,000	29.52	1.00	0.12	0.04	1.16	87.5	29.71	2.15	0.04	(0.06)	2.13	136.4	0.67	0.62	0.70	1.09	105.4	750	4,250	315.4	508.6	557.2	48.6	9.6%
		10,000	29.52	1.00	0.12	0.04	1.16	145.5	29.71	2.15	0.04	(0.06)	2.13	243.0	0.67	0.62	0.70	1.09	210.9	750	9,250	637.5	994.4	1,091.4	97.1	9.8%
		15,000	29.52	1.00	0.12	0.04	1.16	203.5	29.71	2.15	0.04	(0.06)	2.13	349.7	0.67	0.62	0.70	1.09	316.3	750	14,250	959.7	1,480.2	1,625.7	145.5	9.8%
GSe	North Stormor	1,000	**5.37**	**0.78**	**0.37**	**0.26**	**1.41**	19.5	**11.75**	**1.78**	**0.26**	**(0.06)**	**1.98**	31.6	**0.67**	0.62	0.7	**1.092**	21.1	750	250	57.7	98.3	110.3	12.1	12.3%
		2,000	5.37	0.78	0.37	0.26	1.41	33.6	11.75	1.78	0.26	(0.06)	1.98	51.4	0.67	0.62	0.70	1.09	42.2	750	1,250	122.1	197.9	215.7	17.8	9.0%
		5,000	5.37	0.78	0.37	0.26	1.41	75.9	11.75	1.78	0.26	(0.06)	1.98	110.9	0.67	0.62	0.70	1.09	105.4	750	4,250	315.4	496.9	531.7	34.8	7.0%
		10,000	5.37	0.78	0.37	0.26	1.41	146.4	11.75	1.78	0.26	(0.06)	1.98	210.1	0.67	0.62	0.70	1.09	210.9	750	9,250	637.5	995.2	1,058.5	63.3	6.4%
		15,000	5.37	0.78	0.37	0.26	1.41	216.9	11.75	1.78	0.26	(0.06)	1.98	309.2	0.67	0.62	0.70	1.09	316.3	750	14,250	959.7	1,493.5	1,585.2	91.7	6.1%
GSe	Omemee	1,000	**21.28**	**1.47**	**0.18**	**0.09**	**1.74**	38.7	**23.77**	**2.55**	**0.09**	**(0.06)**	**2.58**	49.6	**0.67**	0.62	0.7	**1.092**	21.1	750	250	57.7	117.5	128.4	10.9	9.3%
		2,000	21.28	1.47	0.18	0.09	1.74	56.1	23.77	2.55	0.09	(0.06)	2.58	75.4	0.67	0.62	0.70	1.09	42.2	750	1,250	122.1	220.5	239.7	19.3	8.7%
		5,000	21.28	1.47	0.18	0.09	1.74	108.3	23.77	2.55	0.09	(0.06)	2.58	152.9	0.67	0.62	0.70	1.09	105.4	750	4,250	315.4	529.3	573.8	44.4	8.4%
		10,000	21.28	1.47	0.18	0.09	1.74	195.3	23.77	2.55	0.09	(0.06)	2.58	282.1	0.67	0.62	0.70	1.09	210.9	750	9,250	637.5	1,044.1	1,130.5	86.4	8.3%
		15,000	21.28	1.47	0.18	0.09	1.74	282.3	23.77	2.55	0.09	(0.06)	2.58	411.3	0.67	0.62	0.70	1.09	316.3	750	14,250	959.7	1,558.9	1,687.2	128.3	8.2%
UGe	Perth	1,000	**19.92**	**0.92**	**0.13**	**0.04**	**1.09**	30.8	**17.10**	**2.00**	**0.04**	**(0.06)**	**1.99**	37.0	**0.69**	0.62	0.7	**1.092**	21.3	750	250	57.7	109.6	115.9	6.3	5.8%
		2,000	19.92	0.92	0.13	0.04	1.09	41.7	17.10	2.00	0.04	(0.06)	1.99	56.8	0.69	0.62	0.70	1.09	42.6	750	1,250	122.1	206.1	221.5	15.4	7.5%
		5,000	19.92	0.92	0.13	0.04	1.09	74.4	17.10	2.00	0.04	(0.06)	1.99	116.4	0.69	0.62	0.70	1.09	106.5	750	4,250	315.4	495.5	538.3	42.8	8.6%
		10,000	19.92	0.92	0.13	0.04	1.09	128.9	17.10	2.00	0.04	(0.06)	1.99	215.6	0.69	0.62	0.70	1.09	213.1	750	9,250	637.5	977.8	1,066.2	88.5	9.0%
		15,000	19.92	0.92	0.13	0.04	1.09	183.4	17.10	2.00	0.04	(0.06)	1.99	314.9	0.69	0.62	0.70	1.09	319.6	750	14,250	959.7	1,460.1	1,594.2	134.1	9.2%

New Rate Class: GSe - Metered

Total Bill Impacts of Proposed Distribution Rates [new RTSR+TLF]: Threshold of 750 kWhs

750.0

Classes		Scenario	May 2007 Incl Rate Riders						May 2008 Incl Rate Riders						Non-Dx Compoent				Other Reg	Commodity Bands			Existing	New	$ Incr	% Incr
			Existing Dx Rates					Existing Dx	New Dx Rates					New Dx	RTSR new	WMSC	DRC	TLF new	New	Band 1	Band 2	New	Total Bill	Total Bill	Total Bill	Total Bill
																				5.0	5.9					
New Class	Old Class	kWh	SrChg [$/cust]	base [c/kWh]	Rider1 [c/kWh]	Rider2 [c/kWh]	VarChg [c/kWh]	[$/month]	SrChg [$/cust]	base [c/kWh]	Rider2 [c/kWh]	Rider3 [c/kWh]	VarChg [c/kWh]	[$/month]	c/kWh	c/kWh	c/kWh		$	kWhs	kWhs		[$/month]	[$/month]	[$/month]	%
GSe	Perth East	1,000	14.65	1.29	0.16	0.09	1.54	30.1	18.43	2.25	0.09	(0.06)	2.28	41.3	0.67	0.62	0.7	1.092	21.1	750	250	57.7	108.9	120.0	11.2	10.3%
		2,000	14.65	1.29	0.16	0.09	1.54	45.5	18.43	2.25	0.09	(0.06)	2.28	64.1	0.67	0.62	0.70	1.09	42.2	750	1,250	122.1	209.8	228.4	18.6	8.8%
		5,000	14.65	1.29	0.16	0.09	1.54	91.7	18.43	2.25	0.09	(0.06)	2.28	132.6	0.67	0.62	0.70	1.09	105.4	750	4,250	315.4	512.7	553.4	40.7	7.9%
		10,000	14.65	1.29	0.16	0.09	1.54	168.7	18.43	2.25	0.09	(0.06)	2.28	246.8	0.67	0.62	0.70	1.09	210.9	750	9,250	637.5	1,017.5	1,095.2	77.7	7.6%
		15,000	14.65	1.29	0.16	0.09	1.54	245.7	18.43	2.25	0.09	(0.06)	2.28	360.9	0.67	0.62	0.70	1.09	316.3	750	14,250	959.7	1,522.3	1,636.9	114.6	7.5%
GSe	Prince Edwarc	1,000	22.85	1.42	0.18	0.08	1.68	39.7	24.38	2.57	0.08	(0.06)	2.59	50.3	0.67	0.62	0.7	1.092	21.1	750	250	57.7	118.5	129.1	10.6	9.0%
		2,000	22.85	1.42	0.18	0.08	1.68	56.5	24.38	2.57	0.08	(0.06)	2.59	76.2	0.67	0.62	0.70	1.09	42.2	750	1,250	122.1	220.8	240.5	19.7	8.9%
		5,000	22.85	1.42	0.18	0.08	1.68	106.9	24.38	2.57	0.08	(0.06)	2.59	154.0	0.67	0.62	0.70	1.09	105.4	750	4,250	315.4	527.9	574.9	47.0	8.9%
		10,000	22.85	1.42	0.18	0.08	1.68	190.9	24.38	2.57	0.08	(0.06)	2.59	283.7	0.67	0.62	0.70	1.09	210.9	750	9,250	637.5	1,039.7	1,132.1	92.4	8.9%
		15,000	22.85	1.42	0.18	0.08	1.68	274.9	24.38	2.57	0.08	(0.06)	2.59	413.4	0.67	0.62	0.70	1.09	316.3	750	14,250	959.7	1,551.5	1,689.3	137.8	8.9%
UGe	Quinte West	1,000	3.74	1.05	0.14	0.06	1.25	16.2	5.15	2.00	0.06	(0.06)	2.01	25.2	0.69	0.62	0.7	1.092	21.3	750	250	57.7	95.1	104.2	9.1	9.6%
		2,000	3.74	1.05	0.14	0.06	1.25	28.7	5.15	2.00	0.06	(0.06)	2.01	45.3	0.69	0.62	0.70	1.09	42.6	750	1,250	122.1	193.1	210.0	16.9	8.7%
		5,000	3.74	1.05	0.14	0.06	1.25	66.2	5.15	2.00	0.06	(0.06)	2.01	105.4	0.69	0.62	0.70	1.09	106.5	750	4,250	315.4	487.3	527.3	40.0	8.2%
		10,000	3.74	1.05	0.14	0.06	1.25	128.7	5.15	2.00	0.06	(0.06)	2.01	205.7	0.69	0.62	0.70	1.09	213.1	750	9,250	637.5	977.6	1,056.3	78.7	8.0%
		15,000	3.74	1.05	0.14	0.06	1.25	191.2	5.15	2.00	0.06	(0.06)	2.01	306.0	0.69	0.62	0.70	1.09	319.6	750	14,250	959.7	1,467.9	1,585.2	117.3	8.0%
GSe	Rainy River	1,000	19.29	1.76	0.45	0.36	2.57	45.0	22.27	3.18	0.36	(0.06)	3.48	57.1	0.67	0.62	0.7	1.092	21.1	750	250	57.7	123.8	135.9	12.1	9.7%
		2,000	19.29	1.76	0.45	0.36	2.57	70.7	22.27	3.18	0.36	(0.06)	3.48	91.9	0.67	0.62	0.70	1.09	42.2	750	1,250	122.1	235.1	256.2	21.2	9.0%
		5,000	19.29	1.76	0.45	0.36	2.57	147.8	22.27	3.18	0.36	(0.06)	3.48	196.4	0.67	0.62	0.70	1.09	105.4	750	4,250	315.4	568.8	617.3	48.4	8.5%
		10,000	19.29	1.76	0.45	0.36	2.57	276.3	22.27	3.18	0.36	(0.06)	3.48	370.6	0.67	0.62	0.70	1.09	210.9	750	9,250	637.5	1,125.1	1,219.0	93.9	8.3%
		15,000	19.29	1.76	0.45	0.36	2.57	404.8	22.27	3.18	0.36	(0.06)	3.48	544.8	0.67	0.62	0.70	1.09	316.3	750	14,250	959.7	1,681.4	1,820.7	139.3	8.3%
GSe	Ramara	1,000	20.97	1.06	0.45	0.37	1.88	39.8	22.85	2.48	0.37	(0.06)	2.79	50.8	0.67	0.62	0.7	1.092	21.1	750	250	57.7	118.6	129.5	11.0	9.2%
		2,000	20.97	1.06	0.45	0.37	1.88	58.6	22.85	2.48	0.37	(0.06)	2.79	78.7	0.67	0.62	0.70	1.09	42.2	750	1,250	122.1	222.9	243.0	20.1	9.0%
		5,000	20.97	1.06	0.45	0.37	1.88	115.0	22.85	2.48	0.37	(0.06)	2.79	162.5	0.67	0.62	0.70	1.09	105.4	750	4,250	315.4	536.0	583.3	47.3	8.8%
		10,000	20.97	1.06	0.45	0.37	1.88	209.0	22.85	2.48	0.37	(0.06)	2.79	302.2	0.67	0.62	0.70	1.09	210.9	750	9,250	637.5	1,057.8	1,150.6	92.8	8.8%
		15,000	20.97	1.06	0.45	0.37	1.88	303.0	22.85	2.48	0.37	(0.06)	2.79	441.8	0.67	0.62	0.70	1.09	316.3	750	14,250	959.7	1,579.6	1,717.8	138.2	8.7%

New Rate Class: GSe - Metered

Total Bill Impacts of Proposed Distribution Rates [new RTSR+TLF]: Threshold of 750 kWhs

750.0

Classes		Scenario	May 2007 Incl Rate Riders						May 2008 Incl Rate Riders						Non-Dx Compoent				Other Reg	Commodity Bands			Existing	New	$ Incr	% Incr
			Existing Dx Rates					Existing Dx	New Dx Rates					New Dx	RTSR new	WMSC	DRC	TLF new	New	Band 1	Band 2	New	Total Bill	Total Bill	Total Bill	Total Bill
																				5.0	5.9					
New Class	Old Class	kWh	SrChg [$/cust]	base [c/kWh]	Rider1 [c/kWh]	Rider2 [c/kWh]	VarChg [c/kWh]	[$/month]	SrChg [$/cust]	base [c/kWh]	Rider2 [c/kWh]	Rider3 [c/kWh]	VarChg [c/kWh]	[$/month]	c/kWh	c/kWh	c/kWh		$	kWhs	kWhs		[$/month]	[$/month]	[$/month]	%
GSe	Red Rock	1,000	**21.64**	**1.94**	**0.27**	**0.24**	**2.45**	46.1	**23.68**	**3.21**	**0.24**	**(0.06)**	**3.39**	57.6	**0.67**	0.62	0.7	**1.092**	21.1	750	250	57.7	125.0	136.4	11.4	9.2%
		2,000	21.64	1.94	0.27	0.24	2.45	70.6	23.68	3.21	0.24	(0.06)	3.39	91.6	0.67	0.62	0.70	1.09	42.2	750	1,250	122.1	235.0	255.8	20.8	8.9%
		5,000	21.64	1.94	0.27	0.24	2.45	144.1	23.68	3.21	0.24	(0.06)	3.39	193.4	0.67	0.62	0.70	1.09	105.4	750	4,250	315.4	565.2	614.2	49.0	8.7%
		10,000	21.64	1.94	0.27	0.24	2.45	266.6	23.68	3.21	0.24	(0.06)	3.39	363.1	0.67	0.62	0.70	1.09	210.9	750	9,250	637.5	1,115.5	1,211.5	96.0	8.6%
		15,000	21.64	1.94	0.27	0.24	2.45	389.1	23.68	3.21	0.24	(0.06)	3.39	532.7	0.67	0.62	0.70	1.09	316.3	750	14,250	959.7	1,665.8	1,808.7	142.9	8.6%
GSe	Rockland	1,000	**7.27**	**1.00**	**0.17**	**0.22**	**1.39**	21.2	**13.27**	**1.80**	**0.22**	**(0.06)**	**1.96**	32.9	**0.67**	0.62	0.7	**1.092**	21.1	750	250	57.7	100.0	111.7	11.7	11.7%
		2,000	7.27	1.00	0.17	0.22	1.39	35.1	13.27	1.80	0.22	(0.06)	1.96	52.5	0.67	0.62	0.70	1.09	42.2	750	1,250	122.1	199.4	216.8	17.4	8.7%
		5,000	7.27	1.00	0.17	0.22	1.39	76.8	13.27	1.80	0.22	(0.06)	1.96	111.4	0.67	0.62	0.70	1.09	105.4	750	4,250	315.4	497.8	532.3	34.4	6.9%
		10,000	7.27	1.00	0.17	0.22	1.39	146.3	13.27	1.80	0.22	(0.06)	1.96	209.6	0.67	0.62	0.70	1.09	210.9	750	9,250	637.5	995.1	1,058.0	62.9	6.3%
		15,000	7.27	1.00	0.17	0.22	1.39	215.8	13.27	1.80	0.22	(0.06)	1.96	307.8	0.67	0.62	0.70	1.09	316.3	750	14,250	959.7	1,492.4	1,583.7	91.3	6.1%
GSe	Russell	1,000	**19.26**	**2.24**	**0.18**	**0.11**	**2.53**	44.6	**22.28**	**3.21**	**0.11**	**(0.06)**	**3.26**	54.9	**0.67**	0.62	0.7	**1.092**	21.1	750	250	57.7	123.4	133.7	10.3	8.4%
		2,000	19.26	2.24	0.18	0.11	2.53	69.9	22.28	3.21	0.11	(0.06)	3.26	87.6	0.67	0.62	0.70	1.09	42.2	750	1,250	122.1	234.2	251.8	17.6	7.5%
		5,000	19.26	2.24	0.18	0.11	2.53	145.8	22.28	3.21	0.11	(0.06)	3.26	185.5	0.67	0.62	0.70	1.09	105.4	750	4,250	315.4	566.8	606.3	39.5	7.0%
		10,000	19.26	2.24	0.18	0.11	2.53	272.3	22.28	3.21	0.11	(0.06)	3.26	348.7	0.67	0.62	0.70	1.09	210.9	750	9,250	637.5	1,121.1	1,197.0	75.9	6.8%
		15,000	19.26	2.24	0.18	0.11	2.53	398.8	22.28	3.21	0.11	(0.06)	3.26	511.8	0.67	0.62	0.70	1.09	316.3	750	14,250	959.7	1,675.4	1,787.8	112.4	6.7%
GSe	Schreiber	1,000	**20.70**	**2.51**	**0.50**	**0.40**	**3.41**	54.8	**22.92**	**3.21**	**0.40**	**(0.06)**	**3.55**	58.5	**0.67**	0.62	0.7	**1.092**	21.1	750	250	57.7	133.6	137.2	3.6	2.7%
		2,000	20.70	2.51	0.50	0.40	3.41	88.9	22.92	3.21	0.40	(0.06)	3.55	94.0	0.67	0.62	0.70	1.09	42.2	750	1,250	122.1	253.3	258.3	5.0	2.0%
		5,000	20.70	2.51	0.50	0.40	3.41	191.2	22.92	3.21	0.40	(0.06)	3.55	200.6	0.67	0.62	0.70	1.09	105.4	750	4,250	315.4	612.3	621.4	9.2	1.5%
		10,000	20.70	2.51	0.50	0.40	3.41	361.7	22.92	3.21	0.40	(0.06)	3.55	378.3	0.67	0.62	0.70	1.09	210.9	750	9,250	637.5	1,210.6	1,226.7	16.1	1.3%
		15,000	20.70	2.51	0.50	0.40	3.41	532.2	22.92	3.21	0.40	(0.06)	3.55	556.0	0.67	0.62	0.70	1.09	316.3	750	14,250	959.7	1,808.9	1,832.0	23.1	1.3%
GSe	Severn	1,000	**22.17**	**1.06**	**0.31**	**0.22**	**1.59**	38.1	**24.55**	**2.30**	**0.22**	**(0.06)**	**2.46**	49.2	**0.67**	0.62	0.7	**1.092**	21.1	750	250	57.7	116.9	127.9	11.1	9.5%
		2,000	22.17	1.06	0.31	0.22	1.59	54.0	24.55	2.30	0.22	(0.06)	2.46	73.8	0.67	0.62	0.70	1.09	42.2	750	1,250	122.1	218.3	238.1	19.8	9.0%
		5,000	22.17	1.06	0.31	0.22	1.59	101.7	24.55	2.30	0.22	(0.06)	2.46	147.7	0.67	0.62	0.70	1.09	105.4	750	4,250	315.4	522.7	568.5	45.8	8.8%
		10,000	22.17	1.06	0.31	0.22	1.59	181.2	24.55	2.30	0.22	(0.06)	2.46	270.9	0.67	0.62	0.70	1.09	210.9	750	9,250	637.5	1,030.0	1,119.3	89.3	8.7%
		15,000	22.17	1.06	0.31	0.22	1.59	260.7	24.55	2.30	0.22	(0.06)	2.46	394.0	0.67	0.62	0.70	1.09	316.3	750	14,250	959.7	1,537.3	1,670.0	132.7	8.6%

New Rate Class: GSe - Metered

Total Bill Impacts of Proposed Distribution Rates [new RTSR+TLF]: Threshold of 750 kWhs

750.0

Classes		Scenario	May 2007 Incl Rate Riders						May 2008 Incl Rate Riders						Non-Dx Compoent				Other Reg	Commodity Bands			Existing	New	$ Incr	% Incr
			Existing Dx Rates					Existing Dx	New Dx Rates					New Dx	RTSR new	WMSC	DRC	TLF new	New	Band 1	Band 2	New	Total Bill	Total Bill	Total Bill	Total Bill
																				5.0	5.9					
New Class	Old Class	kWh	SrChg [$/cust]	base [c/kWh]	Rider1 [c/kWh]	Rider2 [c/kWh]	VarChg [c/kWh]	[$/month]	SrChg [$/cust]	base [c/kWh]	Rider2 [c/kWh]	Rider3 [c/kWh]	VarChg [c/kWh]	[$/month]	c/kWh	c/kWh	c/kWh		$	kWhs	kWhs		[$/month]	[$/month]	[$/month]	%
GSe	**Shelburne**	1,000	**20.01**	**0.87**	**0.10**	**0.02**	**0.99**	29.9	**23.09**	**1.79**	**0.02**	**(0.06)**	**1.75**	40.6	**0.67**	0.62	0.7	**1.092**	21.1	750	250	57.7	108.7	119.4	10.7	9.8%
		2,000	20.01	0.87	0.10	0.02	0.99	39.8	23.09	1.79	0.02	(0.06)	1.75	58.2	0.67	0.62	0.70	1.09	42.2	750	1,250	122.1	204.2	222.4	18.3	8.9%
		5,000	20.01	0.87	0.10	0.02	0.99	69.5	23.09	1.79	0.02	(0.06)	1.75	110.8	0.67	0.62	0.70	1.09	105.4	750	4,250	315.4	490.6	531.6	41.0	8.4%
		10,000	20.01	0.87	0.10	0.02	0.99	119.0	23.09	1.79	0.02	(0.06)	1.75	198.4	0.67	0.62	0.70	1.09	210.9	750	9,250	637.5	967.9	1,046.8	79.0	8.2%
		15,000	20.01	0.87	0.10	0.02	0.99	168.5	23.09	1.79	0.02	(0.06)	1.75	286.1	0.67	0.62	0.70	1.09	316.3	750	14,250	959.7	1,445.2	1,562.1	116.9	8.1%
UGe	**Smiths Falls**	1,000	**9.84**	**1.05**	**0.12**	**0.04**	**1.21**	21.9	**9.62**	**2.00**	**0.04**	**(0.06)**	**1.99**	29.5	**0.69**	0.62	0.7	**1.092**	21.3	750	250	57.7	100.8	108.5	7.7	7.7%
		2,000	9.84	1.05	0.12	0.04	1.21	34.0	9.62	2.00	0.04	(0.06)	1.99	49.3	0.69	0.62	0.70	1.09	42.6	750	1,250	122.1	198.4	214.0	15.6	7.9%
		5,000	9.84	1.05	0.12	0.04	1.21	70.3	9.62	2.00	0.04	(0.06)	1.99	108.9	0.69	0.62	0.70	1.09	106.5	750	4,250	315.4	491.4	530.8	39.4	8.0%
		10,000	9.84	1.05	0.12	0.04	1.21	130.8	9.62	2.00	0.04	(0.06)	1.99	208.2	0.69	0.62	0.70	1.09	213.1	750	9,250	637.5	979.7	1,058.7	79.1	8.1%
		15,000	9.84	1.05	0.12	0.04	1.21	191.3	9.62	2.00	0.04	(0.06)	1.99	307.4	0.69	0.62	0.70	1.09	319.6	750	14,250	959.7	1,468.0	1,586.7	118.7	8.1%
GSe	**South Glengai**	1,000	**17.41**	**0.75**	**0.37**	**0.30**	**1.42**	31.6	**20.74**	**1.96**	**0.30**	**(0.06)**	**2.20**	42.8	**0.67**	0.62	0.7	**1.092**	21.1	750	250	57.7	110.4	121.5	11.1	10.1%
		2,000	17.41	0.75	0.37	0.30	1.42	45.8	20.74	1.96	0.30	(0.06)	2.20	64.8	0.67	0.62	0.70	1.09	42.2	750	1,250	122.1	210.2	229.1	18.9	9.0%
		5,000	17.41	0.75	0.37	0.30	1.42	88.4	20.74	1.96	0.30	(0.06)	2.20	130.9	0.67	0.62	0.70	1.09	105.4	750	4,250	315.4	509.5	551.7	42.3	8.3%
		10,000	17.41	0.75	0.37	0.30	1.42	159.4	20.74	1.96	0.30	(0.06)	2.20	241.1	0.67	0.62	0.70	1.09	210.9	750	9,250	637.5	1,008.3	1,089.5	81.2	8.1%
		15,000	17.41	0.75	0.37	0.30	1.42	230.4	20.74	1.96	0.30	(0.06)	2.20	351.2	0.67	0.62	0.70	1.09	316.3	750	14,250	959.7	1,507.1	1,627.2	120.1	8.0%
GSe	**South River**	1,000	**22.11**	**1.58**	**0.39**	**0.30**	**2.27**	44.8	**24.56**	**2.95**	**0.30**	**(0.06)**	**3.19**	56.5	**0.67**	0.62	0.7	**1.092**	21.1	750	250	57.7	123.6	135.3	11.6	9.4%
		2,000	22.11	1.58	0.39	0.30	2.27	67.5	24.56	2.95	0.30	(0.06)	3.19	88.4	0.67	0.62	0.70	1.09	42.2	750	1,250	122.1	231.9	252.7	20.8	9.0%
		5,000	22.11	1.58	0.39	0.30	2.27	135.6	24.56	2.95	0.30	(0.06)	3.19	184.2	0.67	0.62	0.70	1.09	105.4	750	4,250	315.4	556.7	605.1	48.4	8.7%
		10,000	22.11	1.58	0.39	0.30	2.27	249.1	24.56	2.95	0.30	(0.06)	3.19	343.9	0.67	0.62	0.70	1.09	210.9	750	9,250	637.5	1,098.0	1,192.3	94.3	8.6%
		15,000	22.11	1.58	0.39	0.30	2.27	362.6	24.56	2.95	0.30	(0.06)	3.19	503.6	0.67	0.62	0.70	1.09	316.3	750	14,250	959.7	1,639.3	1,779.5	140.3	8.6%
GSe	**Springwater**	1,000	**20.53**	**1.07**	**0.27**	**0.17**	**1.51**	35.6	**22.96**	**2.25**	**0.17**	**(0.06)**	**2.36**	46.6	**0.67**	0.62	0.7	**1.092**	21.1	750	250	57.7	114.4	125.4	10.9	9.5%
		2,000	20.53	1.07	0.27	0.17	1.51	50.7	22.96	2.25	0.17	(0.06)	2.36	70.2	0.67	0.62	0.70	1.09	42.2	750	1,250	122.1	215.1	234.5	19.4	9.0%
		5,000	20.53	1.07	0.27	0.17	1.51	96.0	22.96	2.25	0.17	(0.06)	2.36	141.1	0.67	0.62	0.70	1.09	105.4	750	4,250	315.4	517.1	561.9	44.9	8.7%
		10,000	20.53	1.07	0.27	0.17	1.51	171.5	22.96	2.25	0.17	(0.06)	2.36	259.3	0.67	0.62	0.70	1.09	210.9	750	9,250	637.5	1,020.4	1,107.7	87.3	8.6%
		15,000	20.53	1.07	0.27	0.17	1.51	247.0	22.96	2.25	0.17	(0.06)	2.36	377.4	0.67	0.62	0.70	1.09	316.3	750	14,250	959.7	1,523.7	1,653.4	129.7	8.5%

New Rate Class: GSe - Metered

Total Bill Impacts of Proposed Distribution Rates [new RTSR+TLF]: Threshold of 750 kWhs

750.0

Classes		Scenario	May 2007 Incl Rate Riders						May 2008 Incl Rate Riders						Non-Dx Compoent				Other Reg	Commodity Bands			Existing	New	$ Incr	% Incr
			Existing Dx Rates					Existing Dx	New Dx Rates					New Dx	RTSR new	WMSC	DRC	TLF new	New	Band 1	Band 2	New	Total Bill	Total Bill	Total Bill	Total Bill
																				5.0	5.9					
New Class	Old Class	kWh	SrChg	base	Rider1	Rider2	VarChg	[$/month]	SrChg	base	Rider2	Rider3	VarChg	[$/month]	c/kWh	c/kWh	c/kWh		$	kWhs	kWhs		[$/month]	[$/month]	[$/month]	%
			[$/cust]	[c/kWh]	[c/kWh]	[c/kWh]	[c/kWh]		[$/cust]	[c/kWh]	[c/kWh]	[c/kWh]	[c/kWh]													
GSe	Stirling-Rawdo	1,000	**24.12**	**1.30**	**0.21**	**0.09**	**1.60**	40.1	**26.06**	**2.47**	**0.09**	**(0.06)**	**2.50**	51.1	**0.67**	0.62	0.7	**1.092**	21.1	750	250	57.7	118.9	129.9	10.9	9.2%
		2,000	24.12	1.30	0.21	0.09	1.60	56.1	26.06	2.47	0.09	(0.06)	2.50	76.1	0.67	0.62	0.70	1.09	42.2	750	1,250	122.1	220.5	240.4	19.9	9.0%
		5,000	24.12	1.30	0.21	0.09	1.60	104.1	26.06	2.47	0.09	(0.06)	2.50	151.2	0.67	0.62	0.70	1.09	105.4	750	4,250	315.4	525.2	572.0	46.9	8.9%
		10,000	24.12	1.30	0.21	0.09	1.60	184.1	26.06	2.47	0.09	(0.06)	2.50	276.4	0.67	0.62	0.70	1.09	210.9	750	9,250	637.5	1,033.0	1,124.8	91.8	8.9%
		15,000	24.12	1.30	0.21	0.09	1.60	264.1	26.06	2.47	0.09	(0.06)	2.50	401.6	0.67	0.62	0.70	1.09	316.3	750	14,250	959.7	1,540.8	1,677.5	136.7	8.9%
GSe	Thedford	1,000	**17.83**	**1.06**	**0.36**	**0.31**	**1.73**	35.1	**20.63**	**2.30**	**0.31**	**(0.06)**	**2.55**	46.2	**0.67**	0.62	0.7	**1.092**	21.1	750	250	57.7	113.9	124.9	11.0	9.6%
		2,000	17.83	1.06	0.36	0.31	1.73	52.4	20.63	2.30	0.31	(0.06)	2.55	71.7	0.67	0.62	0.70	1.09	42.2	750	1,250	122.1	216.8	236.0	19.2	8.8%
		5,000	17.83	1.06	0.36	0.31	1.73	104.3	20.63	2.30	0.31	(0.06)	2.55	148.3	0.67	0.62	0.70	1.09	105.4	750	4,250	315.4	525.4	569.1	43.7	8.3%
		10,000	17.83	1.06	0.36	0.31	1.73	190.8	20.63	2.30	0.31	(0.06)	2.55	276.0	0.67	0.62	0.70	1.09	210.9	750	9,250	637.5	1,039.7	1,124.4	84.7	8.1%
		15,000	17.83	1.06	0.36	0.31	1.73	277.3	20.63	2.30	0.31	(0.06)	2.55	403.6	0.67	0.62	0.70	1.09	316.3	750	14,250	959.7	1,554.0	1,679.6	125.6	8.1%
GSe	Thessalon	1,000	**18.90**	**1.55**	**0.10**	**0.08**	**1.73**	36.2	**21.37**	**2.56**	**0.08**	**(0.06)**	**2.58**	47.2	**0.67**	0.62	0.7	**1.092**	21.1	750	250	57.7	115.0	126.0	11.0	9.5%
		2,000	18.90	1.55	0.10	0.08	1.73	53.5	21.37	2.56	0.08	(0.06)	2.58	73.0	0.67	0.62	0.70	1.09	42.2	750	1,250	122.1	217.9	237.3	19.4	8.9%
		5,000	18.90	1.55	0.10	0.08	1.73	105.4	21.37	2.56	0.08	(0.06)	2.58	150.5	0.67	0.62	0.70	1.09	105.4	750	4,250	315.4	526.5	571.4	44.9	8.5%
		10,000	18.90	1.55	0.10	0.08	1.73	191.9	21.37	2.56	0.08	(0.06)	2.58	279.7	0.67	0.62	0.70	1.09	210.9	750	9,250	637.5	1,040.8	1,128.1	87.3	8.4%
		15,000	18.90	1.55	0.10	0.08	1.73	278.4	21.37	2.56	0.08	(0.06)	2.58	408.9	0.67	0.62	0.70	1.09	316.3	750	14,250	959.7	1,555.1	1,684.8	129.8	8.3%
GSe	Thorndale	1,000	**14.52**	**1.02**	**0.52**	**0.32**	**1.86**	33.1	**18.46**	**2.38**	**0.32**	**(0.06)**	**2.64**	44.9	**0.67**	0.62	0.7	**1.092**	21.1	750	250	57.7	111.9	123.7	11.7	10.5%
		2,000	14.52	1.02	0.52	0.32	1.86	51.7	18.46	2.38	0.32	(0.06)	2.64	71.3	0.67	0.62	0.70	1.09	42.2	750	1,250	122.1	216.1	235.6	19.5	9.0%
		5,000	14.52	1.02	0.52	0.32	1.86	107.5	18.46	2.38	0.32	(0.06)	2.64	150.6	0.67	0.62	0.70	1.09	105.4	750	4,250	315.4	528.6	571.4	42.9	8.1%
		10,000	14.52	1.02	0.52	0.32	1.86	200.5	18.46	2.38	0.32	(0.06)	2.64	282.8	0.67	0.62	0.70	1.09	210.9	750	9,250	637.5	1,049.4	1,131.2	81.8	7.8%
		15,000	14.52	1.02	0.52	0.32	1.86	293.5	18.46	2.38	0.32	(0.06)	2.64	415.0	0.67	0.62	0.70	1.09	316.3	750	14,250	959.7	1,570.2	1,690.9	120.7	7.7%
UGe	Thorold	1,000	**22.63**	**1.50**	**0.15**	**0.06**	**1.71**	39.7	**19.43**	**2.00**	**0.06**	**(0.06)**	**2.01**	39.5	**0.69**	0.62	0.7	**1.092**	21.3	750	250	57.7	118.5	118.5	(0.1)	-0.1%
		2,000	22.63	1.50	0.15	0.06	1.71	56.8	19.43	2.00	0.06	(0.06)	2.01	59.5	0.69	0.62	0.70	1.09	42.6	750	1,250	122.1	221.2	224.2	3.0	1.4%
		5,000	22.63	1.50	0.15	0.06	1.71	108.1	19.43	2.00	0.06	(0.06)	2.01	119.7	0.69	0.62	0.70	1.09	106.5	750	4,250	315.4	529.2	541.6	12.4	2.3%
		10,000	22.63	1.50	0.15	0.06	1.71	193.6	19.43	2.00	0.06	(0.06)	2.01	220.0	0.69	0.62	0.70	1.09	213.1	750	9,250	637.5	1,042.5	1,070.5	28.1	2.7%
		15,000	22.63	1.50	0.15	0.06	1.71	279.1	19.43	2.00	0.06	(0.06)	2.01	320.2	0.69	0.62	0.70	1.09	319.6	750	14,250	959.7	1,555.8	1,599.5	43.7	2.8%

New Rate Class: GSe - Metered

Total Bill Impacts of Proposed Distribution Rates [new RTSR+TLF]: Threshold of 750 kWhs

750.0

Classes		Scenario	May 2007 Incl Rate Riders						May 2008 Incl Rate Riders						Non-Dx Compoent				Other Reg	Commodity Bands			Existing	New	$ Incr	% Incr
			Existing Dx Rates					Existing Dx	New Dx Rates					New Dx	RTSR new	WMSC	DRC	TLF new	New	Band 1	Band 2	New	Total Bill	Total Bill	Total Bill	Total Bill
																				5.0	5.9					
New Class	Old Class	kWh	SrChg [$/cust]	base [c/kWh]	Rider1 [c/kWh]	Rider2 [c/kWh]	VarChg [c/kWh]	[$/month]	SrChg [$/cust]	base [c/kWh]	Rider2 [c/kWh]	Rider3 [c/kWh]	VarChg [c/kWh]	[$/month]	c/kWh	c/kWh	c/kWh		$	kWhs	kWhs		[$/month]	[$/month]	[$/month]	%
GSe	**Tweed**	1,000	**8.26**	**0.97**	**0.43**	**0.31**	**1.71**	25.4	**14.03**	**2.10**	**0.31**	**(0.06)**	**2.35**	37.6	**0.67**	0.62	0.7	**1.092**	21.1	750	250	57.7	104.2	116.3	12.2	11.7%
		2,000	8.26	0.97	0.43	0.31	1.71	42.5	14.03	2.10	0.31	(0.06)	2.35	61.1	0.67	0.62	0.70	1.09	42.2	750	1,250	122.1	206.8	225.4	18.5	9.0%
		5,000	8.26	0.97	0.43	0.31	1.71	93.8	14.03	2.10	0.31	(0.06)	2.35	131.7	0.67	0.62	0.70	1.09	105.4	750	4,250	315.4	514.8	552.5	37.7	7.3%
		10,000	8.26	0.97	0.43	0.31	1.71	179.3	14.03	2.10	0.31	(0.06)	2.35	249.4	0.67	0.62	0.70	1.09	210.9	750	9,250	637.5	1,028.1	1,097.8	69.6	6.8%
		15,000	8.26	0.97	0.43	0.31	1.71	264.8	14.03	2.10	0.31	(0.06)	2.35	367.0	0.67	0.62	0.70	1.09	316.3	750	14,250	959.7	1,541.4	1,643.0	101.6	6.6%
GSe	**Wardsville**	1,000	**12.32**	**1.00**	**0.25**	**0.08**	**1.33**	25.6	**17.01**	**1.99**	**0.08**	**(0.06)**	**2.01**	37.1	**0.67**	0.62	0.7	**1.092**	21.1	750	250	57.7	104.4	115.9	11.5	11.0%
		2,000	12.32	1.00	0.25	0.08	1.33	38.9	17.01	1.99	0.08	(0.06)	2.01	57.3	0.67	0.62	0.70	1.09	42.2	750	1,250	122.1	203.3	221.6	18.3	9.0%
		5,000	12.32	1.00	0.25	0.08	1.33	78.8	17.01	1.99	0.08	(0.06)	2.01	117.7	0.67	0.62	0.70	1.09	105.4	750	4,250	315.4	499.9	538.5	38.6	7.7%
		10,000	12.32	1.00	0.25	0.08	1.33	145.3	17.01	1.99	0.08	(0.06)	2.01	218.3	0.67	0.62	0.70	1.09	210.9	750	9,250	637.5	994.2	1,066.7	72.6	7.3%
		15,000	12.32	1.00	0.25	0.08	1.33	211.8	17.01	1.99	0.08	(0.06)	2.01	319.0	0.67	0.62	0.70	1.09	316.3	750	14,250	959.7	1,488.5	1,595.0	106.5	7.2%
GSe	**Warkworth**	1,000	**21.31**	**1.52**	**0.46**	**0.35**	**2.33**	44.6	**23.76**	**2.95**	**0.35**	**(0.06)**	**3.24**	56.2	**0.67**	0.62	0.7	**1.092**	21.1	750	250	57.7	123.4	135.0	11.5	9.4%
		2,000	21.31	1.52	0.46	0.35	2.33	67.9	23.76	2.95	0.35	(0.06)	3.24	88.6	0.67	0.62	0.70	1.09	42.2	750	1,250	122.1	232.3	252.9	20.6	8.9%
		5,000	21.31	1.52	0.46	0.35	2.33	137.8	23.76	2.95	0.35	(0.06)	3.24	185.9	0.67	0.62	0.70	1.09	105.4	750	4,250	315.4	558.9	606.8	47.9	8.6%
		10,000	21.31	1.52	0.46	0.35	2.33	254.3	23.76	2.95	0.35	(0.06)	3.24	348.1	0.67	0.62	0.70	1.09	210.9	750	9,250	637.5	1,103.2	1,196.5	93.3	8.5%
		15,000	21.31	1.52	0.46	0.35	2.33	370.8	23.76	2.95	0.35	(0.06)	3.24	510.3	0.67	0.62	0.70	1.09	316.3	750	14,250	959.7	1,647.5	1,786.2	138.8	8.4%
GSe	**West Elgin**	1,000	**15.40**	**0.70**	**0.17**	**0.07**	**0.94**	24.8	**19.24**	**1.62**	**0.07**	**(0.06)**	**1.63**	35.6	**0.67**	0.62	0.7	**1.092**	21.1	750	250	57.7	103.6	114.3	10.7	10.4%
		2,000	15.40	0.70	0.17	0.07	0.94	34.2	19.24	1.62	0.07	(0.06)	1.63	51.9	0.67	0.62	0.70	1.09	42.2	750	1,250	122.1	198.6	216.2	17.6	8.9%
		5,000	15.40	0.70	0.17	0.07	0.94	62.4	19.24	1.62	0.07	(0.06)	1.63	100.9	0.67	0.62	0.70	1.09	105.4	750	4,250	315.4	483.5	521.7	38.3	7.9%
		10,000	15.40	0.70	0.17	0.07	0.94	109.4	19.24	1.62	0.07	(0.06)	1.63	182.6	0.67	0.62	0.70	1.09	210.9	750	9,250	637.5	958.3	1,031.0	72.7	7.6%
		15,000	15.40	0.70	0.17	0.07	0.94	156.4	19.24	1.62	0.07	(0.06)	1.63	264.2	0.67	0.62	0.70	1.09	316.3	750	14,250	959.7	1,433.1	1,540.2	107.1	7.5%
UGe	**Whitchurch St**	1,000	**21.85**	**0.93**	**0.11**	**0.04**	**1.08**	32.7	**18.62**	**2.00**	**0.04**	**(0.06)**	**1.99**	38.5	**0.69**	0.62	0.7	**1.092**	21.3	750	250	57.7	111.5	117.5	6.0	5.4%
		2,000	21.85	0.93	0.11	0.04	1.08	43.5	18.62	2.00	0.04	(0.06)	1.99	58.3	0.69	0.62	0.70	1.09	42.6	750	1,250	122.1	207.8	223.0	15.2	7.3%
		5,000	21.85	0.93	0.11	0.04	1.08	75.9	18.62	2.00	0.04	(0.06)	1.99	117.9	0.69	0.62	0.70	1.09	106.5	750	4,250	315.4	496.9	539.8	42.9	8.6%
		10,000	21.85	0.93	0.11	0.04	1.08	129.9	18.62	2.00	0.04	(0.06)	1.99	217.2	0.69	0.62	0.70	1.09	213.1	750	9,250	637.5	978.7	1,067.7	89.0	9.1%
		15,000	21.85	0.93	0.11	0.04	1.08	183.9	18.62	2.00	0.04	(0.06)	1.99	316.4	0.69	0.62	0.70	1.09	319.6	750	14,250	959.7	1,460.5	1,595.7	135.2	9.3%

New Rate Class: GSe - Metered

Total Bill Impacts of Proposed Distribution Rates [new RTSR+TLF]: Threshold of 750 kWhs

Classes		Scenario	May 2007 Incl Rate Riders						May 2008 Incl Rate Riders						Non-Dx Compoent				Other Reg	Commodity Bands 750.0			Existing	New	$ Incr	% Incr
			Existing Dx Rates					Existing Dx	New Dx Rates					New Dx	RTSR new	WMSC	DRC	TLF new	New	Band 1	Band 2	New	Total Bill	Total Bill	Total Bill	Total Bill
																				5.0	5.9					
New Class	Old Class	kWh	SrChg	base	Rider1	Rider2	VarChg	[$/month]	SrChg	base	Rider2	Rider3	VarChg	[$/month]	c/kWh	c/kWh	c/kWh		$	kWhs	kWhs		[$/month]	[$/month]	[$/month]	%
			[$/cust]	[c/kWh]	[c/kWh]	[c/kWh]	[c/kWh]		[$/cust]	[c/kWh]	[c/kWh]	[c/kWh]	[c/kWh]													
GSe	**Wiarton**	1,000	**23.78**	**1.89**	**0.19**	**0.09**	**2.17**	45.5	**25.15**	**3.10**	**0.09**	**(0.06)**	**3.13**	56.5	**0.67**	0.62	0.7	**1.092**	21.1	750	250	57.7	124.3	135.2	11.0	8.8%
		2,000	23.78	1.89	0.19	0.09	2.17	67.2	25.15	3.10	0.09	(0.06)	3.13	87.8	0.67	0.62	0.70	1.09	42.2	750	1,250	122.1	231.6	252.1	20.5	8.9%
		5,000	23.78	1.89	0.19	0.09	2.17	132.3	25.15	3.10	0.09	(0.06)	3.13	181.8	0.67	0.62	0.70	1.09	105.4	750	4,250	315.4	553.3	602.6	49.3	8.9%
		10,000	23.78	1.89	0.19	0.09	2.17	240.8	25.15	3.10	0.09	(0.06)	3.13	338.5	0.67	0.62	0.70	1.09	210.9	750	9,250	637.5	1,089.6	1,186.9	97.2	8.9%
		15,000	23.78	1.89	0.19	0.09	2.17	349.3	25.15	3.10	0.09	(0.06)	3.13	495.1	0.67	0.62	0.70	1.09	316.3	750	14,250	959.7	1,625.9	1,771.1	145.2	8.9%
GSe	**Woodville**	1,000	**16.89**	**1.57**	**0.67**	**0.48**	**2.72**	44.1	**19.87**	**3.21**	**0.48**	**(0.06)**	**3.63**	56.2	**0.67**	0.62	0.7	**1.092**	21.1	750	250	57.7	122.9	135.0	12.1	9.8%
		2,000	16.89	1.57	0.67	0.48	2.72	71.3	19.87	3.21	0.48	(0.06)	3.63	92.5	0.67	0.62	0.70	1.09	42.2	750	1,250	122.1	235.7	256.8	21.2	9.0%
		5,000	16.89	1.57	0.67	0.48	2.72	152.9	19.87	3.21	0.48	(0.06)	3.63	201.6	0.67	0.62	0.70	1.09	105.4	750	4,250	315.4	573.9	622.4	48.4	8.4%
		10,000	16.89	1.57	0.67	0.48	2.72	288.9	19.87	3.21	0.48	(0.06)	3.63	383.2	0.67	0.62	0.70	1.09	210.9	750	9,250	637.5	1,137.7	1,231.6	93.9	8.3%
		15,000	16.89	1.57	0.67	0.48	2.72	424.9	19.87	3.21	0.48	(0.06)	3.63	564.9	0.67	0.62	0.70	1.09	316.3	750	14,250	959.7	1,701.5	1,840.9	139.4	8.2%
GSe	**Wyoming**	1,000	**17.36**	**1.45**	**0.16**	**0.07**	**1.68**	34.2	**20.75**	**2.46**	**0.07**	**(0.06)**	**2.47**	45.5	**0.67**	0.62	0.7	**1.092**	21.1	750	250	57.7	113.0	124.2	11.3	10.0%
		2,000	17.36	1.45	0.16	0.07	1.68	51.0	20.75	2.46	0.07	(0.06)	2.47	70.2	0.67	0.62	0.70	1.09	42.2	750	1,250	122.1	215.3	234.5	19.2	8.9%
		5,000	17.36	1.45	0.16	0.07	1.68	101.4	20.75	2.46	0.07	(0.06)	2.47	144.4	0.67	0.62	0.70	1.09	105.4	750	4,250	315.4	522.4	565.2	42.8	8.2%
		10,000	17.36	1.45	0.16	0.07	1.68	185.4	20.75	2.46	0.07	(0.06)	2.47	268.1	0.67	0.62	0.70	1.09	210.9	750	9,250	637.5	1,034.2	1,116.5	82.3	8.0%
		15,000	17.36	1.45	0.16	0.07	1.68	269.4	20.75	2.46	0.07	(0.06)	2.47	391.7	0.67	0.62	0.70	1.09	316.3	750	14,250	959.7	1,546.0	1,667.7	121.7	7.9%
GSe	**Terrace Bay**	1,000	**41.34**	**1.18**	**0.82**		**2.00**	61.3	**38.76**	**2.67**		**(0.06)**	**2.61**	64.9	**0.67**	0.62	0.7	**1.092**	21.1	750	250	57.7	134.5	143.7	9.2	6.8%
		2,000	41.34	1.18	0.82	-	2.00	81.3	38.76	2.67	-	(0.06)	2.61	91.0	0.67	0.62	0.70	1.09	42.2	750	1,250	122.1	234.3	255.3	21.0	8.9%
		5,000	41.34	1.18	0.82	-	2.00	141.3	38.76	2.67	-	(0.06)	2.61	169.4	0.67	0.62	0.70	1.09	105.4	750	4,250	315.4	534.0	590.2	56.3	10.5%
		10,000	41.34	1.18	0.82	-	2.00	241.3	38.76	2.67	-	(0.06)	2.61	300.1	0.67	0.62	0.70	1.09	210.9	750	9,250	637.5	1,033.4	1,148.5	115.1	11.1%
		15,000	41.34	1.18	0.82	-	2.00	341.3	38.76	2.67	-	(0.06)	2.61	430.7	0.67	0.62	0.70	1.09	316.3	750	14,250	959.7	1,532.8	1,706.7	174.0	11.3%

New Rate Class: GSd

Total Bill Impacts of Proposed Distribution Rates [new RTSR+TLF]: Threshold of 750 kWhs

Classes		Scenario			May 2007 Incl Rate Riders						May 2008 Incl Rate Riders						Non-Dx Compoent				Other Reg	Commodity Bands			Existing	New	$ Incr	% Incr
					Existing Dx Rates					Existing Dx	New Dx Rates					New Dx	RTSR new	WMSC	DRC	TLF new	New	Band 1	Band 2	New	Total Bill	Total Bill	Total Bill	Total Bill
																						-	5.2					
New Class	Old Class	kWh	kW	LF	SrChg	base	Rider1	Rider2	VarChg	[$/month]	SrChg	base	Rider2	Rider3	VarChg	[$/month]	$/kW	c/kWh	c/kWh		$	kWhs	kWhs	Total $	[$/month]	[$/month]	[$/month]	%
					[$/cust]	[$/kW]	[$/kW]	[$/kW]	[$/kW]		[$/cust]	[$/kW]	[$/kW]	[$/kW]	[$/kW]													
GSd	F1	15,000	60	35%	28.61	7.06	0.26	0.31	7.63	486.4	56.51	9.44	0.31	(0.22)	9.53	628.5	2.11	0.62	0.7	1.061	338.0	-	15,000	827.6	1,730.1	1,794.1	64.0	3.7%
		43,164	133	45%	28.61	7.06	0.26	0.31	7.63	1,043.4	56.51	9.44	0.31	(0.22)	9.53	1,324.5	2.11	0.62	0.7	1.061	883.8	-	43,164	2,381.4	4,499.7	4,589.8	90.1	2.0%
with RRRP		100,000	500	28%	28.61	7.06	0.26	0.31	7.63	3,843.6	56.51	9.44	0.31	(0.22)	9.53	4,823.4	2.11	0.62	0.7	1.061	2,477.2	-	100,000	5,517.2	12,443.7	12,817.7	374.1	3.0%
		400,000	1000	56%	28.61	7.06	0.26	0.31	7.63	7,658.6	56.51	9.44	0.31	(0.22)	9.53	9,590.2	2.11	0.62	0.7	1.061	7,670.0	-	400,000	22,068.8	38,969.6	39,329.0	359.4	0.9%
		1,000,000	3000	46%	28.61	7.06	0.26	0.31	7.63	22,918.6	56.51	9.44	0.31	(0.22)	9.53	28,657.7	2.11	0.62	0.7	1.061	20,294.3	-	1,000,000	55,172.0	102,740.8	104,124.0	1,383.2	1.3%
		1,500,000	4000	52%	28.61	7.06	0.26	0.31	7.63	30,548.6	56.51	9.44	0.31	(0.22)	9.53	38,191.4	2.11	0.62	0.7	1.061	29,322.1	-	1,500,000	82,758.0	148,737.3	150,271.6	1,534.3	1.0%
GSd	F1	15,000	60	35%	60.71	7.06	0.26	0.31	7.63	518.5	56.51	9.44	0.31	(0.22)	9.53	628.5	2.11	0.62	0.7	1.061	338.0	-	15,000	827.6	1,762.2	1,794.1	31.9	1.8%
		43,164	133	45%	60.71	7.06	0.26	0.31	7.63	1,075.5	56.51	9.44	0.31	(0.22)	9.53	1,324.5	2.11	0.62	0.70	1.061	883.8	-	43,164	2,381.4	4,531.8	4,589.8	58.0	1.3%
no RRRP		100,000	500	28%	60.71	7.06	0.26	0.31	7.63	3,875.7	56.51	9.44	0.31	(0.22)	9.53	4,823.4	2.11	0.62	0.70	1.061	2,477.2	-	100,000	5,517.2	12,475.8	12,817.7	342.0	2.7%
		400,000	1000	56%	60.71	7.06	0.26	0.31	7.63	7,690.7	56.51	9.44	0.31	(0.22)	9.53	9,590.2	2.11	0.62	0.70	1.061	7,670.0	-	400,000	22,068.8	39,001.7	39,329.0	327.3	0.8%
		1,000,000	3000	46%	60.71	7.06	0.26	0.31	7.63	22,950.7	56.51	9.44	0.31	(0.22)	9.53	28,657.7	2.11	0.62	0.70	1.061	20,294.3	-	1,000,000	55,172.0	102,772.9	104,124.0	1,351.1	1.3%
		1,500,000	4000	52%	60.71	7.06	0.26	0.31	7.63	30,580.7	56.51	9.44	0.31	(0.22)	9.53	38,191.4	2.11	0.62	0.70	1.061	29,322.1	-	1,500,000	82,758.0	148,769.4	150,271.6	1,502.2	1.0%
GSd	F3	15,000	60	35%	30.16	10.87	0.10	0.16	11.13	698.0	51.21	9.44	0.16	(0.22)	9.38	614.2	2.11	0.62	0.7	1.061	338.0	-	15,000	827.6	1,928.4	1,779.8	(148.6)	-7.7%
		43,164	133	45%	30.16	10.87	0.10	0.16	11.13	1,510.5	51.21	9.44	0.16	(0.22)	9.38	1,299.2	2.11	0.62	0.70	1.061	883.8	-	43,164	2,381.4	4,919.5	4,564.5	(355.0)	-7.2%
with RRRP		100,000	500	28%	30.16	10.87	0.10	0.16	11.13	5,595.2	51.21	9.44	0.16	(0.22)	9.38	4,743.1	2.11	0.62	0.70	1.061	2,477.2	-	100,000	5,517.2	14,130.1	12,737.4	(1,392.7)	-9.9%
		400,000	1000	56%	30.16	10.87	0.10	0.16	11.13	11,160.2	51.21	9.44	0.16	(0.22)	9.38	9,434.9	2.11	0.62	0.70	1.061	7,670.0	-	400,000	22,068.8	41,980.1	39,173.7	(2,806.4)	-6.7%
		1,000,000	3000	46%	30.16	10.87	0.10	0.16	11.13	33,420.2	51.21	9.44	0.16	(0.22)	9.38	28,202.4	2.11	0.62	0.70	1.061	20,294.3	-	1,000,000	55,172.0	112,130.0	103,668.7	(8,461.2)	-7.5%
		1,500,000	4000	52%	30.16	10.87	0.10	0.16	11.13	44,550.2	51.21	9.44	0.16	(0.22)	9.38	37,586.1	2.11	0.62	0.70	1.061	29,322.1	-	1,500,000	82,758.0	160,954.9	149,666.3	(11,288.7)	-7.0%
GSd	F3	15,000	60	35%	53.91	10.87	0.10	0.16	11.13	721.7	51.21	9.44	0.16	(0.22)	9.38	614.2	2.11	0.62	0.7	1.061	338.0	-	15,000	827.6	1,952.2	1,779.8	(172.3)	-8.8%
		43,164	133	45%	53.91	10.87	0.10	0.16	11.13	1,534.2	51.21	9.44	0.16	(0.22)	9.38	1,299.2	2.11	0.62	0.7	1.061	883.8	-	43,164	2,381.4	4,943.3	4,564.5	(378.7)	-7.7%
no RRRP		100,000	500	28%	53.91	10.87	0.10	0.16	11.13	5,618.9	51.21	9.44	0.16	(0.22)	9.38	4,743.1	2.11	0.62	0.7	1.061	2,477.2	-	100,000	5,517.2	14,153.9	12,737.4	(1,416.4)	-10.0%
		400,000	1000	56%	53.91	10.87	0.10	0.16	11.13	11,183.9	51.21	9.44	0.16	(0.22)	9.38	9,434.9	2.11	0.62	0.7	1.061	7,670.0	-	400,000	22,068.8	42,003.9	39,173.7	(2,830.1)	-6.7%
		1,000,000	3000	46%	53.91	10.87	0.10	0.16	11.13	33,443.9	51.21	9.44	0.16	(0.22)	9.38	28,202.4	2.11	0.62	0.7	1.061	20,294.3	-	1,000,000	55,172.0	112,153.7	103,668.7	(8,485.0)	-7.6%
		1,500,000	4000	52%	53.91	10.87	0.10	0.16	11.13	44,573.9	51.21	9.44	0.16	(0.22)	9.38	37,586.1	2.11	0.62	0.7	1.061	29,322.1	-	1,500,000	82,758.0	160,978.7	149,666.3	(11,312.4)	-7.0%
GSd	G1	15,000	60	35%	36.93	9.59	0.26	0.29	10.14	645.3	38.68	9.44	0.29	(0.22)	9.51	609.5	2.11	0.62	0.7	1.061	338.0	-	15,000	827.6	1,875.2	1,775.1	(100.2)	-5.3%
		43,164	133	45%	36.93	9.59	0.26	0.29	10.14	1,385.6	38.68	9.44	0.29	(0.22)	9.51	1,304.0	2.11	0.62	0.70	1.061	883.8	-	43,164	2,381.4	4,811.3	4,569.3	(242.0)	-5.0%
		100,000	500	28%	36.93	9.59	0.26	0.29	10.14	5,106.9	38.68	9.44	0.29	(0.22)	9.51	4,795.5	2.11	0.62	0.70	1.061	2,477.2	-	100,000	5,517.2	13,592.3	12,789.9	(802.4)	-5.9%
		400,000	1000	56%	36.93	9.59	0.26	0.29	10.14	10,176.9	38.68	9.44	0.29	(0.22)	9.51	9,552.4	2.11	0.62	0.70	1.061	7,670.0	-	400,000	22,068.8	41,258.6	39,291.2	(1,967.4)	-4.8%
		1,000,000	3000	46%	36.93	9.59	0.26	0.29	10.14	30,456.9	38.68	9.44	0.29	(0.22)	9.51	28,579.9	2.11	0.62	0.70	1.061	20,294.3	-	1,000,000	55,172.0	109,591.2	104,046.2	(5,545.0)	-5.1%
		1,500,000	4000	52%	36.93	9.59	0.26	0.29	10.14	40,596.9	38.68	9.44	0.29	(0.22)	9.51	38,093.6	2.11	0.62	0.70	1.061	29,322.1	-	1,500,000	82,758.0	157,868.3	150,173.7	(7,694.6)	-4.9%

New Rate Class: GSd

Total Bill Impacts of Proposed Distribution Rates [new RTSR+TLF]: Threshold of 750 kWhs

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Classes		Scenario			May 2007 Incl Rate Riders						May 2008 Incl Rate Riders						Non-Dx Compoent				Other Reg	Commodity Bands			Existing	New	$ Incr	% Incr
					Existing Dx Rates					Existing Dx	New Dx Rates					New Dx	RTSR new	WMSC	DRC	TLF new	New	Band 1	Band 2	New	Total Bill	Total Bill	Total Bill	Total Bill
																						-	5.2					
New Class	Old Class	kWh	kW	LF	SrChg [$/cust]	base [$/kW]	Rider1 [$/kW]	Rider2 [$/kW]	VarChg [$/kW]	[$/month]	SrChg [$/cust]	base [$/kW]	Rider2 [$/kW]	Rider3 [$/kW]	VarChg [$/kW]	[$/month]	$/kW	c/kWh	c/kWh		$	kWhs	kWhs	Total $	[$/month]	[$/month]	[$/month]	%
GSd	G3	15,000	60	35%	46.78	9.91	0.08	0.15	10.14	655.2	46.00	9.44	0.15	(0.22)	9.37	608.4	2.11	0.62	0.7	1.061	338.0	-	15,000	827.6	1,861.6	1,774.0	(87.6)	-4.7%
		43,164	133	45%	46.78	9.91	0.08	0.15	10.14	1,395.4	46.00	9.44	0.15	(0.22)	9.37	1,292.7	2.11	0.62	0.70	1.061	883.8	-	43,164	2,381.4	4,751.3	4,558.0	(193.3)	-4.1%
		100,000	500	28%	46.78	9.91	0.08	0.15	10.14	5,116.8	46.00	9.44	0.15	(0.22)	9.37	4,732.9	2.11	0.62	0.70	1.061	2,477.2	-	100,000	5,517.2	13,451.7	12,727.2	(724.5)	-5.4%
		400,000	1000	56%	46.78	9.91	0.08	0.15	10.14	10,186.8	46.00	9.44	0.15	(0.22)	9.37	9,419.7	2.11	0.62	0.70	1.061	7,670.0	-	400,000	22,068.8	40,606.7	39,158.5	(1,448.2)	-3.6%
		1,000,000	3000	46%	46.78	9.91	0.08	0.15	10.14	30,466.8	46.00	9.44	0.15	(0.22)	9.37	28,167.2	2.11	0.62	0.70	1.061	20,294.3	-	1,000,000	55,172.0	107,976.6	103,633.5	(4,343.1)	-4.0%
		1,500,000	4000	52%	46.78	9.91	0.08	0.15	10.14	40,606.8	46.00	9.44	0.15	(0.22)	9.37	37,540.9	2.11	0.62	0.70	1.061	29,322.1	-	1,500,000	82,758.0	155,411.6	149,621.1	(5,790.5)	-3.7%
GSd	T	15,000	60	35%	261.54	8.16	0.04	0.09	8.29	758.9	207.30	9.44	0.09	(0.22)	9.31	766.1	2.11	0.62	0.7	1.061	338.0	-	15,000	827.6	1,969.5	1,931.7	(37.8)	-1.9%
		43,164	133	45%	261.54	8.16	0.04	0.09	8.29	1,364.1	207.30	9.44	0.09	(0.22)	9.31	1,446.0	2.11	0.62	0.70	1.061	883.8	-	43,164	2,381.4	4,729.2	4,711.3	(17.8)	-0.4%
		100,000	500	28%	261.54	8.16	0.04	0.09	8.29	4,406.5	207.30	9.44	0.09	(0.22)	9.31	4,864.2	2.11	0.62	0.70	1.061	2,477.2	-	100,000	5,517.2	12,776.0	12,858.5	82.6	0.6%
		400,000	1000	56%	261.54	8.16	0.04	0.09	8.29	8,551.5	207.30	9.44	0.09	(0.22)	9.31	9,521.0	2.11	0.62	0.70	1.061	7,670.0	-	400,000	22,068.8	39,040.5	39,259.8	219.4	0.6%
		1,000,000	3000	46%	261.54	8.16	0.04	0.09	8.29	25,131.5	207.30	9.44	0.09	(0.22)	9.31	28,148.5	2.11	0.62	0.70	1.061	20,294.3	-	1,000,000	55,172.0	102,848.3	103,614.8	766.6	0.7%
		1,500,000	4000	52%	261.54	8.16	0.04	0.09	8.29	33,421.5	207.30	9.44	0.09	(0.22)	9.31	37,462.2	2.11	0.62	0.70	1.061	29,322.1	-	1,500,000	82,758.0	148,502.2	149,542.4	1,040.2	0.7%
GSd	Ailsa Craig	15,000	60	35%	17.31	4.19	0.52	0.27	4.98	316.1	24.36	9.00	0.27	(0.22)	9.05	567.5	2.11	0.62	0.7	1.061	338.0	-	15,000	827.6	1,565.5	1,733.1	167.6	10.7%
		43,164	133	45%	17.31	4.19	0.52	0.27	4.98	679.7	24.36	9.00	0.27	(0.22)	9.05	1,228.4	2.11	0.62	0.70	1.06	883.8	-	43,164	2,381.4	4,127.1	4,493.7	366.6	8.9%
		100,000	500	28%	17.31	4.19	0.52	0.27	4.98	2,507.3	24.36	9.00	0.27	(0.22)	9.05	4,550.7	2.11	0.62	0.70	1.06	2,477.2	-	100,000	5,517.2	11,209.9	12,545.1	1,335.2	11.9%
		400,000	1000	56%	17.31	4.19	0.52	0.27	4.98	4,997.3	24.36	9.00	0.27	(0.22)	9.05	9,077.1	2.11	0.62	0.70	1.06	7,670.0	-	400,000	22,068.8	36,076.9	38,815.9	2,739.0	7.6%
		1,000,000	3000	46%	17.31	4.19	0.52	0.27	4.98	14,957.3	24.36	9.00	0.27	(0.22)	9.05	27,182.5	2.11	0.62	0.70	1.06	20,294.3	-	1,000,000	55,172.0	94,521.7	102,648.8	8,127.1	8.6%
		1,500,000	4000	52%	17.31	4.19	0.52	0.27	4.98	19,937.3	24.36	9.00	0.27	(0.22)	9.05	36,235.2	2.11	0.62	0.70	1.06	29,322.1	-	1,500,000	82,758.0	137,418.4	148,315.3	10,896.9	7.9%
GSd	Arkona	15,000	60	35%	3.20	1.98	1.62	0.83	4.43	269.0	13.89	9.22	0.83	(0.22)	9.84	604.1	2.11	0.62	0.7	1.061	338.0	-	15,000	827.6	1,518.4	1,769.6	251.2	16.5%
	no customer	43,164	133	45%	3.20	1.98	1.62	0.83	4.43	592.4	13.89	9.22	0.83	(0.22)	9.84	1,322.1	2.11	0.62	0.70	1.06	883.8	-	43,164	2,381.4	4,039.8	4,587.4	547.6	13.6%
		100,000	500	28%	3.20	1.98	1.62	0.83	4.43	2,218.2	13.89	9.22	0.83	(0.22)	9.84	4,932.0	2.11	0.62	0.70	1.06	2,477.2	-	100,000	5,517.2	10,920.8	12,926.4	2,005.6	18.4%
		400,000	1000	56%	3.20	1.98	1.62	0.83	4.43	4,433.2	13.89	9.22	0.83	(0.22)	9.84	9,850.2	2.11	0.62	0.70	1.06	7,670.0	-	400,000	22,068.8	35,512.8	39,589.0	4,076.2	11.5%
		1,000,000	3000	46%	3.20	1.98	1.62	0.83	4.43	13,293.2	13.89	9.22	0.83	(0.22)	9.84	29,522.7	2.11	0.62	0.70	1.06	20,294.3	-	1,000,000	55,172.0	92,857.6	104,989.1	12,131.5	13.1%
		1,500,000	4000	52%	3.20	1.98	1.62	0.83	4.43	17,723.2	13.89	9.22	0.83	(0.22)	9.84	39,359.0	2.11	0.62	0.70	1.06	29,322.1	-	1,500,000	82,758.0	135,204.3	151,439.2	16,234.8	12.0%
UGd	Arnprior	15,000	60	35%	21.38	3.70	0.50	0.20	4.40	285.4	22.95	7.33	0.20	(0.27)	7.26	458.6	2.68	0.62	0.7	1.061	374.3	-	15,000	827.6	1,534.8	1,660.4	125.6	8.2%
		43,164	133	45%	21.38	3.70	0.50	0.20	4.40	606.6	22.95	7.33	0.20	(0.27)	7.26	988.6	2.68	0.62	0.70	1.06	964.3	-	43,164	2,381.4	4,054.0	4,334.3	280.3	6.9%
		100,000	500	28%	21.38	3.70	0.50	0.20	4.40	2,221.4	22.95	7.33	0.20	(0.27)	7.26	3,653.1	2.68	0.62	0.70	1.06	2,779.6	-	100,000	5,517.2	10,924.0	11,949.8	1,025.8	9.4%
		400,000	1000	56%	21.38	3.70	0.50	0.20	4.40	4,421.4	22.95	7.33	0.20	(0.27)	7.26	7,283.2	2.68	0.62	0.70	1.06	8,274.8	-	400,000	22,068.8	35,501.0	37,626.7	2,125.8	6.0%
		1,000,000	3000	46%	21.38	3.70	0.50	0.20	4.40	13,221.4	22.95	7.33	0.20	(0.27)	7.26	21,803.6	2.68	0.62	0.70	1.06	22,108.6	-	1,000,000	55,172.0	92,785.7	99,084.2	6,298.5	6.8%
		1,500,000	4000	52%	21.38	3.70	0.50	0.20	4.40	17,621.4	22.95	7.33	0.20	(0.27)	7.26	29,063.8	2.68	0.62	0.70	1.06	31,741.2	-	1,500,000	82,758.0	135,102.5	143,563.0	8,460.5	6.3%

New Rate Class: GSd

Total Bill Impacts of Proposed Distribution Rates [new RTSR+TLF]: Threshold of 750 kWhs

Classes		Scenario			May 2007 Incl Rate Riders						May 2008 Incl Rate Riders						Non-Dx Compoent				Other Reg	Commodity Bands			Existing	New	$ Incr	% Incr
					Existing Dx Rates					Existing Dx	New Dx Rates					New Dx	RTSR new	WMSC	DRC	TLF new	New	Band 1	Band 2	New	Total Bill	Total Bill	Total Bill	Total Bill
																						-	5.2					
New Class	Old Class	kWh	kW	LF	SrChg [$/cust]	base [$/kW]	Rider1 [$/kW]	Rider2 [$/kW]	VarChg [$/kW]	[$/month]	SrChg [$/cust]	base [$/kW]	Rider2 [$/kW]	Rider3 [$/kW]	VarChg [$/kW]	[$/month]	$/kW	c/kWh	c/kWh		$	kWhs	kWhs	Total $	[$/month]	[$/month]	[$/month]	%
GSd	Arran-Elderslie	15,000	60	35%	8.83	3.28	0.55	0.28	4.11	255.4	17.48	8.00	0.28	(0.22)	8.06	501.2	2.11	0.62	0.7	1.061	338.0	-	15,000	827.6	1,504.9	1,666.8	162.0	10.8%
		43,164	133	45%	8.83	3.28	0.55	0.28	4.11	555.5	17.48	8.00	0.28	(0.22)	8.06	1,089.8	2.11	0.62	0.70	1.06	883.8	-	43,164	2,381.4	4,002.9	4,355.1	352.2	8.8%
		100,000	500	28%	8.83	3.28	0.55	0.28	4.11	2,063.8	17.48	8.00	0.28	(0.22)	8.06	4,048.8	2.11	0.62	0.70	1.06	2,477.2	-	100,000	5,517.2	10,766.4	12,043.2	1,276.8	11.9%
		400,000	1000	56%	8.83	3.28	0.55	0.28	4.11	4,118.8	17.48	8.00	0.28	(0.22)	8.06	8,080.2	2.11	0.62	0.70	1.06	7,670.0	-	400,000	22,068.8	35,198.4	37,819.0	2,620.6	7.4%
		1,000,000	3000	46%	8.83	3.28	0.55	0.28	4.11	12,338.8	17.48	8.00	0.28	(0.22)	8.06	24,205.6	2.11	0.62	0.70	1.06	20,294.3	-	1,000,000	55,172.0	91,903.2	99,671.9	7,768.7	8.5%
		1,500,000	4000	52%	8.83	3.28	0.55	0.28	4.11	16,448.8	17.48	8.00	0.28	(0.22)	8.06	32,268.3	2.11	0.62	0.70	1.06	29,322.1	-	1,500,000	82,758.0	133,930.0	144,348.4	10,418.5	7.8%
GSd	Artemesia	15,000	60	35%	19.62	5.49	1.55	1.08	8.12	506.8	25.78	9.22	1.08	(0.22)	10.09	631.0	2.11	0.62	0.7	1.061	338.0	-	15,000	827.6	1,756.2	1,796.5	40.3	2.3%
		43,164	133	45%	19.62	5.49	1.55	1.08	8.12	1,099.6	25.78	9.22	1.08	(0.22)	10.09	1,367.3	2.11	0.62	0.70	1.06	883.8	-	43,164	2,381.4	4,547.0	4,632.5	85.6	1.9%
		100,000	500	28%	19.62	5.49	1.55	1.08	8.12	4,079.6	25.78	9.22	1.08	(0.22)	10.09	5,068.9	2.11	0.62	0.70	1.06	2,477.2	-	100,000	5,517.2	12,782.2	13,063.3	281.1	2.2%
		400,000	1000	56%	19.62	5.49	1.55	1.08	8.12	8,139.6	25.78	9.22	1.08	(0.22)	10.09	10,112.1	2.11	0.62	0.70	1.06	7,670.0	-	400,000	22,068.8	39,219.2	39,850.9	631.7	1.6%
		1,000,000	3000	46%	19.62	5.49	1.55	1.08	8.12	24,379.6	25.78	9.22	1.08	(0.22)	10.09	30,284.6	2.11	0.62	0.70	1.06	20,294.3	-	1,000,000	55,172.0	103,944.0	105,751.0	1,807.0	1.7%
		1,500,000	4000	52%	19.62	5.49	1.55	1.08	8.12	32,499.6	25.78	9.22	1.08	(0.22)	10.09	40,370.9	2.11	0.62	0.70	1.06	29,322.1	-	1,500,000	82,758.0	149,980.8	152,451.1	2,470.3	1.6%
GSd	Bancroft	15,000	60	35%	24.41	3.70	0.54	0.24	4.48	293.2	29.59	8.50	0.24	(0.22)	8.52	540.9	2.11	0.62	0.7	1.061	338.0	-	15,000	827.6	1,542.6	1,706.5	163.9	10.6%
		43,164	133	45%	24.41	3.70	0.54	0.24	4.48	620.3	29.59	8.50	0.24	(0.22)	8.52	1,163.1	2.11	0.62	0.70	1.06	883.8	-	43,164	2,381.4	4,067.7	4,428.4	360.7	8.9%
		100,000	500	28%	24.41	3.70	0.54	0.24	4.48	2,264.4	29.59	8.50	0.24	(0.22)	8.52	4,290.9	2.11	0.62	0.70	1.06	2,477.2	-	100,000	5,517.2	10,967.0	12,285.3	1,318.3	12.0%
		400,000	1000	56%	24.41	3.70	0.54	0.24	4.48	4,504.4	29.59	8.50	0.24	(0.22)	8.52	8,552.3	2.11	0.62	0.70	1.06	7,670.0	-	400,000	22,068.8	35,584.0	38,291.1	2,707.1	7.6%
		1,000,000	3000	46%	24.41	3.70	0.54	0.24	4.48	13,464.4	29.59	8.50	0.24	(0.22)	8.52	25,597.7	2.11	0.62	0.70	1.06	20,294.3	-	1,000,000	55,172.0	93,028.8	101,064.0	8,035.3	8.6%
		1,500,000	4000	52%	24.41	3.70	0.54	0.24	4.48	17,944.4	29.59	8.50	0.24	(0.22)	8.52	34,120.4	2.11	0.62	0.70	1.06	29,322.1	-	1,500,000	82,758.0	135,425.5	146,200.5	10,775.0	8.0%
GSd	Bath	15,000	60	35%	10.65	3.77	0.93	0.63	5.33	330.5	19.03	9.00	0.63	(0.22)	9.41	583.8	2.11	0.62	0.7	1.061	338.0	-	15,000	827.6	1,579.9	1,749.4	169.5	10.7%
		43,164	133	45%	10.65	3.77	0.93	0.63	5.33	719.5	19.03	9.00	0.63	(0.22)	9.41	1,270.9	2.11	0.62	0.70	1.06	883.8	-	43,164	2,381.4	4,166.9	4,536.2	369.3	8.9%
		100,000	500	28%	10.65	3.77	0.93	0.63	5.33	2,675.7	19.03	9.00	0.63	(0.22)	9.41	4,725.4	2.11	0.62	0.70	1.06	2,477.2	-	100,000	5,517.2	11,378.3	12,719.8	1,341.5	11.8%
		400,000	1000	56%	10.65	3.77	0.93	0.63	5.33	5,340.7	19.03	9.00	0.63	(0.22)	9.41	9,431.7	2.11	0.62	0.70	1.06	7,670.0	-	400,000	22,068.8	36,420.2	39,170.5	2,750.3	7.6%
		1,000,000	3000	46%	10.65	3.77	0.93	0.63	5.33	16,000.7	19.03	9.00	0.63	(0.22)	9.41	28,257.1	2.11	0.62	0.70	1.06	20,294.3	-	1,000,000	55,172.0	95,565.0	103,723.5	8,158.5	8.5%
		1,500,000	4000	52%	10.65	3.77	0.93	0.63	5.33	21,330.7	19.03	9.00	0.63	(0.22)	9.41	37,669.8	2.11	0.62	0.70	1.06	29,322.1	-	1,500,000	82,758.0	138,811.8	149,750.0	10,938.2	7.9%
GSd	Blandford-Blenheim	15,000	60	35%	23.85	3.63	0.91	0.65	5.19	335.3	28.73	8.90	0.65	(0.22)	9.33	588.7	2.11	0.62	0.7	1.061	338.0	-	15,000	827.6	1,584.7	1,754.3	169.6	10.7%
		43,164	133	45%	23.85	3.63	0.91	0.65	5.19	714.1	28.73	8.90	0.65	(0.22)	9.33	1,270.0	2.11	0.62	0.70	1.06	883.8	-	43,164	2,381.4	4,161.5	4,535.3	373.7	9.0%
		100,000	500	28%	23.85	3.63	0.91	0.65	5.19	2,618.9	28.73	8.90	0.65	(0.22)	9.33	4,695.1	2.11	0.62	0.70	1.06	2,477.2	-	100,000	5,517.2	11,321.5	12,689.5	1,368.0	12.1%
		400,000	1000	56%	23.85	3.63	0.91	0.65	5.19	5,213.9	28.73	8.90	0.65	(0.22)	9.33	9,361.4	2.11	0.62	0.70	1.06	7,670.0	-	400,000	22,068.8	36,293.4	39,100.2	2,806.8	7.7%
		1,000,000	3000	46%	23.85	3.63	0.91	0.65	5.19	15,593.9	28.73	8.90	0.65	(0.22)	9.33	28,026.8	2.11	0.62	0.70	1.06	20,294.3	-	1,000,000	55,172.0	95,158.2	103,493.2	8,335.0	8.8%
		1,500,000	4000	52%	23.85	3.63	0.91	0.65	5.19	20,783.9	28.73	8.90	0.65	(0.22)	9.33	37,359.5	2.11	0.62	0.70	1.06	29,322.1	-	1,500,000	82,758.0	138,265.0	149,439.7	11,174.7	8.1%

New Rate Class: GSd

Total Bill Impacts of Proposed Distribution Rates [new RTSR+TLF]: Threshold of 750 kWhs

Classes		Scenario			May 2007 Incl Rate Riders						May 2008 Incl Rate Riders						Non-Dx Compoent				Other Reg	Commodity Bands			Existing	New	$ Incr	% Incr
					Existing Dx Rates					Existing Dx	New Dx Rates					New Dx	RTSR new	WMSC	DRC	TLF new	New	Band 1	Band 2	New	Total Bill	Total Bill	Total Bill	Total Bill
																						-	5.2					
New Class	Old Class	kWh	kW	LF	SrChg [$/cust]	base [$/kW]	Rider1 [$/kW]	Rider2 [$/kW]	VarChg [$/kW]	[$/month]	SrChg [$/cust]	base [$/kW]	Rider2 [$/kW]	Rider3 [$/kW]	VarChg [$/kW]	[$/month]	$/kW	c/kWh	c/kWh		$	kWhs	kWhs	Total $	[$/month]	[$/month]	[$/month]	%
GSd	Blyth	15,000	60	35%	21.63	3.37	0.82	0.64	4.83	311.4	27.28	8.50	0.64	(0.22)	8.92	562.6	2.11	0.62	0.7	1.061	338.0	-	15,000	827.6	1,560.9	1,728.2	167.4	10.7%
		43,164	133	45%	21.63	3.37	0.82	0.64	4.83	664.0	27.28	8.50	0.64	(0.22)	8.92	1,214.0	2.11	0.62	0.70	1.06	883.8	-	43,164	2,381.4	4,111.4	4,479.3	367.9	8.9%
		100,000	500	28%	21.63	3.37	0.82	0.64	4.83	2,436.6	27.28	8.50	0.64	(0.22)	8.92	4,488.6	2.11	0.62	0.70	1.06	2,477.2	-	100,000	5,517.2	11,139.2	12,483.0	1,343.8	12.1%
		400,000	1000	56%	21.63	3.37	0.82	0.64	4.83	4,851.6	27.28	8.50	0.64	(0.22)	8.92	8,950.0	2.11	0.62	0.70	1.06	7,670.0	-	400,000	22,068.8	35,931.2	38,688.8	2,757.6	7.7%
		1,000,000	3000	46%	21.63	3.37	0.82	0.64	4.83	14,511.6	27.28	8.50	0.64	(0.22)	8.92	26,795.4	2.11	0.62	0.70	1.06	20,294.3	-	1,000,000	55,172.0	94,076.0	102,261.7	8,185.7	8.7%
		1,500,000	4000	52%	21.63	3.37	0.82	0.64	4.83	19,341.6	27.28	8.50	0.64	(0.22)	8.92	35,718.1	2.11	0.62	0.70	1.06	29,322.1	-	1,500,000	82,758.0	136,822.8	147,798.2	10,975.5	8.0%
GSd	Bobcaygeon	15,000	60	35%	23.20	4.35	0.58	0.27	5.20	335.2	28.89	9.22	0.27	(0.22)	9.28	585.5	2.11	0.62	0.7	1.061	338.0	-	15,000	827.6	1,584.6	1,751.0	166.4	10.5%
		43,164	133	45%	23.20	4.35	0.58	0.27	5.20	714.8	28.89	9.22	0.27	(0.22)	9.28	1,262.6	2.11	0.62	0.70	1.06	883.8	-	43,164	2,381.4	4,162.2	4,527.9	365.7	8.8%
		100,000	500	28%	23.20	4.35	0.58	0.27	5.20	2,623.2	28.89	9.22	0.27	(0.22)	9.28	4,667.0	2.11	0.62	0.70	1.06	2,477.2	-	100,000	5,517.2	11,325.8	12,661.4	1,335.6	11.8%
		400,000	1000	56%	23.20	4.35	0.58	0.27	5.20	5,223.2	28.89	9.22	0.27	(0.22)	9.28	9,305.2	2.11	0.62	0.70	1.06	7,670.0	-	400,000	22,068.8	36,302.8	39,044.0	2,741.2	7.6%
		1,000,000	3000	46%	23.20	4.35	0.58	0.27	5.20	15,623.2	28.89	9.22	0.27	(0.22)	9.28	27,857.7	2.11	0.62	0.70	1.06	20,294.3	-	1,000,000	55,172.0	95,187.6	103,324.1	8,136.5	8.5%
		1,500,000	4000	52%	23.20	4.35	0.58	0.27	5.20	20,823.2	28.89	9.22	0.27	(0.22)	9.28	37,134.0	2.11	0.62	0.70	1.06	29,322.1	-	1,500,000	82,758.0	138,304.3	149,214.2	10,909.8	7.9%
GSd	Brighton	15,000	60	35%	22.90	4.24	0.65	0.25	5.14	331.3	27.96	9.22	0.25	(0.22)	9.26	583.3	2.11	0.62	0.7	1.061	338.0	-	15,000	827.6	1,580.7	1,748.9	168.2	10.6%
		43,164	133	45%	22.90	4.24	0.65	0.25	5.14	706.5	27.96	9.22	0.25	(0.22)	9.26	1,259.0	2.11	0.62	0.70	1.06	883.8	-	43,164	2,381.4	4,153.9	4,524.3	370.4	8.9%
		100,000	500	28%	22.90	4.24	0.65	0.25	5.14	2,592.9	27.96	9.22	0.25	(0.22)	9.26	4,656.1	2.11	0.62	0.70	1.06	2,477.2	-	100,000	5,517.2	11,295.5	12,650.5	1,355.0	12.0%
		400,000	1000	56%	22.90	4.24	0.65	0.25	5.14	5,162.9	27.96	9.22	0.25	(0.22)	9.26	9,284.2	2.11	0.62	0.70	1.06	7,670.0	-	400,000	22,068.8	36,242.5	39,023.0	2,780.6	7.7%
		1,000,000	3000	46%	22.90	4.24	0.65	0.25	5.14	15,442.9	27.96	9.22	0.25	(0.22)	9.26	27,796.8	2.11	0.62	0.70	1.06	20,294.3	-	1,000,000	55,172.0	95,007.3	103,263.1	8,255.9	8.7%
		1,500,000	4000	52%	22.90	4.24	0.65	0.25	5.14	20,582.9	27.96	9.22	0.25	(0.22)	9.26	37,053.1	2.11	0.62	0.70	1.06	29,322.1	-	1,500,000	82,758.0	138,064.0	149,133.2	11,069.2	8.0%
UGd	Brockville	15,000	60	35%	21.65	2.49	0.41	0.12	3.02	202.9	22.89	6.70	0.12	(0.27)	6.55	415.7	2.68	0.62	0.7	1.061	374.3	-	15,000	827.6	1,452.3	1,617.6	165.3	11.4%
		43,164	133	45%	21.65	2.49	0.41	0.12	3.02	423.3	22.89	6.70	0.12	(0.27)	6.55	893.7	2.68	0.62	0.70	1.06	964.3	-	43,164	2,381.4	3,870.7	4,239.4	368.7	9.5%
		100,000	500	28%	21.65	2.49	0.41	0.12	3.02	1,531.7	22.89	6.70	0.12	(0.27)	6.55	3,296.4	2.68	0.62	0.70	1.06	2,779.6	-	100,000	5,517.2	10,234.3	11,593.2	1,359.0	13.3%
		400,000	1000	56%	21.65	2.49	0.41	0.12	3.02	3,041.7	22.89	6.70	0.12	(0.27)	6.55	6,570.0	2.68	0.62	0.70	1.06	8,274.8	-	400,000	22,068.8	34,121.2	36,913.6	2,792.3	8.2%
		1,000,000	3000	46%	21.65	2.49	0.41	0.12	3.02	9,081.7	22.89	6.70	0.12	(0.27)	6.55	19,664.3	2.68	0.62	0.70	1.06	22,108.6	-	1,000,000	55,172.0	88,646.0	96,944.9	8,298.9	9.4%
		1,500,000	4000	52%	21.65	2.49	0.41	0.12	3.02	12,101.7	22.89	6.70	0.12	(0.27)	6.55	26,211.4	2.68	0.62	0.70	1.06	31,741.2	-	1,500,000	82,758.0	129,582.8	140,710.6	11,127.8	8.6%
GSd	Caledon CH	15,000	60	35%	24.21	5.73	0.45	0.27	6.45	411.2	29.64	9.22	0.27	(0.22)	9.28	586.2	2.11	0.62	0.7	1.061	338.0	-	15,000	827.6	1,660.6	1,751.8	91.1	5.5%
		43,164	133	45%	24.21	5.73	0.45	0.27	6.45	882.1	29.64	9.22	0.27	(0.22)	9.28	1,263.4	2.11	0.62	0.70	1.06	883.8	-	43,164	2,381.4	4,329.5	4,528.7	199.2	4.6%
		100,000	500	28%	24.21	5.73	0.45	0.27	6.45	3,249.2	29.64	9.22	0.27	(0.22)	9.28	4,667.8	2.11	0.62	0.70	1.06	2,477.2	-	100,000	5,517.2	11,951.8	12,662.2	710.3	5.9%
		400,000	1000	56%	24.21	5.73	0.45	0.27	6.45	6,474.2	29.64	9.22	0.27	(0.22)	9.28	9,305.9	2.11	0.62	0.70	1.06	7,670.0	-	400,000	22,068.8	37,553.8	39,044.7	1,490.9	4.0%
		1,000,000	3000	46%	24.21	5.73	0.45	0.27	6.45	19,374.2	29.64	9.22	0.27	(0.22)	9.28	27,858.5	2.11	0.62	0.70	1.06	20,294.3	-	1,000,000	55,172.0	98,938.6	103,324.8	4,386.2	4.4%
		1,500,000	4000	52%	24.21	5.73	0.45	0.27	6.45	25,824.2	29.64	9.22	0.27	(0.22)	9.28	37,134.8	2.11	0.62	0.70	1.06	29,322.1	-	1,500,000	82,758.0	143,305.3	149,214.9	5,909.6	4.1%

New Rate Class: GSd

Total Bill Impacts of Proposed Distribution Rates [new RTSR+TLF]: Threshold of 750 kWhs

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Classes		Scenario			May 2007 Incl Rate Riders						May 2008 Incl Rate Riders						Non-Dx Compoent				Other Reg	Commodity Bands			Existing	New	$ Incr	% Incr
					Existing Dx Rates					Existing Dx	New Dx Rates					New Dx	RTSR new	WMSC	DRC	TLF new	New	Band 1	Band 2	New	Total Bill	Total Bill	Total Bill	Total Bill
																						-	5.2					
New Class	Old Class	kWh	kW	LF	SrChg [$/cust]	base [$/kW]	Rider1 [$/kW]	Rider2 [$/kW]	VarChg [$/kW]	[$/month]	SrChg [$/cust]	base [$/kW]	Rider2 [$/kW]	Rider3 [$/kW]	VarChg [$/kW]	[$/month]	$/kW	c/kWh	c/kWh		$	kWhs	kWhs	Total $	[$/month]	[$/month]	[$/month]	%
GSd	Caledon OH	15,000	60	35%	25.56	5.35	0.51	0.24	6.10	391.6	30.30	9.22	0.24	(0.22)	9.25	585.1	2.11	0.62	0.7	1.061	338.0	-	15,000	827.6	1,641.0	1,750.7	109.7	6.7%
		43,164	133	45%	25.56	5.35	0.51	0.24	6.10	836.9	30.30	9.22	0.24	(0.22)	9.25	1,260.1	2.11	0.62	0.70	1.06	883.8	-	43,164	2,381.4	4,284.3	4,525.3	241.1	5.6%
		100,000	500	28%	25.56	5.35	0.51	0.24	6.10	3,075.6	30.30	9.22	0.24	(0.22)	9.25	4,653.4	2.11	0.62	0.70	1.06	2,477.2	-	100,000	5,517.2	11,778.2	12,647.8	869.7	7.4%
		400,000	1000	56%	25.56	5.35	0.51	0.24	6.10	6,125.6	30.30	9.22	0.24	(0.22)	9.25	9,276.6	2.11	0.62	0.70	1.06	7,670.0	-	400,000	22,068.8	37,205.1	39,015.4	1,810.2	4.9%
		1,000,000	3000	46%	25.56	5.35	0.51	0.24	6.10	18,325.6	30.30	9.22	0.24	(0.22)	9.25	27,769.1	2.11	0.62	0.70	1.06	20,294.3	-	1,000,000	55,172.0	97,889.9	103,235.5	5,345.6	5.5%
		1,500,000	4000	52%	25.56	5.35	0.51	0.24	6.10	24,425.6	30.30	9.22	0.24	(0.22)	9.25	37,015.4	2.11	0.62	0.70	1.06	29,322.1	-	1,500,000	82,758.0	141,906.7	149,095.6	7,188.9	5.1%
GSd	Campbellford-Seymou	15,000	60	35%	16.19	3.77	0.53	0.17	4.47	284.4	23.64	8.50	0.17	(0.22)	8.45	530.8	2.11	0.62	0.7	1.061	338.0	-	15,000	827.6	1,533.8	1,696.4	162.6	10.6%
		43,164	133	45%	16.19	3.77	0.53	0.17	4.47	610.7	23.64	8.50	0.17	(0.22)	8.45	1,147.8	2.11	0.62	0.70	1.06	883.8	-	43,164	2,381.4	4,058.1	4,413.1	355.0	8.7%
		100,000	500	28%	16.19	3.77	0.53	0.17	4.47	2,251.2	23.64	8.50	0.17	(0.22)	8.45	4,250.0	2.11	0.62	0.70	1.06	2,477.2	-	100,000	5,517.2	10,953.8	12,244.4	1,290.6	11.8%
		400,000	1000	56%	16.19	3.77	0.53	0.17	4.47	4,486.2	23.64	8.50	0.17	(0.22)	8.45	8,476.3	2.11	0.62	0.70	1.06	7,670.0	-	400,000	22,068.8	35,565.8	38,215.1	2,649.4	7.4%
		1,000,000	3000	46%	16.19	3.77	0.53	0.17	4.47	13,426.2	23.64	8.50	0.17	(0.22)	8.45	25,381.8	2.11	0.62	0.70	1.06	20,294.3	-	1,000,000	55,172.0	92,990.6	100,848.1	7,857.5	8.4%
		1,500,000	4000	52%	16.19	3.77	0.53	0.17	4.47	17,896.2	23.64	8.50	0.17	(0.22)	8.45	33,834.5	2.11	0.62	0.70	1.06	29,322.1	-	1,500,000	82,758.0	135,377.3	145,914.6	10,537.3	7.8%
UGd	Carleton Place	15,000	60	35%	23.65	5.31	0.42	0.22	5.95	380.7	24.39	7.33	0.22	(0.27)	7.28	461.2	2.68	0.62	0.7	1.061	374.3	-	15,000	827.6	1,630.1	1,663.1	33.0	2.0%
		43,164	133	45%	23.65	5.31	0.42	0.22	5.95	815.0	24.39	7.33	0.22	(0.27)	7.28	992.7	2.68	0.62	0.70	1.06	964.3	-	43,164	2,381.4	4,262.4	4,338.4	76.0	1.8%
		100,000	500	28%	23.65	5.31	0.42	0.22	5.95	2,998.7	24.39	7.33	0.22	(0.27)	7.28	3,664.5	2.68	0.62	0.70	1.06	2,779.6	-	100,000	5,517.2	11,701.3	11,961.2	260.0	2.2%
		400,000	1000	56%	23.65	5.31	0.42	0.22	5.95	5,973.7	24.39	7.33	0.22	(0.27)	7.28	7,304.6	2.68	0.62	0.70	1.06	8,274.8	-	400,000	22,068.8	37,053.2	37,648.1	594.9	1.6%
		1,000,000	3000	46%	23.65	5.31	0.42	0.22	5.95	17,873.7	24.39	7.33	0.22	(0.27)	7.28	21,865.0	2.68	0.62	0.70	1.06	22,108.6	-	1,000,000	55,172.0	97,438.0	99,145.6	1,707.6	1.8%
		1,500,000	4000	52%	23.65	5.31	0.42	0.22	5.95	23,823.7	24.39	7.33	0.22	(0.27)	7.28	29,145.2	2.68	0.62	0.70	1.06	31,741.2	-	1,500,000	82,758.0	141,304.8	143,644.4	2,339.6	1.7%
GSd	Cavan-Millbrook-North	15,000	60	35%	22.28	4.67	1.06	0.81	6.54	414.7	28.12	9.22	0.81	(0.22)	9.82	617.1	2.11	0.62	0.7	1.061	338.0	-	15,000	827.6	1,664.1	1,782.7	118.6	7.1%
		43,164	133	45%	22.28	4.67	1.06	0.81	6.54	892.1	28.12	9.22	0.81	(0.22)	9.82	1,333.7	2.11	0.62	0.70	1.06	883.8	-	43,164	2,381.4	4,339.5	4,599.0	259.5	6.0%
		100,000	500	28%	22.28	4.67	1.06	0.81	6.54	3,292.3	28.12	9.22	0.81	(0.22)	9.82	4,936.3	2.11	0.62	0.70	1.06	2,477.2	-	100,000	5,517.2	11,994.9	12,930.6	935.8	7.8%
		400,000	1000	56%	22.28	4.67	1.06	0.81	6.54	6,562.3	28.12	9.22	0.81	(0.22)	9.82	9,844.4	2.11	0.62	0.70	1.06	7,670.0	-	400,000	22,068.8	37,641.9	39,583.2	1,941.3	5.2%
		1,000,000	3000	46%	22.28	4.67	1.06	0.81	6.54	19,642.3	28.12	9.22	0.81	(0.22)	9.82	29,477.0	2.11	0.62	0.70	1.06	20,294.3	-	1,000,000	55,172.0	99,206.6	104,943.3	5,736.7	5.8%
		1,500,000	4000	52%	22.28	4.67	1.06	0.81	6.54	26,182.3	28.12	9.22	0.81	(0.22)	9.82	39,293.3	2.11	0.62	0.70	1.06	29,322.1	-	1,500,000	82,758.0	143,663.4	151,373.4	7,710.0	5.4%
GSd	Centre Hastings	15,000	60	35%	18.38	3.07	0.45	0.20	3.72	241.6	25.09	7.70	0.20	(0.22)	7.68	486.1	2.11	0.62	0.7	1.061	338.0	-	15,000	827.6	1,491.0	1,651.6	160.6	10.8%
		43,164	133	45%	18.38	3.07	0.45	0.20	3.72	513.1	25.09	7.70	0.20	(0.22)	7.68	1,046.9	2.11	0.62	0.70	1.06	883.8	-	43,164	2,381.4	3,960.5	4,312.2	351.6	8.9%
		100,000	500	28%	18.38	3.07	0.45	0.20	3.72	1,878.4	25.09	7.70	0.20	(0.22)	7.68	3,866.4	2.11	0.62	0.70	1.06	2,477.2	-	100,000	5,517.2	10,581.0	11,860.8	1,279.8	12.1%
		400,000	1000	56%	18.38	3.07	0.45	0.20	3.72	3,738.4	25.09	7.70	0.20	(0.22)	7.68	7,707.8	2.11	0.62	0.70	1.06	7,670.0	-	400,000	22,068.8	34,818.0	37,446.6	2,628.6	7.5%
		1,000,000	3000	46%	18.38	3.07	0.45	0.20	3.72	11,178.4	25.09	7.70	0.20	(0.22)	7.68	23,073.2	2.11	0.62	0.70	1.06	20,294.3	-	1,000,000	55,172.0	90,742.7	98,539.5	7,796.8	8.6%
		1,500,000	4000	52%	18.38	3.07	0.45	0.20	3.72	14,898.4	25.09	7.70	0.20	(0.22)	7.68	30,755.9	2.11	0.62	0.70	1.06	29,322.1	-	1,500,000	82,758.0	132,379.5	142,836.0	10,456.5	7.9%

New Rate Class: GSd

Total Bill Impacts of Proposed Distribution Rates [new RTSR+TLF]: Threshold of 750 kWhs

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Classes		Scenario			May 2007 Incl Rate Riders						May 2008 Incl Rate Riders						Non-Dx Compoent				Other Reg	Commodity Bands			Existing	New	$ Incr	% Incr
					Existing Dx Rates					Existing Dx	New Dx Rates					New Dx	RTSR new	WMSC	DRC	TLF new	New	Band 1	Band 2	New	Total Bill	Total Bill	Total Bill	Total Bill
																						-	5.2					
New Class	Old Class	kWh	kW	LF	SrChg [$/cust]	base [$/kW]	Rider1 [$/kW]	Rider2 [$/kW]	VarChg [$/kW]	[$/month]	SrChg [$/cust]	base [$/kW]	Rider2 [$/kW]	Rider3 [$/kW]	VarChg [$/kW]	[$/month]	$/kW	c/kWh	c/kWh		$	kWhs	kWhs	Total $	[$/month]	[$/month]	[$/month]	%
GSd	Chalk River	15,000	60	35%	21.33	5.70	1.23	1.07	8.00	501.3	27.36	9.22	1.07	(0.22)	10.08	631.9	2.11	0.62	0.7	1.061	338.0	-	15,000	827.6	1,750.8	1,797.5	46.7	2.7%
		43,164	133	45%	21.33	5.70	1.23	1.07	8.00	1,085.3	27.36	9.22	1.07	(0.22)	10.08	1,367.5	2.11	0.62	0.70	1.06	883.8	-	43,164	2,381.4	4,532.7	4,632.8	100.0	2.2%
		100,000	500	28%	21.33	5.70	1.23	1.07	8.00	4,021.3	27.36	9.22	1.07	(0.22)	10.08	5,065.5	2.11	0.62	0.70	1.06	2,477.2	-	100,000	5,517.2	12,723.9	13,059.9	335.9	2.6%
		400,000	1000	56%	21.33	5.70	1.23	1.07	8.00	8,021.3	27.36	9.22	1.07	(0.22)	10.08	10,103.6	2.11	0.62	0.70	1.06	7,670.0	-	400,000	22,068.8	39,100.9	39,842.4	741.5	1.9%
		1,000,000	3000	46%	21.33	5.70	1.23	1.07	8.00	24,021.3	27.36	9.22	1.07	(0.22)	10.08	30,256.2	2.11	0.62	0.70	1.06	20,294.3	-	1,000,000	55,172.0	103,585.7	105,722.5	2,136.8	2.1%
		1,500,000	4000	52%	21.33	5.70	1.23	1.07	8.00	32,021.3	27.36	9.22	1.07	(0.22)	10.08	40,332.5	2.11	0.62	0.70	1.06	29,322.1	-	1,500,000	82,758.0	149,502.5	152,412.6	2,910.2	1.9%
GSd	Champlain	15,000	60	35%	20.59	2.88	0.84	0.49	4.21	273.2	26.54	8.00	0.49	(0.22)	8.27	522.9	2.11	0.62	0.7	1.061	338.0	-	15,000	827.6	1,522.6	1,688.5	165.9	10.9%
		43,164	133	45%	20.59	2.88	0.84	0.49	4.21	580.5	26.54	8.00	0.49	(0.22)	8.27	1,126.8	2.11	0.62	0.70	1.06	883.8	-	43,164	2,381.4	4,027.9	4,392.1	364.2	9.0%
		100,000	500	28%	20.59	2.88	0.84	0.49	4.21	2,125.6	26.54	8.00	0.49	(0.22)	8.27	4,162.9	2.11	0.62	0.70	1.06	2,477.2	-	100,000	5,517.2	10,828.2	12,157.3	1,329.1	12.3%
		400,000	1000	56%	20.59	2.88	0.84	0.49	4.21	4,230.6	26.54	8.00	0.49	(0.22)	8.27	8,299.2	2.11	0.62	0.70	1.06	7,670.0	-	400,000	22,068.8	35,310.2	38,038.0	2,727.9	7.7%
		1,000,000	3000	46%	20.59	2.88	0.84	0.49	4.21	12,650.6	26.54	8.00	0.49	(0.22)	8.27	24,844.7	2.11	0.62	0.70	1.06	20,294.3	-	1,000,000	55,172.0	92,215.0	100,311.0	8,096.0	8.8%
		1,500,000	4000	52%	20.59	2.88	0.84	0.49	4.21	16,860.6	26.54	8.00	0.49	(0.22)	8.27	33,117.4	2.11	0.62	0.70	1.06	29,322.1	-	1,500,000	82,758.0	134,341.7	145,197.5	10,855.8	8.1%
GSd	Cobden	15,000	60	35%	21.93	6.49	1.16	0.90	8.55	534.9	27.21	9.22	0.90	(0.22)	9.91	621.6	2.11	0.62	0.7	1.061	338.0	-	15,000	827.6	1,784.4	1,787.2	2.8	0.2%
		43,164	133	45%	21.93	6.49	1.16	0.90	8.55	1,159.1	27.21	9.22	0.90	(0.22)	9.91	1,344.7	2.11	0.62	0.70	1.06	883.8	-	43,164	2,381.4	4,606.5	4,610.0	3.5	0.1%
		100,000	500	28%	21.93	6.49	1.16	0.90	8.55	4,296.9	27.21	9.22	0.90	(0.22)	9.91	4,980.3	2.11	0.62	0.70	1.06	2,477.2	-	100,000	5,517.2	12,999.5	12,974.7	(24.8)	-0.2%
		400,000	1000	56%	21.93	6.49	1.16	0.90	8.55	8,571.9	27.21	9.22	0.90	(0.22)	9.91	9,933.5	2.11	0.62	0.70	1.06	7,670.0	-	400,000	22,068.8	39,651.5	39,672.3	20.8	0.1%
		1,000,000	3000	46%	21.93	6.49	1.16	0.90	8.55	25,671.9	27.21	9.22	0.90	(0.22)	9.91	29,746.1	2.11	0.62	0.70	1.06	20,294.3	-	1,000,000	55,172.0	105,236.3	105,212.4	(23.9)	0.0%
		1,500,000	4000	52%	21.93	6.49	1.16	0.90	8.55	34,221.9	27.21	9.22	0.90	(0.22)	9.91	39,652.3	2.11	0.62	0.70	1.06	29,322.1	-	1,500,000	82,758.0	151,703.1	151,732.5	29.4	0.0%
GSd	Deep River	15,000	60	35%	23.94	7.18	0.46	0.46	8.10	509.9	28.70	9.22	0.46	(0.22)	9.47	596.7	2.11	0.62	0.7	1.061	338.0	-	15,000	827.6	1,759.4	1,762.3	2.9	0.2%
		43,164	133	45%	23.94	7.18	0.46	0.46	8.10	1,101.2	28.70	9.22	0.46	(0.22)	9.47	1,287.7	2.11	0.62	0.70	1.06	883.8	-	43,164	2,381.4	4,548.6	4,553.0	4.4	0.1%
		100,000	500	28%	23.94	7.18	0.46	0.46	8.10	4,073.9	28.70	9.22	0.46	(0.22)	9.47	4,761.8	2.11	0.62	0.70	1.06	2,477.2	-	100,000	5,517.2	12,776.5	12,756.2	(20.3)	-0.2%
		400,000	1000	56%	23.94	7.18	0.46	0.46	8.10	8,123.9	28.70	9.22	0.46	(0.22)	9.47	9,495.0	2.11	0.62	0.70	1.06	7,670.0	-	400,000	22,068.8	39,203.5	39,233.8	30.3	0.1%
		1,000,000	3000	46%	23.94	7.18	0.46	0.46	8.10	24,323.9	28.70	9.22	0.46	(0.22)	9.47	28,427.6	2.11	0.62	0.70	1.06	20,294.3	-	1,000,000	55,172.0	103,888.3	103,893.9	5.6	0.0%
		1,500,000	4000	52%	23.94	7.18	0.46	0.46	8.10	32,423.9	28.70	9.22	0.46	(0.22)	9.47	37,893.8	2.11	0.62	0.70	1.06	29,322.1	-	1,500,000	82,758.0	149,905.1	149,974.0	68.9	0.0%
GSd	Deseronto	15,000	60	35%	10.14	3.85	0.41	0.14	4.40	274.1	19.15	8.50	0.14	(0.22)	8.42	524.5	2.11	0.62	0.7	1.061	338.0	-	15,000	827.6	1,523.6	1,690.1	166.5	10.9%
		43,164	133	45%	10.14	3.85	0.41	0.14	4.40	595.3	19.15	8.50	0.14	(0.22)	8.42	1,139.4	2.11	0.62	0.70	1.06	883.8	-	43,164	2,381.4	4,042.7	4,404.7	361.9	9.0%
		100,000	500	28%	10.14	3.85	0.41	0.14	4.40	2,210.1	19.15	8.50	0.14	(0.22)	8.42	4,230.5	2.11	0.62	0.70	1.06	2,477.2	-	100,000	5,517.2	10,912.7	12,224.9	1,312.1	12.0%
		400,000	1000	56%	10.14	3.85	0.41	0.14	4.40	4,410.1	19.15	8.50	0.14	(0.22)	8.42	8,441.9	2.11	0.62	0.70	1.06	7,670.0	-	400,000	22,068.8	35,489.7	38,180.6	2,690.9	7.6%
		1,000,000	3000	46%	10.14	3.85	0.41	0.14	4.40	13,210.1	19.15	8.50	0.14	(0.22)	8.42	25,287.3	2.11	0.62	0.70	1.06	20,294.3	-	1,000,000	55,172.0	92,774.5	100,753.6	7,979.1	8.6%
		1,500,000	4000	52%	10.14	3.85	0.41	0.14	4.40	17,610.1	19.15	8.50	0.14	(0.22)	8.42	33,710.0	2.11	0.62	0.70	1.06	29,322.1	-	1,500,000	82,758.0	135,091.3	145,790.1	10,698.8	7.9%

New Rate Class: GSd

Total Bill Impacts of Proposed Distribution Rates [new RTSR+TLF]: Threshold of 750 kWhs

Classes		Scenario			May 2007 Incl Rate Riders						May 2008 Incl Rate Riders						Non-Dx Compoent				Other Reg	Commodity Bands			Existing	New	$ Incr	% Incr
					Existing Dx Rates					Existing Dx	New Dx Rates					New Dx	RTSR new	WMSC	DRC	TLF new	New	Band 1	Band 2	New	Total Bill	Total Bill	Total Bill	Total Bill
																						-	5.2					
New Class	Old Class	kWh	kW	LF	SrChg [$/cust]	base [$/kW]	Rider1 [$/kW]	Rider2 [$/kW]	VarChg [$/kW]	[$/month]	SrChg [$/cust]	base [$/kW]	Rider2 [$/kW]	Rider3 [$/kW]	VarChg [$/kW]	[$/month]	$/kW	c/kWh	c/kWh		$	kWhs	kWhs	Total $	[$/month]	[$/month]	[$/month]	%
UGd	**Dryden**	15,000	60	35%	**19.11**	**3.29**	**0.38**	**0.13**	**3.80**	247.1	**21.52**	**7.33**	**0.13**	**(0.27)**	**7.19**	452.9	**2.68**	0.62	0.7	**1.061**	374.3	-	15,000	827.6	1,496.5	1,654.8	158.3	10.6%
		43,164	133	45%	19.11	3.29	0.38	0.13	3.80	524.5	21.52	7.33	0.13	(0.27)	7.19	977.8	2.68	0.62	0.70	1.06	964.3	-	43,164	2,381.4	3,971.9	4,323.5	351.6	8.9%
		100,000	500	28%	19.11	3.29	0.38	0.13	3.80	1,919.1	21.52	7.33	0.13	(0.27)	7.19	3,616.6	2.68	0.62	0.70	1.06	2,779.6	-	100,000	5,517.2	10,621.7	11,913.4	1,291.7	12.2%
		400,000	1000	56%	19.11	3.29	0.38	0.13	3.80	3,819.1	21.52	7.33	0.13	(0.27)	7.19	7,211.7	2.68	0.62	0.70	1.06	8,274.8	-	400,000	22,068.8	34,898.7	37,555.3	2,656.6	7.6%
		1,000,000	3000	46%	19.11	3.29	0.38	0.13	3.80	11,419.1	21.52	7.33	0.13	(0.27)	7.19	21,592.1	2.68	0.62	0.70	1.06	22,108.6	-	1,000,000	55,172.0	90,983.5	98,872.8	7,889.3	8.7%
		1,500,000	4000	52%	19.11	3.29	0.38	0.13	3.80	15,219.1	21.52	7.33	0.13	(0.27)	7.19	28,782.3	2.68	0.62	0.70	1.06	31,741.2	-	1,500,000	82,758.0	132,700.2	143,281.6	10,581.3	8.0%
GSd	**Dundalk**	15,000	60	35%	**23.56**	**5.17**	**0.74**	**0.28**	**6.19**	395.0	**28.80**	**9.22**	**0.28**	**(0.22)**	**9.29**	586.0	**2.11**	0.62	0.7	**1.061**	338.0	-	15,000	827.6	1,644.4	1,751.6	107.2	6.5%
		43,164	133	45%	23.56	5.17	0.74	0.28	6.19	846.8	28.80	9.22	0.28	(0.22)	9.29	1,263.9	2.11	0.62	0.70	1.06	883.8	-	43,164	2,381.4	4,294.2	4,529.2	234.9	5.5%
		100,000	500	28%	23.56	5.17	0.74	0.28	6.19	3,118.6	28.80	9.22	0.28	(0.22)	9.29	4,671.9	2.11	0.62	0.70	1.06	2,477.2	-	100,000	5,517.2	11,821.2	12,666.3	845.2	7.1%
		400,000	1000	56%	23.56	5.17	0.74	0.28	6.19	6,213.6	28.80	9.22	0.28	(0.22)	9.29	9,315.1	2.11	0.62	0.70	1.06	7,670.0	-	400,000	22,068.8	37,293.1	39,053.9	1,760.7	4.7%
		1,000,000	3000	46%	23.56	5.17	0.74	0.28	6.19	18,593.6	28.80	9.22	0.28	(0.22)	9.29	27,887.6	2.11	0.62	0.70	1.06	20,294.3	-	1,000,000	55,172.0	98,157.9	103,354.0	5,196.1	5.3%
		1,500,000	4000	52%	23.56	5.17	0.74	0.28	6.19	24,783.6	28.80	9.22	0.28	(0.22)	9.29	37,173.9	2.11	0.62	0.70	1.06	29,322.1	-	1,500,000	82,758.0	142,264.7	149,254.1	6,989.4	4.9%
GSd	**Durham**	15,000	60	35%	**24.12**	**4.31**	**0.48**	**0.18**	**4.97**	322.3	**29.66**	**9.22**	**0.18**	**(0.22)**	**9.19**	580.8	**2.11**	0.62	0.7	**1.061**	338.0	-	15,000	827.6	1,571.7	1,746.4	174.7	11.1%
		43,164	133	45%	24.12	4.31	0.48	0.18	4.97	685.1	29.66	9.22	0.18	(0.22)	9.19	1,251.4	2.11	0.62	0.70	1.06	883.8	-	43,164	2,381.4	4,132.5	4,516.7	384.2	9.3%
		100,000	500	28%	24.12	4.31	0.48	0.18	4.97	2,509.1	29.66	9.22	0.18	(0.22)	9.19	4,622.8	2.11	0.62	0.70	1.06	2,477.2	-	100,000	5,517.2	11,211.7	12,617.2	1,405.5	12.5%
		400,000	1000	56%	24.12	4.31	0.48	0.18	4.97	4,994.1	29.66	9.22	0.18	(0.22)	9.19	9,215.9	2.11	0.62	0.70	1.06	7,670.0	-	400,000	22,068.8	36,073.7	38,954.7	2,881.0	8.0%
		1,000,000	3000	46%	24.12	4.31	0.48	0.18	4.97	14,934.1	29.66	9.22	0.18	(0.22)	9.19	27,588.5	2.11	0.62	0.70	1.06	20,294.3	-	1,000,000	55,172.0	94,498.5	103,054.8	8,556.4	9.1%
		1,500,000	4000	52%	24.12	4.31	0.48	0.18	4.97	19,904.1	29.66	9.22	0.18	(0.22)	9.19	36,774.8	2.11	0.62	0.70	1.06	29,322.1	-	1,500,000	82,758.0	137,385.3	148,854.9	11,469.7	8.3%
GSd	**Eganville**	15,000	60	35%	**21.35**	**7.35**	**0.55**	**0.37**	**8.27**	517.6	**27.35**	**9.22**	**0.37**	**(0.22)**	**9.38**	589.9	**2.11**	0.62	0.7	**1.061**	338.0	-	15,000	827.6	1,767.0	1,755.5	(11.5)	-0.6%
		43,164	133	45%	21.35	7.35	0.55	0.37	8.27	1,121.3	27.35	9.22	0.37	(0.22)	9.38	1,274.4	2.11	0.62	0.70	1.06	883.8	-	43,164	2,381.4	4,568.7	4,539.7	(29.0)	-0.6%
		100,000	500	28%	21.35	7.35	0.55	0.37	8.27	4,156.4	27.35	9.22	0.37	(0.22)	9.38	4,715.5	2.11	0.62	0.70	1.06	2,477.2	-	100,000	5,517.2	12,859.0	12,709.9	(149.1)	-1.2%
		400,000	1000	56%	21.35	7.35	0.55	0.37	8.27	8,291.4	27.35	9.22	0.37	(0.22)	9.38	9,403.6	2.11	0.62	0.70	1.06	7,670.0	-	400,000	22,068.8	39,370.9	39,142.4	(228.5)	-0.6%
		1,000,000	3000	46%	21.35	7.35	0.55	0.37	8.27	24,831.4	27.35	9.22	0.37	(0.22)	9.38	28,156.2	2.11	0.62	0.70	1.06	20,294.3	-	1,000,000	55,172.0	104,395.7	103,622.5	(773.2)	-0.7%
		1,500,000	4000	52%	21.35	7.35	0.55	0.37	8.27	33,101.4	27.35	9.22	0.37	(0.22)	9.38	37,532.5	2.11	0.62	0.70	1.06	29,322.1	-	1,500,000	82,758.0	150,582.5	149,612.6	(969.9)	-0.6%
GSd	**Erin**	15,000	60	35%	**40.38**	**2.36**	**0.59**	**0.25**	**3.20**	232.4	**41.59**	**7.20**	**0.25**	**(0.22)**	**7.23**	475.6	**2.11**	0.62	0.7	**1.061**	338.0	-	15,000	827.6	1,481.8	1,641.1	159.3	10.8%
		43,164	133	45%	40.38	2.36	0.59	0.25	3.20	466.0	41.59	7.20	0.25	(0.22)	7.23	1,003.5	2.11	0.62	0.70	1.06	883.8	-	43,164	2,381.4	3,913.4	4,268.8	355.4	9.1%
		100,000	500	28%	40.38	2.36	0.59	0.25	3.20	1,640.4	41.59	7.20	0.25	(0.22)	7.23	3,657.9	2.11	0.62	0.70	1.06	2,477.2	-	100,000	5,517.2	10,343.0	11,652.3	1,309.3	12.7%
		400,000	1000	56%	40.38	2.36	0.59	0.25	3.20	3,240.4	41.59	7.20	0.25	(0.22)	7.23	7,274.3	2.11	0.62	0.70	1.06	7,670.0	-	400,000	22,068.8	34,320.0	37,013.1	2,693.1	7.8%
		1,000,000	3000	46%	40.38	2.36	0.59	0.25	3.20	9,640.4	41.59	7.20	0.25	(0.22)	7.23	21,739.7	2.11	0.62	0.70	1.06	20,294.3	-	1,000,000	55,172.0	89,204.7	97,206.0	8,001.3	9.0%
		1,500,000	4000	52%	40.38	2.36	0.59	0.25	3.20	12,840.4	41.59	7.20	0.25	(0.22)	7.23	28,972.4	2.11	0.62	0.70	1.06	29,322.1	-	1,500,000	82,758.0	130,321.5	141,052.5	10,731.0	8.2%

New Rate Class: GSd

Total Bill Impacts of Proposed Distribution Rates [new RTSR+TLF]: Threshold of 750 kWhs

Classes		Scenario			May 2007 Incl Rate Riders						May 2008 Incl Rate Riders						Non-Dx Compoent				Other Reg	Commodity Bands			Existing	New	$ Incr	% Incr
					Existing Dx Rates					Existing Dx	New Dx Rates					New Dx	RTSR new	WMSC	DRC	TLF new	New	Band 1	Band 2	New	Total Bill	Total Bill	Total Bill	Total Bill
																						-	5.2					
New Class	Old Class	kWh	kW	LF	SrChg [$/cust]	base [$/kW]	Rider1 [$/kW]	Rider2 [$/kW]	VarChg [$/kW]	[$/month]	SrChg [$/cust]	base [$/kW]	Rider2 [$/kW]	Rider3 [$/kW]	VarChg [$/kW]	[$/month]	$/kW	c/kWh	c/kWh		$	kWhs	kWhs	Total $	[$/month]	[$/month]	[$/month]	%
GSd	**Exeter**	15,000	60	35%	**11.36**	**4.11**	**0.49**	**0.18**	**4.78**	298.2	**19.85**	**8.95**	**0.18**	**(0.22)**	**8.91**	554.6	**2.11**	0.62	0.7	**1.061**	338.0	-	15,000	827.6	1,547.6	1,720.2	172.6	11.2%
		43,164	133	45%	11.36	4.11	0.49	0.18	4.78	647.1	19.85	8.95	0.18	(0.22)	8.91	1,205.2	2.11	0.62	0.70	1.06	883.8	-	43,164	2,381.4	4,094.5	4,470.5	376.0	9.2%
		100,000	500	28%	11.36	4.11	0.49	0.18	4.78	2,401.4	19.85	8.95	0.18	(0.22)	8.91	4,476.2	2.11	0.62	0.70	1.06	2,477.2	-	100,000	5,517.2	11,104.0	12,470.6	1,366.6	12.3%
		400,000	1000	56%	11.36	4.11	0.49	0.18	4.78	4,791.4	19.85	8.95	0.18	(0.22)	8.91	8,932.6	2.11	0.62	0.70	1.06	7,670.0	-	400,000	22,068.8	35,870.9	38,671.3	2,800.4	7.8%
		1,000,000	3000	46%	11.36	4.11	0.49	0.18	4.78	14,351.4	19.85	8.95	0.18	(0.22)	8.91	26,758.0	2.11	0.62	0.70	1.06	20,294.3	-	1,000,000	55,172.0	93,915.7	102,224.3	8,308.6	8.8%
		1,500,000	4000	52%	11.36	4.11	0.49	0.18	4.78	19,131.4	19.85	8.95	0.18	(0.22)	8.91	35,670.7	2.11	0.62	0.70	1.06	29,322.1	-	1,500,000	82,758.0	136,612.5	147,750.8	11,138.3	8.2%
GSd	**Fenelon Falls**	15,000	60	35%	**19.81**	**3.02**	**0.47**	**0.24**	**3.73**	243.6	**25.74**	**7.75**	**0.24**	**(0.22)**	**7.77**	492.1	**2.11**	0.62	0.7	**1.061**	338.0	-	15,000	827.6	1,493.0	1,657.7	164.6	11.0%
		43,164	133	45%	19.81	3.02	0.47	0.24	3.73	515.9	25.74	7.75	0.24	(0.22)	7.77	1,059.5	2.11	0.62	0.70	1.06	883.8	-	43,164	2,381.4	3,963.3	4,324.8	361.5	9.1%
		100,000	500	28%	19.81	3.02	0.47	0.24	3.73	1,884.8	25.74	7.75	0.24	(0.22)	7.77	3,912.1	2.11	0.62	0.70	1.06	2,477.2	-	100,000	5,517.2	10,587.4	11,906.5	1,319.1	12.5%
		400,000	1000	56%	19.81	3.02	0.47	0.24	3.73	3,749.8	25.74	7.75	0.24	(0.22)	7.77	7,798.4	2.11	0.62	0.70	1.06	7,670.0	-	400,000	22,068.8	34,829.4	37,537.2	2,707.8	7.8%
		1,000,000	3000	46%	19.81	3.02	0.47	0.24	3.73	11,209.8	25.74	7.75	0.24	(0.22)	7.77	23,343.8	2.11	0.62	0.70	1.06	20,294.3	-	1,000,000	55,172.0	90,774.2	98,810.2	8,036.0	8.9%
		1,500,000	4000	52%	19.81	3.02	0.47	0.24	3.73	14,939.8	25.74	7.75	0.24	(0.22)	7.77	31,116.5	2.11	0.62	0.70	1.06	29,322.1	-	1,500,000	82,758.0	132,420.9	143,196.7	10,775.7	8.1%
GSd	**Forest**	15,000	60	35%	**24.91**	**3.74**	**0.50**	**0.20**	**4.44**	291.3	**29.46**	**8.50**	**0.20**	**(0.22)**	**8.48**	538.4	**2.11**	0.62	0.7	**1.061**	338.0	-	15,000	827.6	1,540.7	1,704.0	163.3	10.6%
		43,164	133	45%	24.91	3.74	0.50	0.20	4.44	615.4	29.46	8.50	0.20	(0.22)	8.48	1,157.7	2.11	0.62	0.70	1.06	883.8	-	43,164	2,381.4	4,062.8	4,422.9	360.1	8.9%
		100,000	500	28%	24.91	3.74	0.50	0.20	4.44	2,244.9	29.46	8.50	0.20	(0.22)	8.48	4,270.8	2.11	0.62	0.70	1.06	2,477.2	-	100,000	5,517.2	10,947.5	12,265.2	1,317.7	12.0%
		400,000	1000	56%	24.91	3.74	0.50	0.20	4.44	4,464.9	29.46	8.50	0.20	(0.22)	8.48	8,512.2	2.11	0.62	0.70	1.06	7,670.0	-	400,000	22,068.8	35,544.5	38,251.0	2,706.5	7.6%
		1,000,000	3000	46%	24.91	3.74	0.50	0.20	4.44	13,344.9	29.46	8.50	0.20	(0.22)	8.48	25,477.6	2.11	0.62	0.70	1.06	20,294.3	-	1,000,000	55,172.0	92,909.3	100,943.9	8,034.6	8.6%
		1,500,000	4000	52%	24.91	3.74	0.50	0.20	4.44	17,784.9	29.46	8.50	0.20	(0.22)	8.48	33,960.3	2.11	0.62	0.70	1.06	29,322.1	-	1,500,000	82,758.0	135,266.0	146,040.4	10,774.4	8.0%
UGd	**GBE**	15,000	60	35%	**10.77**	**3.64**	**0.49**	**0.19**	**4.32**	270.0	**14.61**	**7.33**	**0.19**	**(0.27)**	**7.25**	449.6	**2.68**	0.62	0.7	**1.061**	374.3	-	15,000	827.6	1,519.4	1,651.5	132.1	8.7%
		43,164	133	45%	10.77	3.64	0.49	0.19	4.32	585.3	14.61	7.33	0.19	(0.27)	7.25	978.9	2.68	0.62	0.70	1.06	964.3	-	43,164	2,381.4	4,032.7	4,324.6	291.9	7.2%
		100,000	500	28%	10.77	3.64	0.49	0.19	4.32	2,170.8	14.61	7.33	0.19	(0.27)	7.25	3,639.7	2.68	0.62	0.70	1.06	2,779.6	-	100,000	5,517.2	10,873.4	11,936.5	1,063.1	9.8%
		400,000	1000	56%	10.77	3.64	0.49	0.19	4.32	4,330.8	14.61	7.33	0.19	(0.27)	7.25	7,264.8	2.68	0.62	0.70	1.06	8,274.8	-	400,000	22,068.8	35,410.4	37,608.4	2,198.0	6.2%
		1,000,000	3000	46%	10.77	3.64	0.49	0.19	4.32	12,970.8	14.61	7.33	0.19	(0.27)	7.25	21,765.2	2.68	0.62	0.70	1.06	22,108.6	-	1,000,000	55,172.0	92,535.1	99,045.9	6,510.7	7.0%
		1,500,000	4000	52%	10.77	3.64	0.49	0.19	4.32	17,290.8	14.61	7.33	0.19	(0.27)	7.25	29,015.4	2.68	0.62	0.70	1.06	31,741.2	-	1,500,000	82,758.0	134,771.9	143,514.6	8,742.7	6.5%
GSd	**Georgina**	15,000	60	35%	**17.40**	**5.10**	**0.51**	**0.25**	**5.86**	369.0	**24.34**	**9.22**	**0.25**	**(0.22)**	**9.26**	579.7	**2.11**	0.62	0.7	**1.061**	338.0	-	15,000	827.6	1,618.4	1,745.3	126.9	7.8%
		43,164	133	45%	17.40	5.10	0.51	0.25	5.86	796.8	24.34	9.22	0.25	(0.22)	9.26	1,255.4	2.11	0.62	0.70	1.06	883.8	-	43,164	2,381.4	4,244.2	4,520.7	276.5	6.5%
		100,000	500	28%	17.40	5.10	0.51	0.25	5.86	2,947.4	24.34	9.22	0.25	(0.22)	9.26	4,652.5	2.11	0.62	0.70	1.06	2,477.2	-	100,000	5,517.2	11,650.0	12,646.9	996.9	8.6%
		400,000	1000	56%	17.40	5.10	0.51	0.25	5.86	5,877.4	24.34	9.22	0.25	(0.22)	9.26	9,280.6	2.11	0.62	0.70	1.06	7,670.0	-	400,000	22,068.8	36,957.0	39,019.4	2,062.4	5.6%
		1,000,000	3000	46%	17.40	5.10	0.51	0.25	5.86	17,597.4	24.34	9.22	0.25	(0.22)	9.26	27,793.2	2.11	0.62	0.70	1.06	20,294.3	-	1,000,000	55,172.0	97,161.8	103,259.5	6,097.8	6.3%
		1,500,000	4000	52%	17.40	5.10	0.51	0.25	5.86	23,457.4	24.34	9.22	0.25	(0.22)	9.26	37,049.5	2.11	0.62	0.70	1.06	29,322.1	-	1,500,000	82,758.0	140,938.5	149,129.6	8,191.1	5.8%

New Rate Class: GSd

Total Bill Impacts of Proposed Distribution Rates [new RTSR+TLF]: Threshold of 750 kWhs

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Classes		Scenario			May 2007 Incl Rate Riders						May 2008 Incl Rate Riders						Non-Dx Compoent				Other Reg	Commodity Bands			Existing	New	$ Incr	% Incr
					Existing Dx Rates					Existing Dx	New Dx Rates					New Dx	RTSR new	WMSC	DRC	TLF new	New	Band 1	Band 2	New	Total Bill	Total Bill	Total Bill	Total Bill
																						-	5.2					
New Class	Old Class	kWh	kW	LF	SrChg [$/cust]	base [$/kW]	Rider1 [$/kW]	Rider2 [$/kW]	VarChg [$/kW]	[$/month]	SrChg [$/cust]	base [$/kW]	Rider2 [$/kW]	Rider3 [$/kW]	VarChg [$/kW]	[$/month]	$/kW	c/kWh	c/kWh		$	kWhs	kWhs	Total $	[$/month]	[$/month]	[$/month]	%
GSd	**Glencoe**	15,000	60	35%	**11.37**	**2.55**	**0.69**	**0.44**	**3.68**	232.2	**19.85**	**7.40**	**0.44**	**(0.22)**	**7.62**	477.2	**2.11**	0.62	0.7	**1.061**	338.0	-	15,000	827.6	1,481.6	1,642.8	161.2	10.9%
		43,164	133	45%	11.37	2.55	0.69	0.44	3.68	500.8	19.85	7.40	0.44	(0.22)	7.62	1,033.7	2.11	0.62	0.70	1.06	883.8	-	43,164	2,381.4	3,948.2	4,298.9	350.7	8.9%
		100,000	500	28%	11.37	2.55	0.69	0.44	3.68	1,851.4	19.85	7.40	0.44	(0.22)	7.62	3,831.2	2.11	0.62	0.70	1.06	2,477.2	-	100,000	5,517.2	10,554.0	11,825.6	1,271.6	12.0%
		400,000	1000	56%	11.37	2.55	0.69	0.44	3.68	3,691.4	19.85	7.40	0.44	(0.22)	7.62	7,642.5	2.11	0.62	0.70	1.06	7,670.0	-	400,000	22,068.8	34,771.0	37,381.3	2,610.4	7.5%
		1,000,000	3000	46%	11.37	2.55	0.69	0.44	3.68	11,051.4	19.85	7.40	0.44	(0.22)	7.62	22,888.0	2.11	0.62	0.70	1.06	20,294.3	-	1,000,000	55,172.0	90,615.7	98,354.3	7,738.6	8.5%
		1,500,000	4000	52%	11.37	2.55	0.69	0.44	3.68	14,731.4	19.85	7.40	0.44	(0.22)	7.62	30,510.7	2.11	0.62	0.70	1.06	29,322.1	-	1,500,000	82,758.0	132,212.5	142,590.8	10,378.3	7.8%
GSd	**Grand Bend**	15,000	60	35%	**22.20**	**3.90**	**0.59**	**0.23**	**4.72**	305.4	**28.14**	**8.75**	**0.23**	**(0.22)**	**8.76**	553.9	**2.11**	0.62	0.7	**1.061**	338.0	-	15,000	827.6	1,554.8	1,719.5	164.6	10.6%
		43,164	133	45%	22.20	3.90	0.59	0.23	4.72	650.0	28.14	8.75	0.23	(0.22)	8.76	1,193.6	2.11	0.62	0.70	1.06	883.8	-	43,164	2,381.4	4,097.4	4,458.9	361.5	8.8%
		100,000	500	28%	22.20	3.90	0.59	0.23	4.72	2,382.2	28.14	8.75	0.23	(0.22)	8.76	4,409.5	2.11	0.62	0.70	1.06	2,477.2	-	100,000	5,517.2	11,084.8	12,403.9	1,319.1	11.9%
		400,000	1000	56%	22.20	3.90	0.59	0.23	4.72	4,742.2	28.14	8.75	0.23	(0.22)	8.76	8,790.8	2.11	0.62	0.70	1.06	7,670.0	-	400,000	22,068.8	35,821.8	38,529.6	2,707.9	7.6%
		1,000,000	3000	46%	22.20	3.90	0.59	0.23	4.72	14,182.2	28.14	8.75	0.23	(0.22)	8.76	26,316.2	2.11	0.62	0.70	1.06	20,294.3	-	1,000,000	55,172.0	93,746.6	101,782.6	8,036.0	8.6%
		1,500,000	4000	52%	22.20	3.90	0.59	0.23	4.72	18,902.2	28.14	8.75	0.23	(0.22)	8.76	35,079.0	2.11	0.62	0.70	1.06	29,322.1	-	1,500,000	82,758.0	136,383.3	147,159.1	10,775.8	7.9%
GSd	**Hastings**	15,000	60	35%	**22.89**	**5.32**	**0.74**	**0.29**	**6.35**	403.9	**27.97**	**9.22**	**0.29**	**(0.22)**	**9.30**	585.7	**2.11**	0.62	0.7	**1.061**	338.0	-	15,000	827.6	1,653.3	1,751.3	98.0	5.9%
		43,164	133	45%	22.89	5.32	0.74	0.29	6.35	867.4	27.97	9.22	0.29	(0.22)	9.30	1,264.4	2.11	0.62	0.70	1.06	883.8	-	43,164	2,381.4	4,314.8	4,529.7	214.8	5.0%
		100,000	500	28%	22.89	5.32	0.74	0.29	6.35	3,197.9	27.97	9.22	0.29	(0.22)	9.30	4,676.1	2.11	0.62	0.70	1.06	2,477.2	-	100,000	5,517.2	11,900.5	12,670.5	770.0	6.5%
		400,000	1000	56%	22.89	5.32	0.74	0.29	6.35	6,372.9	27.97	9.22	0.29	(0.22)	9.30	9,324.2	2.11	0.62	0.70	1.06	7,670.0	-	400,000	22,068.8	37,452.5	39,063.0	1,610.6	4.3%
		1,000,000	3000	46%	22.89	5.32	0.74	0.29	6.35	19,072.9	27.97	9.22	0.29	(0.22)	9.30	27,916.8	2.11	0.62	0.70	1.06	20,294.3	-	1,000,000	55,172.0	98,637.3	103,383.1	4,745.9	4.8%
		1,500,000	4000	52%	22.89	5.32	0.74	0.29	6.35	25,422.9	27.97	9.22	0.29	(0.22)	9.30	37,213.1	2.11	0.62	0.70	1.06	29,322.1	-	1,500,000	82,758.0	142,904.0	149,293.2	6,389.2	4.5%
GSd	**Havelock**	15,000	60	35%	**22.18**	**4.82**	**0.50**	**0.28**	**5.60**	358.2	**28.14**	**9.22**	**0.28**	**(0.22)**	**9.29**	585.3	**2.11**	0.62	0.7	**1.061**	338.0	-	15,000	827.6	1,607.6	1,750.9	143.3	8.9%
		43,164	133	45%	22.18	4.82	0.50	0.28	5.60	767.0	28.14	9.22	0.28	(0.22)	9.29	1,263.2	2.11	0.62	0.70	1.06	883.8	-	43,164	2,381.4	4,214.4	4,528.5	314.1	7.5%
		100,000	500	28%	22.18	4.82	0.50	0.28	5.60	2,822.2	28.14	9.22	0.28	(0.22)	9.29	4,671.3	2.11	0.62	0.70	1.06	2,477.2	-	100,000	5,517.2	11,524.8	12,665.7	1,140.9	9.9%
		400,000	1000	56%	22.18	4.82	0.50	0.28	5.60	5,622.2	28.14	9.22	0.28	(0.22)	9.29	9,314.4	2.11	0.62	0.70	1.06	7,670.0	-	400,000	22,068.8	36,701.8	39,053.2	2,351.5	6.4%
		1,000,000	3000	46%	22.18	4.82	0.50	0.28	5.60	16,822.2	28.14	9.22	0.28	(0.22)	9.29	27,887.0	2.11	0.62	0.70	1.06	20,294.3	-	1,000,000	55,172.0	96,386.5	103,353.3	6,966.8	7.2%
		1,500,000	4000	52%	22.18	4.82	0.50	0.28	5.60	22,422.2	28.14	9.22	0.28	(0.22)	9.29	37,173.3	2.11	0.62	0.70	1.06	29,322.1	-	1,500,000	82,758.0	139,903.3	149,253.4	9,350.1	6.7%
GSd	**Kirkfield**	15,000	60	35%	**14.69**	**5.92**	**1.95**	**1.34**	**9.21**	567.3	**22.02**	**9.22**	**1.34**	**(0.22)**	**10.35**	642.8	**2.11**	0.62	0.7	**1.061**	338.0	-	15,000	827.6	1,816.7	1,808.4	(8.4)	-0.5%
		43,164	133	45%	14.69	5.92	1.95	1.34	9.21	1,239.6	22.02	9.22	1.34	(0.22)	10.35	1,398.1	2.11	0.62	0.70	1.06	883.8	-	43,164	2,381.4	4,687.0	4,663.4	(23.7)	-0.5%
		100,000	500	28%	14.69	5.92	1.95	1.34	9.21	4,619.7	22.02	9.22	1.34	(0.22)	10.35	5,195.2	2.11	0.62	0.70	1.06	2,477.2	-	100,000	5,517.2	13,322.3	13,189.5	(132.8)	-1.0%
		400,000	1000	56%	14.69	5.92	1.95	1.34	9.21	9,224.7	22.02	9.22	1.34	(0.22)	10.35	10,368.3	2.11	0.62	0.70	1.06	7,670.0	-	400,000	22,068.8	40,304.3	40,107.1	(197.2)	-0.5%
		1,000,000	3000	46%	14.69	5.92	1.95	1.34	9.21	27,644.7	22.02	9.22	1.34	(0.22)	10.35	31,060.9	2.11	0.62	0.70	1.06	20,294.3	-	1,000,000	55,172.0	107,209.1	106,527.2	(681.9)	-0.6%
		1,500,000	4000	52%	14.69	5.92	1.95	1.34	9.21	36,854.7	22.02	9.22	1.34	(0.22)	10.35	41,407.2	2.11	0.62	0.70	1.06	29,322.1	-	1,500,000	82,758.0	154,335.8	153,487.3	(848.5)	-0.5%

New Rate Class: GSd

Total Bill Impacts of Proposed Distribution Rates [new RTSR+TLF]: Threshold of 750 kWhs

Classes		Scenario			May 2007 Incl Rate Riders						May 2008 Incl Rate Riders						Non-Dx Compoent				Other Reg	Commodity Bands			Existing	New	$ Incr	% Incr
					Existing Dx Rates					Existing Dx	New Dx Rates					New Dx	RTSR new	WMSC	DRC	TLF new	New	Band 1	Band 2	New	Total Bill	Total Bill	Total Bill	Total Bill
																						-	5.2					
New Class	Old Class	kWh	kW	LF	SrChg [$/cust]	base [$/kW]	Rider1 [$/kW]	Rider2 [$/kW]	VarChg [$/kW]	[$/month]	SrChg [$/cust]	base [$/kW]	Rider2 [$/kW]	Rider3 [$/kW]	VarChg [$/kW]	[$/month]	$/kW	c/kWh	c/kWh		$	kWhs	kWhs	Total $	[$/month]	[$/month]	[$/month]	%
GSd	Lanark Highlands	15,000	60	35%	18.43	5.26	1.99	1.32	8.57	532.6	25.08	9.22	1.32	(0.22)	10.33	644.7	2.11	0.62	0.7	1.061	338.0	-	15,000	827.6	1,782.1	1,810.2	28.2	1.6%
		43,164	133	45%	18.43	5.26	1.99	1.32	8.57	1,158.2	25.08	9.22	1.32	(0.22)	10.33	1,398.5	2.11	0.62	0.70	1.06	883.8	-	43,164	2,381.4	4,605.6	4,663.8	58.1	1.3%
		100,000	500	28%	18.43	5.26	1.99	1.32	8.57	4,303.4	25.08	9.22	1.32	(0.22)	10.33	5,188.2	2.11	0.62	0.70	1.06	2,477.2	-	100,000	5,517.2	13,006.0	13,182.6	176.6	1.4%
		400,000	1000	56%	18.43	5.26	1.99	1.32	8.57	8,588.4	25.08	9.22	1.32	(0.22)	10.33	10,351.4	2.11	0.62	0.70	1.06	7,670.0	-	400,000	22,068.8	39,668.0	40,090.2	422.1	1.1%
		1,000,000	3000	46%	18.43	5.26	1.99	1.32	8.57	25,728.4	25.08	9.22	1.32	(0.22)	10.33	31,003.9	2.11	0.62	0.70	1.06	20,294.3	-	1,000,000	55,172.0	105,292.8	106,470.3	1,177.5	1.1%
		1,500,000	4000	52%	18.43	5.26	1.99	1.32	8.57	34,298.4	25.08	9.22	1.32	(0.22)	10.33	41,330.2	2.11	0.62	0.70	1.06	29,322.1	-	1,500,000	82,758.0	151,779.6	153,410.4	1,630.8	1.1%
GSd	Larder Lake	15,000	60	35%	20.18	4.30	1.61	0.99	6.90	434.2	26.64	9.22	0.99	(0.22)	10.00	626.4	2.11	0.62	0.7	1.061	338.0	-	15,000	827.6	1,683.6	1,792.0	108.4	6.4%
		43,164	133	45%	20.18	4.30	1.61	0.99	6.90	937.9	26.64	9.22	0.99	(0.22)	10.00	1,356.1	2.11	0.62	0.70	1.06	883.8	-	43,164	2,381.4	4,385.3	4,621.4	236.1	5.4%
		100,000	500	28%	20.18	4.30	1.61	0.99	6.90	3,470.2	26.64	9.22	0.99	(0.22)	10.00	5,024.8	2.11	0.62	0.70	1.06	2,477.2	-	100,000	5,517.2	12,172.8	13,019.2	846.4	7.0%
		400,000	1000	56%	20.18	4.30	1.61	0.99	6.90	6,920.2	26.64	9.22	0.99	(0.22)	10.00	10,022.9	2.11	0.62	0.70	1.06	7,670.0	-	400,000	22,068.8	37,999.8	39,761.7	1,762.0	4.6%
		1,000,000	3000	46%	20.18	4.30	1.61	0.99	6.90	20,720.2	26.64	9.22	0.99	(0.22)	10.00	30,015.5	2.11	0.62	0.70	1.06	20,294.3	-	1,000,000	55,172.0	100,284.5	105,481.8	5,197.3	5.2%
		1,500,000	4000	52%	20.18	4.30	1.61	0.99	6.90	27,620.2	26.64	9.22	0.99	(0.22)	10.00	40,011.8	2.11	0.62	0.70	1.06	29,322.1	-	1,500,000	82,758.0	145,101.3	152,091.9	6,990.6	4.8%
GSd	Latchford	15,000	60	35%	2.88	2.44	2.06	0.48	4.98	301.7	12.97	8.80	0.48	(0.22)	9.06	556.7	2.11	0.62	0.7	1.061	338.0	-	15,000	827.6	1,551.1	1,722.3	171.2	11.0%
		43,164	133	45%	2.88	2.44	2.06	0.48	4.98	665.2	12.97	8.80	0.48	(0.22)	9.06	1,218.3	2.11	0.62	0.70	1.06	883.8	-	43,164	2,381.4	4,112.6	4,483.6	371.0	9.0%
		100,000	500	28%	2.88	2.44	2.06	0.48	4.98	2,492.9	12.97	8.80	0.48	(0.22)	9.06	4,544.3	2.11	0.62	0.70	1.06	2,477.2	-	100,000	5,517.2	11,195.5	12,538.7	1,343.2	12.0%
		400,000	1000	56%	2.88	2.44	2.06	0.48	4.98	4,982.9	12.97	8.80	0.48	(0.22)	9.06	9,075.7	2.11	0.62	0.70	1.06	7,670.0	-	400,000	22,068.8	36,062.5	38,814.5	2,752.0	7.6%
		1,000,000	3000	46%	2.88	2.44	2.06	0.48	4.98	14,942.9	12.97	8.80	0.48	(0.22)	9.06	27,201.1	2.11	0.62	0.70	1.06	20,294.3	-	1,000,000	55,172.0	94,507.2	102,667.4	8,160.2	8.6%
		1,500,000	4000	52%	2.88	2.44	2.06	0.48	4.98	19,922.9	12.97	8.80	0.48	(0.22)	9.06	36,263.8	2.11	0.62	0.70	1.06	29,322.1	-	1,500,000	82,758.0	137,404.0	148,343.9	10,939.9	8.0%
UGd	Lindsay	15,000	60	35%	23.94	4.36	0.49	0.19	5.04	326.3	24.31	7.33	0.19	(0.27)	7.25	459.3	2.68	0.62	0.7	1.061	374.3	-	15,000	827.6	1,575.8	1,661.2	85.4	5.4%
		43,164	133	45%	23.94	4.36	0.49	0.19	5.04	694.3	24.31	7.33	0.19	(0.27)	7.25	988.6	2.68	0.62	0.70	1.06	964.3	-	43,164	2,381.4	4,141.7	4,334.3	192.6	4.7%
		100,000	500	28%	23.94	4.36	0.49	0.19	5.04	2,543.9	24.31	7.33	0.19	(0.27)	7.25	3,649.4	2.68	0.62	0.70	1.06	2,779.6	-	100,000	5,517.2	11,246.5	11,946.2	699.6	6.2%
		400,000	1000	56%	23.94	4.36	0.49	0.19	5.04	5,063.9	24.31	7.33	0.19	(0.27)	7.25	7,274.5	2.68	0.62	0.70	1.06	8,274.8	-	400,000	22,068.8	36,143.5	37,618.1	1,474.6	4.1%
		1,000,000	3000	46%	23.94	4.36	0.49	0.19	5.04	15,143.9	24.31	7.33	0.19	(0.27)	7.25	21,774.9	2.68	0.62	0.70	1.06	22,108.6	-	1,000,000	55,172.0	94,708.3	99,055.6	4,347.3	4.6%
		1,500,000	4000	52%	23.94	4.36	0.49	0.19	5.04	20,183.9	24.31	7.33	0.19	(0.27)	7.25	29,025.1	2.68	0.62	0.70	1.06	31,741.2	-	1,500,000	82,758.0	137,665.1	143,524.4	5,859.3	4.3%
GSd	Lucan Granton	15,000	60	35%	16.99	4.61	0.53	0.30	5.44	343.4	23.44	9.22	0.30	(0.22)	9.31	581.8	2.11	0.62	0.7	1.061	338.0	-	15,000	827.6	1,592.8	1,747.4	154.6	9.7%
		43,164	133	45%	16.99	4.61	0.53	0.30	5.44	740.5	23.44	9.22	0.30	(0.22)	9.31	1,261.2	2.11	0.62	0.70	1.06	883.8	-	43,164	2,381.4	4,187.9	4,526.5	338.5	8.1%
		100,000	500	28%	16.99	4.61	0.53	0.30	5.44	2,737.0	23.44	9.22	0.30	(0.22)	9.31	4,676.6	2.11	0.62	0.70	1.06	2,477.2	-	100,000	5,517.2	11,439.6	12,671.0	1,231.4	10.8%
		400,000	1000	56%	16.99	4.61	0.53	0.30	5.44	5,457.0	23.44	9.22	0.30	(0.22)	9.31	9,329.7	2.11	0.62	0.70	1.06	7,670.0	-	400,000	22,068.8	36,536.6	39,068.5	2,531.9	6.9%
		1,000,000	3000	46%	16.99	4.61	0.53	0.30	5.44	16,337.0	23.44	9.22	0.30	(0.22)	9.31	27,942.3	2.11	0.62	0.70	1.06	20,294.3	-	1,000,000	55,172.0	95,901.4	103,408.6	7,507.3	7.8%
		1,500,000	4000	52%	16.99	4.61	0.53	0.30	5.44	21,777.0	23.44	9.22	0.30	(0.22)	9.31	37,248.6	2.11	0.62	0.70	1.06	29,322.1	-	1,500,000	82,758.0	139,258.1	149,328.7	10,070.6	7.2%

New Rate Class: GSd

Total Bill Impacts of Proposed Distribution Rates [new RTSR+TLF]: Threshold of 750 kWhs

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Classes		Scenario			May 2007 Incl Rate Riders						May 2008 Incl Rate Riders						Non-Dx Compoent				Other Reg	Commodity Bands			Existing	New	$ Incr	% Incr
					Existing Dx Rates					Existing Dx	New Dx Rates					New Dx	RTSR new	WMSC	DRC	TLF new	New	Band 1	Band 2	New	Total Bill	Total Bill	Total Bill	Total Bill
																						-	5.2					
New Class	Old Class	kWh	kW	LF	SrChg [$/cust]	base [$/kW]	Rider1 [$/kW]	Rider2 [$/kW]	VarChg [$/kW]	[$/month]	SrChg [$/cust]	base [$/kW]	Rider2 [$/kW]	Rider3 [$/kW]	VarChg [$/kW]	[$/month]	$/kW	c/kWh	c/kWh		$	kWhs	kWhs	Total $	[$/month]	[$/month]	[$/month]	%
GSd	**Malahide**	15,000	60	35%	**15.99**	**5.42**	**2.57**	**1.32**	**9.31**	574.6	**22.69**	**9.22**	**1.32**	**(0.22)**	**10.33**	642.3	**2.11**	0.62	0.7	**1.061**	338.0	-	15,000	827.6	1,824.0	1,807.8	(16.2)	-0.9%
		43,164	133	45%	15.99	5.42	2.57	1.32	9.31	1,254.2	22.69	9.22	1.32	(0.22)	10.33	1,396.1	2.11	0.62	0.70	1.06	883.8	-	43,164	2,381.4	4,701.6	4,661.4	(40.3)	-0.9%
		100,000	500	28%	15.99	5.42	2.57	1.32	9.31	4,671.0	22.69	9.22	1.32	(0.22)	10.33	5,185.8	2.11	0.62	0.70	1.06	2,477.2	-	100,000	5,517.2	13,373.6	13,180.2	(193.4)	-1.4%
		400,000	1000	56%	15.99	5.42	2.57	1.32	9.31	9,326.0	22.69	9.22	1.32	(0.22)	10.33	10,349.0	2.11	0.62	0.70	1.06	7,670.0	-	400,000	22,068.8	40,405.6	40,087.8	(317.8)	-0.8%
		1,000,000	3000	46%	15.99	5.42	2.57	1.32	9.31	27,946.0	22.69	9.22	1.32	(0.22)	10.33	31,001.5	2.11	0.62	0.70	1.06	20,294.3	-	1,000,000	55,172.0	107,510.4	106,467.9	(1,042.5)	-1.0%
		1,500,000	4000	52%	15.99	5.42	2.57	1.32	9.31	37,256.0	22.69	9.22	1.32	(0.22)	10.33	41,327.8	2.11	0.62	0.70	1.06	29,322.1	-	1,500,000	82,758.0	154,737.1	153,408.0	(1,329.2)	-0.9%
GSd	**Mapleton**	15,000	60	35%	**21.55**	**5.42**	**1.26**	**0.93**	**7.61**	478.2	**27.30**	**9.22**	**0.93**	**(0.22)**	**9.94**	623.5	**2.11**	0.62	0.7	**1.061**	338.0	-	15,000	827.6	1,727.6	1,789.1	61.5	3.6%
		43,164	133	45%	21.55	5.42	1.26	0.93	7.61	1,033.7	27.30	9.22	0.93	(0.22)	9.94	1,348.8	2.11	0.62	0.70	1.06	883.8	-	43,164	2,381.4	4,481.1	4,614.1	133.0	3.0%
		100,000	500	28%	21.55	5.42	1.26	0.93	7.61	3,826.6	27.30	9.22	0.93	(0.22)	9.94	4,995.4	2.11	0.62	0.70	1.06	2,477.2	-	100,000	5,517.2	12,529.2	12,989.8	460.7	3.7%
		400,000	1000	56%	21.55	5.42	1.26	0.93	7.61	7,631.6	27.30	9.22	0.93	(0.22)	9.94	9,963.6	2.11	0.62	0.70	1.06	7,670.0	-	400,000	22,068.8	38,711.1	39,702.4	991.2	2.6%
		1,000,000	3000	46%	21.55	5.42	1.26	0.93	7.61	22,851.6	27.30	9.22	0.93	(0.22)	9.94	29,836.2	2.11	0.62	0.70	1.06	20,294.3	-	1,000,000	55,172.0	102,415.9	105,302.5	2,886.6	2.8%
		1,500,000	4000	52%	21.55	5.42	1.26	0.93	7.61	30,461.6	27.30	9.22	0.93	(0.22)	9.94	39,772.4	2.11	0.62	0.70	1.06	29,322.1	-	1,500,000	82,758.0	147,942.7	151,852.6	3,909.9	2.6%
GSd	**Markdale**	15,000	60	35%	**23.00**	**2.54**	**0.49**	**0.13**	**3.16**	212.6	**28.94**	**7.25**	**0.13**	**(0.22)**	**7.16**	458.7	**2.11**	0.62	0.7	**1.061**	338.0	-	15,000	827.6	1,462.0	1,624.3	162.2	11.1%
		43,164	133	45%	23.00	2.54	0.49	0.13	3.16	443.3	28.94	7.25	0.13	(0.22)	7.16	981.6	2.11	0.62	0.70	1.06	883.8	-	43,164	2,381.4	3,890.7	4,246.9	356.2	9.2%
		100,000	500	28%	23.00	2.54	0.49	0.13	3.16	1,603.0	28.94	7.25	0.13	(0.22)	7.16	3,610.3	2.11	0.62	0.70	1.06	2,477.2	-	100,000	5,517.2	10,305.6	11,604.7	1,299.1	12.6%
		400,000	1000	56%	23.00	2.54	0.49	0.13	3.16	3,183.0	28.94	7.25	0.13	(0.22)	7.16	7,191.6	2.11	0.62	0.70	1.06	7,670.0	-	400,000	22,068.8	34,262.6	36,930.4	2,667.9	7.8%
		1,000,000	3000	46%	23.00	2.54	0.49	0.13	3.16	9,503.0	28.94	7.25	0.13	(0.22)	7.16	21,517.0	2.11	0.62	0.70	1.06	20,294.3	-	1,000,000	55,172.0	89,067.4	96,983.4	7,916.0	8.9%
		1,500,000	4000	52%	23.00	2.54	0.49	0.13	3.16	12,663.0	28.94	7.25	0.13	(0.22)	7.16	28,679.8	2.11	0.62	0.70	1.06	29,322.1	-	1,500,000	82,758.0	130,144.1	140,759.9	10,615.8	8.2%
GSd	**Marmora**	15,000	60	35%	**10.02**	**3.33**	**0.49**	**0.16**	**3.98**	248.8	**19.18**	**8.00**	**0.16**	**(0.22)**	**7.94**	495.7	**2.11**	0.62	0.7	**1.061**	338.0	-	15,000	827.6	1,498.2	1,661.3	163.1	10.9%
		43,164	133	45%	10.02	3.33	0.49	0.16	3.98	539.4	19.18	8.00	0.16	(0.22)	7.94	1,075.6	2.11	0.62	0.70	1.06	883.8	-	43,164	2,381.4	3,986.8	4,340.8	354.1	8.9%
		100,000	500	28%	10.02	3.33	0.49	0.16	3.98	2,000.0	19.18	8.00	0.16	(0.22)	7.94	3,990.5	2.11	0.62	0.70	1.06	2,477.2	-	100,000	5,517.2	10,702.6	11,984.9	1,282.3	12.0%
		400,000	1000	56%	10.02	3.33	0.49	0.16	3.98	3,990.0	19.18	8.00	0.16	(0.22)	7.94	7,961.9	2.11	0.62	0.70	1.06	7,670.0	-	400,000	22,068.8	35,069.6	37,700.7	2,631.1	7.5%
		1,000,000	3000	46%	10.02	3.33	0.49	0.16	3.98	11,950.0	19.18	8.00	0.16	(0.22)	7.94	23,847.3	2.11	0.62	0.70	1.06	20,294.3	-	1,000,000	55,172.0	91,514.4	99,313.6	7,799.2	8.5%
		1,500,000	4000	52%	10.02	3.33	0.49	0.16	3.98	15,930.0	19.18	8.00	0.16	(0.22)	7.94	31,790.0	2.11	0.62	0.70	1.06	29,322.1	-	1,500,000	82,758.0	133,411.2	143,870.1	10,459.0	7.8%
GSd	**McGarry**	15,000	60	35%	**20.18**	**5.68**	**1.80**	**1.42**	**8.90**	554.2	**26.64**	**9.22**	**1.42**	**(0.22)**	**10.43**	652.2	**2.11**	0.62	0.7	**1.061**	338.0	-	15,000	827.6	1,803.6	1,817.8	14.2	0.8%
		43,164	133	45%	20.18	5.68	1.80	1.42	8.90	1,203.9	26.64	9.22	1.42	(0.22)	10.43	1,413.3	2.11	0.62	0.70	1.06	883.8	-	43,164	2,381.4	4,651.3	4,678.6	27.3	0.6%
		100,000	500	28%	20.18	5.68	1.80	1.42	8.90	4,470.2	26.64	9.22	1.42	(0.22)	10.43	5,239.8	2.11	0.62	0.70	1.06	2,477.2	-	100,000	5,517.2	13,172.8	13,234.2	61.4	0.5%
		400,000	1000	56%	20.18	5.68	1.80	1.42	8.90	8,920.2	26.64	9.22	1.42	(0.22)	10.43	10,452.9	2.11	0.62	0.70	1.06	7,670.0	-	400,000	22,068.8	39,999.8	40,191.7	192.0	0.5%
		1,000,000	3000	46%	20.18	5.68	1.80	1.42	8.90	26,720.2	26.64	9.22	1.42	(0.22)	10.43	31,305.5	2.11	0.62	0.70	1.06	20,294.3	-	1,000,000	55,172.0	106,284.5	106,771.8	487.3	0.5%
		1,500,000	4000	52%	20.18	5.68	1.80	1.42	8.90	35,620.2	26.64	9.22	1.42	(0.22)	10.43	41,731.8	2.11	0.62	0.70	1.06	29,322.1	-	1,500,000	82,758.0	153,101.3	153,811.9	710.6	0.5%

New Rate Class: GSd

Total Bill Impacts of Proposed Distribution Rates [new RTSR+TLF]: Threshold of 750 kWhs

Classes		Scenario			May 2007 Incl Rate Riders						May 2008 Incl Rate Riders						Non-Dx Compoent				Other Reg	Commodity Bands			Existing	New	$ Incr	% Incr
					Existing Dx Rates					Existing Dx	New Dx Rates					New Dx	RTSR new	WMSC	DRC	TLF new	New	Band 1	Band 2	New	Total Bill	Total Bill	Total Bill	Total Bill
																						-	5.2					
New Class	Old Class	kWh	kW	LF	SrChg [$/cust]	base [$/kW]	Rider1 [$/kW]	Rider2 [$/kW]	VarChg [$/kW]	[$/month]	SrChg [$/cust]	base [$/kW]	Rider2 [$/kW]	Rider3 [$/kW]	VarChg [$/kW]	[$/month]	$/kW	c/kWh	c/kWh		$	kWhs	kWhs	Total $	[$/month]	[$/month]	[$/month]	%
GSd	Meaford	15,000	60	35%	24.05	3.90	0.50	0.21	4.61	300.7	29.68	8.75	0.21	(0.22)	8.74	554.2	2.11	0.62	0.7	1.061	338.0	-	15,000	827.6	1,550.1	1,719.8	169.7	11.0%
		43,164	133	45%	24.05	3.90	0.50	0.21	4.61	637.2	29.68	8.75	0.21	(0.22)	8.74	1,192.5	2.11	0.62	0.70	1.06	883.8	-	43,164	2,381.4	4,084.6	4,457.7	373.2	9.1%
		100,000	500	28%	24.05	3.90	0.50	0.21	4.61	2,329.1	29.68	8.75	0.21	(0.22)	8.74	4,401.0	2.11	0.62	0.70	1.06	2,477.2	-	100,000	5,517.2	11,031.7	12,395.4	1,363.8	12.4%
		400,000	1000	56%	24.05	3.90	0.50	0.21	4.61	4,634.1	29.68	8.75	0.21	(0.22)	8.74	8,772.4	2.11	0.62	0.70	1.06	7,670.0	-	400,000	22,068.8	35,713.6	38,511.2	2,797.5	7.8%
		1,000,000	3000	46%	24.05	3.90	0.50	0.21	4.61	13,854.1	29.68	8.75	0.21	(0.22)	8.74	26,257.8	2.11	0.62	0.70	1.06	20,294.3	-	1,000,000	55,172.0	93,418.4	101,724.1	8,305.7	8.9%
		1,500,000	4000	52%	24.05	3.90	0.50	0.21	4.61	18,464.1	29.68	8.75	0.21	(0.22)	8.74	35,000.5	2.11	0.62	0.70	1.06	29,322.1	-	1,500,000	82,758.0	135,945.2	147,080.6	11,135.4	8.2%
GSd	Middlesex Centre	15,000	60	35%	17.35	3.29	1.39	0.84	5.52	348.6	24.35	9.00	0.84	(0.22)	9.62	601.7	2.11	0.62	0.7	1.061	338.0	-	15,000	827.6	1,598.0	1,767.3	169.3	10.6%
		43,164	133	45%	17.35	3.29	1.39	0.84	5.52	751.5	24.35	9.00	0.84	(0.22)	9.62	1,304.2	2.11	0.62	0.70	1.06	883.8	-	43,164	2,381.4	4,198.9	4,569.5	370.5	8.8%
		100,000	500	28%	17.35	3.29	1.39	0.84	5.52	2,777.4	24.35	9.00	0.84	(0.22)	9.62	4,835.7	2.11	0.62	0.70	1.06	2,477.2	-	100,000	5,517.2	11,480.0	12,830.1	1,350.1	11.8%
		400,000	1000	56%	17.35	3.29	1.39	0.84	5.52	5,537.4	24.35	9.00	0.84	(0.22)	9.62	9,647.1	2.11	0.62	0.70	1.06	7,670.0	-	400,000	22,068.8	36,616.9	39,385.8	2,768.9	7.6%
		1,000,000	3000	46%	17.35	3.29	1.39	0.84	5.52	16,577.4	24.35	9.00	0.84	(0.22)	9.62	28,892.5	2.11	0.62	0.70	1.06	20,294.3	-	1,000,000	55,172.0	96,141.7	104,358.8	8,217.1	8.5%
		1,500,000	4000	52%	17.35	3.29	1.39	0.84	5.52	22,097.4	24.35	9.00	0.84	(0.22)	9.62	38,515.2	2.11	0.62	0.70	1.06	29,322.1	-	1,500,000	82,758.0	139,578.5	150,595.3	11,016.8	7.9%
GSd	Napanee	15,000	60	35%	22.17	4.04	0.52	0.20	4.76	307.8	28.15	8.90	0.20	(0.22)	8.88	561.1	2.11	0.62	0.7	1.061	338.0	-	15,000	827.6	1,557.2	1,726.7	169.5	10.9%
		43,164	133	45%	22.17	4.04	0.52	0.20	4.76	655.3	28.15	8.90	0.20	(0.22)	8.88	1,209.5	2.11	0.62	0.70	1.06	883.8	-	43,164	2,381.4	4,102.7	4,474.8	372.2	9.1%
		100,000	500	28%	22.17	4.04	0.52	0.20	4.76	2,402.2	28.15	8.90	0.20	(0.22)	8.88	4,469.5	2.11	0.62	0.70	1.06	2,477.2	-	100,000	5,517.2	11,104.8	12,463.9	1,359.1	12.2%
		400,000	1000	56%	22.17	4.04	0.52	0.20	4.76	4,782.2	28.15	8.90	0.20	(0.22)	8.88	8,910.8	2.11	0.62	0.70	1.06	7,670.0	-	400,000	22,068.8	35,861.8	38,649.6	2,787.9	7.8%
		1,000,000	3000	46%	22.17	4.04	0.52	0.20	4.76	14,302.2	28.15	8.90	0.20	(0.22)	8.88	26,676.3	2.11	0.62	0.70	1.06	20,294.3	-	1,000,000	55,172.0	93,866.5	102,142.6	8,276.1	8.8%
		1,500,000	4000	52%	22.17	4.04	0.52	0.20	4.76	19,062.2	28.15	8.90	0.20	(0.22)	8.88	35,559.0	2.11	0.62	0.70	1.06	29,322.1	-	1,500,000	82,758.0	136,543.3	147,639.1	11,095.8	8.1%
GSd	Nipigon	15,000	60	35%	23.32	3.38	1.07	0.68	5.13	331.1	28.86	8.80	0.68	(0.22)	9.26	584.6	2.11	0.62	0.7	1.061	338.0	-	15,000	827.6	1,580.5	1,750.2	169.6	10.7%
		43,164	133	45%	23.32	3.38	1.07	0.68	5.13	705.6	28.86	8.80	0.68	(0.22)	9.26	1,260.8	2.11	0.62	0.70	1.06	883.8	-	43,164	2,381.4	4,153.0	4,526.1	373.1	9.0%
		100,000	500	28%	23.32	3.38	1.07	0.68	5.13	2,588.3	28.86	8.80	0.68	(0.22)	9.26	4,660.2	2.11	0.62	0.70	1.06	2,477.2	-	100,000	5,517.2	11,290.9	12,654.6	1,363.7	12.1%
		400,000	1000	56%	23.32	3.38	1.07	0.68	5.13	5,153.3	28.86	8.80	0.68	(0.22)	9.26	9,291.6	2.11	0.62	0.70	1.06	7,670.0	-	400,000	22,068.8	36,232.9	39,030.4	2,797.5	7.7%
		1,000,000	3000	46%	23.32	3.38	1.07	0.68	5.13	15,413.3	28.86	8.80	0.68	(0.22)	9.26	27,817.0	2.11	0.62	0.70	1.06	20,294.3	-	1,000,000	55,172.0	94,977.7	103,283.3	8,305.6	8.7%
		1,500,000	4000	52%	23.32	3.38	1.07	0.68	5.13	20,543.3	28.86	8.80	0.68	(0.22)	9.26	37,079.7	2.11	0.62	0.70	1.06	29,322.1	-	1,500,000	82,758.0	138,024.5	149,159.8	11,135.4	8.1%
GSd	North Dorchester	15,000	60	35%	15.88	2.85	1.12	0.81	4.78	302.7	22.72	8.30	0.81	(0.22)	8.89	556.3	2.11	0.62	0.7	1.061	338.0	-	15,000	827.6	1,552.1	1,721.9	169.7	10.9%
		43,164	133	45%	15.88	2.85	1.12	0.81	4.78	651.6	22.72	8.30	0.81	(0.22)	8.89	1,205.4	2.11	0.62	0.70	1.06	883.8	-	43,164	2,381.4	4,099.0	4,470.7	371.7	9.1%
		100,000	500	28%	15.88	2.85	1.12	0.81	4.78	2,405.9	22.72	8.30	0.81	(0.22)	8.89	4,469.1	2.11	0.62	0.70	1.06	2,477.2	-	100,000	5,517.2	11,108.5	12,463.4	1,355.0	12.2%
		400,000	1000	56%	15.88	2.85	1.12	0.81	4.78	4,795.9	22.72	8.30	0.81	(0.22)	8.89	8,915.4	2.11	0.62	0.70	1.06	7,670.0	-	400,000	22,068.8	35,875.5	38,654.2	2,778.8	7.7%
		1,000,000	3000	46%	15.88	2.85	1.12	0.81	4.78	14,355.9	22.72	8.30	0.81	(0.22)	8.89	26,700.8	2.11	0.62	0.70	1.06	20,294.3	-	1,000,000	55,172.0	93,920.2	102,167.2	8,246.9	8.8%
		1,500,000	4000	52%	15.88	2.85	1.12	0.81	4.78	19,135.9	22.72	8.30	0.81	(0.22)	8.89	35,593.5	2.11	0.62	0.70	1.06	29,322.1	-	1,500,000	82,758.0	136,617.0	147,673.7	11,056.7	8.1%

New Rate Class: GSd

Total Bill Impacts of Proposed Distribution Rates [new RTSR+TLF]: Threshold of 750 kWhs

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Classes		Scenario			May 2007 Incl Rate Riders						May 2008 Incl Rate Riders						Non-Dx Compoent				Other Reg	Commodity Bands			Existing	New	$ Incr	% Incr
					Existing Dx Rates					Existing Dx	New Dx Rates					New Dx	RTSR new	WMSC	DRC	TLF new	New	Band 1	Band 2	New	Total Bill	Total Bill	Total Bill	Total Bill
																						-	5.2					
New Class	Old Class	kWh	kW	LF	SrChg [$/cust]	base [$/kW]	Rider1 [$/kW]	Rider2 [$/kW]	VarChg [$/kW]	[$/month]	SrChg [$/cust]	base [$/kW]	Rider2 [$/kW]	Rider3 [$/kW]	VarChg [$/kW]	[$/month]	$/kW	c/kWh	c/kWh		$	kWhs	kWhs	Total $	[$/month]	[$/month]	[$/month]	%
GSd	**North Dundas**	15,000	60	35%	**13.52**	**2.42**	**0.52**	**0.11**	**3.05**	196.5	**21.31**	**7.00**	**0.11**	**(0.22)**	**6.89**	434.9	**2.11**	0.62	0.7	**1.061**	338.0	-	15,000	827.6	1,445.9	1,600.4	154.5	10.7%
		43,164	133	45%	13.52	2.42	0.52	0.11	3.05	419.2	21.31	7.00	0.11	(0.22)	6.89	938.0	2.11	0.62	0.70	1.06	883.8	-	43,164	2,381.4	3,866.6	4,203.3	336.7	8.7%
		100,000	500	28%	13.52	2.42	0.52	0.11	3.05	1,538.5	21.31	7.00	0.11	(0.22)	6.89	3,467.7	2.11	0.62	0.70	1.06	2,477.2	-	100,000	5,517.2	10,241.1	11,462.0	1,220.9	11.9%
		400,000	1000	56%	13.52	2.42	0.52	0.11	3.05	3,063.5	21.31	7.00	0.11	(0.22)	6.89	6,914.0	2.11	0.62	0.70	1.06	7,670.0	-	400,000	22,068.8	34,143.1	36,652.8	2,509.7	7.4%
		1,000,000	3000	46%	13.52	2.42	0.52	0.11	3.05	9,163.5	21.31	7.00	0.11	(0.22)	6.89	20,699.4	2.11	0.62	0.70	1.06	20,294.3	-	1,000,000	55,172.0	88,727.9	96,165.7	7,437.9	8.4%
		1,500,000	4000	52%	13.52	2.42	0.52	0.11	3.05	12,213.5	21.31	7.00	0.11	(0.22)	6.89	27,592.1	2.11	0.62	0.70	1.06	29,322.1	-	1,500,000	82,758.0	129,694.7	139,672.3	9,977.6	7.7%
GSd	**North Glengarry**	15,000	60	35%	**17.72**	**2.82**	**0.69**	**0.39**	**3.90**	251.7	**24.26**	**7.70**	**0.39**	**(0.22)**	**7.87**	496.6	**2.11**	0.62	0.7	**1.061**	338.0	-	15,000	827.6	1,501.1	1,662.2	161.0	10.7%
		43,164	133	45%	17.72	2.82	0.69	0.39	3.90	536.4	24.26	7.70	0.39	(0.22)	7.87	1,071.3	2.11	0.62	0.70	1.06	883.8	-	43,164	2,381.4	3,983.8	4,336.6	352.8	8.9%
		100,000	500	28%	17.72	2.82	0.69	0.39	3.90	1,967.7	24.26	7.70	0.39	(0.22)	7.87	3,960.6	2.11	0.62	0.70	1.06	2,477.2	-	100,000	5,517.2	10,670.3	11,955.0	1,284.7	12.0%
		400,000	1000	56%	17.72	2.82	0.69	0.39	3.90	3,917.7	24.26	7.70	0.39	(0.22)	7.87	7,897.0	2.11	0.62	0.70	1.06	7,670.0	-	400,000	22,068.8	34,997.3	37,635.8	2,638.5	7.5%
		1,000,000	3000	46%	17.72	2.82	0.69	0.39	3.90	11,717.7	24.26	7.70	0.39	(0.22)	7.87	23,642.4	2.11	0.62	0.70	1.06	20,294.3	-	1,000,000	55,172.0	91,282.1	99,108.7	7,826.6	8.6%
		1,500,000	4000	52%	17.72	2.82	0.69	0.39	3.90	15,617.7	24.26	7.70	0.39	(0.22)	7.87	31,515.1	2.11	0.62	0.70	1.06	29,322.1	-	1,500,000	82,758.0	133,098.9	143,595.2	10,496.4	7.9%
GSd	**North Grenville**	15,000	60	35%	**20.42**	**5.41**	**0.45**	**0.25**	**6.11**	387.0	**26.58**	**9.22**	**0.25**	**(0.22)**	**9.26**	582.0	**2.11**	0.62	0.7	**1.061**	338.0	-	15,000	827.6	1,636.4	1,747.5	111.1	6.8%
		43,164	133	45%	20.42	5.41	0.45	0.25	6.11	833.1	26.58	9.22	0.25	(0.22)	9.26	1,257.7	2.11	0.62	0.70	1.06	883.8	-	43,164	2,381.4	4,280.5	4,523.0	242.5	5.7%
		100,000	500	28%	20.42	5.41	0.45	0.25	6.11	3,075.4	26.58	9.22	0.25	(0.22)	9.26	4,654.7	2.11	0.62	0.70	1.06	2,477.2	-	100,000	5,517.2	11,778.0	12,649.1	871.1	7.4%
		400,000	1000	56%	20.42	5.41	0.45	0.25	6.11	6,130.4	26.58	9.22	0.25	(0.22)	9.26	9,282.9	2.11	0.62	0.70	1.06	7,670.0	-	400,000	22,068.8	37,210.0	39,021.7	1,811.7	4.9%
		1,000,000	3000	46%	20.42	5.41	0.45	0.25	6.11	18,350.4	26.58	9.22	0.25	(0.22)	9.26	27,795.4	2.11	0.62	0.70	1.06	20,294.3	-	1,000,000	55,172.0	97,914.8	103,261.8	5,347.0	5.5%
		1,500,000	4000	52%	20.42	5.41	0.45	0.25	6.11	24,460.4	26.58	9.22	0.25	(0.22)	9.26	37,051.7	2.11	0.62	0.70	1.06	29,322.1	-	1,500,000	82,758.0	141,941.6	149,131.9	7,190.3	5.1%
GSd	**North Perth**	15,000	60	35%	**29.52**	**3.16**	**0.36**	**0.13**	**3.65**	248.5	**33.31**	**7.70**	**0.13**	**(0.22)**	**7.61**	490.1	**2.11**	0.62	0.7	**1.061**	338.0	-	15,000	827.6	1,497.9	1,655.6	157.7	10.5%
		43,164	133	45%	29.52	3.16	0.36	0.13	3.65	515.0	33.31	7.70	0.13	(0.22)	7.61	1,045.8	2.11	0.62	0.70	1.06	883.8	-	43,164	2,381.4	3,962.4	4,311.1	348.7	8.8%
		100,000	500	28%	29.52	3.16	0.36	0.13	3.65	1,854.5	33.31	7.70	0.13	(0.22)	7.61	3,839.7	2.11	0.62	0.70	1.06	2,477.2	-	100,000	5,517.2	10,557.1	11,834.0	1,276.9	12.1%
		400,000	1000	56%	29.52	3.16	0.36	0.13	3.65	3,679.5	33.31	7.70	0.13	(0.22)	7.61	7,646.0	2.11	0.62	0.70	1.06	7,670.0	-	400,000	22,068.8	34,759.1	37,384.8	2,625.7	7.6%
		1,000,000	3000	46%	29.52	3.16	0.36	0.13	3.65	10,979.5	33.31	7.70	0.13	(0.22)	7.61	22,871.4	2.11	0.62	0.70	1.06	20,294.3	-	1,000,000	55,172.0	90,543.9	98,337.7	7,793.9	8.6%
		1,500,000	4000	52%	29.52	3.16	0.36	0.13	3.65	14,629.5	33.31	7.70	0.13	(0.22)	7.61	30,484.1	2.11	0.62	0.70	1.06	29,322.1	-	1,500,000	82,758.0	132,110.7	142,564.3	10,453.6	7.9%
GSd	**North Stormont**	15,000	60	35%	**5.37**	**2.52**	**1.17**	**0.82**	**4.51**	276.0	**15.35**	**9.22**	**0.82**	**(0.22)**	**9.83**	604.9	**2.11**	0.62	0.7	**1.061**	338.0	-	15,000	827.6	1,525.4	1,770.5	245.1	16.1%
	no customer	43,164	133	45%	5.37	2.52	1.17	0.82	4.51	605.2	15.35	9.22	0.82	(0.22)	9.83	1,322.2	2.11	0.62	0.70	1.06	883.8	-	43,164	2,381.4	4,052.6	4,587.5	534.9	13.2%
		100,000	500	28%	5.37	2.52	1.17	0.82	4.51	2,260.4	15.35	9.22	0.82	(0.22)	9.83	4,928.5	2.11	0.62	0.70	1.06	2,477.2	-	100,000	5,517.2	10,963.0	12,922.9	1,959.9	17.9%
		400,000	1000	56%	5.37	2.52	1.17	0.82	4.51	4,515.4	15.35	9.22	0.82	(0.22)	9.83	9,841.6	2.11	0.62	0.70	1.06	7,670.0	-	400,000	22,068.8	35,595.0	39,580.4	3,985.5	11.2%
		1,000,000	3000	46%	5.37	2.52	1.17	0.82	4.51	13,535.4	15.35	9.22	0.82	(0.22)	9.83	29,494.2	2.11	0.62	0.70	1.06	20,294.3	-	1,000,000	55,172.0	93,099.7	104,960.5	11,860.8	12.7%
		1,500,000	4000	52%	5.37	2.52	1.17	0.82	4.51	18,045.4	15.35	9.22	0.82	(0.22)	9.83	39,320.5	2.11	0.62	0.70	1.06	29,322.1	-	1,500,000	82,758.0	135,526.5	151,400.6	15,874.1	11.7%

New Rate Class: GSd

Total Bill Impacts of Proposed Distribution Rates [new RTSR+TLF]: Threshold of 750 kWhs

Classes		Scenario			May 2007 Incl Rate Riders						May 2008 Incl Rate Riders						Non-Dx Compoent				Other Reg	Commodity Bands			Existing	New	$ Incr	% Incr
					Existing Dx Rates					Existing Dx	New Dx Rates					New Dx	RTSR new	WMSC	DRC	TLF new	New	Band 1	Band 2	New	Total Bill	Total Bill	Total Bill	Total Bill
																						-	5.2					
New Class	Old Class	kWh	kW	LF	SrChg [$/cust]	base [$/kW]	Rider1 [$/kW]	Rider2 [$/kW]	VarChg [$/kW]	[$/month]	SrChg [$/cust]	base [$/kW]	Rider2 [$/kW]	Rider3 [$/kW]	VarChg [$/kW]	[$/month]	$/kW	c/kWh	c/kWh		$	kWhs	kWhs	Total $	[$/month]	[$/month]	[$/month]	%
GSd	Omemee	15,000	60	35%	**21.28**	**4.64**	**0.55**	**0.27**	**5.46**	348.9	**27.37**	**9.22**	**0.27**	**(0.22)**	**9.28**	583.9	**2.11**	0.62	0.7	**1.061**	338.0	-	15,000	827.6	1,598.3	1,749.5	151.2	9.5%
		43,164	133	45%	21.28	4.64	0.55	0.27	5.46	747.5	27.37	9.22	0.27	(0.22)	9.28	1,261.1	2.11	0.62	0.70	1.06	883.8	-	43,164	2,381.4	4,194.9	4,526.4	331.5	7.9%
		100,000	500	28%	21.28	4.64	0.55	0.27	5.46	2,751.3	27.37	9.22	0.27	(0.22)	9.28	4,665.5	2.11	0.62	0.70	1.06	2,477.2	-	100,000	5,517.2	11,453.9	12,659.9	1,206.0	10.5%
		400,000	1000	56%	21.28	4.64	0.55	0.27	5.46	5,481.3	27.37	9.22	0.27	(0.22)	9.28	9,303.7	2.11	0.62	0.70	1.06	7,670.0	-	400,000	22,068.8	36,560.9	39,042.4	2,481.6	6.8%
		1,000,000	3000	46%	21.28	4.64	0.55	0.27	5.46	16,401.3	27.37	9.22	0.27	(0.22)	9.28	27,856.2	2.11	0.62	0.70	1.06	20,294.3	-	1,000,000	55,172.0	95,965.6	103,322.5	7,356.9	7.7%
		1,500,000	4000	52%	21.28	4.64	0.55	0.27	5.46	21,861.3	27.37	9.22	0.27	(0.22)	9.28	37,132.5	2.11	0.62	0.70	1.06	29,322.1	-	1,500,000	82,758.0	139,342.4	149,212.6	9,870.2	7.1%
UGd	Perth	15,000	60	35%	**19.92**	**2.87**	**0.42**	**0.12**	**3.41**	224.5	**21.32**	**7.15**	**0.12**	**(0.27)**	**7.00**	441.1	**2.68**	0.62	0.7	**1.061**	374.3	-	15,000	827.6	1,473.9	1,643.0	169.1	11.5%
		43,164	133	45%	19.92	2.87	0.42	0.12	3.41	473.5	21.32	7.15	0.12	(0.27)	7.00	951.9	2.68	0.62	0.70	1.06	964.3	-	43,164	2,381.4	3,920.9	4,297.7	376.8	9.6%
		100,000	500	28%	19.92	2.87	0.42	0.12	3.41	1,724.9	21.32	7.15	0.12	(0.27)	7.00	3,519.9	2.68	0.62	0.70	1.06	2,779.6	-	100,000	5,517.2	10,427.5	11,816.6	1,389.1	13.3%
		400,000	1000	56%	19.92	2.87	0.42	0.12	3.41	3,429.9	21.32	7.15	0.12	(0.27)	7.00	7,018.4	2.68	0.62	0.70	1.06	8,274.8	-	400,000	22,068.8	34,509.5	37,362.0	2,852.5	8.3%
		1,000,000	3000	46%	19.92	2.87	0.42	0.12	3.41	10,249.9	21.32	7.15	0.12	(0.27)	7.00	21,012.7	2.68	0.62	0.70	1.06	22,108.6	-	1,000,000	55,172.0	89,814.3	98,293.3	8,479.1	9.4%
		1,500,000	4000	52%	19.92	2.87	0.42	0.12	3.41	13,659.9	21.32	7.15	0.12	(0.27)	7.00	28,009.8	2.68	0.62	0.70	1.06	31,741.2	-	1,500,000	82,758.0	131,141.1	142,509.0	11,368.0	8.7%
GSd	Perth East	15,000	60	35%	**14.65**	**4.08**	**0.52**	**0.27**	**4.87**	306.9	**22.03**	**8.95**	**0.27**	**(0.22)**	**9.00**	562.2	**2.11**	0.62	0.7	**1.061**	338.0	-	15,000	827.6	1,556.3	1,727.8	171.5	11.0%
		43,164	133	45%	14.65	4.08	0.52	0.27	4.87	662.4	22.03	8.95	0.27	(0.22)	9.00	1,219.4	2.11	0.62	0.70	1.06	883.8	-	43,164	2,381.4	4,109.8	4,484.7	374.9	9.1%
		100,000	500	28%	14.65	4.08	0.52	0.27	4.87	2,449.7	22.03	8.95	0.27	(0.22)	9.00	4,523.4	2.11	0.62	0.70	1.06	2,477.2	-	100,000	5,517.2	11,152.3	12,517.8	1,365.5	12.2%
		400,000	1000	56%	14.65	4.08	0.52	0.27	4.87	4,884.7	22.03	8.95	0.27	(0.22)	9.00	9,024.7	2.11	0.62	0.70	1.06	7,670.0	-	400,000	22,068.8	35,964.2	38,763.5	2,799.3	7.8%
		1,000,000	3000	46%	14.65	4.08	0.52	0.27	4.87	14,624.7	22.03	8.95	0.27	(0.22)	9.00	27,030.1	2.11	0.62	0.70	1.06	20,294.3	-	1,000,000	55,172.0	94,189.0	102,496.5	8,307.5	8.8%
		1,500,000	4000	52%	14.65	4.08	0.52	0.27	4.87	19,494.7	22.03	8.95	0.27	(0.22)	9.00	36,032.8	2.11	0.62	0.70	1.06	29,322.1	-	1,500,000	82,758.0	136,975.8	148,113.0	11,137.2	8.1%
GSd	Prince Edward	15,000	60	35%	**22.85**	**4.45**	**0.58**	**0.24**	**5.27**	339.1	**27.98**	**9.22**	**0.24**	**(0.22)**	**9.25**	582.8	**2.11**	0.62	0.7	**1.061**	338.0	-	15,000	827.6	1,588.5	1,748.3	159.8	10.1%
		43,164	133	45%	22.85	4.45	0.58	0.24	5.27	723.8	27.98	9.22	0.24	(0.22)	9.25	1,257.7	2.11	0.62	0.70	1.06	883.8	-	43,164	2,381.4	4,171.2	4,523.0	351.8	8.4%
		100,000	500	28%	22.85	4.45	0.58	0.24	5.27	2,657.9	27.98	9.22	0.24	(0.22)	9.25	4,651.1	2.11	0.62	0.70	1.06	2,477.2	-	100,000	5,517.2	11,360.5	12,645.5	1,285.0	11.3%
		400,000	1000	56%	22.85	4.45	0.58	0.24	5.27	5,292.9	27.98	9.22	0.24	(0.22)	9.25	9,274.3	2.11	0.62	0.70	1.06	7,670.0	-	400,000	22,068.8	36,372.4	39,013.0	2,640.6	7.3%
		1,000,000	3000	46%	22.85	4.45	0.58	0.24	5.27	15,832.9	27.98	9.22	0.24	(0.22)	9.25	27,766.8	2.11	0.62	0.70	1.06	20,294.3	-	1,000,000	55,172.0	95,397.2	103,233.2	7,835.9	8.2%
		1,500,000	4000	52%	22.85	4.45	0.58	0.24	5.27	21,102.9	27.98	9.22	0.24	(0.22)	9.25	37,013.1	2.11	0.62	0.70	1.06	29,322.1	-	1,500,000	82,758.0	138,584.0	149,093.3	10,509.3	7.6%
UGd	Quinte West	15,000	60	35%	**3.74**	**3.32**	**0.46**	**0.18**	**3.96**	241.3	**9.36**	**7.33**	**0.18**	**(0.27)**	**7.24**	443.8	**2.68**	0.62	0.7	**1.061**	374.3	-	15,000	827.6	1,490.8	1,645.6	154.9	10.4%
		43,164	133	45%	3.74	3.32	0.46	0.18	3.96	530.4	9.36	7.33	0.18	(0.27)	7.24	972.3	2.68	0.62	0.70	1.06	964.3	-	43,164	2,381.4	3,977.8	4,318.0	340.2	8.6%
		100,000	500	28%	3.74	3.32	0.46	0.18	3.96	1,983.7	9.36	7.33	0.18	(0.27)	7.24	3,629.5	2.68	0.62	0.70	1.06	2,779.6	-	100,000	5,517.2	10,686.3	11,926.2	1,239.9	11.6%
		400,000	1000	56%	3.74	3.32	0.46	0.18	3.96	3,963.7	9.36	7.33	0.18	(0.27)	7.24	7,249.6	2.68	0.62	0.70	1.06	8,274.8	-	400,000	22,068.8	35,043.3	37,593.1	2,549.8	7.3%
		1,000,000	3000	46%	3.74	3.32	0.46	0.18	3.96	11,883.7	9.36	7.33	0.18	(0.27)	7.24	21,730.0	2.68	0.62	0.70	1.06	22,108.6	-	1,000,000	55,172.0	91,448.1	99,010.6	7,562.5	8.3%
		1,500,000	4000	52%	3.74	3.32	0.46	0.18	3.96	15,843.7	9.36	7.33	0.18	(0.27)	7.24	28,970.2	2.68	0.62	0.70	1.06	31,741.2	-	1,500,000	82,758.0	133,324.9	143,469.4	10,144.5	7.6%

New Rate Class: GSd

Total Bill Impacts of Proposed Distribution Rates [new RTSR+TLF]: Threshold of 750 kWhs

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Classes		Scenario			May 2007 Incl Rate Riders						May 2008 Incl Rate Riders						Non-Dx Compoent				Other Reg	Commodity Bands			Existing	New	$ Incr	% Incr
					Existing Dx Rates					Existing Dx	New Dx Rates					New Dx	RTSR new	WMSC	DRC	TLF new	New	Band 1	Band 2	New	Total Bill	Total Bill	Total Bill	Total Bill
																						-	5.2					
New Class	Old Class	kWh	kW	LF	SrChg [$/cust]	base [$/kW]	Rider1 [$/kW]	Rider2 [$/kW]	VarChg [$/kW]	[$/month]	SrChg [$/cust]	base [$/kW]	Rider2 [$/kW]	Rider3 [$/kW]	VarChg [$/kW]	[$/month]	$/kW	c/kWh	c/kWh		$	kWhs	kWhs	Total $	[$/month]	[$/month]	[$/month]	%
GSd	Rainy River	15,000	60	35%	19.29	5.59	1.44	1.14	8.17	509.5	25.87	9.22	1.14	(0.22)	10.15	634.6	2.11	0.62	0.7	1.061	338.0	-	15,000	827.6	1,758.9	1,800.2	41.3	2.3%
		43,164	133	45%	19.29	5.59	1.44	1.14	8.17	1,105.9	25.87	9.22	1.14	(0.22)	10.15	1,375.3	2.11	0.62	0.70	1.06	883.8	-	43,164	2,381.4	4,553.3	4,640.6	87.3	1.9%
		100,000	500	28%	19.29	5.59	1.44	1.14	8.17	4,104.3	25.87	9.22	1.14	(0.22)	10.15	5,099.0	2.11	0.62	0.70	1.06	2,477.2	-	100,000	5,517.2	12,806.9	13,093.4	286.5	2.2%
		400,000	1000	56%	19.29	5.59	1.44	1.14	8.17	8,189.3	25.87	9.22	1.14	(0.22)	10.15	10,172.1	2.11	0.62	0.70	1.06	7,670.0	-	400,000	22,068.8	39,268.9	39,910.9	642.1	1.6%
		1,000,000	3000	46%	19.29	5.59	1.44	1.14	8.17	24,529.3	25.87	9.22	1.14	(0.22)	10.15	30,464.7	2.11	0.62	0.70	1.06	20,294.3	-	1,000,000	55,172.0	104,093.7	105,931.0	1,837.4	1.8%
		1,500,000	4000	52%	19.29	5.59	1.44	1.14	8.17	32,699.3	25.87	9.22	1.14	(0.22)	10.15	40,611.0	2.11	0.62	0.70	1.06	29,322.1	-	1,500,000	82,758.0	150,180.4	152,691.1	2,510.7	1.7%
GSd	Ramara	15,000	60	35%	20.97	3.35	1.43	1.16	5.94	377.4	26.45	9.22	1.16	(0.22)	10.17	636.4	2.11	0.62	0.7	1.061	338.0	-	15,000	827.6	1,626.8	1,802.0	175.2	10.8%
		43,164	133	45%	20.97	3.35	1.43	1.16	5.94	811.0	26.45	9.22	1.16	(0.22)	10.17	1,378.6	2.11	0.62	0.70	1.06	883.8	-	43,164	2,381.4	4,258.4	4,643.8	385.4	9.1%
		100,000	500	28%	20.97	3.35	1.43	1.16	5.94	2,991.0	26.45	9.22	1.16	(0.22)	10.17	5,109.6	2.11	0.62	0.70	1.06	2,477.2	-	100,000	5,517.2	11,693.6	13,104.0	1,410.4	12.1%
		400,000	1000	56%	20.97	3.35	1.43	1.16	5.94	5,961.0	26.45	9.22	1.16	(0.22)	10.17	10,192.7	2.11	0.62	0.70	1.06	7,670.0	-	400,000	22,068.8	37,040.6	39,931.5	2,891.0	7.8%
		1,000,000	3000	46%	20.97	3.35	1.43	1.16	5.94	17,841.0	26.45	9.22	1.16	(0.22)	10.17	30,525.3	2.11	0.62	0.70	1.06	20,294.3	-	1,000,000	55,172.0	97,405.3	105,991.6	8,586.3	8.8%
		1,500,000	4000	52%	20.97	3.35	1.43	1.16	5.94	23,781.0	26.45	9.22	1.16	(0.22)	10.17	40,691.6	2.11	0.62	0.70	1.06	29,322.1	-	1,500,000	82,758.0	141,262.1	152,771.7	11,509.6	8.1%
GSd	Red Rock	15,000	60	35%	21.64	6.15	0.86	0.75	7.76	487.2	27.28	9.22	0.75	(0.22)	9.76	612.7	2.11	0.62	0.7	1.061	338.0	-	15,000	827.6	1,736.7	1,778.2	41.6	2.4%
		43,164	133	45%	21.64	6.15	0.86	0.75	7.76	1,053.7	27.28	9.22	0.75	(0.22)	9.76	1,324.9	2.11	0.62	0.70	1.06	883.8	-	43,164	2,381.4	4,501.1	4,590.1	89.0	2.0%
		100,000	500	28%	21.64	6.15	0.86	0.75	7.76	3,901.6	27.28	9.22	0.75	(0.22)	9.76	4,905.4	2.11	0.62	0.70	1.06	2,477.2	-	100,000	5,517.2	12,604.2	12,899.8	295.6	2.3%
		400,000	1000	56%	21.64	6.15	0.86	0.75	7.76	7,781.6	27.28	9.22	0.75	(0.22)	9.76	9,783.6	2.11	0.62	0.70	1.06	7,670.0	-	400,000	22,068.8	38,861.2	39,522.4	661.1	1.7%
		1,000,000	3000	46%	21.64	6.15	0.86	0.75	7.76	23,301.6	27.28	9.22	0.75	(0.22)	9.76	29,296.1	2.11	0.62	0.70	1.06	20,294.3	-	1,000,000	55,172.0	102,866.0	104,762.5	1,896.5	1.8%
		1,500,000	4000	52%	21.64	6.15	0.86	0.75	7.76	31,061.6	27.28	9.22	0.75	(0.22)	9.76	39,052.4	2.11	0.62	0.70	1.06	29,322.1	-	1,500,000	82,758.0	148,542.8	151,132.6	2,589.8	1.7%
GSd	Rockland	15,000	60	35%	7.27	2.59	0.53	0.57	3.69	228.7	16.87	7.25	0.57	(0.22)	7.60	473.0	2.11	0.62	0.7	1.061	338.0	-	15,000	827.6	1,478.1	1,638.6	160.5	10.9%
		43,164	133	45%	7.27	2.59	0.53	0.57	3.69	498.0	16.87	7.25	0.57	(0.22)	7.60	1,028.0	2.11	0.62	0.70	1.06	883.8	-	43,164	2,381.4	3,945.4	4,293.3	347.9	8.8%
		100,000	500	28%	7.27	2.59	0.53	0.57	3.69	1,852.3	16.87	7.25	0.57	(0.22)	7.60	3,818.2	2.11	0.62	0.70	1.06	2,477.2	-	100,000	5,517.2	10,554.9	11,812.6	1,257.7	11.9%
		400,000	1000	56%	7.27	2.59	0.53	0.57	3.69	3,697.3	16.87	7.25	0.57	(0.22)	7.60	7,619.6	2.11	0.62	0.70	1.06	7,670.0	-	400,000	22,068.8	34,776.9	37,358.4	2,581.5	7.4%
		1,000,000	3000	46%	7.27	2.59	0.53	0.57	3.69	11,077.3	16.87	7.25	0.57	(0.22)	7.60	22,825.0	2.11	0.62	0.70	1.06	20,294.3	-	1,000,000	55,172.0	90,641.6	98,291.3	7,649.7	8.4%
		1,500,000	4000	52%	7.27	2.59	0.53	0.57	3.69	14,767.3	16.87	7.25	0.57	(0.22)	7.60	30,427.7	2.11	0.62	0.70	1.06	29,322.1	-	1,500,000	82,758.0	132,248.4	142,507.8	10,259.4	7.8%
GSd	Russell	15,000	60	35%	19.26	7.10	0.58	0.36	8.04	501.7	25.87	9.22	0.36	(0.22)	9.37	587.8	2.11	0.62	0.7	1.061	338.0	-	15,000	827.6	1,751.1	1,753.4	2.3	0.1%
		43,164	133	45%	19.26	7.10	0.58	0.36	8.04	1,088.6	25.87	9.22	0.36	(0.22)	9.37	1,271.6	2.11	0.62	0.70	1.06	883.8	-	43,164	2,381.4	4,536.0	4,536.9	0.9	0.0%
		100,000	500	28%	19.26	7.10	0.58	0.36	8.04	4,039.3	25.87	9.22	0.36	(0.22)	9.37	4,709.0	2.11	0.62	0.70	1.06	2,477.2	-	100,000	5,517.2	12,741.9	12,703.4	(38.5)	-0.3%
		400,000	1000	56%	19.26	7.10	0.58	0.36	8.04	8,059.3	25.87	9.22	0.36	(0.22)	9.37	9,392.2	2.11	0.62	0.70	1.06	7,670.0	-	400,000	22,068.8	39,138.8	39,130.9	(7.9)	0.0%
		1,000,000	3000	46%	19.26	7.10	0.58	0.36	8.04	24,139.3	25.87	9.22	0.36	(0.22)	9.37	28,124.7	2.11	0.62	0.70	1.06	20,294.3	-	1,000,000	55,172.0	103,703.6	103,591.1	(112.6)	-0.1%
		1,500,000	4000	52%	19.26	7.10	0.58	0.36	8.04	32,179.3	25.87	9.22	0.36	(0.22)	9.37	37,491.0	2.11	0.62	0.70	1.06	29,322.1	-	1,500,000	82,758.0	149,660.4	149,571.1	(89.2)	-0.1%

New Rate Class: GSd

Total Bill Impacts of Proposed Distribution Rates [new RTSR+TLF]: Threshold of 750 kWhs

Classes		Scenario			May 2007 Incl Rate Riders						May 2008 Incl Rate Riders						Non-Dx Compoent				Other Reg	Commodity Bands			Existing	New	$ Incr	% Incr
					Existing Dx Rates					Existing Dx	New Dx Rates					New Dx	RTSR new	WMSC	DRC	TLF new	New	Band 1	Band 2	New	Total Bill	Total Bill	Total Bill	Total Bill
																						-	5.2					
New Class	Old Class	kWh	kW	LF	SrChg	base	Rider1	Rider2	VarChg	[$/month]	SrChg	base	Rider2	Rider3	VarChg	[$/month]	$/kW	c/kWh	c/kWh		$	kWhs	kWhs	Total $	[$/month]	[$/month]	[$/month]	%
					[$/cust]	[$/kW]	[$/kW]	[$/kW]	[$/kW]		[$/cust]	[$/kW]	[$/kW]	[$/kW]	[$/kW]													
GSd	Schreiber	15,000	60	35%	20.70	7.36	1.57	1.17	10.10	626.7	26.51	9.22	1.17	(0.22)	10.18	637.1	2.11	0.62	0.7	1.061	338.0	-	15,000	827.6	1,876.1	1,802.7	(73.5)	-3.9%
		43,164	133	45%	20.70	7.36	1.57	1.17	10.10	1,364.0	26.51	9.22	1.17	(0.22)	10.18	1,380.0	2.11	0.62	0.70	1.06	883.8	-	43,164	2,381.4	4,811.4	4,645.2	(166.2)	-3.5%
		100,000	500	28%	20.70	7.36	1.57	1.17	10.10	5,070.7	26.51	9.22	1.17	(0.22)	10.18	5,114.7	2.11	0.62	0.70	1.06	2,477.2	-	100,000	5,517.2	13,773.3	13,109.0	(664.3)	-4.8%
		400,000	1000	56%	20.70	7.36	1.57	1.17	10.10	10,120.7	26.51	9.22	1.17	(0.22)	10.18	10,202.8	2.11	0.62	0.70	1.06	7,670.0	-	400,000	22,068.8	41,200.3	39,941.6	(1,258.7)	-3.1%
		1,000,000	3000	46%	20.70	7.36	1.57	1.17	10.10	30,320.7	26.51	9.22	1.17	(0.22)	10.18	30,555.4	2.11	0.62	0.70	1.06	20,294.3	-	1,000,000	55,172.0	109,885.1	106,021.7	(3,863.4)	-3.5%
		1,500,000	4000	52%	20.70	7.36	1.57	1.17	10.10	40,420.7	26.51	9.22	1.17	(0.22)	10.18	40,731.6	2.11	0.62	0.70	1.06	29,322.1	-	1,500,000	82,758.0	157,901.8	152,811.8	(5,090.0)	-3.2%
GSd	Severn	15,000	60	35%	22.17	3.35	0.98	0.69	5.02	323.4	28.15	8.70	0.69	(0.22)	9.17	578.5	2.11	0.62	0.7	1.061	338.0	-	15,000	827.6	1,572.8	1,744.1	171.3	10.9%
		43,164	133	45%	22.17	3.35	0.98	0.69	5.02	689.8	28.15	8.70	0.69	(0.22)	9.17	1,248.1	2.11	0.62	0.70	1.06	883.8	-	43,164	2,381.4	4,137.2	4,513.4	376.2	9.1%
		100,000	500	28%	22.17	3.35	0.98	0.69	5.02	2,532.2	28.15	8.70	0.69	(0.22)	9.17	4,614.5	2.11	0.62	0.70	1.06	2,477.2	-	100,000	5,517.2	11,234.8	12,608.9	1,374.1	12.2%
		400,000	1000	56%	22.17	3.35	0.98	0.69	5.02	5,042.2	28.15	8.70	0.69	(0.22)	9.17	9,200.8	2.11	0.62	0.70	1.06	7,670.0	-	400,000	22,068.8	36,121.8	38,939.6	2,817.9	7.8%
		1,000,000	3000	46%	22.17	3.35	0.98	0.69	5.02	15,082.2	28.15	8.70	0.69	(0.22)	9.17	27,546.3	2.11	0.62	0.70	1.06	20,294.3	-	1,000,000	55,172.0	94,646.5	103,012.6	8,366.1	8.8%
		1,500,000	4000	52%	22.17	3.35	0.98	0.69	5.02	20,102.2	28.15	8.70	0.69	(0.22)	9.17	36,719.0	2.11	0.62	0.70	1.06	29,322.1	-	1,500,000	82,758.0	137,583.3	148,799.1	11,215.8	8.2%
GSd	Shelburne	15,000	60	35%	20.01	2.78	0.32	0.08	3.18	210.8	26.69	7.25	0.08	(0.22)	7.11	453.4	2.11	0.62	0.7	1.061	338.0	-	15,000	827.6	1,460.2	1,619.0	158.8	10.9%
		43,164	133	45%	20.01	2.78	0.32	0.08	3.18	443.0	26.69	7.25	0.08	(0.22)	7.11	972.7	2.11	0.62	0.70	1.06	883.8	-	43,164	2,381.4	3,890.4	4,238.0	347.6	8.9%
		100,000	500	28%	20.01	2.78	0.32	0.08	3.18	1,610.0	26.69	7.25	0.08	(0.22)	7.11	3,583.0	2.11	0.62	0.70	1.06	2,477.2	-	100,000	5,517.2	10,312.6	11,577.4	1,264.8	12.3%
		400,000	1000	56%	20.01	2.78	0.32	0.08	3.18	3,200.0	26.69	7.25	0.08	(0.22)	7.11	7,139.4	2.11	0.62	0.70	1.06	7,670.0	-	400,000	22,068.8	34,279.6	36,878.2	2,598.6	7.6%
		1,000,000	3000	46%	20.01	2.78	0.32	0.08	3.18	9,560.0	26.69	7.25	0.08	(0.22)	7.11	21,364.8	2.11	0.62	0.70	1.06	20,294.3	-	1,000,000	55,172.0	89,124.4	96,831.1	7,706.8	8.6%
		1,500,000	4000	52%	20.01	2.78	0.32	0.08	3.18	12,740.0	26.69	7.25	0.08	(0.22)	7.11	28,477.5	2.11	0.62	0.70	1.06	29,322.1	-	1,500,000	82,758.0	130,221.1	140,557.6	10,336.5	7.9%
UGd	Smiths Falls	15,000	60	35%	9.84	3.33	0.39	0.13	3.85	240.8	13.84	7.33	0.13	(0.27)	7.19	445.2	2.68	0.62	0.7	1.061	374.3	-	15,000	827.6	1,490.3	1,647.1	156.8	10.5%
		43,164	133	45%	9.84	3.33	0.39	0.13	3.85	521.9	13.84	7.33	0.13	(0.27)	7.19	970.1	2.68	0.62	0.70	1.06	964.3	-	43,164	2,381.4	3,969.3	4,315.9	346.6	8.7%
		100,000	500	28%	9.84	3.33	0.39	0.13	3.85	1,934.8	13.84	7.33	0.13	(0.27)	7.19	3,608.9	2.68	0.62	0.70	1.06	2,779.6	-	100,000	5,517.2	10,637.4	11,905.7	1,268.3	11.9%
		400,000	1000	56%	9.84	3.33	0.39	0.13	3.85	3,859.8	13.84	7.33	0.13	(0.27)	7.19	7,204.0	2.68	0.62	0.70	1.06	8,274.8	-	400,000	22,068.8	34,939.4	37,547.6	2,608.2	7.5%
		1,000,000	3000	46%	9.84	3.33	0.39	0.13	3.85	11,559.8	13.84	7.33	0.13	(0.27)	7.19	21,584.5	2.68	0.62	0.70	1.06	22,108.6	-	1,000,000	55,172.0	91,124.2	98,865.1	7,740.9	8.5%
		1,500,000	4000	52%	9.84	3.33	0.39	0.13	3.85	15,409.8	13.84	7.33	0.13	(0.27)	7.19	28,774.7	2.68	0.62	0.70	1.06	31,741.2	-	1,500,000	82,758.0	132,891.0	143,273.9	10,382.9	7.8%
GSd	South Glengarry	15,000	60	35%	17.41	2.37	1.18	0.94	4.49	286.8	24.34	7.75	0.94	(0.22)	8.47	532.7	2.11	0.62	0.7	1.061	338.0	-	15,000	827.6	1,536.2	1,698.3	162.0	10.5%
		43,164	133	45%	17.41	2.37	1.18	0.94	4.49	614.6	24.34	7.75	0.94	(0.22)	8.47	1,151.2	2.11	0.62	0.70	1.06	883.8	-	43,164	2,381.4	4,062.0	4,416.5	354.5	8.7%
		100,000	500	28%	17.41	2.37	1.18	0.94	4.49	2,262.4	24.34	7.75	0.94	(0.22)	8.47	4,260.7	2.11	0.62	0.70	1.06	2,477.2	-	100,000	5,517.2	10,965.0	12,255.1	1,290.1	11.8%
		400,000	1000	56%	17.41	2.37	1.18	0.94	4.49	4,507.4	24.34	7.75	0.94	(0.22)	8.47	8,497.0	2.11	0.62	0.70	1.06	7,670.0	-	400,000	22,068.8	35,587.0	38,235.8	2,648.8	7.4%
		1,000,000	3000	46%	17.41	2.37	1.18	0.94	4.49	13,487.4	24.34	7.75	0.94	(0.22)	8.47	25,442.4	2.11	0.62	0.70	1.06	20,294.3	-	1,000,000	55,172.0	93,051.8	100,908.8	7,857.0	8.4%
		1,500,000	4000	52%	17.41	2.37	1.18	0.94	4.49	17,977.4	24.34	7.75	0.94	(0.22)	8.47	33,915.1	2.11	0.62	0.70	1.06	29,322.1	-	1,500,000	82,758.0	135,458.5	145,995.3	10,536.7	7.8%

New Rate Class: GSd

Total Bill Impacts of Proposed Distribution Rates [new RTSR+TLF]: Threshold of 750 kWhs

Classes		Scenario			May 2007 Incl Rate Riders						May 2008 Incl Rate Riders						Non-Dx Compoent				Other Reg	Commodity Bands			Existing	New	$ Incr	% Incr
					Existing Dx Rates					Existing Dx	New Dx Rates					New Dx	RTSR new	WMSC	DRC	TLF new	New	Band 1	Band 2	New	Total Bill	Total Bill	Total Bill	Total Bill
																						-	5.2					
New Class	Old Class	kWh	kW	LF	SrChg	base	Rider1	Rider2	VarChg	[$/month]	SrChg	base	Rider2	Rider3	VarChg	[$/month]	$/kW	c/kWh	c/kWh		$	kWhs	kWhs	Total $	[$/month]	[$/month]	[$/month]	%
					[$/cust]	[$/kW]	[$/kW]	[$/kW]	[$/kW]		[$/cust]	[$/kW]	[$/kW]	[$/kW]	[$/kW]													
GSd	**South River**	15,000	60	35%	**22.11**	**4.87**	**1.22**	**0.92**	**7.01**	442.7	**28.16**	**9.22**	**0.92**	**(0.22)**	**9.93**	623.7	**2.11**	0.62	0.7	**1.061**	338.0	-	15,000	827.6	1,692.1	1,789.3	97.2	5.7%
		43,164	133	45%	22.11	4.87	1.22	0.92	7.01	954.4	28.16	9.22	0.92	(0.22)	9.93	1,348.4	2.11	0.62	0.70	1.06	883.8	-	43,164	2,381.4	4,401.8	4,613.6	211.8	4.8%
		100,000	500	28%	22.11	4.87	1.22	0.92	7.01	3,527.1	28.16	9.22	0.92	(0.22)	9.93	4,991.3	2.11	0.62	0.70	1.06	2,477.2	-	100,000	5,517.2	12,229.7	12,985.7	756.0	6.2%
		400,000	1000	56%	22.11	4.87	1.22	0.92	7.01	7,032.1	28.16	9.22	0.92	(0.22)	9.93	9,954.4	2.11	0.62	0.70	1.06	7,670.0	-	400,000	22,068.8	38,111.7	39,693.2	1,581.5	4.1%
		1,000,000	3000	46%	22.11	4.87	1.22	0.92	7.01	21,052.1	28.16	9.22	0.92	(0.22)	9.93	29,807.0	2.11	0.62	0.70	1.06	20,294.3	-	1,000,000	55,172.0	100,616.5	105,273.3	4,656.9	4.6%
		1,500,000	4000	52%	22.11	4.87	1.22	0.92	7.01	28,062.1	28.16	9.22	0.92	(0.22)	9.93	39,733.3	2.11	0.62	0.70	1.06	29,322.1	-	1,500,000	82,758.0	145,543.2	151,813.4	6,270.2	4.3%
GSd	**Springwater**	15,000	60	35%	**20.53**	**3.42**	**0.85**	**0.53**	**4.80**	308.5	**26.56**	**8.60**	**0.53**	**(0.22)**	**8.91**	561.3	**2.11**	0.62	0.7	**1.061**	338.0	-	15,000	827.6	1,558.0	1,726.9	168.9	10.8%
		43,164	133	45%	20.53	3.42	0.85	0.53	4.80	658.9	26.56	8.60	0.53	(0.22)	8.91	1,211.9	2.11	0.62	0.70	1.06	883.8	-	43,164	2,381.4	4,106.3	4,477.2	370.9	9.0%
		100,000	500	28%	20.53	3.42	0.85	0.53	4.80	2,420.5	26.56	8.60	0.53	(0.22)	8.91	4,482.9	2.11	0.62	0.70	1.06	2,477.2	-	100,000	5,517.2	11,123.1	12,477.3	1,354.2	12.2%
		400,000	1000	56%	20.53	3.42	0.85	0.53	4.80	4,820.5	26.56	8.60	0.53	(0.22)	8.91	8,939.3	2.11	0.62	0.70	1.06	7,670.0	-	400,000	22,068.8	35,900.1	38,678.0	2,777.9	7.7%
		1,000,000	3000	46%	20.53	3.42	0.85	0.53	4.80	14,420.5	26.56	8.60	0.53	(0.22)	8.91	26,764.7	2.11	0.62	0.70	1.06	20,294.3	-	1,000,000	55,172.0	93,984.9	102,231.0	8,246.1	8.8%
		1,500,000	4000	52%	20.53	3.42	0.85	0.53	4.80	19,220.5	26.56	8.60	0.53	(0.22)	8.91	35,677.4	2.11	0.62	0.70	1.06	29,322.1	-	1,500,000	82,758.0	136,701.7	147,757.5	11,055.8	8.1%
GSd	**Stirling-Rawdon**	15,000	60	35%	**24.12**	**4.11**	**0.67**	**0.30**	**5.08**	328.9	**29.66**	**9.22**	**0.30**	**(0.22)**	**9.31**	588.0	**2.11**	0.62	0.7	**1.061**	338.0	-	15,000	827.6	1,578.3	1,753.6	175.3	11.1%
		43,164	133	45%	24.12	4.11	0.67	0.30	5.08	699.8	29.66	9.22	0.30	(0.22)	9.31	1,267.4	2.11	0.62	0.70	1.06	883.8	-	43,164	2,381.4	4,147.2	4,532.7	385.5	9.3%
		100,000	500	28%	24.12	4.11	0.67	0.30	5.08	2,564.1	29.66	9.22	0.30	(0.22)	9.31	4,682.8	2.11	0.62	0.70	1.06	2,477.2	-	100,000	5,517.2	11,266.7	12,677.2	1,410.5	12.5%
		400,000	1000	56%	24.12	4.11	0.67	0.30	5.08	5,104.1	29.66	9.22	0.30	(0.22)	9.31	9,335.9	2.11	0.62	0.70	1.06	7,670.0	-	400,000	22,068.8	36,183.7	39,074.7	2,891.0	8.0%
		1,000,000	3000	46%	24.12	4.11	0.67	0.30	5.08	15,264.1	29.66	9.22	0.30	(0.22)	9.31	27,948.5	2.11	0.62	0.70	1.06	20,294.3	-	1,000,000	55,172.0	94,828.5	103,414.8	8,586.4	9.1%
		1,500,000	4000	52%	24.12	4.11	0.67	0.30	5.08	20,344.1	29.66	9.22	0.30	(0.22)	9.31	37,254.8	2.11	0.62	0.70	1.06	29,322.1	-	1,500,000	82,758.0	137,825.3	149,334.9	11,509.7	8.4%
GSd	**Thedford**	15,000	60	35%	**17.83**	**3.38**	**1.14**	**1.00**	**5.52**	349.0	**24.23**	**8.95**	**1.00**	**(0.22)**	**9.73**	608.2	**2.11**	0.62	0.7	**1.061**	338.0	-	15,000	827.6	1,598.5	1,773.8	175.3	11.0%
		43,164	133	45%	17.83	3.38	1.14	1.00	5.52	752.0	24.23	8.95	1.00	(0.22)	9.73	1,318.7	2.11	0.62	0.70	1.06	883.8	-	43,164	2,381.4	4,199.4	4,584.0	384.6	9.2%
		100,000	500	28%	17.83	3.38	1.14	1.00	5.52	2,777.8	24.23	8.95	1.00	(0.22)	9.73	4,890.6	2.11	0.62	0.70	1.06	2,477.2	-	100,000	5,517.2	11,480.4	12,885.0	1,404.5	12.2%
		400,000	1000	56%	17.83	3.38	1.14	1.00	5.52	5,537.8	24.23	8.95	1.00	(0.22)	9.73	9,756.9	2.11	0.62	0.70	1.06	7,670.0	-	400,000	22,068.8	36,617.4	39,495.7	2,878.3	7.9%
		1,000,000	3000	46%	17.83	3.38	1.14	1.00	5.52	16,577.8	24.23	8.95	1.00	(0.22)	9.73	29,222.3	2.11	0.62	0.70	1.06	20,294.3	-	1,000,000	55,172.0	96,142.2	104,688.7	8,546.5	8.9%
		1,500,000	4000	52%	17.83	3.38	1.14	1.00	5.52	22,097.8	24.23	8.95	1.00	(0.22)	9.73	38,955.0	2.11	0.62	0.70	1.06	29,322.1	-	1,500,000	82,758.0	139,579.0	151,035.2	11,456.2	8.2%
GSd	**Thessalon**	15,000	60	35%	**18.90**	**3.22**	**0.21**	**0.17**	**3.60**	234.9	**24.96**	**7.60**	**0.17**	**(0.22)**	**7.55**	478.1	**2.11**	0.62	0.7	**1.061**	338.0	-	15,000	827.6	1,484.3	1,643.7	159.4	10.7%
		43,164	133	45%	18.90	3.22	0.21	0.17	3.60	497.7	24.96	7.60	0.17	(0.22)	7.55	1,029.5	2.11	0.62	0.70	1.06	883.8	-	43,164	2,381.4	3,945.1	4,294.8	349.7	8.9%
		100,000	500	28%	18.90	3.22	0.21	0.17	3.60	1,818.9	24.96	7.60	0.17	(0.22)	7.55	3,801.3	2.11	0.62	0.70	1.06	2,477.2	-	100,000	5,517.2	10,521.5	11,795.7	1,274.2	12.1%
		400,000	1000	56%	18.90	3.22	0.21	0.17	3.60	3,618.9	24.96	7.60	0.17	(0.22)	7.55	7,577.7	2.11	0.62	0.70	1.06	7,670.0	-	400,000	22,068.8	34,698.5	37,316.5	2,618.0	7.5%
		1,000,000	3000	46%	18.90	3.22	0.21	0.17	3.60	10,818.9	24.96	7.60	0.17	(0.22)	7.55	22,683.1	2.11	0.62	0.70	1.06	20,294.3	-	1,000,000	55,172.0	90,383.3	98,149.4	7,766.1	8.6%
		1,500,000	4000	52%	18.90	3.22	0.21	0.17	3.60	14,418.9	24.96	7.60	0.17	(0.22)	7.55	30,235.8	2.11	0.62	0.70	1.06	29,322.1	-	1,500,000	82,758.0	131,900.0	142,315.9	10,415.9	7.9%

New Rate Class: GSd

Total Bill Impacts of Proposed Distribution Rates [new RTSR+TLF]: Threshold of 750 kWhs

Classes		Scenario			May 2007 Incl Rate Riders						May 2008 Incl Rate Riders						Non-Dx Compoent				Other Reg	Commodity Bands			Existing	New	$ Incr	% Incr
					Existing Dx Rates					Existing Dx	New Dx Rates					New Dx	RTSR new	WMSC	DRC	TLF new	New	Band 1	Band 2	New	Total Bill	Total Bill	Total Bill	Total Bill
																						-	5.2					
New Class	Old Class	kWh	kW	LF	SrChg [$/cust]	base [$/kW]	Rider1 [$/kW]	Rider2 [$/kW]	VarChg [$/kW]	[$/month]	SrChg [$/cust]	base [$/kW]	Rider2 [$/kW]	Rider3 [$/kW]	VarChg [$/kW]	[$/month]	$/kW	c/kWh	c/kWh		$	kWhs	kWhs	Total $	[$/month]	[$/month]	[$/month]	%
GSd	Thorndale	15,000	60	35%	14.52	3.25	1.67	1.03	5.95	371.5	22.06	9.22	1.03	(0.22)	10.04	624.2	2.11	0.62	0.7	1.061	338.0	-	15,000	827.6	1,620.9	1,789.8	168.9	10.4%
		43,164	133	45%	14.52	3.25	1.67	1.03	5.95	805.9	22.06	9.22	1.03	(0.22)	10.04	1,356.9	2.11	0.62	0.70	1.06	883.8	-	43,164	2,381.4	4,253.3	4,622.2	368.9	8.7%
		100,000	500	28%	14.52	3.25	1.67	1.03	5.95	2,989.5	22.06	9.22	1.03	(0.22)	10.04	5,040.2	2.11	0.62	0.70	1.06	2,477.2	-	100,000	5,517.2	11,692.1	13,034.6	1,342.5	11.5%
		400,000	1000	56%	14.52	3.25	1.67	1.03	5.95	5,964.5	22.06	9.22	1.03	(0.22)	10.04	10,058.3	2.11	0.62	0.70	1.06	7,670.0	-	400,000	22,068.8	37,044.1	39,797.1	2,753.0	7.4%
		1,000,000	3000	46%	14.52	3.25	1.67	1.03	5.95	17,864.5	22.06	9.22	1.03	(0.22)	10.04	30,130.9	2.11	0.62	0.70	1.06	20,294.3	-	1,000,000	55,172.0	97,428.9	105,597.2	8,168.4	8.4%
		1,500,000	4000	52%	14.52	3.25	1.67	1.03	5.95	23,814.5	22.06	9.22	1.03	(0.22)	10.04	40,167.2	2.11	0.62	0.70	1.06	29,322.1	-	1,500,000	82,758.0	141,295.7	152,247.3	10,951.7	7.8%
UGd	Thorold	15,000	60	35%	22.63	4.76	0.46	0.20	5.42	347.8	23.64	7.33	0.20	(0.27)	7.26	459.3	2.68	0.62	0.7	1.061	374.3	-	15,000	827.6	1,597.3	1,661.1	63.9	4.0%
		43,164	133	45%	22.63	4.76	0.46	0.20	5.42	743.5	23.64	7.33	0.20	(0.27)	7.26	989.2	2.68	0.62	0.70	1.06	964.3	-	43,164	2,381.4	4,190.9	4,335.0	144.1	3.4%
		100,000	500	28%	22.63	4.76	0.46	0.20	5.42	2,732.6	23.64	7.33	0.20	(0.27)	7.26	3,653.7	2.68	0.62	0.70	1.06	2,779.6	-	100,000	5,517.2	11,435.2	11,950.5	515.3	4.5%
		400,000	1000	56%	22.63	4.76	0.46	0.20	5.42	5,442.6	23.64	7.33	0.20	(0.27)	7.26	7,283.8	2.68	0.62	0.70	1.06	8,274.8	-	400,000	22,068.8	36,522.2	37,627.4	1,105.2	3.0%
		1,000,000	3000	46%	22.63	4.76	0.46	0.20	5.42	16,282.6	23.64	7.33	0.20	(0.27)	7.26	21,804.3	2.68	0.62	0.70	1.06	22,108.6	-	1,000,000	55,172.0	95,847.0	99,084.9	3,237.9	3.4%
		1,500,000	4000	52%	22.63	4.76	0.46	0.20	5.42	21,702.6	23.64	7.33	0.20	(0.27)	7.26	29,064.5	2.68	0.62	0.70	1.06	31,741.2	-	1,500,000	82,758.0	139,183.8	143,563.7	4,379.9	3.1%
GSd	Tweed	15,000	60	35%	8.26	3.11	1.35	0.99	5.45	335.3	17.62	8.80	0.99	(0.22)	9.57	592.0	2.11	0.62	0.7	1.061	338.0	-	15,000	827.6	1,584.7	1,757.6	172.9	10.9%
		43,164	133	45%	8.26	3.11	1.35	0.99	5.45	733.1	17.62	8.80	0.99	(0.22)	9.57	1,290.8	2.11	0.62	0.70	1.06	883.8	-	43,164	2,381.4	4,180.5	4,556.1	375.6	9.0%
		100,000	500	28%	8.26	3.11	1.35	0.99	5.45	2,733.3	17.62	8.80	0.99	(0.22)	9.57	4,804.0	2.11	0.62	0.70	1.06	2,477.2	-	100,000	5,517.2	11,435.2	12,798.3	1,362.5	11.9%
		400,000	1000	56%	8.26	3.11	1.35	0.99	5.45	5,458.3	17.62	8.80	0.99	(0.22)	9.57	9,590.3	2.11	0.62	0.70	1.06	7,670.0	-	400,000	22,068.8	36,537.8	39,329.1	2,791.3	7.6%
		1,000,000	3000	46%	8.26	3.11	1.35	0.99	5.45	16,358.3	17.62	8.80	0.99	(0.22)	9.57	28,735.7	2.11	0.62	0.70	1.06	20,294.3	-	1,000,000	55,172.0	95,922.6	104,202.1	8,279.4	8.6%
		1,500,000	4000	52%	8.26	3.11	1.35	0.99	5.45	21,808.3	17.62	8.80	0.99	(0.22)	9.57	38,308.4	2.11	0.62	0.70	1.06	29,322.1	-	1,500,000	82,758.0	139,289.4	150,388.6	11,099.2	8.0%
GSd	Wardsville	15,000	60	35%	12.32	3.16	0.81	0.26	4.23	266.1	20.61	8.20	0.26	(0.22)	8.24	515.2	2.11	0.62	0.7	1.061	338.0	-	15,000	827.6	1,515.5	1,680.7	165.2	10.9%
		43,164	133	45%	12.32	3.16	0.81	0.26	4.23	574.9	20.61	8.20	0.26	(0.22)	8.24	1,116.9	2.11	0.62	0.70	1.06	883.8	-	43,164	2,381.4	4,022.3	4,382.2	359.9	8.9%
		100,000	500	28%	12.32	3.16	0.81	0.26	4.23	2,127.3	20.61	8.20	0.26	(0.22)	8.24	4,142.0	2.11	0.62	0.70	1.06	2,477.2	-	100,000	5,517.2	10,829.9	12,136.3	1,306.4	12.1%
		400,000	1000	56%	12.32	3.16	0.81	0.26	4.23	4,242.3	20.61	8.20	0.26	(0.22)	8.24	8,263.3	2.11	0.62	0.70	1.06	7,670.0	-	400,000	22,068.8	35,321.9	38,002.1	2,680.2	7.6%
		1,000,000	3000	46%	12.32	3.16	0.81	0.26	4.23	12,702.3	20.61	8.20	0.26	(0.22)	8.24	24,748.7	2.11	0.62	0.70	1.06	20,294.3	-	1,000,000	55,172.0	92,266.7	100,215.0	7,948.4	8.6%
		1,500,000	4000	52%	12.32	3.16	0.81	0.26	4.23	16,932.3	20.61	8.20	0.26	(0.22)	8.24	32,991.4	2.11	0.62	0.70	1.06	29,322.1	-	1,500,000	82,758.0	134,413.5	145,071.6	10,658.1	7.9%
GSd	Warkworth	15,000	60	35%	21.31	4.47	1.44	1.03	6.94	437.7	27.36	9.22	1.03	(0.22)	10.04	629.5	2.11	0.62	0.7	1.061	338.0	-	15,000	827.6	1,687.1	1,795.1	108.0	6.4%
		43,164	133	45%	21.31	4.47	1.44	1.03	6.94	944.3	27.36	9.22	1.03	(0.22)	10.04	1,362.2	2.11	0.62	0.70	1.06	883.8	-	43,164	2,381.4	4,391.7	4,627.5	235.7	5.4%
		100,000	500	28%	21.31	4.47	1.44	1.03	6.94	3,491.3	27.36	9.22	1.03	(0.22)	10.04	5,045.5	2.11	0.62	0.70	1.06	2,477.2	-	100,000	5,517.2	12,193.9	13,039.9	846.0	6.9%
		400,000	1000	56%	21.31	4.47	1.44	1.03	6.94	6,961.3	27.36	9.22	1.03	(0.22)	10.04	10,063.6	2.11	0.62	0.70	1.06	7,670.0	-	400,000	22,068.8	38,040.9	39,802.4	1,761.5	4.6%
		1,000,000	3000	46%	21.31	4.47	1.44	1.03	6.94	20,841.3	27.36	9.22	1.03	(0.22)	10.04	30,136.2	2.11	0.62	0.70	1.06	20,294.3	-	1,000,000	55,172.0	100,405.7	105,602.5	5,196.9	5.2%
		1,500,000	4000	52%	21.31	4.47	1.44	1.03	6.94	27,781.3	27.36	9.22	1.03	(0.22)	10.04	40,172.5	2.11	0.62	0.70	1.06	29,322.1	-	1,500,000	82,758.0	145,262.4	152,252.6	6,990.2	4.8%

New Rate Class: GSd

Total Bill Impacts of Proposed Distribution Rates [new RTSR+TLF]: Threshold of 750 kWhs

Classes		Scenario			May 2007 Incl Rate Riders						May 2008 Incl Rate Riders						Non-Dx Compoent				Other Reg	Commodity Bands			Existing	New	$ Incr	% Incr
					Existing Dx Rates					Existing Dx	New Dx Rates					New Dx	RTSR new	WMSC	DRC	TLF new	New	Band 1	Band 2	New	Total Bill	Total Bill	Total Bill	Total Bill
																						-	5.2					
New Class	Old Class	kWh	kW	LF	SrChg [$/cust]	base [$/kW]	Rider1 [$/kW]	Rider2 [$/kW]	VarChg [$/kW]	[$/month]	SrChg [$/cust]	base [$/kW]	Rider2 [$/kW]	Rider3 [$/kW]	VarChg [$/kW]	[$/month]	$/kW	c/kWh	c/kWh		$	kWhs	kWhs	Total $	[$/month]	[$/month]	[$/month]	%
GSd	**West Elgin**	15,000	60	35%	**15.40**	**2.21**	**0.54**	**0.21**	**2.96**	193.0	**22.84**	**6.85**	**0.21**	**(0.22)**	**6.84**	433.4	**2.11**	0.62	0.7	**1.061**	338.0	-	15,000	827.6	1,442.4	1,599.0	156.5	10.9%
		43,164	133	45%	15.40	2.21	0.54	0.21	2.96	409.1	22.84	6.85	0.21	(0.22)	6.84	932.9	2.11	0.62	0.70	1.06	883.8	-	43,164	2,381.4	3,856.5	4,198.2	341.7	8.9%
		100,000	500	28%	15.40	2.21	0.54	0.21	2.96	1,495.4	22.84	6.85	0.21	(0.22)	6.84	3,444.2	2.11	0.62	0.70	1.06	2,477.2	-	100,000	5,517.2	10,198.0	11,438.6	1,240.6	12.2%
		400,000	1000	56%	15.40	2.21	0.54	0.21	2.96	2,975.4	22.84	6.85	0.21	(0.22)	6.84	6,865.5	2.11	0.62	0.70	1.06	7,670.0	-	400,000	22,068.8	34,055.0	36,604.3	2,549.4	7.5%
		1,000,000	3000	46%	15.40	2.21	0.54	0.21	2.96	8,895.4	22.84	6.85	0.21	(0.22)	6.84	20,550.9	2.11	0.62	0.70	1.06	20,294.3	-	1,000,000	55,172.0	88,459.8	96,017.3	7,557.5	8.5%
		1,500,000	4000	52%	15.40	2.21	0.54	0.21	2.96	11,855.4	22.84	6.85	0.21	(0.22)	6.84	27,393.7	2.11	0.62	0.70	1.06	29,322.1	-	1,500,000	82,758.0	129,336.5	139,473.8	10,137.3	7.8%
UGd	**Whitchurch Stouffville**	15,000	60	35%	**21.85**	**2.93**	**0.35**	**0.13**	**3.41**	226.5	**22.84**	**7.15**	**0.13**	**(0.27)**	**7.01**	443.3	**2.68**	0.62	0.7	**1.061**	374.3	-	15,000	827.6	1,475.9	1,645.1	169.2	11.5%
		43,164	133	45%	21.85	2.93	0.35	0.13	3.41	475.4	22.84	7.15	0.13	(0.27)	7.01	954.8	2.68	0.62	0.70	1.06	964.3	-	43,164	2,381.4	3,922.8	4,300.5	377.7	9.6%
		100,000	500	28%	21.85	2.93	0.35	0.13	3.41	1,726.9	22.84	7.15	0.13	(0.27)	7.01	3,526.4	2.68	0.62	0.70	1.06	2,779.6	-	100,000	5,517.2	10,429.5	11,823.2	1,393.7	13.4%
		400,000	1000	56%	21.85	2.93	0.35	0.13	3.41	3,431.9	22.84	7.15	0.13	(0.27)	7.01	7,030.0	2.68	0.62	0.70	1.06	8,274.8	-	400,000	22,068.8	34,511.4	37,373.5	2,862.1	8.3%
		1,000,000	3000	46%	21.85	2.93	0.35	0.13	3.41	10,251.9	22.84	7.15	0.13	(0.27)	7.01	21,044.2	2.68	0.62	0.70	1.06	22,108.6	-	1,000,000	55,172.0	89,816.2	98,324.9	8,508.6	9.5%
		1,500,000	4000	52%	21.85	2.93	0.35	0.13	3.41	13,661.9	22.84	7.15	0.13	(0.27)	7.01	28,051.3	2.68	0.62	0.70	1.06	31,741.2	-	1,500,000	82,758.0	131,143.0	142,550.6	11,407.6	8.7%
GSd	**Wiarton**	15,000	60	35%	**23.78**	**5.99**	**0.59**	**0.29**	**6.87**	436.0	**28.74**	**9.22**	**0.29**	**(0.22)**	**9.30**	586.5	**2.11**	0.62	0.7	**1.061**	338.0	-	15,000	827.6	1,685.4	1,752.1	66.7	4.0%
		43,164	133	45%	23.78	5.99	0.59	0.29	6.87	937.5	28.74	9.22	0.29	(0.22)	9.30	1,265.1	2.11	0.62	0.70	1.06	883.8	-	43,164	2,381.4	4,384.9	4,530.4	145.5	3.3%
		100,000	500	28%	23.78	5.99	0.59	0.29	6.87	3,458.8	28.74	9.22	0.29	(0.22)	9.30	4,676.9	2.11	0.62	0.70	1.06	2,477.2	-	100,000	5,517.2	12,161.4	12,671.3	509.9	4.2%
		400,000	1000	56%	23.78	5.99	0.59	0.29	6.87	6,893.8	28.74	9.22	0.29	(0.22)	9.30	9,325.0	2.11	0.62	0.70	1.06	7,670.0	-	400,000	22,068.8	37,973.4	39,063.8	1,090.5	2.9%
		1,000,000	3000	46%	23.78	5.99	0.59	0.29	6.87	20,633.8	28.74	9.22	0.29	(0.22)	9.30	27,917.6	2.11	0.62	0.70	1.06	20,294.3	-	1,000,000	55,172.0	100,198.1	103,383.9	3,185.8	3.2%
		1,500,000	4000	52%	23.78	5.99	0.59	0.29	6.87	27,503.8	28.74	9.22	0.29	(0.22)	9.30	37,213.9	2.11	0.62	0.70	1.06	29,322.1	-	1,500,000	82,758.0	144,984.9	149,294.0	4,309.1	3.0%
GSd	**Woodville**	15,000	60	35%	**16.89**	**4.34**	**2.12**	**1.35**	**7.81**	485.5	**23.47**	**9.22**	**1.35**	**(0.22)**	**10.36**	644.8	**2.11**	0.62	0.7	**1.061**	338.0	-	15,000	827.6	1,734.9	1,810.4	75.5	4.4%
		43,164	133	45%	16.89	4.34	2.12	1.35	7.81	1,055.6	23.47	9.22	1.35	(0.22)	10.36	1,400.9	2.11	0.62	0.70	1.06	883.8	-	43,164	2,381.4	4,503.0	4,666.1	163.1	3.6%
		100,000	500	28%	16.89	4.34	2.12	1.35	7.81	3,921.9	23.47	9.22	1.35	(0.22)	10.36	5,201.6	2.11	0.62	0.70	1.06	2,477.2	-	100,000	5,517.2	12,624.5	13,196.0	571.5	4.5%
		400,000	1000	56%	16.89	4.34	2.12	1.35	7.81	7,826.9	23.47	9.22	1.35	(0.22)	10.36	10,379.7	2.11	0.62	0.70	1.06	7,670.0	-	400,000	22,068.8	38,906.5	40,118.5	1,212.1	3.1%
		1,000,000	3000	46%	16.89	4.34	2.12	1.35	7.81	23,446.9	23.47	9.22	1.35	(0.22)	10.36	31,092.3	2.11	0.62	0.70	1.06	20,294.3	-	1,000,000	55,172.0	103,011.3	106,558.6	3,547.4	3.4%
		1,500,000	4000	52%	16.89	4.34	2.12	1.35	7.81	31,256.9	23.47	9.22	1.35	(0.22)	10.36	41,448.6	2.11	0.62	0.70	1.06	29,322.1	-	1,500,000	82,758.0	148,738.0	153,528.7	4,790.7	3.2%
GSd	**Wyoming**	15,000	60	35%	**17.36**	**4.57**	**0.52**	**0.23**	**5.32**	336.6	**24.35**	**9.22**	**0.23**	**(0.22)**	**9.24**	578.5	**2.11**	0.62	0.7	**1.061**	338.0	-	15,000	827.6	1,586.0	1,744.1	158.1	10.0%
		43,164	133	45%	17.36	4.57	0.52	0.23	5.32	724.9	24.35	9.22	0.23	(0.22)	9.24	1,252.8	2.11	0.62	0.70	1.06	883.8	-	43,164	2,381.4	4,172.3	4,518.1	345.7	8.3%
		100,000	500	28%	17.36	4.57	0.52	0.23	5.32	2,677.4	24.35	9.22	0.23	(0.22)	9.24	4,642.5	2.11	0.62	0.70	1.06	2,477.2	-	100,000	5,517.2	11,380.0	12,636.9	1,256.9	11.0%
		400,000	1000	56%	17.36	4.57	0.52	0.23	5.32	5,337.4	24.35	9.22	0.23	(0.22)	9.24	9,260.6	2.11	0.62	0.70	1.06	7,670.0	-	400,000	22,068.8	36,416.9	38,999.4	2,582.5	7.1%
		1,000,000	3000	46%	17.36	4.57	0.52	0.23	5.32	15,977.4	24.35	9.22	0.23	(0.22)	9.24	27,733.2	2.11	0.62	0.70	1.06	20,294.3	-	1,000,000	55,172.0	95,541.7	103,199.5	7,657.8	8.0%
		1,500,000	4000	52%	17.36	4.57	0.52	0.23	5.32	21,297.4	24.35	9.22	0.23	(0.22)	9.24	36,969.5	2.11	0.62	0.70	1.06	29,322.1	-	1,500,000	82,758.0	138,778.5	149,049.6	10,271.1	7.4%

New Rate Class: GSd

Total Bill Impacts of Proposed Distribution Rates [new RTSR+TLF]: Threshold of 750 kWhs

Classes		Scenario			May 2007 Incl Rate Riders						May 2008 Incl Rate Riders						Non-Dx Compoent				Other Reg	Commodity Bands			Existing	New	$ Incr	% Incr
					Existing Dx Rates					Existing Dx	New Dx Rates					New Dx	RTSR new	WMSC	DRC	TLF new	New	Band 1	Band 2	New	Total Bill	Total Bill	Total Bill	Total Bill
																						-	5.2					
New Class	Old Class	kWh	kW	LF	SrChg	base	Rider1	Rider2	VarChg	[$/month]	SrChg	base	Rider2	Rider3	VarChg	[$/month]	$/kW	c/kWh	c/kWh		$	kWhs	kWhs	Total $	[$/month]	[$/month]	[$/month]	%
					[$/cust]	[$/kW]	[$/kW]	[$/kW]	[$/kW]		[$/cust]	[$/kW]	[$/kW]	[$/kW]	[$/kW]													
GSd	**Terrace Bay**	15,000	60	35%	**293.24**	**4.00**	**2.27**		**6.27**	669.7	**231.38**	**9.22**	**-**	**(0.22)**	**9.01**	771.8	**2.11**	0.62	0.7	**1.061**	338.0	-	15,000	827.6	1,794.1	1,937.3	143.2	8.0%
		43,164	133	45%	293.24	4.00	2.27	-	6.27	1,127.8	231.38	9.22	-	(0.22)	9.01	1,429.2	2.11	0.62	0.70	1.06	883.8	-	43,164	2,381.4	4,285.1	4,694.5	409.4	9.6%
		100,000	500	28%	293.24	4.00	2.27	-	6.27	3,430.5	231.38	9.22	-	(0.22)	9.01	4,734.5	2.11	0.62	0.70	1.06	2,477.2	-	100,000	5,517.2	11,123.8	12,728.9	1,605.1	14.4%
		400,000	1000	56%	293.24	4.00	2.27	-	6.27	6,567.8	231.38	9.22	-	(0.22)	9.01	9,237.7	2.11	0.62	0.70	1.06	7,670.0	-	400,000	22,068.8	35,368.0	38,976.5	3,608.5	10.2%
		1,000,000	3000	46%	293.24	4.00	2.27	-	6.27	19,117.0	231.38	9.22	-	(0.22)	9.01	27,250.2	2.11	0.62	0.70	1.06	20,294.3	-	1,000,000	55,172.0	92,103.8	102,716.6	10,612.7	11.5%
		1,500,000	4000	52%	293.24	4.00	2.27	-	6.27	25,391.6	231.38	9.22	-	(0.22)	9.01	36,256.5	2.11	0.62	0.70	1.06	29,322.1	-	1,500,000	82,758.0	133,885.4	148,336.7	14,451.2	10.8%

New Rate Class: GSe - Unmetered

Total Bill Impacts of Proposed Distribution Rates [new RTSR+TLF]: Threshold of 600 kWhs

600.0

Classes		Scenario	May 2007 Incl Rate Riders						May 2008 Incl Rate Riders						Non-Dx Compoent				Other Reg	Commodity Bands			Existing	New	$ Incr	% Incr
			Existing Dx Rates					Existing Dx	New Dx Rates					New Dx	RTSR new	WMSC	DRC	TLF new	New	Band 1	Band 2	New	Total Bill	Total Bill	Total Bill	Total Bill
																				5.0	5.9					
New Class	Old Class	kWh	SrChg [$/cust]	base [c/kWh]	Rider1 [c/kWh]	Rider2 [c/kWh]	VarChg [c/kWh]	[$/month]	SrChg [$/cust]	base [c/kWh]	Rider2 [c/kWh]	Rider3 [c/kWh]	VarChg [c/kWh]	[$/month]	c/kWh	c/kWh	c/kWh		$	kWhs	kWhs		[$/month]	[$/month]	[$/month]	%
Unmtr	**G1**	100	**22.16**	**3.12**	**0.09**	**0.09**	**3.30**	25.5	**22.84**	**5.38**	**0.09**	**(0.06)**	**5.41**	28.2	**0.67**	0.62	0.7	**1.092**	2.1	100	-	5.5	33.2	35.8	2.6	7.8%
		250	22.16	3.12	0.09	0.09	3.30	30.4	22.84	5.38	0.09	(0.06)	5.41	36.4	0.67	0.62	0.7	1.092	5.3	250	-	13.7	49.9	55.3	5.4	10.9%
		500	22.16	3.12	0.09	0.09	3.30	38.7	22.84	5.38	0.09	(0.06)	5.41	49.9	0.67	0.62	0.7	1.092	10.5	500	-	27.3	77.5	87.7	10.2	13.2%
		750	22.16	3.12	0.09	0.09	3.30	46.9	22.84	5.38	0.09	(0.06)	5.41	63.4	0.67	0.62	0.7	1.092	15.8	600	150	42.9	107.2	122.2	15.0	14.0%
		1,000	22.16	3.12	0.09	0.09	3.30	55.2	22.84	5.38	0.09	(0.06)	5.41	77.0	0.67	0.62	0.7	1.092	21.1	600	400	59.0	137.3	157.1	19.7	14.4%
Unmtr	**G3**	100	**6.29**	**3.07**	**0.02**	**0.05**	**3.14**	9.4	**10.81**	**3.60**	**0.05**	**(0.06)**	**3.59**	14.4	**0.67**	0.62	0.7	**1.092**	2.1	100	-	5.5	17.0	22.0	5.0	29.3%
		250	6.29	3.07	0.02	0.05	3.14	14.1	10.81	3.60	0.05	(0.06)	3.59	19.8	0.67	0.62	0.70	1.092	5.3	250	-	13.7	33.1	38.7	5.7	17.1%
		500	6.29	3.07	0.02	0.05	3.14	22.0	10.81	3.60	0.05	(0.06)	3.59	28.8	0.67	0.62	0.70	1.092	10.5	500	-	27.3	59.8	66.6	6.8	11.4%
		750	6.29	3.07	0.02	0.05	3.14	29.8	10.81	3.60	0.05	(0.06)	3.59	37.8	0.67	0.62	0.70	1.092	15.8	600	150	42.9	88.3	96.5	8.2	9.2%
		1,000	6.29	3.07	0.02	0.05	3.14	37.7	10.81	3.60	0.05	(0.06)	3.59	46.7	0.67	0.62	0.70	1.092	21.1	600	400	59.0	117.5	126.9	9.4	8.0%
Unmtr	**UG**	100	**0.79**	**2.74**	**0.03**	**0.03**	**2.80**	3.6	**6.18**	**3.50**	**0.03**	**(0.06)**	**3.47**	9.7	**0.67**	0.62	0.7	**1.092**	2.1	100	-	5.5	11.4	17.2	5.9	51.7%
		250	0.79	2.74	0.03	0.03	2.80	7.8	6.18	3.50	0.03	(0.06)	3.47	14.9	0.67	0.62	0.70	1.092	5.3	250	-	13.7	27.2	33.8	6.6	24.2%
		500	0.79	2.74	0.03	0.03	2.80	14.8	6.18	3.50	0.03	(0.06)	3.47	23.5	0.67	0.62	0.70	1.092	10.5	500	-	27.3	53.6	61.4	7.8	14.5%
		750	0.79	2.74	0.03	0.03	2.80	21.8	6.18	3.50	0.03	(0.06)	3.47	32.2	0.67	0.62	0.70	1.092	15.8	600	150	42.9	82.0	91.0	9.0	10.9%
		1,000	0.79	2.74	0.03	0.03	2.80	28.8	6.18	3.50	0.03	(0.06)	3.47	40.9	0.67	0.62	0.70	1.092	21.1	600	400	59.0	110.9	121.0	10.2	9.2%
Unmtr	**Ailsa Craig**	100	**8.20**	**1.32**	**0.17**	**0.09**	**1.58**	9.8	**12.33**	**2.00**	**0.09**	**(0.06)**	**2.03**	14.4	**0.67**	0.62	0.7	**1.092**	2.1	100	-	5.5	17.4	21.9	4.5	26.1%
		250	8.20	1.32	0.17	0.09	1.58	12.2	12.33	2.00	0.09	(0.06)	2.03	17.4	0.67	0.62	0.70	1.092	5.3	250	-	13.7	31.2	36.3	5.2	16.6%
		500	8.20	1.32	0.17	0.09	1.58	16.1	12.33	2.00	0.09	(0.06)	2.03	22.5	0.67	0.62	0.70	1.092	10.5	500	-	27.3	54.1	60.3	6.2	11.5%
		750	8.20	1.32	0.17	0.09	1.58	20.1	12.33	2.00	0.09	(0.06)	2.03	27.6	0.67	0.62	0.70	1.092	15.8	600	150	42.9	78.8	86.3	7.5	9.5%
		1,000	8.20	1.32	0.17	0.09	1.58	24.0	12.33	2.00	0.09	(0.06)	2.03	32.7	0.67	0.62	0.70	1.092	21.1	600	400	59.0	104.2	112.8	8.6	8.3%
Unmtr	**Arkona**	100	**1.14**	**0.86**	**0.51**	**0.36**	**1.73**	2.9	**7.09**	**2.00**	**0.36**	**(0.06)**	**2.30**	9.4	**0.67**	0.62	0.7	**1.092**	2.1	100	-	5.5	10.5	17.0	6.5	61.9%
		250	1.14	0.86	0.51	0.36	1.73	5.5	7.09	2.00	0.36	(0.06)	2.30	12.9	0.67	0.62	0.70	1.092	5.3	250	-	13.7	24.5	31.8	7.3	29.8%
		500	1.14	0.86	0.51	0.36	1.73	9.8	7.09	2.00	0.36	(0.06)	2.30	18.6	0.67	0.62	0.70	1.092	10.5	500	-	27.3	47.8	56.5	8.6	18.0%
		750	1.14	0.86	0.51	0.36	1.73	14.1	7.09	2.00	0.36	(0.06)	2.30	24.4	0.67	0.62	0.70	1.092	15.8	600	150	42.9	72.9	83.1	10.2	14.0%
		1,000	1.14	0.86	0.51	0.36	1.73	18.4	7.09	2.00	0.36	(0.06)	2.30	30.1	0.67	0.62	0.70	1.092	21.1	600	400	59.0	98.6	110.2	11.6	11.8%

New Rate Class: GSe - Unmetered

Total Bill Impacts of Proposed Distribution Rates [new RTSR+TLF]: Threshold of 600 kWhs

Classes		Scenario	May 2007 Incl Rate Riders						May 2008 Incl Rate Riders						Non-Dx Compoent				Other Reg	Commodity Bands (600.0)			Existing	New	$ Incr	% Incr
			Existing Dx Rates					Existing Dx	New Dx Rates					New Dx	RTSR new	WMSC	DRC	TLF new	New	Band 1 (5.0)	Band 2 (5.9)	New	Total Bill	Total Bill	Total Bill	Total Bill
New Class	Old Class	kWh	SrChg [$/cust]	base [c/kWh]	Rider1 [c/kWh]	Rider2 [c/kWh]	VarChg [c/kWh]	[$/month]	SrChg [$/cust]	base [c/kWh]	Rider2 [c/kWh]	Rider3 [c/kWh]	VarChg [c/kWh]	[$/month]	c/kWh	c/kWh	c/kWh		$	kWhs	kWhs		[$/month]	[$/month]	[$/month]	%
Unmtr	Arnprior	100	**10.23**	**1.17**	**0.16**	**0.06**	**1.39**	11.6	**13.82**	**2.00**	**0.06**	**(0.06)**	**2.00**	15.8	**0.67**	0.62	0.7	**1.092**	2.1	100	-	5.5	19.2	23.4	4.2	21.7%
		250	10.23	1.17	0.16	0.06	1.39	13.7	13.82	2.00	0.06	(0.06)	2.00	18.8	0.67	0.62	0.70	1.092	5.3	250	-	13.7	32.7	37.8	5.0	15.4%
		500	10.23	1.17	0.16	0.06	1.39	17.2	13.82	2.00	0.06	(0.06)	2.00	23.8	0.67	0.62	0.70	1.092	10.5	500	-	27.3	55.2	61.7	6.5	11.7%
		750	10.23	1.17	0.16	0.06	1.39	20.7	13.82	2.00	0.06	(0.06)	2.00	28.8	0.67	0.62	0.70	1.092	15.8	600	150	42.9	79.4	87.6	8.2	10.3%
		1,000	10.23	1.17	0.16	0.06	1.39	24.1	13.82	2.00	0.06	(0.06)	2.00	33.9	0.67	0.62	0.70	1.092	21.1	600	400	59.0	104.3	114.0	9.7	9.3%
Unmtr	Arran-Elders	100	**3.95**	**1.03**	**0.17**	**0.09**	**1.29**	5.2	**8.39**	**2.00**	**0.09**	**(0.06)**	**2.03**	10.4	**0.67**	0.62	0.7	**1.092**	2.1	100	-	5.5	12.8	18.0	5.1	40.0%
		250	3.95	1.03	0.17	0.09	1.29	7.2	8.39	2.00	0.09	(0.06)	2.03	13.5	0.67	0.62	0.70	1.092	5.3	250	-	13.7	26.2	32.4	6.2	23.7%
		500	3.95	1.03	0.17	0.09	1.29	10.4	8.39	2.00	0.09	(0.06)	2.03	18.6	0.67	0.62	0.70	1.092	10.5	500	-	27.3	48.4	56.4	8.0	16.4%
		750	3.95	1.03	0.17	0.09	1.29	13.6	8.39	2.00	0.09	(0.06)	2.03	23.6	0.67	0.62	0.70	1.092	15.8	600	150	42.9	72.4	82.4	10.0	13.8%
		1,000	3.95	1.03	0.17	0.09	1.29	16.9	8.39	2.00	0.09	(0.06)	2.03	28.7	0.67	0.62	0.70	1.092	21.1	600	400	59.0	97.0	108.8	11.8	12.2%
Unmtr	Artemesia	100	**9.34**	**1.74**	**0.49**	**0.34**	**2.57**	11.9	**13.04**	**2.00**	**0.34**	**(0.06)**	**2.28**	15.3	**0.67**	0.62	0.7	**1.092**	2.1	100	-	5.5	19.5	22.9	3.4	17.3%
		250	9.34	1.74	0.49	0.34	2.57	15.8	13.04	2.00	0.34	(0.06)	2.28	18.8	0.67	0.62	0.70	1.092	5.3	250	-	13.7	34.8	37.7	2.9	8.3%
		500	9.34	1.74	0.49	0.34	2.57	22.2	13.04	2.00	0.34	(0.06)	2.28	24.5	0.67	0.62	0.70	1.092	10.5	500	-	27.3	60.2	62.3	2.1	3.4%
		750	9.34	1.74	0.49	0.34	2.57	28.6	13.04	2.00	0.34	(0.06)	2.28	30.2	0.67	0.62	0.70	1.092	15.8	600	150	42.9	87.4	88.9	1.5	1.7%
		1,000	9.34	1.74	0.49	0.34	2.57	35.0	13.04	2.00	0.34	(0.06)	2.28	35.9	0.67	0.62	0.70	1.092	21.1	600	400	59.0	115.2	116.0	0.8	0.7%
Unmtr	Bancroft	100	**11.73**	**1.18**	**0.17**	**0.08**	**1.43**	13.2	**14.45**	**2.00**	**0.08**	**(0.06)**	**2.02**	16.5	**0.67**	0.62	0.7	**1.092**	2.1	100	-	5.5	20.8	24.0	3.3	15.7%
		250	11.73	1.18	0.17	0.08	1.43	15.3	14.45	2.00	0.08	(0.06)	2.02	19.5	0.67	0.62	0.70	1.092	5.3	250	-	13.7	34.3	38.4	4.1	12.0%
		500	11.73	1.18	0.17	0.08	1.43	18.9	14.45	2.00	0.08	(0.06)	2.02	24.6	0.67	0.62	0.70	1.092	10.5	500	-	27.3	56.9	62.4	5.5	9.6%
		750	11.73	1.18	0.17	0.08	1.43	22.5	14.45	2.00	0.08	(0.06)	2.02	29.6	0.67	0.62	0.70	1.092	15.8	600	150	42.9	81.2	88.4	7.1	8.8%
		1,000	11.73	1.18	0.17	0.08	1.43	26.0	14.45	2.00	0.08	(0.06)	2.02	34.7	0.67	0.62	0.70	1.092	21.1	600	400	59.0	106.2	114.8	8.6	8.1%
Unmtr	Bath	100	**4.86**	**1.47**	**0.29**	**0.24**	**2.00**	6.9	**9.16**	**2.00**	**0.24**	**(0.06)**	**2.18**	11.3	**0.67**	0.62	0.7	**1.092**	2.1	100	-	5.5	14.5	18.9	4.4	30.7%
		250	4.86	1.47	0.29	0.24	2.00	9.9	9.16	2.00	0.24	(0.06)	2.18	14.6	0.67	0.62	0.70	1.092	5.3	250	-	13.7	28.9	33.5	4.7	16.2%
		500	4.86	1.47	0.29	0.24	2.00	14.9	9.16	2.00	0.24	(0.06)	2.18	20.1	0.67	0.62	0.70	1.092	10.5	500	-	27.3	52.9	57.9	5.0	9.5%
		750	4.86	1.47	0.29	0.24	2.00	19.9	9.16	2.00	0.24	(0.06)	2.18	25.5	0.67	0.62	0.70	1.092	15.8	600	150	42.9	78.6	84.3	5.6	7.2%
		1,000	4.86	1.47	0.29	0.24	2.00	24.9	9.16	2.00	0.24	(0.06)	2.18	31.0	0.67	0.62	0.70	1.092	21.1	600	400	59.0	105.0	111.1	6.1	5.8%

New Rate Class: GSe - Unmetered

Total Bill Impacts of Proposed Distribution Rates [new RTSR+TLF]: Threshold of 600 kWhs

Classes		Scenario	May 2007 Incl Rate Riders						May 2008 Incl Rate Riders						Non-Dx Compoent				Other Reg	Commodity Bands (600.0)			Existing	New	$ Incr	% Incr
			Existing Dx Rates					Existing Dx	New Dx Rates					New Dx	RTSR new	WMSC	DRC	TLF new	New	Band 1	Band 2	New	Total Bill	Total Bill	Total Bill	Total Bill
																				5.0	5.9					
New Class	Old Class	kWh	SrChg	base	Rider1	Rider2	VarChg	[$/month]	SrChg	base	Rider2	Rider3	VarChg	[$/month]	c/kWh	c/kWh	c/kWh		$	kWhs	kWhs		[$/month]	[$/month]	[$/month]	%
			[$/cust]	[c/kWh]	[c/kWh]	[c/kWh]	[c/kWh]		[$/cust]	[c/kWh]	[c/kWh]	[c/kWh]	[c/kWh]													
Unmtr	**Blandford-B**	100	**11.46**	**1.14**	**0.28**	**0.20**	**1.62**	13.1	**14.51**	**2.00**	**0.20**	**(0.06)**	**2.14**	16.7	**0.67**	0.62	0.7	**1.092**	2.1	100	-	5.5	20.7	24.2	3.5	17.1%
		250	11.46	1.14	0.28	0.20	1.62	15.5	14.51	2.00	0.20	(0.06)	2.14	19.9	0.67	0.62	0.70	1.092	5.3	250	-	13.7	34.5	38.8	4.3	12.4%
		500	11.46	1.14	0.28	0.20	1.62	19.6	14.51	2.00	0.20	(0.06)	2.14	25.2	0.67	0.62	0.70	1.092	10.5	500	-	27.3	57.6	63.1	5.5	9.5%
		750	11.46	1.14	0.28	0.20	1.62	23.6	14.51	2.00	0.20	(0.06)	2.14	30.6	0.67	0.62	0.70	1.092	15.8	600	150	42.9	82.4	89.3	6.9	8.4%
		1,000	11.46	1.14	0.28	0.20	1.62	27.7	14.51	2.00	0.20	(0.06)	2.14	35.9	0.67	0.62	0.70	1.092	21.1	600	400	59.0	107.8	116.1	8.2	7.6%
Unmtr	**Blyth**	100	**10.35**	**1.05**	**0.26**	**0.20**	**1.51**	11.9	**13.79**	**2.00**	**0.20**	**(0.06)**	**2.14**	15.9	**0.67**	0.62	0.7	**1.092**	2.1	100	-	5.5	19.5	23.5	4.0	20.7%
		250	10.35	1.05	0.26	0.20	1.51	14.1	13.79	2.00	0.20	(0.06)	2.14	19.1	0.67	0.62	0.70	1.092	5.3	250	-	13.7	33.1	38.1	4.9	14.9%
		500	10.35	1.05	0.26	0.20	1.51	17.9	13.79	2.00	0.20	(0.06)	2.14	24.5	0.67	0.62	0.70	1.092	10.5	500	-	27.3	55.9	62.3	6.4	11.5%
		750	10.35	1.05	0.26	0.20	1.51	21.7	13.79	2.00	0.20	(0.06)	2.14	29.9	0.67	0.62	0.70	1.092	15.8	600	150	42.9	80.4	88.6	8.2	10.1%
		1,000	10.35	1.05	0.26	0.20	1.51	25.5	13.79	2.00	0.20	(0.06)	2.14	35.2	0.67	0.62	0.70	1.092	21.1	600	400	59.0	105.6	115.3	9.7	9.2%
Unmtr	**Bobcaygeor**	100	**11.14**	**1.38**	**0.18**	**0.09**	**1.65**	12.8	**14.59**	**2.00**	**0.09**	**(0.06)**	**2.03**	16.6	**0.67**	0.62	0.7	**1.092**	2.1	100	-	5.5	20.4	24.2	3.8	18.6%
		250	11.14	1.38	0.18	0.09	1.65	15.3	14.59	2.00	0.09	(0.06)	2.03	19.7	0.67	0.62	0.70	1.092	5.3	250	-	13.7	34.3	38.6	4.3	12.6%
		500	11.14	1.38	0.18	0.09	1.65	19.4	14.59	2.00	0.09	(0.06)	2.03	24.8	0.67	0.62	0.70	1.092	10.5	500	-	27.3	57.4	62.6	5.2	9.0%
		750	11.14	1.38	0.18	0.09	1.65	23.5	14.59	2.00	0.09	(0.06)	2.03	29.8	0.67	0.62	0.70	1.092	15.8	600	150	42.9	82.3	88.6	6.3	7.6%
		1,000	11.14	1.38	0.18	0.09	1.65	27.6	14.59	2.00	0.09	(0.06)	2.03	34.9	0.67	0.62	0.70	1.092	21.1	600	400	59.0	107.8	115.0	7.2	6.7%
Unmtr	**Brighton**	100	**10.99**	**1.35**	**0.20**	**0.08**	**1.63**	12.6	**13.63**	**2.00**	**0.08**	**(0.06)**	**2.02**	15.7	**0.67**	0.62	0.7	**1.092**	2.1	100	-	5.5	20.2	23.2	3.0	14.8%
		250	10.99	1.35	0.20	0.08	1.63	15.1	13.63	2.00	0.08	(0.06)	2.02	18.7	0.67	0.62	0.70	1.092	5.3	250	-	13.7	34.1	37.6	3.5	10.4%
		500	10.99	1.35	0.20	0.08	1.63	19.1	13.63	2.00	0.08	(0.06)	2.02	23.7	0.67	0.62	0.70	1.092	10.5	500	-	27.3	57.2	61.6	4.4	7.7%
		750	10.99	1.35	0.20	0.08	1.63	23.2	13.63	2.00	0.08	(0.06)	2.02	28.8	0.67	0.62	0.70	1.092	15.8	600	150	42.9	82.0	87.5	5.6	6.8%
		1,000	10.99	1.35	0.20	0.08	1.63	27.3	13.63	2.00	0.08	(0.06)	2.02	33.9	0.67	0.62	0.70	1.092	21.1	600	400	59.0	107.5	114.0	6.5	6.1%
Unmtr	**Brockville**	100	**10.37**	**0.78**	**0.13**	**0.04**	**0.95**	11.3	**13.79**	**2.00**	**0.04**	**(0.06)**	**1.98**	15.8	**0.67**	0.62	0.7	**1.092**	2.1	100	-	5.5	18.9	23.3	4.4	23.3%
		250	10.37	0.78	0.13	0.04	0.95	12.7	13.79	2.00	0.04	(0.06)	1.98	18.7	0.67	0.62	0.70	1.092	5.3	250	-	13.7	31.8	37.7	5.9	18.6%
		500	10.37	0.78	0.13	0.04	0.95	15.1	13.79	2.00	0.04	(0.06)	1.98	23.7	0.67	0.62	0.70	1.092	10.5	500	-	27.3	53.2	61.5	8.4	15.8%
		750	10.37	0.78	0.13	0.04	0.95	17.5	13.79	2.00	0.04	(0.06)	1.98	28.7	0.67	0.62	0.70	1.092	15.8	600	150	42.9	76.3	87.4	11.1	14.6%
		1,000	10.37	0.78	0.13	0.04	0.95	19.9	13.79	2.00	0.04	(0.06)	1.98	33.6	0.67	0.62	0.70	1.092	21.1	600	400	59.0	100.0	113.7	13.7	13.7%

New Rate Class: GSe - Unmetered

Total Bill Impacts of Proposed Distribution Rates [new RTSR+TLF]: Threshold of 600 kWhs

Classes		Scenario	May 2007 Incl Rate Riders						May 2008 Incl Rate Riders						Non-Dx Compoent				Other Reg	Commodity Bands			Existing	New	$ Incr	% Incr
			Existing Dx Rates					Existing Dx	New Dx Rates					New Dx	RTSR new	WMSC	DRC	TLF new	New	Band 1	Band 2	New	Total Bill	Total Bill	Total Bill	Total Bill
																				600.0						
																				5.0	5.9					
New Class	Old Class	kWh	SrChg	base	Rider1	Rider2	VarChg	[$/month]	SrChg	base	Rider2	Rider3	VarChg	[$/month]	c/kWh	c/kWh	c/kWh		$	kWhs	kWhs		[$/month]	[$/month]	[$/month]	%
			[$/cust]	[c/kWh]	[c/kWh]	[c/kWh]	[c/kWh]		[$/cust]	[c/kWh]	[c/kWh]	[c/kWh]	[c/kWh]													
Unmtr	**Caledon CH**	100	**11.63**	**1.80**	**0.14**	**0.08**	**2.02**	13.7	**14.47**	**2.00**	**0.08**	**(0.06)**	**2.02**	16.5	**0.67**	0.62	0.7	**1.092**	2.1	100	-	5.5	21.3	24.1	2.8	13.2%
		250	11.63	1.80	0.14	0.08	2.02	16.7	14.47	2.00	0.08	(0.06)	2.02	19.5	0.67	0.62	0.70	1.092	5.3	250	-	13.7	35.7	38.5	2.8	7.7%
		500	11.63	1.80	0.14	0.08	2.02	21.7	14.47	2.00	0.08	(0.06)	2.02	24.6	0.67	0.62	0.70	1.092	10.5	500	-	27.3	59.8	62.4	2.7	4.5%
		750	11.63	1.80	0.14	0.08	2.02	26.8	14.47	2.00	0.08	(0.06)	2.02	29.6	0.67	0.62	0.70	1.092	15.8	600	150	42.9	85.6	88.4	2.8	3.3%
		1,000	11.63	1.80	0.14	0.08	2.02	31.8	14.47	2.00	0.08	(0.06)	2.02	34.7	0.67	0.62	0.70	1.092	21.1	600	400	59.0	112.0	114.8	2.8	2.5%
Unmtr	**Campbellfor**	100	**7.63**	**1.19**	**0.17**	**0.05**	**1.41**	9.0	**11.47**	**2.00**	**0.05**	**(0.06)**	**1.99**	13.5	**0.67**	0.62	0.7	**1.092**	2.1	100	-	5.5	16.6	21.0	4.4	26.3%
		250	7.63	1.19	0.17	0.05	1.41	11.2	11.47	2.00	0.05	(0.06)	1.99	16.5	0.67	0.62	0.70	1.092	5.3	250	-	13.7	30.2	35.4	5.2	17.2%
		500	7.63	1.19	0.17	0.05	1.41	14.7	11.47	2.00	0.05	(0.06)	1.99	21.4	0.67	0.62	0.70	1.092	10.5	500	-	27.3	52.7	59.3	6.6	12.5%
		750	7.63	1.19	0.17	0.05	1.41	18.2	11.47	2.00	0.05	(0.06)	1.99	26.4	0.67	0.62	0.70	1.092	15.8	600	150	42.9	77.0	85.2	8.2	10.6%
		1,000	7.63	1.19	0.17	0.05	1.41	21.7	11.47	2.00	0.05	(0.06)	1.99	31.4	0.67	0.62	0.70	1.092	21.1	600	400	59.0	101.9	111.5	9.6	9.4%
Unmtr	**Carleton Pla**	100	**11.36**	**1.68**	**0.13**	**0.07**	**1.88**	13.2	**14.54**	**2.00**	**0.07**	**(0.06)**	**2.01**	16.6	**0.67**	0.62	0.7	**1.092**	2.1	100	-	5.5	20.8	24.1	3.3	15.7%
		250	11.36	1.68	0.13	0.07	1.88	16.1	14.54	2.00	0.07	(0.06)	2.01	19.6	0.67	0.62	0.70	1.092	5.3	250	-	13.7	35.1	38.5	3.4	9.7%
		500	11.36	1.68	0.13	0.07	1.88	20.8	14.54	2.00	0.07	(0.06)	2.01	24.6	0.67	0.62	0.70	1.092	10.5	500	-	27.3	58.8	62.4	3.7	6.2%
		750	11.36	1.68	0.13	0.07	1.88	25.5	14.54	2.00	0.07	(0.06)	2.01	29.6	0.67	0.62	0.70	1.092	15.8	600	150	42.9	84.2	88.4	4.1	4.9%
		1,000	11.36	1.68	0.13	0.07	1.88	30.2	14.54	2.00	0.07	(0.06)	2.01	34.7	0.67	0.62	0.70	1.092	21.1	600	400	59.0	110.3	114.8	4.5	4.0%
Unmtr	**Cavan-Millbr**	100	**10.68**	**1.50**	**0.33**	**0.26**	**2.09**	12.8	**13.71**	**2.00**	**0.26**	**(0.06)**	**2.20**	15.9	**0.67**	0.62	0.7	**1.092**	2.1	100	-	5.5	20.4	23.5	3.1	15.2%
		250	10.68	1.50	0.33	0.26	2.09	15.9	13.71	2.00	0.26	(0.06)	2.20	19.2	0.67	0.62	0.70	1.092	5.3	250	-	13.7	34.9	38.1	3.2	9.2%
		500	10.68	1.50	0.33	0.26	2.09	21.1	13.71	2.00	0.26	(0.06)	2.20	24.7	0.67	0.62	0.70	1.092	10.5	500	-	27.3	59.2	62.6	3.4	5.8%
		750	10.68	1.50	0.33	0.26	2.09	26.4	13.71	2.00	0.26	(0.06)	2.20	30.2	0.67	0.62	0.70	1.092	15.8	600	150	42.9	85.1	89.0	3.8	4.5%
		1,000	10.68	1.50	0.33	0.26	2.09	31.6	13.71	2.00	0.26	(0.06)	2.20	35.7	0.67	0.62	0.70	1.092	21.1	600	400	59.0	111.7	115.9	4.1	3.7%
Unmtr	**Centre Hasti**	100	**8.73**	**0.97**	**0.14**	**0.06**	**1.17**	9.9	**12.20**	**2.00**	**0.06**	**(0.06)**	**2.00**	14.2	**0.67**	0.62	0.7	**1.092**	2.1	100	-	5.5	17.5	21.8	4.3	24.3%
		250	8.73	0.97	0.14	0.06	1.17	11.7	12.20	2.00	0.06	(0.06)	2.00	17.2	0.67	0.62	0.70	1.092	5.3	250	-	13.7	30.7	36.1	5.5	17.8%
		500	8.73	0.97	0.14	0.06	1.17	14.6	12.20	2.00	0.06	(0.06)	2.00	22.2	0.67	0.62	0.70	1.092	10.5	500	-	27.3	52.6	60.1	7.4	14.1%
		750	8.73	0.97	0.14	0.06	1.17	17.5	12.20	2.00	0.06	(0.06)	2.00	27.2	0.67	0.62	0.70	1.092	15.8	600	150	42.9	76.3	86.0	9.7	12.7%
		1,000	8.73	0.97	0.14	0.06	1.17	20.4	12.20	2.00	0.06	(0.06)	2.00	32.2	0.67	0.62	0.70	1.092	21.1	600	400	59.0	100.6	112.3	11.8	11.7%

New Rate Class: GSe - Unmetered

Total Bill Impacts of Proposed Distribution Rates [new RTSR+TLF]: Threshold of 600 kWhs

Classes		Scenario	May 2007 Incl Rate Riders						May 2008 Incl Rate Riders						Non-Dx Compoent				Other Reg	Commodity Bands (600.0)			Existing	New	$ Incr	% Incr
			Existing Dx Rates					Existing Dx	New Dx Rates					New Dx	RTSR new	WMSC	DRC	TLF new	New	Band 1	Band 2	New	Total Bill	Total Bill	Total Bill	Total Bill
																				5.0	5.9					
New Class	Old Class	kWh	SrChg [$/cust]	base [c/kWh]	Rider1 [c/kWh]	Rider2 [c/kWh]	VarChg [c/kWh]	[$/month]	SrChg [$/cust]	base [c/kWh]	Rider2 [c/kWh]	Rider3 [c/kWh]	VarChg [c/kWh]	[$/month]	c/kWh	c/kWh	c/kWh		$	kWhs	kWhs		[$/month]	[$/month]	[$/month]	%
Unmtr	**Chalk River**	100	**10.20**	**1.79**	**0.39**	**0.34**	**2.52**	12.7	**13.83**	**2.00**	**0.34**	**(0.06)**	**2.28**	16.1	**0.67**	0.62	0.7	**1.092**	2.1	100	-	5.5	20.3	23.7	3.4	16.5%
		250	10.20	1.79	0.39	0.34	2.52	16.5	13.83	2.00	0.34	(0.06)	2.28	19.5	0.67	0.62	0.70	1.092	5.3	250	-	13.7	35.5	38.5	2.9	8.3%
		500	10.20	1.79	0.39	0.34	2.52	22.8	13.83	2.00	0.34	(0.06)	2.28	25.2	0.67	0.62	0.70	1.092	10.5	500	-	27.3	60.8	63.1	2.3	3.7%
		750	10.20	1.79	0.39	0.34	2.52	29.1	13.83	2.00	0.34	(0.06)	2.28	31.0	0.67	0.62	0.70	1.092	15.8	600	150	42.9	87.9	89.7	1.8	2.1%
		1,000	10.20	1.79	0.39	0.34	2.52	35.4	13.83	2.00	0.34	(0.06)	2.28	36.7	0.67	0.62	0.70	1.092	21.1	600	400	59.0	115.6	116.8	1.2	1.1%
Unmtr	**Champlain**	100	**9.83**	**0.91**	**0.26**	**0.15**	**1.32**	11.2	**12.92**	**2.00**	**0.15**	**(0.06)**	**2.09**	15.0	**0.67**	0.62	0.7	**1.092**	2.1	100	-	5.5	18.8	22.6	3.8	20.4%
		250	9.83	0.91	0.26	0.15	1.32	13.1	12.92	2.00	0.15	(0.06)	2.09	18.2	0.67	0.62	0.70	1.092	5.3	250	-	13.7	32.1	37.1	4.9	15.3%
		500	9.83	0.91	0.26	0.15	1.32	16.4	12.92	2.00	0.15	(0.06)	2.09	23.4	0.67	0.62	0.70	1.092	10.5	500	-	27.3	54.5	61.2	6.8	12.4%
		750	9.83	0.91	0.26	0.15	1.32	19.7	12.92	2.00	0.15	(0.06)	2.09	28.6	0.67	0.62	0.70	1.092	15.8	600	150	42.9	78.5	87.4	8.9	11.3%
		1,000	9.83	0.91	0.26	0.15	1.32	23.0	12.92	2.00	0.15	(0.06)	2.09	33.9	0.67	0.62	0.70	1.092	21.1	600	400	59.0	103.2	114.0	10.8	10.4%
Unmtr	**Cobden**	100	**10.50**	**2.13**	**0.36**	**0.30**	**2.79**	13.3	**13.75**	**2.00**	**0.30**	**(0.06)**	**2.24**	16.0	**0.67**	0.62	0.7	**1.092**	2.1	100	-	5.5	20.9	23.6	2.7	12.8%
		250	10.50	2.13	0.36	0.30	2.79	17.5	13.75	2.00	0.30	(0.06)	2.24	19.4	0.67	0.62	0.70	1.092	5.3	250	-	13.7	36.5	38.3	1.8	4.9%
		500	10.50	2.13	0.36	0.30	2.79	24.5	13.75	2.00	0.30	(0.06)	2.24	25.0	0.67	0.62	0.70	1.092	10.5	500	-	27.3	62.5	62.8	0.3	0.5%
		750	10.50	2.13	0.36	0.30	2.79	31.4	13.75	2.00	0.30	(0.06)	2.24	30.6	0.67	0.62	0.70	1.092	15.8	600	150	42.9	90.2	89.3	(0.9)	-1.0%
		1,000	10.50	2.13	0.36	0.30	2.79	38.4	13.75	2.00	0.30	(0.06)	2.24	36.2	0.67	0.62	0.70	1.092	21.1	600	400	59.0	118.6	116.3	(2.3)	-1.9%
Unmtr	**Deep River**	100	**11.50**	**2.26**	**0.15**	**0.14**	**2.55**	14.1	**14.50**	**2.00**	**0.14**	**(0.06)**	**2.08**	16.6	**0.67**	0.62	0.7	**1.092**	2.1	100	-	5.5	21.7	24.2	2.5	11.5%
		250	11.50	2.26	0.15	0.14	2.55	17.9	14.50	2.00	0.14	(0.06)	2.08	19.7	0.67	0.62	0.70	1.092	5.3	250	-	13.7	36.9	38.6	1.7	4.7%
		500	11.50	2.26	0.15	0.14	2.55	24.3	14.50	2.00	0.14	(0.06)	2.08	24.9	0.67	0.62	0.70	1.092	10.5	500	-	27.3	62.3	62.8	0.5	0.8%
		750	11.50	2.26	0.15	0.14	2.55	30.6	14.50	2.00	0.14	(0.06)	2.08	30.1	0.67	0.62	0.70	1.092	15.8	600	150	42.9	89.4	88.9	(0.5)	-0.6%
		1,000	11.50	2.26	0.15	0.14	2.55	37.0	14.50	2.00	0.14	(0.06)	2.08	35.3	0.67	0.62	0.70	1.092	21.1	600	400	59.0	117.2	115.5	(1.7)	-1.5%
Unmtr	**Deseronto**	100	**4.61**	**1.35**	**0.13**	**0.05**	**1.53**	6.1	**9.23**	**2.00**	**0.05**	**(0.06)**	**1.99**	11.2	**0.67**	0.62	0.7	**1.092**	2.1	100	-	5.5	13.7	18.8	5.0	36.7%
		250	4.61	1.35	0.13	0.05	1.53	8.4	9.23	2.00	0.05	(0.06)	1.99	14.2	0.67	0.62	0.70	1.092	5.3	250	-	13.7	27.5	33.1	5.7	20.7%
		500	4.61	1.35	0.13	0.05	1.53	12.3	9.23	2.00	0.05	(0.06)	1.99	19.2	0.67	0.62	0.70	1.092	10.5	500	-	27.3	50.3	57.0	6.7	13.4%
		750	4.61	1.35	0.13	0.05	1.53	16.1	9.23	2.00	0.05	(0.06)	1.99	24.2	0.67	0.62	0.70	1.092	15.8	600	150	42.9	74.9	82.9	8.1	10.8%
		1,000	4.61	1.35	0.13	0.05	1.53	19.9	9.23	2.00	0.05	(0.06)	1.99	29.2	0.67	0.62	0.70	1.092	21.1	600	400	59.0	100.1	109.3	9.2	9.2%

New Rate Class: GSe - Unmetered

Total Bill Impacts of Proposed Distribution Rates [new RTSR+TLF]: Threshold of 600 kWhs

600.0

Classes		Scenario	May 2007 Incl Rate Riders						May 2008 Incl Rate Riders						Non-Dx Compoent				Other Reg	Commodity Bands			Existing	New	$ Incr	% Incr
			Existing Dx Rates					Existing Dx	New Dx Rates					New Dx	RTSR new	WMSC	DRC	TLF new	New	Band 1	Band 2	New	Total Bill	Total Bill	Total Bill	Total Bill
																				5.0	5.9					
New Class	Old Class	kWh	SrChg	base	Rider1	Rider2	VarChg	[$/month]	SrChg	base	Rider2	Rider3	VarChg	[$/month]	c/kWh	c/kWh	c/kWh		$	kWhs	kWhs		[$/month]	[$/month]	[$/month]	%
			[$/cust]	[c/kWh]	[c/kWh]	[c/kWh]	[c/kWh]		[$/cust]	[c/kWh]	[c/kWh]	[c/kWh]	[c/kWh]													
Unmtr	**Dryden**	100	**9.09**	**1.03**	**0.12**	**0.04**	**1.19**	10.3	**13.11**	**2.00**	**0.04**	**(0.06)**	**1.98**	15.1	**0.67**	0.62	0.7	**1.092**	2.1	100	-	5.5	17.9	22.7	4.8	26.7%
		250	9.09	1.03	0.12	0.04	1.19	12.1	13.11	2.00	0.04	(0.06)	1.98	18.1	0.67	0.62	0.70	1.092	5.3	250	-	13.7	31.1	37.0	5.9	19.0%
		500	9.09	1.03	0.12	0.04	1.19	15.0	13.11	2.00	0.04	(0.06)	1.98	23.0	0.67	0.62	0.70	1.092	10.5	500	-	27.3	53.1	60.9	7.8	14.7%
		750	9.09	1.03	0.12	0.04	1.19	18.0	13.11	2.00	0.04	(0.06)	1.98	28.0	0.67	0.62	0.70	1.092	15.8	600	150	42.9	76.8	86.7	9.9	12.9%
		1,000	9.09	1.03	0.12	0.04	1.19	21.0	13.11	2.00	0.04	(0.06)	1.98	32.9	0.67	0.62	0.70	1.092	21.1	600	400	59.0	101.2	113.1	11.9	11.8%
Unmtr	**Dundalk**	100	**11.32**	**1.64**	**0.23**	**0.09**	**1.96**	13.3	**14.55**	**2.00**	**0.09**	**(0.06)**	**2.03**	16.6	**0.67**	0.62	0.7	**1.092**	2.1	100	-	5.5	20.9	24.1	3.3	15.6%
		250	11.32	1.64	0.23	0.09	1.96	16.2	14.55	2.00	0.09	(0.06)	2.03	19.6	0.67	0.62	0.70	1.092	5.3	250	-	13.7	35.2	38.6	3.3	9.4%
		500	11.32	1.64	0.23	0.09	1.96	21.1	14.55	2.00	0.09	(0.06)	2.03	24.7	0.67	0.62	0.70	1.092	10.5	500	-	27.3	59.2	62.6	3.4	5.8%
		750	11.32	1.64	0.23	0.09	1.96	26.0	14.55	2.00	0.09	(0.06)	2.03	29.8	0.67	0.62	0.70	1.092	15.8	600	150	42.9	84.8	88.5	3.7	4.4%
		1,000	11.32	1.64	0.23	0.09	1.96	30.9	14.55	2.00	0.09	(0.06)	2.03	34.9	0.67	0.62	0.70	1.092	21.1	600	400	59.0	111.1	115.0	3.9	3.5%
Unmtr	**Durham**	100	**11.59**	**1.37**	**0.15**	**0.06**	**1.58**	13.2	**14.48**	**2.00**	**0.06**	**(0.06)**	**2.00**	16.5	**0.67**	0.62	0.7	**1.092**	2.1	100	-	5.5	20.8	24.1	3.3	15.8%
		250	11.59	1.37	0.15	0.06	1.58	15.5	14.48	2.00	0.06	(0.06)	2.00	19.5	0.67	0.62	0.70	1.092	5.3	250	-	13.7	34.6	38.4	3.9	11.1%
		500	11.59	1.37	0.15	0.06	1.58	19.5	14.48	2.00	0.06	(0.06)	2.00	24.5	0.67	0.62	0.70	1.092	10.5	500	-	27.3	57.5	62.3	4.8	8.4%
		750	11.59	1.37	0.15	0.06	1.58	23.4	14.48	2.00	0.06	(0.06)	2.00	29.5	0.67	0.62	0.70	1.092	15.8	600	150	42.9	82.2	88.2	6.0	7.3%
		1,000	11.59	1.37	0.15	0.06	1.58	27.4	14.48	2.00	0.06	(0.06)	2.00	34.5	0.67	0.62	0.70	1.092	21.1	600	400	59.0	107.6	114.6	7.1	6.6%
Unmtr	**Eganville**	100	**10.22**	**2.32**	**0.17**	**0.12**	**2.61**	12.8	**13.82**	**2.00**	**0.12**	**(0.06)**	**2.06**	15.9	**0.67**	0.62	0.7	**1.092**	2.1	100	-	5.5	20.4	23.5	3.0	14.8%
		250	10.22	2.32	0.17	0.12	2.61	16.7	13.82	2.00	0.12	(0.06)	2.06	19.0	0.67	0.62	0.70	1.092	5.3	250	-	13.7	35.8	37.9	2.1	6.0%
		500	10.22	2.32	0.17	0.12	2.61	23.3	13.82	2.00	0.12	(0.06)	2.06	24.1	0.67	0.62	0.70	1.092	10.5	500	-	27.3	61.3	62.0	0.7	1.1%
		750	10.22	2.32	0.17	0.12	2.61	29.8	13.82	2.00	0.12	(0.06)	2.06	29.3	0.67	0.62	0.70	1.092	15.8	600	150	42.9	88.6	88.0	(0.5)	-0.6%
		1,000	10.22	2.32	0.17	0.12	2.61	36.3	13.82	2.00	0.12	(0.06)	2.06	34.5	0.67	0.62	0.70	1.092	21.1	600	400	59.0	116.5	114.6	(1.9)	-1.6%
Unmtr	**Erin**	100	**19.72**	**0.73**	**0.19**	**0.08**	**1.00**	20.7	**20.45**	**2.00**	**0.08**	**(0.06)**	**2.02**	22.5	**0.67**	0.62	0.7	**1.092**	2.1	100	-	5.5	28.3	30.0	1.7	6.0%
		250	19.72	0.73	0.19	0.08	1.00	22.2	20.45	2.00	0.08	(0.06)	2.02	25.5	0.67	0.62	0.70	1.092	5.3	250	-	13.7	41.2	44.4	3.2	7.7%
		500	19.72	0.73	0.19	0.08	1.00	24.7	20.45	2.00	0.08	(0.06)	2.02	30.6	0.67	0.62	0.70	1.092	10.5	500	-	27.3	62.8	68.4	5.7	9.0%
		750	19.72	0.73	0.19	0.08	1.00	27.2	20.45	2.00	0.08	(0.06)	2.02	35.6	0.67	0.62	0.70	1.092	15.8	600	150	42.9	86.0	94.4	8.4	9.7%
		1,000	19.72	0.73	0.19	0.08	1.00	29.7	20.45	2.00	0.08	(0.06)	2.02	40.7	0.67	0.62	0.70	1.092	21.1	600	400	59.0	109.9	120.8	10.9	9.9%

New Rate Class: GSe - Unmetered

Total Bill Impacts of Proposed Distribution Rates [new RTSR+TLF]: Threshold of 600 kWhs

Classes		Scenario	May 2007 Incl Rate Riders						May 2008 Incl Rate Riders						Non-Dx Compoent				Other Reg	Commodity Bands			Existing	New	$ Incr	% Incr
																				600.0						
			Existing Dx Rates					Existing Dx	New Dx Rates					New Dx	RTSR new	WMSC	DRC	TLF new	New	Band 1	Band 2	New	Total Bill	Total Bill	Total Bill	Total Bill
																				5.0	5.9					
New Class	Old Class	kWh	SrChg	base	Rider1	Rider2	VarChg	[$/month]	SrChg	base	Rider2	Rider3	VarChg	[$/month]	c/kWh	c/kWh	c/kWh		$	kWhs	kWhs		[$/month]	[$/month]	[$/month]	%
			[$/cust]	[c/kWh]	[c/kWh]	[c/kWh]	[c/kWh]		[$/cust]	[c/kWh]	[c/kWh]	[c/kWh]	[c/kWh]													
Unmtr	**Exeter**	100	**5.21**	**1.30**	**0.15**	**0.06**	**1.51**	6.7	**10.08**	**2.00**	**0.06**	**(0.06)**	**2.00**	12.1	**0.67**	0.62	0.7	**1.092**	2.1	100	-	5.5	14.3	19.6	5.3	37.1%
		250	5.21	1.30	0.15	0.06	1.51	9.0	10.08	2.00	0.06	(0.06)	2.00	15.1	0.67	0.62	0.70	1.092	5.3	250	-	13.7	28.0	34.0	6.0	21.4%
		500	5.21	1.30	0.15	0.06	1.51	12.8	10.08	2.00	0.06	(0.06)	2.00	20.1	0.67	0.62	0.70	1.092	10.5	500	-	27.3	50.8	57.9	7.1	14.1%
		750	5.21	1.30	0.15	0.06	1.51	16.5	10.08	2.00	0.06	(0.06)	2.00	25.1	0.67	0.62	0.70	1.092	15.8	600	150	42.9	75.3	83.8	8.5	11.3%
		1,000	5.21	1.30	0.15	0.06	1.51	20.3	10.08	2.00	0.06	(0.06)	2.00	30.1	0.67	0.62	0.70	1.092	21.1	600	400	59.0	100.5	110.2	9.8	9.7%
Unmtr	**Fenelon Fall**	100	**9.43**	**0.95**	**0.15**	**0.08**	**1.18**	10.6	**13.02**	**2.00**	**0.08**	**(0.06)**	**2.02**	15.0	**0.67**	0.62	0.7	**1.092**	2.1	100	-	5.5	18.2	22.6	4.4	24.1%
		250	9.43	0.95	0.15	0.08	1.18	12.4	13.02	2.00	0.08	(0.06)	2.02	18.1	0.67	0.62	0.70	1.092	5.3	250	-	13.7	31.4	37.0	5.6	17.8%
		500	9.43	0.95	0.15	0.08	1.18	15.3	13.02	2.00	0.08	(0.06)	2.02	23.1	0.67	0.62	0.70	1.092	10.5	500	-	27.3	53.4	61.0	7.6	14.3%
		750	9.43	0.95	0.15	0.08	1.18	18.3	13.02	2.00	0.08	(0.06)	2.02	28.2	0.67	0.62	0.70	1.092	15.8	600	150	42.9	77.1	86.9	9.9	12.8%
		1,000	9.43	0.95	0.15	0.08	1.18	21.2	13.02	2.00	0.08	(0.06)	2.02	33.3	0.67	0.62	0.70	1.092	21.1	600	400	59.0	101.4	113.4	12.0	11.8%
Unmtr	**Forest**	100	**11.98**	**1.18**	**0.16**	**0.06**	**1.40**	13.4	**14.38**	**2.00**	**0.06**	**(0.06)**	**2.00**	16.4	**0.67**	0.62	0.7	**1.092**	2.1	100	-	5.5	21.0	24.0	3.0	14.1%
		250	11.98	1.18	0.16	0.06	1.40	15.5	14.38	2.00	0.06	(0.06)	2.00	19.4	0.67	0.62	0.70	1.092	5.3	250	-	13.7	34.5	38.3	3.8	11.1%
		500	11.98	1.18	0.16	0.06	1.40	19.0	14.38	2.00	0.06	(0.06)	2.00	24.4	0.67	0.62	0.70	1.092	10.5	500	-	27.3	57.0	62.2	5.2	9.2%
		750	11.98	1.18	0.16	0.06	1.40	22.5	14.38	2.00	0.06	(0.06)	2.00	29.4	0.67	0.62	0.70	1.092	15.8	600	150	42.9	81.3	88.1	6.9	8.5%
		1,000	11.98	1.18	0.16	0.06	1.40	26.0	14.38	2.00	0.06	(0.06)	2.00	34.4	0.67	0.62	0.70	1.092	21.1	600	400	59.0	106.1	114.5	8.4	7.9%
Unmtr	**GBE**	100	**4.92**	**1.14**	**0.16**	**0.06**	**1.36**	6.3	**9.15**	**2.00**	**0.06**	**(0.06)**	**2.00**	11.2	**0.67**	0.62	0.7	**1.092**	2.1	100	-	5.5	13.9	18.7	4.8	34.8%
		250	4.92	1.14	0.16	0.06	1.36	8.3	9.15	2.00	0.06	(0.06)	2.00	14.2	0.67	0.62	0.70	1.092	5.3	250	-	13.7	27.3	33.1	5.7	21.0%
		500	4.92	1.14	0.16	0.06	1.36	11.7	9.15	2.00	0.06	(0.06)	2.00	19.2	0.67	0.62	0.70	1.092	10.5	500	-	27.3	49.8	57.0	7.3	14.6%
		750	4.92	1.14	0.16	0.06	1.36	15.1	9.15	2.00	0.06	(0.06)	2.00	24.2	0.67	0.62	0.70	1.092	15.8	600	150	42.9	73.9	82.9	9.0	12.2%
		1,000	4.92	1.14	0.16	0.06	1.36	18.5	9.15	2.00	0.06	(0.06)	2.00	29.2	0.67	0.62	0.70	1.092	21.1	600	400	59.0	98.7	109.3	10.6	10.8%
Unmtr	**Georgina**	100	**8.24**	**1.62**	**0.16**	**0.08**	**1.86**	10.1	**12.32**	**2.00**	**0.08**	**(0.06)**	**2.02**	14.3	**0.67**	0.62	0.7	**1.092**	2.1	100	-	5.5	17.7	21.9	4.2	23.7%
		250	8.24	1.62	0.16	0.08	1.86	12.9	12.32	2.00	0.08	(0.06)	2.02	17.4	0.67	0.62	0.70	1.092	5.3	250	-	13.7	31.9	36.3	4.4	13.8%
		500	8.24	1.62	0.16	0.08	1.86	17.5	12.32	2.00	0.08	(0.06)	2.02	22.4	0.67	0.62	0.70	1.092	10.5	500	-	27.3	55.6	60.3	4.7	8.5%
		750	8.24	1.62	0.16	0.08	1.86	22.2	12.32	2.00	0.08	(0.06)	2.02	27.5	0.67	0.62	0.70	1.092	15.8	600	150	42.9	81.0	86.2	5.3	6.5%
		1,000	8.24	1.62	0.16	0.08	1.86	26.8	12.32	2.00	0.08	(0.06)	2.02	32.6	0.67	0.62	0.70	1.092	21.1	600	400	59.0	107.0	112.7	5.7	5.3%

New Rate Class: GSe - Unmetered

Total Bill Impacts of Proposed Distribution Rates [new RTSR+TLF]: Threshold of 600 kWhs

Classes		Scenario	May 2007 Incl Rate Riders						May 2008 Incl Rate Riders						Non-Dx Compoent				Other Reg	Commodity Bands			Existing	New	$ Incr	% Incr
			Existing Dx Rates					Existing Dx	New Dx Rates					New Dx	RTSR new	WMSC	DRC	TLF new	New	Band 1	Band 2	New	Total Bill	Total Bill	Total Bill	Total Bill
																				600.0						
																				5.0	5.9					
New Class	Old Class	kWh	SrChg [$/cust]	base [c/kWh]	Rider1 [c/kWh]	Rider2 [c/kWh]	VarChg [c/kWh]	[$/month]	SrChg [$/cust]	base [c/kWh]	Rider2 [c/kWh]	Rider3 [c/kWh]	VarChg [c/kWh]	[$/month]	c/kWh	c/kWh	c/kWh		$	kWhs	kWhs		[$/month]	[$/month]	[$/month]	%
Unmtr	**Glencoe**	100	**5.21**	**0.81**	**0.22**	**0.14**	**1.17**	6.4	**10.08**	**2.00**	**0.14**	**(0.06)**	**2.08**	12.2	**0.67**	0.62	0.7	**1.092**	2.1	100	-	5.5	14.0	19.7	5.7	41.0%
		250	5.21	0.81	0.22	0.14	1.17	8.1	10.08	2.00	0.14	(0.06)	2.08	15.3	0.67	0.62	0.70	1.092	5.3	250	-	13.7	27.2	34.2	7.1	26.0%
		500	5.21	0.81	0.22	0.14	1.17	11.1	10.08	2.00	0.14	(0.06)	2.08	20.5	0.67	0.62	0.70	1.092	10.5	500	-	27.3	49.1	58.3	9.2	18.8%
		750	5.21	0.81	0.22	0.14	1.17	14.0	10.08	2.00	0.14	(0.06)	2.08	25.7	0.67	0.62	0.70	1.092	15.8	600	150	42.9	72.8	84.4	11.7	16.1%
		1,000	5.21	0.81	0.22	0.14	1.17	16.9	10.08	2.00	0.14	(0.06)	2.08	30.9	0.67	0.62	0.70	1.092	21.1	600	400	59.0	97.1	111.0	14.0	14.4%
Unmtr	**Grand Bend**	100	**10.63**	**1.23**	**0.19**	**0.07**	**1.49**	12.1	**13.72**	**2.00**	**0.07**	**(0.06)**	**2.01**	15.7	**0.67**	0.62	0.7	**1.092**	2.1	100	-	5.5	19.7	23.3	3.6	18.1%
		250	10.63	1.23	0.19	0.07	1.49	14.4	13.72	2.00	0.07	(0.06)	2.01	18.8	0.67	0.62	0.70	1.092	5.3	250	-	13.7	33.4	37.7	4.3	12.9%
		500	10.63	1.23	0.19	0.07	1.49	18.1	13.72	2.00	0.07	(0.06)	2.01	23.8	0.67	0.62	0.70	1.092	10.5	500	-	27.3	56.1	61.6	5.5	9.8%
		750	10.63	1.23	0.19	0.07	1.49	21.8	13.72	2.00	0.07	(0.06)	2.01	28.8	0.67	0.62	0.70	1.092	15.8	600	150	42.9	80.6	87.6	7.0	8.7%
		1,000	10.63	1.23	0.19	0.07	1.49	25.5	13.72	2.00	0.07	(0.06)	2.01	33.9	0.67	0.62	0.70	1.092	21.1	600	400	59.0	105.7	114.0	8.3	7.8%
Unmtr	**Hastings**	100	**10.98**	**1.69**	**0.23**	**0.09**	**2.01**	13.0	**13.63**	**2.00**	**0.09**	**(0.06)**	**2.03**	15.7	**0.67**	0.62	0.7	**1.092**	2.1	100	-	5.5	20.6	23.2	2.6	12.8%
		250	10.98	1.69	0.23	0.09	2.01	16.0	13.63	2.00	0.09	(0.06)	2.03	18.7	0.67	0.62	0.70	1.092	5.3	250	-	13.7	35.0	37.6	2.6	7.5%
		500	10.98	1.69	0.23	0.09	2.01	21.0	13.63	2.00	0.09	(0.06)	2.03	23.8	0.67	0.62	0.70	1.092	10.5	500	-	27.3	59.1	61.6	2.6	4.4%
		750	10.98	1.69	0.23	0.09	2.01	26.1	13.63	2.00	0.09	(0.06)	2.03	28.9	0.67	0.62	0.70	1.092	15.8	600	150	42.9	84.8	87.6	2.8	3.3%
		1,000	10.98	1.69	0.23	0.09	2.01	31.1	13.63	2.00	0.09	(0.06)	2.03	34.0	0.67	0.62	0.70	1.092	21.1	600	400	59.0	111.2	114.1	2.8	2.6%
Unmtr	**Havelock**	100	**10.63**	**1.52**	**0.16**	**0.09**	**1.77**	12.4	**13.72**	**2.00**	**0.09**	**(0.06)**	**2.03**	15.8	**0.67**	0.62	0.7	**1.092**	2.1	100	-	5.5	20.0	23.3	3.3	16.6%
		250	10.63	1.52	0.16	0.09	1.77	15.1	13.72	2.00	0.09	(0.06)	2.03	18.8	0.67	0.62	0.70	1.092	5.3	250	-	13.7	34.1	37.7	3.7	10.7%
		500	10.63	1.52	0.16	0.09	1.77	19.5	13.72	2.00	0.09	(0.06)	2.03	23.9	0.67	0.62	0.70	1.092	10.5	500	-	27.3	57.5	61.7	4.2	7.3%
		750	10.63	1.52	0.16	0.09	1.77	23.9	13.72	2.00	0.09	(0.06)	2.03	29.0	0.67	0.62	0.70	1.092	15.8	600	150	42.9	82.7	87.7	5.0	6.1%
		1,000	10.63	1.52	0.16	0.09	1.77	28.3	13.72	2.00	0.09	(0.06)	2.03	34.1	0.67	0.62	0.70	1.092	21.1	600	400	59.0	108.5	114.2	5.7	5.2%
Unmtr	**Kirkfield**	100	**6.88**	**1.95**	**0.61**	**0.44**	**3.00**	9.9	**10.66**	**2.00**	**0.44**	**(0.06)**	**2.38**	13.0	**0.67**	0.62	0.7	**1.092**	2.1	100	-	5.5	17.5	20.6	3.1	17.9%
		250	6.88	1.95	0.61	0.44	3.00	14.4	10.66	2.00	0.44	(0.06)	2.38	16.6	0.67	0.62	0.70	1.092	5.3	250	-	13.7	33.4	35.5	2.1	6.4%
		500	6.88	1.95	0.61	0.44	3.00	21.9	10.66	2.00	0.44	(0.06)	2.38	22.6	0.67	0.62	0.70	1.092	10.5	500	-	27.3	59.9	60.4	0.5	0.8%
		750	6.88	1.95	0.61	0.44	3.00	29.4	10.66	2.00	0.44	(0.06)	2.38	28.5	0.67	0.62	0.70	1.092	15.8	600	150	42.9	88.2	87.3	(0.9)	-1.0%
		1,000	6.88	1.95	0.61	0.44	3.00	36.9	10.66	2.00	0.44	(0.06)	2.38	34.5	0.67	0.62	0.70	1.092	21.1	600	400	59.0	117.0	114.6	(2.4)	-2.1%

New Rate Class: GSe - Unmetered

Total Bill Impacts of Proposed Distribution Rates [new RTSR+TLF]: Threshold of 600 kWhs

600.0

Classes		Scenario	May 2007 Incl Rate Riders						May 2008 Incl Rate Riders						Non-Dx Compoent				Other Reg	Commodity Bands			Existing	New	$ Incr	% Incr
			Existing Dx Rates					Existing Dx	New Dx Rates					New Dx	RTSR new	WMSC	DRC	TLF new	New	Band 1	Band 2	New	Total Bill	Total Bill	Total Bill	Total Bill
																				5.0	5.9					
New Class	Old Class	kWh	SrChg [$/cust]	base [c/kWh]	Rider1 [c/kWh]	Rider2 [c/kWh]	VarChg [c/kWh]	[$/month]	SrChg [$/cust]	base [c/kWh]	Rider2 [c/kWh]	Rider3 [c/kWh]	VarChg [c/kWh]	[$/month]	c/kWh	c/kWh	c/kWh		$	kWhs	kWhs		[$/month]	[$/month]	[$/month]	%
Unmtr	Lanark High	100	8.75	1.99	0.63	0.50	3.12	11.9	12.19	2.00	0.50	(0.06)	2.44	14.6	0.67	0.62	0.7	1.092	2.1	100	-	5.5	19.5	22.2	2.7	14.0%
		250	8.75	1.99	0.63	0.50	3.12	16.6	12.19	2.00	0.50	(0.06)	2.44	18.3	0.67	0.62	0.70	1.092	5.3	250	-	13.7	35.6	37.2	1.7	4.6%
		500	8.75	1.99	0.63	0.50	3.12	24.4	12.19	2.00	0.50	(0.06)	2.44	24.4	0.67	0.62	0.70	1.092	10.5	500	-	27.3	62.4	62.2	(0.1)	-0.2%
		750	8.75	1.99	0.63	0.50	3.12	32.2	12.19	2.00	0.50	(0.06)	2.44	30.5	0.67	0.62	0.70	1.092	15.8	600	150	42.9	90.9	89.3	(1.7)	-1.8%
		1,000	8.75	1.99	0.63	0.50	3.12	40.0	12.19	2.00	0.50	(0.06)	2.44	36.6	0.67	0.62	0.70	1.092	21.1	600	400	59.0	120.1	116.7	(3.4)	-2.8%
Unmtr	Larder Lake	100	9.62	1.58	0.51	0.36	2.45	12.1	12.97	2.00	0.36	(0.06)	2.30	15.3	0.67	0.62	0.7	1.092	2.1	100	-	5.5	19.7	22.8	3.2	16.1%
		250	9.62	1.58	0.51	0.36	2.45	15.7	12.97	2.00	0.36	(0.06)	2.30	18.7	0.67	0.62	0.70	1.092	5.3	250	-	13.7	34.8	37.7	2.9	8.3%
		500	9.62	1.58	0.51	0.36	2.45	21.9	12.97	2.00	0.36	(0.06)	2.30	24.5	0.67	0.62	0.70	1.092	10.5	500	-	27.3	59.9	62.3	2.4	4.1%
		750	9.62	1.58	0.51	0.36	2.45	28.0	12.97	2.00	0.36	(0.06)	2.30	30.2	0.67	0.62	0.70	1.092	15.8	600	150	42.9	86.8	89.0	2.2	2.6%
		1,000	9.62	1.58	0.51	0.36	2.45	34.1	12.97	2.00	0.36	(0.06)	2.30	36.0	0.67	0.62	0.70	1.092	21.1	600	400	59.0	114.3	116.1	1.8	1.6%
Unmtr	Latchford	100	0.97	1.02	0.65	0.20	1.87	2.8	6.14	2.00	0.20	(0.06)	2.14	8.3	0.67	0.62	0.7	1.092	2.1	100	-	5.5	10.4	15.8	5.4	51.7%
		250	0.97	1.02	0.65	0.20	1.87	5.6	6.14	2.00	0.20	(0.06)	2.14	11.5	0.67	0.62	0.70	1.092	5.3	250	-	13.7	24.7	30.4	5.8	23.3%
		500	0.97	1.02	0.65	0.20	1.87	10.3	6.14	2.00	0.20	(0.06)	2.14	16.9	0.67	0.62	0.70	1.092	10.5	500	-	27.3	48.4	54.7	6.3	13.1%
		750	0.97	1.02	0.65	0.20	1.87	15.0	6.14	2.00	0.20	(0.06)	2.14	22.2	0.67	0.62	0.70	1.092	15.8	600	150	42.9	73.8	80.9	7.2	9.7%
		1,000	0.97	1.02	0.65	0.20	1.87	19.7	6.14	2.00	0.20	(0.06)	2.14	27.6	0.67	0.62	0.70	1.092	21.1	600	400	59.0	99.8	107.7	7.9	7.9%
Unmtr	Lindsay	100	11.50	1.38	0.15	0.06	1.59	13.1	14.50	2.00	0.06	(0.06)	2.00	16.5	0.67	0.62	0.7	1.092	2.1	100	-	5.5	20.7	24.1	3.4	16.3%
		250	11.50	1.38	0.15	0.06	1.59	15.5	14.50	2.00	0.06	(0.06)	2.00	19.5	0.67	0.62	0.70	1.092	5.3	250	-	13.7	34.5	38.4	3.9	11.4%
		500	11.50	1.38	0.15	0.06	1.59	19.5	14.50	2.00	0.06	(0.06)	2.00	24.5	0.67	0.62	0.70	1.092	10.5	500	-	27.3	57.5	62.4	4.9	8.5%
		750	11.50	1.38	0.15	0.06	1.59	23.4	14.50	2.00	0.06	(0.06)	2.00	29.5	0.67	0.62	0.70	1.092	15.8	600	150	42.9	82.2	88.3	6.1	7.4%
		1,000	11.50	1.38	0.15	0.06	1.59	27.4	14.50	2.00	0.06	(0.06)	2.00	34.5	0.67	0.62	0.70	1.092	21.1	600	400	59.0	107.6	114.7	7.1	6.6%
Unmtr	Lucan Grant	100	8.03	1.47	0.17	0.10	1.74	9.8	12.37	2.00	0.10	(0.06)	2.04	14.4	0.67	0.62	0.7	1.092	2.1	100	-	5.5	17.4	22.0	4.6	26.5%
		250	8.03	1.47	0.17	0.10	1.74	12.4	12.37	2.00	0.10	(0.06)	2.04	17.5	0.67	0.62	0.70	1.092	5.3	250	-	13.7	31.4	36.4	5.0	15.9%
		500	8.03	1.47	0.17	0.10	1.74	16.7	12.37	2.00	0.10	(0.06)	2.04	22.6	0.67	0.62	0.70	1.092	10.5	500	-	27.3	54.8	60.4	5.7	10.3%
		750	8.03	1.47	0.17	0.10	1.74	21.1	12.37	2.00	0.10	(0.06)	2.04	27.7	0.67	0.62	0.70	1.092	15.8	600	150	42.9	79.9	86.4	6.6	8.2%
		1,000	8.03	1.47	0.17	0.10	1.74	25.4	12.37	2.00	0.10	(0.06)	2.04	32.8	0.67	0.62	0.70	1.092	21.1	600	400	59.0	105.6	112.9	7.3	6.9%

New Rate Class: GSe - Unmetered

Total Bill Impacts of Proposed Distribution Rates [new RTSR+TLF]: Threshold of 600 kWhs

600.0

Classes		Scenario	May 2007 Incl Rate Riders						May 2008 Incl Rate Riders						Non-Dx Compoent				Other Reg	Commodity Bands			Existing	New	$ Incr	% Incr
			Existing Dx Rates					Existing Dx	New Dx Rates					New Dx	RTSR new	WMSC	DRC	TLF new	New	Band 1	Band 2	New	Total Bill	Total Bill	Total Bill	Total Bill
																				5.0	5.9					
New Class	Old Class	kWh	SrChg [$/cust]	base [c/kWh]	Rider1 [c/kWh]	Rider2 [c/kWh]	VarChg [c/kWh]	[$/month]	SrChg [$/cust]	base [c/kWh]	Rider2 [c/kWh]	Rider3 [c/kWh]	VarChg [c/kWh]	[$/month]	c/kWh	c/kWh	c/kWh		$	kWhs	kWhs		[$/month]	[$/month]	[$/month]	%
Unmtr	**Malahide**	100	**7.45**	**1.98**	**0.81**	**0.49**	**3.28**	10.7	**11.52**	**2.00**	**0.49**	**(0.06)**	**2.43**	13.9	**0.67**	0.62	0.7	**1.092**	2.1	100	-	5.5	18.3	21.5	3.2	17.3%
		250	7.45	1.98	0.81	0.49	3.28	15.7	11.52	2.00	0.49	(0.06)	2.43	17.6	0.67	0.62	0.70	1.092	5.3	250	-	13.7	34.7	36.5	1.9	5.3%
		500	7.45	1.98	0.81	0.49	3.28	23.9	11.52	2.00	0.49	(0.06)	2.43	23.7	0.67	0.62	0.70	1.092	10.5	500	-	27.3	61.9	61.5	(0.4)	-0.6%
		750	7.45	1.98	0.81	0.49	3.28	32.1	11.52	2.00	0.49	(0.06)	2.43	29.8	0.67	0.62	0.70	1.092	15.8	600	150	42.9	90.8	88.5	(2.3)	-2.6%
		1,000	7.45	1.98	0.81	0.49	3.28	40.3	11.52	2.00	0.49	(0.06)	2.43	35.8	0.67	0.62	0.70	1.092	21.1	600	400	59.0	120.4	116.0	(4.4)	-3.7%
Unmtr	**Mapleton**	100	**10.32**	**1.71**	**0.40**	**0.29**	**2.40**	12.7	**13.80**	**2.00**	**0.29**	**(0.06)**	**2.23**	16.0	**0.67**	0.62	0.7	**1.092**	2.1	100	-	5.5	20.3	23.6	3.3	16.1%
		250	10.32	1.71	0.40	0.29	2.40	16.3	13.80	2.00	0.29	(0.06)	2.23	19.4	0.67	0.62	0.70	1.092	5.3	250	-	13.7	35.3	38.3	3.0	8.4%
		500	10.32	1.71	0.40	0.29	2.40	22.3	13.80	2.00	0.29	(0.06)	2.23	25.0	0.67	0.62	0.70	1.092	10.5	500	-	27.3	60.4	62.8	2.5	4.1%
		750	10.32	1.71	0.40	0.29	2.40	28.3	13.80	2.00	0.29	(0.06)	2.23	30.5	0.67	0.62	0.70	1.092	15.8	600	150	42.9	87.1	89.3	2.2	2.5%
		1,000	10.32	1.71	0.40	0.29	2.40	34.3	13.80	2.00	0.29	(0.06)	2.23	36.1	0.67	0.62	0.70	1.092	21.1	600	400	59.0	114.5	116.2	1.8	1.5%
Unmtr	**Markdale**	100	**11.04**	**0.80**	**0.15**	**0.04**	**0.99**	12.0	**14.62**	**2.00**	**0.04**	**(0.06)**	**1.98**	16.6	**0.67**	0.62	0.7	**1.092**	2.1	100	-	5.5	19.6	24.2	4.5	23.1%
		250	11.04	0.80	0.15	0.04	0.99	13.5	14.62	2.00	0.04	(0.06)	1.98	19.6	0.67	0.62	0.70	1.092	5.3	250	-	13.7	32.5	38.5	6.0	18.3%
		500	11.04	0.80	0.15	0.04	0.99	16.0	14.62	2.00	0.04	(0.06)	1.98	24.5	0.67	0.62	0.70	1.092	10.5	500	-	27.3	54.0	62.4	8.4	15.5%
		750	11.04	0.80	0.15	0.04	0.99	18.5	14.62	2.00	0.04	(0.06)	1.98	29.5	0.67	0.62	0.70	1.092	15.8	600	150	42.9	77.2	88.2	11.0	14.2%
		1,000	11.04	0.80	0.15	0.04	0.99	20.9	14.62	2.00	0.04	(0.06)	1.98	34.5	0.67	0.62	0.70	1.092	21.1	600	400	59.0	101.1	114.6	13.5	13.3%
Unmtr	**Marmora**	100	**4.54**	**1.05**	**0.15**	**0.05**	**1.25**	5.8	**9.24**	**2.00**	**0.05**	**(0.06)**	**1.99**	11.2	**0.67**	0.62	0.7	**1.092**	2.1	100	-	5.5	13.4	18.8	5.4	40.4%
		250	4.54	1.05	0.15	0.05	1.25	7.7	9.24	2.00	0.05	(0.06)	1.99	14.2	0.67	0.62	0.70	1.092	5.3	250	-	13.7	26.7	33.1	6.5	24.2%
		500	4.54	1.05	0.15	0.05	1.25	10.8	9.24	2.00	0.05	(0.06)	1.99	19.2	0.67	0.62	0.70	1.092	10.5	500	-	27.3	48.8	57.1	8.2	16.9%
		750	4.54	1.05	0.15	0.05	1.25	13.9	9.24	2.00	0.05	(0.06)	1.99	24.2	0.67	0.62	0.70	1.092	15.8	600	150	42.9	72.7	82.9	10.2	14.1%
		1,000	4.54	1.05	0.15	0.05	1.25	17.0	9.24	2.00	0.05	(0.06)	1.99	29.2	0.67	0.62	0.70	1.092	21.1	600	400	59.0	97.2	109.3	12.1	12.4%
Unmtr	**McGarry**	100	**9.52**	**2.00**	**0.57**	**0.50**	**3.07**	12.6	**13.00**	**2.00**	**0.50**	**(0.06)**	**2.44**	15.4	**0.67**	0.62	0.7	**1.092**	2.1	100	-	5.5	20.2	23.0	2.8	13.9%
		250	9.52	2.00	0.57	0.50	3.07	17.2	13.00	2.00	0.50	(0.06)	2.44	19.1	0.67	0.62	0.70	1.092	5.3	250	-	13.7	36.2	38.0	1.8	5.0%
		500	9.52	2.00	0.57	0.50	3.07	24.9	13.00	2.00	0.50	(0.06)	2.44	25.2	0.67	0.62	0.70	1.092	10.5	500	-	27.3	62.9	63.1	0.2	0.2%
		750	9.52	2.00	0.57	0.50	3.07	32.5	13.00	2.00	0.50	(0.06)	2.44	31.3	0.67	0.62	0.70	1.092	15.8	600	150	42.9	91.3	90.1	(1.3)	-1.4%
		1,000	9.52	2.00	0.57	0.50	3.07	40.2	13.00	2.00	0.50	(0.06)	2.44	37.4	0.67	0.62	0.70	1.092	21.1	600	400	59.0	120.4	117.5	(2.8)	-2.4%

New Rate Class: GSe - Unmetered

Total Bill Impacts of Proposed Distribution Rates [new RTSR+TLF]: Threshold of 600 kWhs

Classes		Scenario	May 2007 Incl Rate Riders						May 2008 Incl Rate Riders						Non-Dx Compoent				Other Reg	600.0 Commodity Bands			Existing	New	$ Incr	% Incr
			Existing Dx Rates					Existing Dx	New Dx Rates					New Dx	RTSR new	WMSC	DRC	TLF new	New	Band 1	Band 2	New	Total Bill	Total Bill	Total Bill	Total Bill
																				5.0	5.9					
New Class	Old Class	kWh	SrChg	base	Rider1	Rider2	VarChg	[$/month]	SrChg	base	Rider2	Rider3	VarChg	[$/month]	c/kWh	c/kWh	c/kWh		$	kWhs	kWhs		[$/month]	[$/month]	[$/month]	%
			[$/cust]	[c/kWh]	[c/kWh]	[c/kWh]	[c/kWh]		[$/cust]	[c/kWh]	[c/kWh]	[c/kWh]	[c/kWh]													
Unmtr	**Meaford**	100	**11.55**	**1.23**	**0.16**	**0.07**	**1.46**	13.0	**14.49**	**2.00**	**0.07**	**(0.06)**	**2.01**	16.5	**0.67**	0.62	0.7	**1.092**	2.1	100	-	5.5	20.6	24.1	3.5	16.8%
		250	11.55	1.23	0.16	0.07	1.46	15.2	14.49	2.00	0.07	(0.06)	2.01	19.5	0.67	0.62	0.70	1.092	5.3	250	-	13.7	34.2	38.4	4.2	12.4%
		500	11.55	1.23	0.16	0.07	1.46	18.9	14.49	2.00	0.07	(0.06)	2.01	24.6	0.67	0.62	0.70	1.092	10.5	500	-	27.3	56.9	62.4	5.5	9.7%
		750	11.55	1.23	0.16	0.07	1.46	22.5	14.49	2.00	0.07	(0.06)	2.01	29.6	0.67	0.62	0.70	1.092	15.8	600	150	42.9	81.3	88.3	7.1	8.7%
		1,000	11.55	1.23	0.16	0.07	1.46	26.2	14.49	2.00	0.07	(0.06)	2.01	34.6	0.67	0.62	0.70	1.092	21.1	600	400	59.0	106.3	114.7	8.4	7.9%
Unmtr	**Middlesex C**	100	**8.21**	**1.37**	**0.44**	**0.35**	**2.16**	10.4	**12.33**	**2.00**	**0.35**	**(0.06)**	**2.29**	14.6	**0.67**	0.62	0.7	**1.092**	2.1	100	-	5.5	18.0	22.2	4.2	23.4%
		250	8.21	1.37	0.44	0.35	2.16	13.6	12.33	2.00	0.35	(0.06)	2.29	18.1	0.67	0.62	0.70	1.092	5.3	250	-	13.7	32.6	37.0	4.4	13.3%
		500	8.21	1.37	0.44	0.35	2.16	19.0	12.33	2.00	0.35	(0.06)	2.29	23.8	0.67	0.62	0.70	1.092	10.5	500	-	27.3	57.0	61.6	4.6	8.0%
		750	8.21	1.37	0.44	0.35	2.16	24.4	12.33	2.00	0.35	(0.06)	2.29	29.5	0.67	0.62	0.70	1.092	15.8	600	150	42.9	83.2	88.3	5.1	6.1%
		1,000	8.21	1.37	0.44	0.35	2.16	29.8	12.33	2.00	0.35	(0.06)	2.29	35.3	0.67	0.62	0.70	1.092	21.1	600	400	59.0	110.0	115.4	5.4	4.9%
Unmtr	**Napanee**	100	**10.62**	**1.28**	**0.16**	**0.06**	**1.50**	12.1	**13.72**	**2.00**	**0.06**	**(0.06)**	**2.00**	15.7	**0.67**	0.62	0.7	**1.092**	2.1	100	-	5.5	19.7	23.3	3.6	18.1%
		250	10.62	1.28	0.16	0.06	1.50	14.4	13.72	2.00	0.06	(0.06)	2.00	18.7	0.67	0.62	0.70	1.092	5.3	250	-	13.7	33.4	37.7	4.3	12.8%
		500	10.62	1.28	0.16	0.06	1.50	18.1	13.72	2.00	0.06	(0.06)	2.00	23.7	0.67	0.62	0.70	1.092	10.5	500	-	27.3	56.2	61.6	5.4	9.7%
		750	10.62	1.28	0.16	0.06	1.50	21.9	13.72	2.00	0.06	(0.06)	2.00	28.7	0.67	0.62	0.70	1.092	15.8	600	150	42.9	80.6	87.5	6.8	8.5%
		1,000	10.62	1.28	0.16	0.06	1.50	25.6	13.72	2.00	0.06	(0.06)	2.00	33.8	0.67	0.62	0.70	1.092	21.1	600	400	59.0	105.8	113.9	8.1	7.6%
Unmtr	**Nipigon**	100	**11.19**	**1.05**	**0.34**	**0.21**	**1.60**	12.8	**14.58**	**2.00**	**0.21**	**(0.06)**	**2.15**	16.7	**0.67**	0.62	0.7	**1.092**	2.1	100	-	5.5	20.4	24.3	3.9	19.1%
		250	11.19	1.05	0.34	0.21	1.60	15.2	14.58	2.00	0.21	(0.06)	2.15	20.0	0.67	0.62	0.70	1.092	5.3	250	-	13.7	34.2	38.9	4.7	13.7%
		500	11.19	1.05	0.34	0.21	1.60	19.2	14.58	2.00	0.21	(0.06)	2.15	25.3	0.67	0.62	0.70	1.092	10.5	500	-	27.3	57.2	63.2	6.0	10.4%
		750	11.19	1.05	0.34	0.21	1.60	23.2	14.58	2.00	0.21	(0.06)	2.15	30.7	0.67	0.62	0.70	1.092	15.8	600	150	42.9	82.0	89.5	7.5	9.2%
		1,000	11.19	1.05	0.34	0.21	1.60	27.2	14.58	2.00	0.21	(0.06)	2.15	36.1	0.67	0.62	0.70	1.092	21.1	600	400	59.0	107.4	116.2	8.9	8.3%
Unmtr	**North Dorch**	100	**7.47**	**0.90**	**0.35**	**0.26**	**1.51**	9.0	**11.51**	**2.00**	**0.26**	**(0.06)**	**2.20**	13.7	**0.67**	0.62	0.7	**1.092**	2.1	100	-	5.5	16.6	21.3	4.7	28.3%
		250	7.47	0.90	0.35	0.26	1.51	11.2	11.51	2.00	0.26	(0.06)	2.20	17.0	0.67	0.62	0.70	1.092	5.3	250	-	13.7	30.3	35.9	5.7	18.8%
		500	7.47	0.90	0.35	0.26	1.51	15.0	11.51	2.00	0.26	(0.06)	2.20	22.5	0.67	0.62	0.70	1.092	10.5	500	-	27.3	53.1	60.4	7.3	13.8%
		750	7.47	0.90	0.35	0.26	1.51	18.8	11.51	2.00	0.26	(0.06)	2.20	28.0	0.67	0.62	0.70	1.092	15.8	600	150	42.9	77.6	86.8	9.2	11.9%
		1,000	7.47	0.90	0.35	0.26	1.51	22.6	11.51	2.00	0.26	(0.06)	2.20	33.5	0.67	0.62	0.70	1.092	21.1	600	400	59.0	102.7	113.7	10.9	10.6%

New Rate Class: GSe - Unmetered

Total Bill Impacts of Proposed Distribution Rates [new RTSR+TLF]: Threshold of 600 kWhs

Classes		Scenario	May 2007 Incl Rate Riders						May 2008 Incl Rate Riders						Non-Dx Compoent				Other Reg	Commodity Bands (600.0)			Existing	New	$ Incr	% Incr
			Existing Dx Rates					Existing Dx	New Dx Rates					New Dx	RTSR new	WMSC	DRC	TLF new	New	Band 1 (5.0)	Band 2 (5.9)	New	Total Bill	Total Bill	Total Bill	Total Bill
New Class	Old Class	kWh	SrChg [$/cust]	base [c/kWh]	Rider1 [c/kWh]	Rider2 [c/kWh]	VarChg [c/kWh]	[$/month]	SrChg [$/cust]	base [c/kWh]	Rider2 [c/kWh]	Rider3 [c/kWh]	VarChg [c/kWh]	[$/month]	c/kWh	c/kWh	c/kWh		$	kWhs	kWhs		[$/month]	[$/month]	[$/month]	%
Unmtr	**North Dunda**	100	**6.29**	**0.83**	**0.16**	**0.04**	**1.03**	7.3	**10.81**	**2.00**	**0.04**	**(0.06)**	**1.98**	12.8	**0.67**	0.62	0.7	**1.092**	2.1	100	-	5.5	14.9	20.4	5.4	36.4%
		250	6.29	0.83	0.16	0.04	1.03	8.9	10.81	2.00	0.04	(0.06)	1.98	15.8	0.67	0.62	0.70	1.092	5.3	250	-	13.7	27.9	34.7	6.8	24.4%
		500	6.29	0.83	0.16	0.04	1.03	11.4	10.81	2.00	0.04	(0.06)	1.98	20.7	0.67	0.62	0.70	1.092	10.5	500	-	27.3	49.5	58.6	9.1	18.4%
		750	6.29	0.83	0.16	0.04	1.03	14.0	10.81	2.00	0.04	(0.06)	1.98	25.7	0.67	0.62	0.70	1.092	15.8	600	150	42.9	72.8	84.4	11.6	16.0%
		1,000	6.29	0.83	0.16	0.04	1.03	16.6	10.81	2.00	0.04	(0.06)	1.98	30.6	0.67	0.62	0.70	1.092	21.1	600	400	59.0	96.8	110.8	14.0	14.5%
Unmtr	**North Gleng**	100	**8.40**	**0.90**	**0.21**	**0.12**	**1.23**	9.6	**12.28**	**2.00**	**0.12**	**(0.06)**	**2.06**	14.3	**0.67**	0.62	0.7	**1.092**	2.1	100	-	5.5	17.2	21.9	4.7	27.1%
		250	8.40	0.90	0.21	0.12	1.23	11.5	12.28	2.00	0.12	(0.06)	2.06	17.4	0.67	0.62	0.70	1.092	5.3	250	-	13.7	30.5	36.4	5.9	19.2%
		500	8.40	0.90	0.21	0.12	1.23	14.6	12.28	2.00	0.12	(0.06)	2.06	22.6	0.67	0.62	0.70	1.092	10.5	500	-	27.3	52.6	60.4	7.9	14.9%
		750	8.40	0.90	0.21	0.12	1.23	17.6	12.28	2.00	0.12	(0.06)	2.06	27.8	0.67	0.62	0.70	1.092	15.8	600	150	42.9	76.4	86.5	10.1	13.2%
		1,000	8.40	0.90	0.21	0.12	1.23	20.7	12.28	2.00	0.12	(0.06)	2.06	32.9	0.67	0.62	0.70	1.092	21.1	600	400	59.0	100.9	113.0	12.2	12.1%
Unmtr	**North Grenv**	100	**9.74**	**1.71**	**0.14**	**0.08**	**1.93**	11.7	**12.94**	**2.00**	**0.08**	**(0.06)**	**2.02**	15.0	**0.67**	0.62	0.7	**1.092**	2.1	100	-	5.5	19.3	22.5	3.3	16.9%
		250	9.74	1.71	0.14	0.08	1.93	14.6	12.94	2.00	0.08	(0.06)	2.02	18.0	0.67	0.62	0.70	1.092	5.3	250	-	13.7	33.6	36.9	3.3	9.9%
		500	9.74	1.71	0.14	0.08	1.93	19.4	12.94	2.00	0.08	(0.06)	2.02	23.1	0.67	0.62	0.70	1.092	10.5	500	-	27.3	57.4	60.9	3.5	6.1%
		750	9.74	1.71	0.14	0.08	1.93	24.2	12.94	2.00	0.08	(0.06)	2.02	28.1	0.67	0.62	0.70	1.092	15.8	600	150	42.9	83.0	86.9	3.9	4.7%
		1,000	9.74	1.71	0.14	0.08	1.93	29.0	12.94	2.00	0.08	(0.06)	2.02	33.2	0.67	0.62	0.70	1.092	21.1	600	400	59.0	109.2	113.3	4.1	3.7%
Unmtr	**North Perth**	100	**14.30**	**1.00**	**0.12**	**0.04**	**1.16**	15.5	**16.80**	**2.00**	**0.04**	**(0.06)**	**1.98**	18.8	**0.67**	0.62	0.7	**1.092**	2.1	100	-	5.5	23.1	26.4	3.3	14.3%
		250	14.30	1.00	0.12	0.04	1.16	17.2	16.80	2.00	0.04	(0.06)	1.98	21.8	0.67	0.62	0.70	1.092	5.3	250	-	13.7	36.2	40.7	4.5	12.3%
		500	14.30	1.00	0.12	0.04	1.16	20.1	16.80	2.00	0.04	(0.06)	1.98	26.7	0.67	0.62	0.70	1.092	10.5	500	-	27.3	58.1	64.6	6.4	11.1%
		750	14.30	1.00	0.12	0.04	1.16	23.0	16.80	2.00	0.04	(0.06)	1.98	31.7	0.67	0.62	0.70	1.092	15.8	600	150	42.9	81.8	90.4	8.6	10.6%
		1,000	14.30	1.00	0.12	0.04	1.16	25.9	16.80	2.00	0.04	(0.06)	1.98	36.6	0.67	0.62	0.70	1.092	21.1	600	400	59.0	106.1	116.8	10.7	10.1%
Unmtr	**North Storm**	100	**2.22**	**0.78**	**0.37**	**0.26**	**1.41**	3.6	**7.82**	**2.00**	**0.26**	**(0.06)**	**2.20**	10.0	**0.67**	0.62	0.7	**1.092**	2.1	100	-	5.5	11.2	17.6	6.4	56.6%
		250	2.22	0.78	0.37	0.26	1.41	5.7	7.82	2.00	0.26	(0.06)	2.20	13.3	0.67	0.62	0.70	1.092	5.3	250	-	13.7	24.8	32.3	7.5	30.2%
		500	2.22	0.78	0.37	0.26	1.41	9.3	7.82	2.00	0.26	(0.06)	2.20	18.8	0.67	0.62	0.70	1.092	10.5	500	-	27.3	47.3	56.7	9.4	19.8%
		750	2.22	0.78	0.37	0.26	1.41	12.8	7.82	2.00	0.26	(0.06)	2.20	24.3	0.67	0.62	0.70	1.092	15.8	600	150	42.9	71.6	83.1	11.5	16.1%
		1,000	2.22	0.78	0.37	0.26	1.41	16.3	7.82	2.00	0.26	(0.06)	2.20	29.9	0.67	0.62	0.70	1.092	21.1	600	400	59.0	96.5	110.0	13.5	14.0%

New Rate Class: GSe - Unmetered

Total Bill Impacts of Proposed Distribution Rates [new RTSR+TLF]: Threshold of 600 kWhs

Classes		Scenario	May 2007 Incl Rate Riders						May 2008 Incl Rate Riders						Non-Dx Compoent				Other Reg	Commodity Bands			Existing	New	$ Incr	% Incr
			Existing Dx Rates					Existing Dx	New Dx Rates					New Dx	RTSR new	WMSC	DRC	TLF new	New	Band 1	Band 2	New	Total Bill	Total Bill	Total Bill	Total Bill
																				600.0						
																				5.0	5.9					
New Class	Old Class	kWh	SrChg [$/cust]	base [c/kWh]	Rider1 [c/kWh]	Rider2 [c/kWh]	VarChg [c/kWh]	[$/month]	SrChg [$/cust]	base [c/kWh]	Rider2 [c/kWh]	Rider3 [c/kWh]	VarChg [c/kWh]	[$/month]	c/kWh	c/kWh	c/kWh		$	kWhs	kWhs		[$/month]	[$/month]	[$/month]	%
Unmtr	**Omemee**	100	**10.18**	**1.47**	**0.18**	**0.09**	**1.74**	11.9	**13.83**	**2.00**	**0.09**	**(0.06)**	**2.03**	15.9	**0.67**	0.62	0.7	**1.092**	2.1	100	-	5.5	19.5	23.4	3.9	20.0%
		250	10.18	1.47	0.18	0.09	1.74	14.5	13.83	2.00	0.09	(0.06)	2.03	18.9	0.67	0.62	0.70	1.092	5.3	250	-	13.7	33.5	37.8	4.3	12.8%
		500	10.18	1.47	0.18	0.09	1.74	18.9	13.83	2.00	0.09	(0.06)	2.03	24.0	0.67	0.62	0.70	1.092	10.5	500	-	27.3	56.9	61.8	4.9	8.7%
		750	10.18	1.47	0.18	0.09	1.74	23.2	13.83	2.00	0.09	(0.06)	2.03	29.1	0.67	0.62	0.70	1.092	15.8	600	150	42.9	82.0	87.8	5.8	7.1%
		1,000	10.18	1.47	0.18	0.09	1.74	27.6	13.83	2.00	0.09	(0.06)	2.03	34.2	0.67	0.62	0.70	1.092	21.1	600	400	59.0	107.7	114.3	6.5	6.1%
Unmtr	**Perth**	100	**9.49**	**0.92**	**0.13**	**0.04**	**1.09**	10.6	**13.01**	**2.00**	**0.04**	**(0.06)**	**1.98**	15.0	**0.67**	0.62	0.7	**1.092**	2.1	100	-	5.5	18.2	22.6	4.4	24.0%
		250	9.49	0.92	0.13	0.04	1.09	12.2	13.01	2.00	0.04	(0.06)	1.98	18.0	0.67	0.62	0.70	1.092	5.3	250	-	13.7	31.2	36.9	5.7	18.1%
		500	9.49	0.92	0.13	0.04	1.09	14.9	13.01	2.00	0.04	(0.06)	1.98	22.9	0.67	0.62	0.70	1.092	10.5	500	-	27.3	53.0	60.8	7.8	14.7%
		750	9.49	0.92	0.13	0.04	1.09	17.7	13.01	2.00	0.04	(0.06)	1.98	27.9	0.67	0.62	0.70	1.092	15.8	600	150	42.9	76.4	86.6	10.2	13.3%
		1,000	9.49	0.92	0.13	0.04	1.09	20.4	13.01	2.00	0.04	(0.06)	1.98	32.8	0.67	0.62	0.70	1.092	21.1	600	400	59.0	100.6	113.0	12.4	12.3%
Unmtr	**Perth East**	100	**6.86**	**1.29**	**0.16**	**0.09**	**1.54**	8.4	**10.66**	**2.00**	**0.09**	**(0.06)**	**2.03**	12.7	**0.67**	0.62	0.7	**1.092**	2.1	100	-	5.5	16.0	20.3	4.3	26.6%
		250	6.86	1.29	0.16	0.09	1.54	10.7	10.66	2.00	0.09	(0.06)	2.03	15.7	0.67	0.62	0.70	1.092	5.3	250	-	13.7	29.7	34.7	4.9	16.6%
		500	6.86	1.29	0.16	0.09	1.54	14.6	10.66	2.00	0.09	(0.06)	2.03	20.8	0.67	0.62	0.70	1.092	10.5	500	-	27.3	52.6	58.7	6.1	11.6%
		750	6.86	1.29	0.16	0.09	1.54	18.4	10.66	2.00	0.09	(0.06)	2.03	25.9	0.67	0.62	0.70	1.092	15.8	600	150	42.9	77.2	84.6	7.5	9.7%
		1,000	6.86	1.29	0.16	0.09	1.54	22.3	10.66	2.00	0.09	(0.06)	2.03	31.0	0.67	0.62	0.70	1.092	21.1	600	400	59.0	102.4	111.1	8.7	8.5%
Unmtr	**Prince Edwa**	100	**10.96**	**1.42**	**0.18**	**0.08**	**1.68**	12.6	**13.64**	**2.00**	**0.08**	**(0.06)**	**2.02**	15.7	**0.67**	0.62	0.7	**1.092**	2.1	100	-	5.5	20.2	23.2	3.0	14.7%
		250	10.96	1.42	0.18	0.08	1.68	15.2	13.64	2.00	0.08	(0.06)	2.02	18.7	0.67	0.62	0.70	1.092	5.3	250	-	13.7	34.2	37.6	3.4	10.1%
		500	10.96	1.42	0.18	0.08	1.68	19.4	13.64	2.00	0.08	(0.06)	2.02	23.8	0.67	0.62	0.70	1.092	10.5	500	-	27.3	57.4	61.6	4.2	7.3%
		750	10.96	1.42	0.18	0.08	1.68	23.6	13.64	2.00	0.08	(0.06)	2.02	28.8	0.67	0.62	0.70	1.092	15.8	600	150	42.9	82.3	87.5	5.2	6.3%
		1,000	10.96	1.42	0.18	0.08	1.68	27.8	13.64	2.00	0.08	(0.06)	2.02	33.9	0.67	0.62	0.70	1.092	21.1	600	400	59.0	107.9	114.0	6.1	5.6%
Unmtr	**Quinte West**	100	**1.41**	**1.05**	**0.14**	**0.06**	**1.25**	2.7	**7.03**	**2.00**	**0.06**	**(0.06)**	**2.00**	9.0	**0.67**	0.62	0.7	**1.092**	2.1	100	-	5.5	10.3	16.6	6.3	61.7%
		250	1.41	1.05	0.14	0.06	1.25	4.5	7.03	2.00	0.06	(0.06)	2.00	12.0	0.67	0.62	0.70	1.092	5.3	250	-	13.7	23.6	31.0	7.4	31.4%
		500	1.41	1.05	0.14	0.06	1.25	7.7	7.03	2.00	0.06	(0.06)	2.00	17.0	0.67	0.62	0.70	1.092	10.5	500	-	27.3	45.7	54.9	9.2	20.1%
		750	1.41	1.05	0.14	0.06	1.25	10.8	7.03	2.00	0.06	(0.06)	2.00	22.0	0.67	0.62	0.70	1.092	15.8	600	150	42.9	69.6	80.8	11.2	16.1%
		1,000	1.41	1.05	0.14	0.06	1.25	13.9	7.03	2.00	0.06	(0.06)	2.00	27.1	0.67	0.62	0.70	1.092	21.1	600	400	59.0	94.1	107.2	13.1	13.9%

New Rate Class: GSe - Unmetered

Total Bill Impacts of Proposed Distribution Rates [new RTSR+TLF]: Threshold of 600 kWhs

Classes		Scenario	May 2007 Incl Rate Riders						May 2008 Incl Rate Riders						Non-Dx Compoent				Other Reg	Commodity Bands			Existing	New	$ Incr	% Incr
			Existing Dx Rates					Existing Dx	New Dx Rates					New Dx	RTSR new	WMSC	DRC	TLF new	New	Band 1	Band 2	New	Total Bill	Total Bill	Total Bill	Total Bill
																				600.0						
																				5.0	5.9					
New Class	Old Class	kWh	SrChg [$/cust]	base [c/kWh]	Rider1 [c/kWh]	Rider2 [c/kWh]	VarChg [c/kWh]	[$/month]	SrChg [$/cust]	base [c/kWh]	Rider2 [c/kWh]	Rider3 [c/kWh]	VarChg [c/kWh]	[$/month]	c/kWh	c/kWh	c/kWh		$	kWhs	kWhs		[$/month]	[$/month]	[$/month]	%
Unmtr	Rainy River	100	9.18	1.76	0.45	0.36	2.57	11.8	13.08	2.00	0.36	(0.06)	2.30	15.4	0.67	0.62	0.7	1.092	2.1	100	-	5.5	19.4	23.0	3.6	18.6%
		250	9.18	1.76	0.45	0.36	2.57	15.6	13.08	2.00	0.36	(0.06)	2.30	18.8	0.67	0.62	0.70	1.092	5.3	250	-	13.7	34.6	37.8	3.1	9.1%
		500	9.18	1.76	0.45	0.36	2.57	22.0	13.08	2.00	0.36	(0.06)	2.30	24.6	0.67	0.62	0.70	1.092	10.5	500	-	27.3	60.1	62.4	2.4	4.0%
		750	9.18	1.76	0.45	0.36	2.57	28.5	13.08	2.00	0.36	(0.06)	2.30	30.4	0.67	0.62	0.70	1.092	15.8	600	150	42.9	87.2	89.1	1.9	2.1%
		1,000	9.18	1.76	0.45	0.36	2.57	34.9	13.08	2.00	0.36	(0.06)	2.30	36.1	0.67	0.62	0.70	1.092	21.1	600	400	59.0	115.0	116.2	1.2	1.0%
Unmtr	Ramara	100	10.02	1.06	0.45	0.37	1.88	11.9	13.87	2.00	0.37	(0.06)	2.31	16.2	0.67	0.62	0.7	1.092	2.1	100	-	5.5	19.5	23.8	4.2	21.8%
		250	10.02	1.06	0.45	0.37	1.88	14.7	13.87	2.00	0.37	(0.06)	2.31	19.7	0.67	0.62	0.70	1.092	5.3	250	-	13.7	33.7	38.6	4.8	14.3%
		500	10.02	1.06	0.45	0.37	1.88	19.4	13.87	2.00	0.37	(0.06)	2.31	25.4	0.67	0.62	0.70	1.092	10.5	500	-	27.3	57.5	63.3	5.8	10.1%
		750	10.02	1.06	0.45	0.37	1.88	24.1	13.87	2.00	0.37	(0.06)	2.31	31.2	0.67	0.62	0.70	1.092	15.8	600	150	42.9	82.9	90.0	7.1	8.5%
		1,000	10.02	1.06	0.45	0.37	1.88	28.8	13.87	2.00	0.37	(0.06)	2.31	37.0	0.67	0.62	0.70	1.092	21.1	600	400	59.0	109.0	117.1	8.1	7.5%
Unmtr	Red Rock	100	10.36	1.94	0.27	0.24	2.45	12.8	13.79	2.00	0.24	(0.06)	2.18	16.0	0.67	0.62	0.7	1.092	2.1	100	-	5.5	20.4	23.5	3.1	15.3%
		250	10.36	1.94	0.27	0.24	2.45	16.5	13.79	2.00	0.24	(0.06)	2.18	19.2	0.67	0.62	0.70	1.092	5.3	250	-	13.7	35.5	38.2	2.7	7.5%
		500	10.36	1.94	0.27	0.24	2.45	22.6	13.79	2.00	0.24	(0.06)	2.18	24.7	0.67	0.62	0.70	1.092	10.5	500	-	27.3	60.6	62.5	1.9	3.1%
		750	10.36	1.94	0.27	0.24	2.45	28.7	13.79	2.00	0.24	(0.06)	2.18	30.2	0.67	0.62	0.70	1.092	15.8	600	150	42.9	87.5	88.9	1.4	1.6%
		1,000	10.36	1.94	0.27	0.24	2.45	34.9	13.79	2.00	0.24	(0.06)	2.18	35.6	0.67	0.62	0.70	1.092	21.1	600	400	59.0	115.0	115.7	0.7	0.6%
Unmtr	Rockland	100	3.16	1.00	0.17	0.22	1.39	4.6	8.59	2.00	0.22	(0.06)	2.16	10.8	0.67	0.62	0.7	1.092	2.1	100	-	5.5	12.2	18.3	6.2	50.7%
		250	3.16	1.00	0.17	0.22	1.39	6.6	8.59	2.00	0.22	(0.06)	2.16	14.0	0.67	0.62	0.70	1.092	5.3	250	-	13.7	25.7	32.9	7.3	28.3%
		500	3.16	1.00	0.17	0.22	1.39	10.1	8.59	2.00	0.22	(0.06)	2.16	19.4	0.67	0.62	0.70	1.092	10.5	500	-	27.3	48.1	57.2	9.1	18.9%
		750	3.16	1.00	0.17	0.22	1.39	13.6	8.59	2.00	0.22	(0.06)	2.16	24.8	0.67	0.62	0.70	1.092	15.8	600	150	42.9	72.4	83.5	11.2	15.5%
		1,000	3.16	1.00	0.17	0.22	1.39	17.1	8.59	2.00	0.22	(0.06)	2.16	30.2	0.67	0.62	0.70	1.092	21.1	600	400	59.0	97.2	110.3	13.1	13.5%
Unmtr	Russell	100	9.17	2.24	0.18	0.11	2.53	11.7	13.09	2.00	0.11	(0.06)	2.05	15.1	0.67	0.62	0.7	1.092	2.1	100	-	5.5	19.3	22.7	3.4	17.6%
		250	9.17	2.24	0.18	0.11	2.53	15.5	13.09	2.00	0.11	(0.06)	2.05	18.2	0.67	0.62	0.70	1.092	5.3	250	-	13.7	34.5	37.1	2.6	7.6%
		500	9.17	2.24	0.18	0.11	2.53	21.8	13.09	2.00	0.11	(0.06)	2.05	23.4	0.67	0.62	0.70	1.092	10.5	500	-	27.3	59.9	61.2	1.3	2.2%
		750	9.17	2.24	0.18	0.11	2.53	28.1	13.09	2.00	0.11	(0.06)	2.05	28.5	0.67	0.62	0.70	1.092	15.8	600	150	42.9	86.9	87.2	0.3	0.4%
		1,000	9.17	2.24	0.18	0.11	2.53	34.5	13.09	2.00	0.11	(0.06)	2.05	33.6	0.67	0.62	0.70	1.092	21.1	600	400	59.0	114.6	113.7	(0.9)	-0.8%

New Rate Class: GSe - Unmetered

Total Bill Impacts of Proposed Distribution Rates [new RTSR+TLF]: Threshold of 600 kWhs

600.0

Classes		Scenario	May 2007 Incl Rate Riders						May 2008 Incl Rate Riders						Non-Dx Compoent				Other Reg	Commodity Bands			Existing	New	$ Incr	% Incr
			Existing Dx Rates					Existing Dx	New Dx Rates					New Dx	RTSR new	WMSC	DRC	TLF new	New	Band 1	Band 2	New	Total Bill	Total Bill	Total Bill	Total Bill
																				5.0	5.9					
New Class	Old Class	kWh	SrChg [$/cust]	base [c/kWh]	Rider1 [c/kWh]	Rider2 [c/kWh]	VarChg [c/kWh]	[$/month]	SrChg [$/cust]	base [c/kWh]	Rider2 [c/kWh]	Rider3 [c/kWh]	VarChg [c/kWh]	[$/month]	c/kWh	c/kWh	c/kWh		$	kWhs	kWhs		[$/month]	[$/month]	[$/month]	%
Unmtr	**Schreiber**	100	**9.88**	**2.51**	**0.50**	**0.40**	**3.41**	13.3	**12.91**	**2.00**	**0.40**	**(0.06)**	**2.34**	15.3	**0.67**	0.62	0.7	**1.092**	2.1	100	-	5.5	20.9	22.8	1.9	9.2%
		250	9.88	2.51	0.50	0.40	3.41	18.4	12.91	2.00	0.40	(0.06)	2.34	18.8	0.67	0.62	0.70	1.092	5.3	250	-	13.7	37.4	37.7	0.3	0.7%
		500	9.88	2.51	0.50	0.40	3.41	26.9	12.91	2.00	0.40	(0.06)	2.34	24.6	0.67	0.62	0.70	1.092	10.5	500	-	27.3	65.0	62.5	(2.5)	-3.8%
		750	9.88	2.51	0.50	0.40	3.41	35.5	12.91	2.00	0.40	(0.06)	2.34	30.5	0.67	0.62	0.70	1.092	15.8	600	150	42.9	94.2	89.2	(5.0)	-5.3%
		1,000	9.88	2.51	0.50	0.40	3.41	44.0	12.91	2.00	0.40	(0.06)	2.34	36.3	0.67	0.62	0.70	1.092	21.1	600	400	59.0	124.1	116.5	(7.7)	-6.2%
Unmtr	**Severn**	100	**10.62**	**1.06**	**0.31**	**0.22**	**1.59**	12.2	**13.72**	**2.00**	**0.22**	**(0.06)**	**2.16**	15.9	**0.67**	0.62	0.7	**1.092**	2.1	100	-	5.5	19.8	23.5	3.6	18.4%
		250	10.62	1.06	0.31	0.22	1.59	14.6	13.72	2.00	0.22	(0.06)	2.16	19.1	0.67	0.62	0.70	1.092	5.3	250	-	13.7	33.6	38.1	4.4	13.2%
		500	10.62	1.06	0.31	0.22	1.59	18.6	13.72	2.00	0.22	(0.06)	2.16	24.5	0.67	0.62	0.70	1.092	10.5	500	-	27.3	56.6	62.4	5.8	10.2%
		750	10.62	1.06	0.31	0.22	1.59	22.5	13.72	2.00	0.22	(0.06)	2.16	29.9	0.67	0.62	0.70	1.092	15.8	600	150	42.9	81.3	88.7	7.4	9.1%
		1,000	10.62	1.06	0.31	0.22	1.59	26.5	13.72	2.00	0.22	(0.06)	2.16	35.4	0.67	0.62	0.70	1.092	21.1	600	400	59.0	106.7	115.5	8.8	8.2%
Unmtr	**Shelburne**	100	**9.53**	**0.87**	**0.10**	**0.02**	**0.99**	10.5	**13.00**	**2.00**	**0.02**	**(0.06)**	**1.96**	15.0	**0.67**	0.62	0.7	**1.092**	2.1	100	-	5.5	18.1	22.5	4.4	24.3%
		250	9.53	0.87	0.10	0.02	0.99	12.0	13.00	2.00	0.02	(0.06)	1.96	17.9	0.67	0.62	0.70	1.092	5.3	250	-	13.7	31.0	36.8	5.8	18.7%
		500	9.53	0.87	0.10	0.02	0.99	14.5	13.00	2.00	0.02	(0.06)	1.96	22.8	0.67	0.62	0.70	1.092	10.5	500	-	27.3	52.5	60.7	8.1	15.5%
		750	9.53	0.87	0.10	0.02	0.99	17.0	13.00	2.00	0.02	(0.06)	1.96	27.7	0.67	0.62	0.70	1.092	15.8	600	150	42.9	75.7	86.5	10.7	14.2%
		1,000	9.53	0.87	0.10	0.02	0.99	19.4	13.00	2.00	0.02	(0.06)	1.96	32.6	0.67	0.62	0.70	1.092	21.1	600	400	59.0	99.6	112.7	13.2	13.2%
Unmtr	**Smiths Falls**	100	**4.46**	**1.05**	**0.12**	**0.04**	**1.21**	5.7	**9.26**	**2.00**	**0.04**	**(0.06)**	**1.98**	11.2	**0.67**	0.62	0.7	**1.092**	2.1	100	-	5.5	13.3	18.8	5.5	41.7%
		250	4.46	1.05	0.12	0.04	1.21	7.5	9.26	2.00	0.04	(0.06)	1.98	14.2	0.67	0.62	0.70	1.092	5.3	250	-	13.7	26.5	33.1	6.6	25.1%
		500	4.46	1.05	0.12	0.04	1.21	10.5	9.26	2.00	0.04	(0.06)	1.98	19.2	0.67	0.62	0.70	1.092	10.5	500	-	27.3	48.5	57.0	8.5	17.5%
		750	4.46	1.05	0.12	0.04	1.21	13.5	9.26	2.00	0.04	(0.06)	1.98	24.1	0.67	0.62	0.70	1.092	15.8	600	150	42.9	72.3	82.9	10.6	14.6%
		1,000	4.46	1.05	0.12	0.04	1.21	16.6	9.26	2.00	0.04	(0.06)	1.98	29.1	0.67	0.62	0.70	1.092	21.1	600	400	59.0	96.7	109.2	12.5	12.9%
Unmtr	**South Glenc**	100	**8.25**	**0.75**	**0.37**	**0.30**	**1.42**	9.7	**12.32**	**2.00**	**0.30**	**(0.06)**	**2.24**	14.6	**0.67**	0.62	0.7	**1.092**	2.1	100	-	5.5	17.3	22.1	4.9	28.1%
		250	8.25	0.75	0.37	0.30	1.42	11.8	12.32	2.00	0.30	(0.06)	2.24	17.9	0.67	0.62	0.70	1.092	5.3	250	-	13.7	30.8	36.8	6.0	19.6%
		500	8.25	0.75	0.37	0.30	1.42	15.4	12.32	2.00	0.30	(0.06)	2.24	23.5	0.67	0.62	0.70	1.092	10.5	500	-	27.3	53.4	61.4	8.0	15.0%
		750	8.25	0.75	0.37	0.30	1.42	18.9	12.32	2.00	0.30	(0.06)	2.24	29.1	0.67	0.62	0.70	1.092	15.8	600	150	42.9	77.7	87.9	10.2	13.1%
		1,000	8.25	0.75	0.37	0.30	1.42	22.5	12.32	2.00	0.30	(0.06)	2.24	34.7	0.67	0.62	0.70	1.092	21.1	600	400	59.0	102.6	114.9	12.3	11.9%

New Rate Class: GSe - Unmetered

Total Bill Impacts of Proposed Distribution Rates [new RTSR+TLF]: Threshold of 600 kWhs

600.0

Classes		Scenario	May 2007 Incl Rate Riders						May 2008 Incl Rate Riders						Non-Dx Compoent				Other Reg	Commodity Bands			Existing	New	$ Incr	% Incr
			Existing Dx Rates					Existing Dx	New Dx Rates					New Dx	RTSR new	WMSC	DRC	TLF new	New	Band 1	Band 2	New	Total Bill	Total Bill	Total Bill	Total Bill
																				5.0	5.9					
New Class	Old Class	kWh	SrChg [$/cust]	base [c/kWh]	Rider1 [c/kWh]	Rider2 [c/kWh]	VarChg [c/kWh]	[$/month]	SrChg [$/cust]	base [c/kWh]	Rider2 [c/kWh]	Rider3 [c/kWh]	VarChg [c/kWh]	[$/month]	c/kWh	c/kWh	c/kWh		$	kWhs	kWhs		[$/month]	[$/month]	[$/month]	%
Unmtr	**South River**	100	**10.59**	**1.58**	**0.39**	**0.30**	**2.27**	12.9	**13.73**	**2.00**	**0.30**	**(0.06)**	**2.24**	16.0	**0.67**	0.62	0.7	**1.092**	2.1	100	-	5.5	20.5	23.5	3.1	15.0%
		250	10.59	1.58	0.39	0.30	2.27	16.3	13.73	2.00	0.30	(0.06)	2.24	19.3	0.67	0.62	0.70	1.092	5.3	250	-	13.7	35.3	38.3	3.0	8.4%
		500	10.59	1.58	0.39	0.30	2.27	21.9	13.73	2.00	0.30	(0.06)	2.24	24.9	0.67	0.62	0.70	1.092	10.5	500	-	27.3	60.0	62.8	2.8	4.7%
		750	10.59	1.58	0.39	0.30	2.27	27.6	13.73	2.00	0.30	(0.06)	2.24	30.6	0.67	0.62	0.70	1.092	15.8	600	150	42.9	86.4	89.3	2.9	3.4%
		1,000	10.59	1.58	0.39	0.30	2.27	33.3	13.73	2.00	0.30	(0.06)	2.24	36.2	0.67	0.62	0.70	1.092	21.1	600	400	59.0	113.5	116.3	2.8	2.5%
Unmtr	**Springwater**	100	**9.80**	**1.07**	**0.27**	**0.17**	**1.51**	11.3	**12.93**	**2.00**	**0.17**	**(0.06)**	**2.11**	15.0	**0.67**	0.62	0.7	**1.092**	2.1	100	-	5.5	18.9	22.6	3.7	19.5%
		250	9.80	1.07	0.27	0.17	1.51	13.6	12.93	2.00	0.17	(0.06)	2.11	18.2	0.67	0.62	0.70	1.092	5.3	250	-	13.7	32.6	37.1	4.5	13.9%
		500	9.80	1.07	0.27	0.17	1.51	17.4	12.93	2.00	0.17	(0.06)	2.11	23.5	0.67	0.62	0.70	1.092	10.5	500	-	27.3	55.4	61.3	6.0	10.7%
		750	9.80	1.07	0.27	0.17	1.51	21.1	12.93	2.00	0.17	(0.06)	2.11	28.8	0.67	0.62	0.70	1.092	15.8	600	150	42.9	79.9	87.5	7.6	9.5%
		1,000	9.80	1.07	0.27	0.17	1.51	24.9	12.93	2.00	0.17	(0.06)	2.11	34.1	0.67	0.62	0.70	1.092	21.1	600	400	59.0	105.1	114.2	9.1	8.7%
Unmtr	**Stirling-Raw**	100	**11.59**	**1.30**	**0.21**	**0.09**	**1.60**	13.2	**14.48**	**2.00**	**0.09**	**(0.06)**	**2.03**	16.5	**0.67**	0.62	0.7	**1.092**	2.1	100	-	5.5	20.8	24.1	3.3	15.8%
		250	11.59	1.30	0.21	0.09	1.60	15.6	14.48	2.00	0.09	(0.06)	2.03	19.6	0.67	0.62	0.70	1.092	5.3	250	-	13.7	34.6	38.5	3.9	11.2%
		500	11.59	1.30	0.21	0.09	1.60	19.6	14.48	2.00	0.09	(0.06)	2.03	24.6	0.67	0.62	0.70	1.092	10.5	500	-	27.3	57.6	62.5	4.9	8.4%
		750	11.59	1.30	0.21	0.09	1.60	23.6	14.48	2.00	0.09	(0.06)	2.03	29.7	0.67	0.62	0.70	1.092	15.8	600	150	42.9	82.4	88.5	6.1	7.4%
		1,000	11.59	1.30	0.21	0.09	1.60	27.6	14.48	2.00	0.09	(0.06)	2.03	34.8	0.67	0.62	0.70	1.092	21.1	600	400	59.0	107.8	114.9	7.2	6.7%
Unmtr	**Thedford**	100	**8.45**	**1.06**	**0.36**	**0.31**	**1.73**	10.2	**12.27**	**2.00**	**0.31**	**(0.06)**	**2.25**	14.5	**0.67**	0.62	0.7	**1.092**	2.1	100	-	5.5	17.8	22.1	4.3	24.2%
		250	8.45	1.06	0.36	0.31	1.73	12.8	12.27	2.00	0.31	(0.06)	2.25	17.9	0.67	0.62	0.70	1.092	5.3	250	-	13.7	31.8	36.8	5.0	15.8%
		500	8.45	1.06	0.36	0.31	1.73	17.1	12.27	2.00	0.31	(0.06)	2.25	23.5	0.67	0.62	0.70	1.092	10.5	500	-	27.3	55.1	61.4	6.2	11.3%
		750	8.45	1.06	0.36	0.31	1.73	21.4	12.27	2.00	0.31	(0.06)	2.25	29.2	0.67	0.62	0.70	1.092	15.8	600	150	42.9	80.2	87.9	7.7	9.6%
		1,000	8.45	1.06	0.36	0.31	1.73	25.8	12.27	2.00	0.31	(0.06)	2.25	34.8	0.67	0.62	0.70	1.092	21.1	600	400	59.0	105.9	114.9	9.0	8.5%
Unmtr	**Thessalon**	100	**8.99**	**1.55**	**0.10**	**0.08**	**1.73**	10.7	**12.13**	**2.00**	**0.08**	**(0.06)**	**2.02**	14.2	**0.67**	0.62	0.7	**1.092**	2.1	100	-	5.5	18.3	21.7	3.4	18.5%
		250	8.99	1.55	0.10	0.08	1.73	13.3	12.13	2.00	0.08	(0.06)	2.02	17.2	0.67	0.62	0.70	1.092	5.3	250	-	13.7	32.3	36.1	3.8	11.7%
		500	8.99	1.55	0.10	0.08	1.73	17.6	12.13	2.00	0.08	(0.06)	2.02	22.2	0.67	0.62	0.70	1.092	10.5	500	-	27.3	55.7	60.1	4.4	7.9%
		750	8.99	1.55	0.10	0.08	1.73	22.0	12.13	2.00	0.08	(0.06)	2.02	27.3	0.67	0.62	0.70	1.092	15.8	600	150	42.9	80.7	86.0	5.3	6.6%
		1,000	8.99	1.55	0.10	0.08	1.73	26.3	12.13	2.00	0.08	(0.06)	2.02	32.4	0.67	0.62	0.70	1.092	21.1	600	400	59.0	106.5	112.5	6.0	5.7%

New Rate Class: GSe - Unmetered

Total Bill Impacts of Proposed Distribution Rates [new RTSR+TLF]: Threshold of 600 kWhs

600.0

Classes		Scenario	May 2007 Incl Rate Riders						May 2008 Incl Rate Riders						Non-Dx Compoent				Other Reg	Commodity Bands			Existing	New	$ Incr	% Incr
			Existing Dx Rates					Existing Dx	New Dx Rates					New Dx	RTSR new	WMSC	DRC	TLF new	New	Band 1	Band 2	New	Total Bill	Total Bill	Total Bill	Total Bill
																				5.0	5.9					
New Class	Old Class	kWh	SrChg	base	Rider1	Rider2	VarChg	[$/month]	SrChg	base	Rider2	Rider3	VarChg	[$/month]	c/kWh	c/kWh	c/kWh		$	kWhs	kWhs		[$/month]	[$/month]	[$/month]	%
			[$/cust]	[c/kWh]	[c/kWh]	[c/kWh]	[c/kWh]		[$/cust]	[c/kWh]	[c/kWh]	[c/kWh]	[c/kWh]													
Unmtr	**Thorndale**	100	**6.79**	**1.02**	**0.52**	**0.32**	**1.86**	8.7	**10.68**	**2.00**	**0.32**	**(0.06)**	**2.26**	12.9	**0.67**	0.62	0.7	**1.092**	2.1	100	-	5.5	16.3	20.5	4.3	26.2%
		250	6.79	1.02	0.52	0.32	1.86	11.4	10.68	2.00	0.32	(0.06)	2.26	16.3	0.67	0.62	0.70	1.092	5.3	250	-	13.7	30.5	35.3	4.8	15.8%
		500	6.79	1.02	0.52	0.32	1.86	16.1	10.68	2.00	0.32	(0.06)	2.26	22.0	0.67	0.62	0.70	1.092	10.5	500	-	27.3	54.1	59.8	5.7	10.6%
		750	6.79	1.02	0.52	0.32	1.86	20.7	10.68	2.00	0.32	(0.06)	2.26	27.7	0.67	0.62	0.70	1.092	15.8	600	150	42.9	79.5	86.4	6.9	8.7%
		1,000	6.79	1.02	0.52	0.32	1.86	25.4	10.68	2.00	0.32	(0.06)	2.26	33.3	0.67	0.62	0.70	1.092	21.1	600	400	59.0	105.6	113.4	7.9	7.5%
Unmtr	**Thorold**	100	**10.85**	**1.50**	**0.15**	**0.06**	**1.71**	12.6	**13.67**	**2.00**	**0.06**	**(0.06)**	**2.00**	15.7	**0.67**	0.62	0.7	**1.092**	2.1	100	-	5.5	20.2	23.2	3.1	15.2%
		250	10.85	1.50	0.15	0.06	1.71	15.1	13.67	2.00	0.06	(0.06)	2.00	18.7	0.67	0.62	0.70	1.092	5.3	250	-	13.7	34.1	37.6	3.5	10.1%
		500	10.85	1.50	0.15	0.06	1.71	19.4	13.67	2.00	0.06	(0.06)	2.00	23.7	0.67	0.62	0.70	1.092	10.5	500	-	27.3	57.4	61.5	4.1	7.1%
		750	10.85	1.50	0.15	0.06	1.71	23.7	13.67	2.00	0.06	(0.06)	2.00	28.7	0.67	0.62	0.70	1.092	15.8	600	150	42.9	82.4	87.4	5.0	6.0%
		1,000	10.85	1.50	0.15	0.06	1.71	28.0	13.67	2.00	0.06	(0.06)	2.00	33.7	0.67	0.62	0.70	1.092	21.1	600	400	59.0	108.1	113.8	5.7	5.3%
Unmtr	**Tweed**	100	**3.67**	**0.97**	**0.43**	**0.31**	**1.71**	5.4	**8.46**	**2.00**	**0.31**	**(0.06)**	**2.25**	10.7	**0.67**	0.62	0.7	**1.092**	2.1	100	-	5.5	13.0	18.3	5.3	40.8%
		250	3.67	0.97	0.43	0.31	1.71	7.9	8.46	2.00	0.31	(0.06)	2.25	14.1	0.67	0.62	0.70	1.092	5.3	250	-	13.7	27.0	33.0	6.1	22.4%
		500	3.67	0.97	0.43	0.31	1.71	12.2	8.46	2.00	0.31	(0.06)	2.25	19.7	0.67	0.62	0.70	1.092	10.5	500	-	27.3	50.3	57.6	7.3	14.6%
		750	3.67	0.97	0.43	0.31	1.71	16.5	8.46	2.00	0.31	(0.06)	2.25	25.4	0.67	0.62	0.70	1.092	15.8	600	150	42.9	75.3	84.1	8.8	11.7%
		1,000	3.67	0.97	0.43	0.31	1.71	20.8	8.46	2.00	0.31	(0.06)	2.25	31.0	0.67	0.62	0.70	1.092	21.1	600	400	59.0	100.9	111.1	10.2	10.1%
Unmtr	**Wardsville**	100	**5.70**	**1.00**	**0.25**	**0.08**	**1.33**	7.0	**9.95**	**2.00**	**0.08**	**(0.06)**	**2.02**	12.0	**0.67**	0.62	0.7	**1.092**	2.1	100	-	5.5	14.6	19.5	4.9	33.5%
		250	5.70	1.00	0.25	0.08	1.33	9.0	9.95	2.00	0.08	(0.06)	2.02	15.0	0.67	0.62	0.70	1.092	5.3	250	-	13.7	28.0	33.9	5.9	21.0%
		500	5.70	1.00	0.25	0.08	1.33	12.4	9.95	2.00	0.08	(0.06)	2.02	20.1	0.67	0.62	0.70	1.092	10.5	500	-	27.3	50.4	57.9	7.5	14.9%
		750	5.70	1.00	0.25	0.08	1.33	15.7	9.95	2.00	0.08	(0.06)	2.02	25.1	0.67	0.62	0.70	1.092	15.8	600	150	42.9	74.4	83.9	9.4	12.7%
		1,000	5.70	1.00	0.25	0.08	1.33	19.0	9.95	2.00	0.08	(0.06)	2.02	30.2	0.67	0.62	0.70	1.092	21.1	600	400	59.0	99.2	110.3	11.1	11.2%
Unmtr	**Warkworth**	100	**10.20**	**1.52**	**0.46**	**0.35**	**2.33**	12.5	**13.83**	**2.00**	**0.35**	**(0.06)**	**2.29**	16.1	**0.67**	0.62	0.7	**1.092**	2.1	100	-	5.5	20.1	23.7	3.6	17.6%
		250	10.20	1.52	0.46	0.35	2.33	16.0	13.83	2.00	0.35	(0.06)	2.29	19.6	0.67	0.62	0.70	1.092	5.3	250	-	13.7	35.0	38.5	3.4	9.8%
		500	10.20	1.52	0.46	0.35	2.33	21.9	13.83	2.00	0.35	(0.06)	2.29	25.3	0.67	0.62	0.70	1.092	10.5	500	-	27.3	59.9	63.1	3.3	5.4%
		750	10.20	1.52	0.46	0.35	2.33	27.7	13.83	2.00	0.35	(0.06)	2.29	31.0	0.67	0.62	0.70	1.092	15.8	600	150	42.9	86.4	89.8	3.3	3.8%
		1,000	10.20	1.52	0.46	0.35	2.33	33.5	13.83	2.00	0.35	(0.06)	2.29	36.8	0.67	0.62	0.70	1.092	21.1	600	400	59.0	113.7	116.9	3.2	2.8%

New Rate Class: GSe - Unmetered

Total Bill Impacts of Proposed Distribution Rates [new RTSR+TLF]: Threshold of 600 kWhs

Classes		Scenario	May 2007 Incl Rate Riders						May 2008 Incl Rate Riders						Non-Dx Compoent				Other Reg	Commodity Bands			Existing	New	$ Incr	% Incr
			Existing Dx Rates					Existing Dx	New Dx Rates					New Dx	RTSR new	WMSC	DRC	TLF new	New	Band 1	Band 2	New	Total Bill	Total Bill	Total Bill	Total Bill
																				600.0						
																				5.0	5.9					
New Class	Old Class	kWh	SrChg	base	Rider1	Rider2	VarChg	[$/month]	SrChg	base	Rider2	Rider3	VarChg	[$/month]	c/kWh	c/kWh	c/kWh		$	kWhs	kWhs		[$/month]	[$/month]	[$/month]	%
			[$/cust]	[c/kWh]	[c/kWh]	[c/kWh]	[c/kWh]		[$/cust]	[c/kWh]	[c/kWh]	[c/kWh]	[c/kWh]													
Unmtr	West Elgin	100	**7.23**	**0.70**	**0.17**	**0.07**	**0.94**	8.2	**11.57**	**2.00**	**0.07**	**(0.06)**	**2.01**	13.6	**0.67**	0.62	0.7	**1.092**	2.1	100	-	5.5	15.8	21.2	5.4	34.1%
		250	7.23	0.70	0.17	0.07	0.94	9.6	11.57	2.00	0.07	(0.06)	2.01	16.6	0.67	0.62	0.70	1.092	5.3	250	-	13.7	28.6	35.5	6.9	24.2%
		500	7.23	0.70	0.17	0.07	0.94	11.9	11.57	2.00	0.07	(0.06)	2.01	21.6	0.67	0.62	0.70	1.092	10.5	500	-	27.3	50.0	59.5	9.5	19.0%
		750	7.23	0.70	0.17	0.07	0.94	14.3	11.57	2.00	0.07	(0.06)	2.01	26.7	0.67	0.62	0.70	1.092	15.8	600	150	42.9	73.1	85.4	12.4	16.9%
		1,000	7.23	0.70	0.17	0.07	0.94	16.6	11.57	2.00	0.07	(0.06)	2.01	31.7	0.67	0.62	0.70	1.092	21.1	600	400	59.0	96.8	111.8	15.0	15.5%
Unmtr	Whitchurch	100	**10.46**	**0.93**	**0.11**	**0.04**	**1.08**	11.5	**13.76**	**2.00**	**0.04**	**(0.06)**	**1.98**	15.7	**0.67**	0.62	0.7	**1.092**	2.1	100	-	5.5	19.1	23.3	4.2	21.8%
		250	10.46	0.93	0.11	0.04	1.08	13.2	13.76	2.00	0.04	(0.06)	1.98	18.7	0.67	0.62	0.70	1.092	5.3	250	-	13.7	32.2	37.6	5.5	17.0%
		500	10.46	0.93	0.11	0.04	1.08	15.9	13.76	2.00	0.04	(0.06)	1.98	23.7	0.67	0.62	0.70	1.092	10.5	500	-	27.3	53.9	61.5	7.6	14.2%
		750	10.46	0.93	0.11	0.04	1.08	18.6	13.76	2.00	0.04	(0.06)	1.98	28.6	0.67	0.62	0.70	1.092	15.8	600	150	42.9	77.3	87.4	10.0	13.0%
		1,000	10.46	0.93	0.11	0.04	1.08	21.3	13.76	2.00	0.04	(0.06)	1.98	33.6	0.67	0.62	0.70	1.092	21.1	600	400	59.0	101.4	113.7	12.3	12.1%
Unmtr	Wiarton	100	**11.42**	**1.89**	**0.19**	**0.09**	**2.17**	13.6	**14.52**	**2.00**	**0.09**	**(0.06)**	**2.03**	16.6	**0.67**	0.62	0.7	**1.092**	2.1	100	-	5.5	21.2	24.1	2.9	13.8%
		250	11.42	1.89	0.19	0.09	2.17	16.8	14.52	2.00	0.09	(0.06)	2.03	19.6	0.67	0.62	0.70	1.092	5.3	250	-	13.7	35.9	38.5	2.7	7.4%
		500	11.42	1.89	0.19	0.09	2.17	22.3	14.52	2.00	0.09	(0.06)	2.03	24.7	0.67	0.62	0.70	1.092	10.5	500	-	27.3	60.3	62.5	2.2	3.7%
		750	11.42	1.89	0.19	0.09	2.17	27.7	14.52	2.00	0.09	(0.06)	2.03	29.8	0.67	0.62	0.70	1.092	15.8	600	150	42.9	86.5	88.5	2.0	2.4%
		1,000	11.42	1.89	0.19	0.09	2.17	33.1	14.52	2.00	0.09	(0.06)	2.03	34.9	0.67	0.62	0.70	1.092	21.1	600	400	59.0	113.3	115.0	1.7	1.5%
Unmtr	Woodville	100	**7.98**	**1.57**	**0.67**	**0.48**	**2.72**	10.7	**11.38**	**2.00**	**0.48**	**(0.06)**	**2.42**	13.8	**0.67**	0.62	0.7	**1.092**	2.1	100	-	5.5	18.3	21.4	3.1	16.8%
		250	7.98	1.57	0.67	0.48	2.72	14.8	11.38	2.00	0.48	(0.06)	2.42	17.4	0.67	0.62	0.70	1.092	5.3	250	-	13.7	33.8	36.4	2.6	7.6%
		500	7.98	1.57	0.67	0.48	2.72	21.6	11.38	2.00	0.48	(0.06)	2.42	23.5	0.67	0.62	0.70	1.092	10.5	500	-	27.3	59.6	61.3	1.7	2.9%
		750	7.98	1.57	0.67	0.48	2.72	28.4	11.38	2.00	0.48	(0.06)	2.42	29.6	0.67	0.62	0.70	1.092	15.8	600	150	42.9	87.2	88.3	1.1	1.3%
		1,000	7.98	1.57	0.67	0.48	2.72	35.2	11.38	2.00	0.48	(0.06)	2.42	35.6	0.67	0.62	0.70	1.092	21.1	600	400	59.0	115.3	115.7	0.4	0.3%
Unmtr	Wyoming	100	**8.22**	**1.45**	**0.16**	**0.07**	**1.68**	9.9	**12.32**	**2.00**	**0.07**	**(0.06)**	**2.01**	14.3	**0.67**	0.62	0.7	**1.092**	2.1	100	-	5.5	17.5	21.9	4.4	25.1%
		250	8.22	1.45	0.16	0.07	1.68	12.4	12.32	2.00	0.07	(0.06)	2.01	17.4	0.67	0.62	0.70	1.092	5.3	250	-	13.7	31.4	36.3	4.8	15.4%
		500	8.22	1.45	0.16	0.07	1.68	16.6	12.32	2.00	0.07	(0.06)	2.01	22.4	0.67	0.62	0.70	1.092	10.5	500	-	27.3	54.7	60.2	5.6	10.2%
		750	8.22	1.45	0.16	0.07	1.68	20.8	12.32	2.00	0.07	(0.06)	2.01	27.4	0.67	0.62	0.70	1.092	15.8	600	150	42.9	79.6	86.2	6.6	8.3%
		1,000	8.22	1.45	0.16	0.07	1.68	25.0	12.32	2.00	0.07	(0.06)	2.01	32.5	0.67	0.62	0.70	1.092	21.1	600	400	59.0	105.2	112.6	7.4	7.0%

New Rate Class: GSe - Unmetered

Total Bill Impacts of Proposed Distribution Rates [new RTSR+TLF]: Threshold of 600 kWhs

Classes		Scenario	May 2007 Incl Rate Riders						May 2008 Incl Rate Riders						Non-Dx Compoent				Other Reg	Commodity Bands			Existing	New	$ Incr	% Incr
			Existing Dx Rates					Existing Dx	New Dx Rates					New Dx	RTSR new	WMSC	DRC	TLF new	New	Band 1	Band 2	New	Total Bill	Total Bill	Total Bill	Total Bill
																				600.0						
																				5.0	5.9					
New Class	Old Class	kWh	SrChg	base	Rider1	Rider2	VarChg	[$/month]	SrChg	base	Rider2	Rider3	VarChg	[$/month]	c/kWh	c/kWh	c/kWh		$	kWhs	kWhs		[$/month]	[$/month]	[$/month]	%
			[$/cust]	[c/kWh]	[c/kWh]	[c/kWh]	[c/kWh]		[$/cust]	[c/kWh]	[c/kWh]	[c/kWh]	[c/kWh]													
Unmtr	**Terrace Bay**	100	**20.53**	**1.29**	**0.82**		**2.11**	22.6	**21.25**	**2.00**		**(0.06)**	**1.94**	23.2	**0.67**	0.62	0.7	**1.092**	2.1	100	-	5.5	29.7	30.8	1.1	3.6%
		250	20.53	1.29	0.82	-	2.11	25.8	21.25	2.00	-	(0.06)	1.94	26.1	0.67	0.62	0.70	1.092	5.3	250	-	13.7	43.4	45.0	1.6	3.7%
		500	20.53	1.29	0.82	-	2.11	31.1	21.25	2.00	-	(0.06)	1.94	31.0	0.67	0.62	0.70	1.092	10.5	500	-	27.3	66.3	68.8	2.5	3.7%
		750	20.53	1.29	0.82	-	2.11	36.4	21.25	2.00	-	(0.06)	1.94	35.8	0.67	0.62	0.70	1.092	15.8	600	150	42.9	90.9	94.6	3.7	4.1%
		1,000	20.53	1.29	0.82	-	2.11	41.6	21.25	2.00	-	(0.06)	1.94	40.7	0.67	0.62	0.70	1.092	21.1	600	400	59.0	116.1	120.8	4.7	4.0%

New Rate Class: DGen

Total Bill Impacts of Proposed Distribution Rates [new RTSR+TLF]: Threshold of 750 kWhs

Classes		Scenario			May 2007 Incl Rate Riders						May 2008 Incl Rate Riders						Non-Dx Compoent				Other Reg	Commodity Bands (750.0)			Existing	New	$ Incr	% Incr
					Existing Dx Rates					Existing Dx	New Dx Rates					New Dx	RTSR new	WMSC	DRC	TLF new	New	Band 1	Band 2	New	Total Bill	Total Bill	Total Bill	Total Bill
																						5.0	5.9					
New Class	Old Class	kWh	kW	LF	SrChg	base	Rider1	Rider2	VarChg	[$/month]	SrChg	base	Rider2	Rider3	VarChg	[$/month]	$/kW	c/kWh	c/kWh		$	kWhs	kWhs		[$/month]	[$/month]	[$/month]	%
					[$/cust]	[$/kW]	[$/kW]	[$/kW]	[$/kW]		[$/cust]	[$/kW]	[$/kW]	[$/kW]	[$/kW]													
Dgen	**G3**	5,000	10	69%	**46.78**	**9.91**	**0.08**	**0.15**	**10.14**	148.2	**36.66**	**7.07**	**0.15**	**(0.04)**	**7.18**	108.4	**0.48**	0.62	0.7	**1.061**	73.0	750	4,250	306.2	551.5	487.6	(63.86)	-11.6%
	D-billed	5,000	20	35%	46.78	9.91	0.08	0.15	10.14	249.6	36.66	7.07	0.15	(0.04)	7.18	180.2	0.48	0.62	0.7	1.061	78.1	750	4,250	306.2	682.1	564.5	(117.61)	-17.2%
		5,000	30	23%	46.78	9.91	0.08	0.15	10.14	351.0	36.66	7.07	0.15	(0.04)	7.18	251.9	0.48	0.62	0.7	1.061	83.2	750	4,250	306.2	812.7	641.3	(171.36)	-21.1%
		5,000	40	17%	46.78	9.91	0.08	0.15	10.14	452.4	36.66	7.07	0.15	(0.04)	7.18	323.7	0.48	0.62	0.7	1.061	88.3	750	4,250	306.2	943.3	718.2	(225.11)	-23.9%
		5,000	50	14%	46.78	9.91	0.08	0.15	10.14	553.8	36.66	7.07	0.15	(0.04)	7.18	395.4	0.48	0.62	0.7	1.061	93.4	750	4,250	306.2	1,073.9	795.0	(278.86)	-26.0%
		5,000	60	12%	46.78	9.91	0.08	0.15	10.14	655.2	36.66	7.07	0.15	(0.04)	7.18	467.2	0.48	0.62	0.7	1.061	98.4	750	4,250	306.2	1,204.5	871.9	(332.61)	-27.6%
		35,000	90	54%	46.78	9.91	0.08	0.15	10.14	956.7	36.66	7.07	0.15	(0.04)	7.18	680.6	0.48	0.62	0.7	1.061	520.9	750	34,250	2,184.2	3,878.1	3,385.7	(492.42)	-12.7%
					[$/cust]	[$/kW]	[$/kW]	[$/kW]	[$/kW]																			
Dgen	**T**	5,000	10	69%	**261.54**	**8.16**	**0.04**	**0.09**	**8.29**	344.4	**36.66**	**7.07**	**0.09**	**(0.04)**	**7.12**	107.8	**0.48**	0.62	0.7	**1.061**	73.0	750	4,250	306.2	748.5	487.0	(261.41)	-34.9%
	D-billed	5,000	20	35%	261.54	8.16	0.04	0.09	8.29	427.3	36.66	7.07	0.09	(0.04)	7.12	179.0	0.48	0.62	0.70	1.061	78.1	750	4,250	306.2	861.3	563.3	(297.95)	-34.6%
		5,000	30	23%	261.54	8.16	0.04	0.09	8.29	510.2	36.66	7.07	0.09	(0.04)	7.12	250.1	0.48	0.62	0.70	1.061	83.2	750	4,250	306.2	974.0	639.5	(334.49)	-34.3%
		5,000	40	17%	261.54	8.16	0.04	0.09	8.29	593.1	36.66	7.07	0.09	(0.04)	7.12	321.3	0.48	0.62	0.70	1.061	88.3	750	4,250	306.2	1,086.8	715.8	(371.03)	-34.1%
		5,000	50	14%	261.54	8.16	0.04	0.09	8.29	676.0	36.66	7.07	0.09	(0.04)	7.12	392.4	0.48	0.62	0.70	1.061	93.4	750	4,250	306.2	1,199.6	792.0	(407.57)	-34.0%
		5,000	60	12%	261.54	8.16	0.04	0.09	8.29	758.9	36.66	7.07	0.09	(0.04)	7.12	463.6	0.48	0.62	0.70	1.061	98.4	750	4,250	306.2	1,312.4	868.3	(444.11)	-33.8%
		7,700	##	5%	261.54	8.16	0.04	0.09	8.29	1,920.5	36.66	7.07	0.09	(0.04)	7.12	1,460.6	0.48	0.62	0.70	1.061	206.5	750	6,950	475.3	3,098.5	2,142.4	(956.09)	-30.9%
					[$/cust]	[c/kWh]	[c/kWh]	[c/kWh]	[c/kWh]								[$/kW]											
Dgen	**G3**	5,000	10	69%	**46.78**	**3.07**	**0.02**	**0.05**	**3.14**	203.8	**36.66**	**7.07**	**0.15**	**(0.04)**	**7.18**	108.4	**0.48**	0.62	0.7	**1.061**	73.0	750	4,250	306.2	623.0	487.6	(135.36)	-21.7%
	E-billed	5,000	20	35%	46.78	3.07	0.02	0.05	3.14	203.8	36.66	7.07	0.15	(0.04)	7.18	180.2	0.48	0.62	0.7	1.061	78.1	750	4,250	306.2	623.0	564.5	(58.51)	-9.4%
		5,000	30	23%	46.78	3.07	0.02	0.05	3.14	203.8	36.66	7.07	0.15	(0.04)	7.18	251.9	0.48	0.62	0.7	1.061	83.2	750	4,250	306.2	623.0	641.3	18.34	2.9%
		5,000	40	17%	46.78	3.07	0.02	0.05	3.14	203.8	36.66	7.07	0.15	(0.04)	7.18	323.7	0.48	0.62	0.7	1.061	88.3	750	4,250	306.2	623.0	718.2	95.19	15.3%
		5,000	50	14%	46.78	3.07	0.02	0.05	3.14	203.8	36.66	7.07	0.15	(0.04)	7.18	395.4	0.48	0.62	0.7	1.061	93.4	750	4,250	306.2	623.0	795.0	172.04	27.6%
		5,000	60	12%	46.78	3.07	0.02	0.05	3.14	203.8	36.66	7.07	0.15	(0.04)	7.18	467.2	0.48	0.62	0.7	1.061	98.4	750	4,250	306.2	623.0	871.9	248.89	39.9%
		802	8	14%	46.78	3.07	0.02	0.05	3.14	72.0	36.66	7.07	0.15	(0.04)	7.18	95.2	0.48	0.62	0.7	1.061	15.0	750	52	43.5	133.5	153.7	20.16	15.1%
					[$/cust]	[c/kWh]	[c/kWh]	[c/kWh]	[c/kWh]								[$/kW]											
Dgen	**T**	5,000	10	69%	**261.54**	**2.43**	**0.01**	**0.03**	**2.47**	385.0	**36.66**	**7.07**	**0.09**	**(0.04)**	**7.12**	107.8	**0.48**	0.62	0.7	**1.061**	73.0	750	4,250	306.2	803.7	487.0	(316.69)	-39.4%
	E-billed	5,000	20	35%	261.54	2.43	0.01	0.03	2.47	385.0	36.66	7.07	0.09	(0.04)	7.12	179.0	0.48	0.62	0.70	1.061	78.1	750	4,250	306.2	803.7	563.3	(240.44)	-29.9%
		5,000	30	23%	261.54	2.43	0.01	0.03	2.47	385.0	36.66	7.07	0.09	(0.04)	7.12	250.1	0.48	0.62	0.70	1.061	83.2	750	4,250	306.2	803.7	639.5	(164.19)	-20.4%
		5,000	40	17%	261.54	2.43	0.01	0.03	2.47	385.0	36.66	7.07	0.09	(0.04)	7.12	321.3	0.48	0.62	0.70	1.061	88.3	750	4,250	306.2	803.7	715.8	(87.94)	-10.9%
		5,000	50	14%	261.54	2.43	0.01	0.03	2.47	385.0	36.66	7.07	0.09	(0.04)	7.12	392.4	0.48	0.62	0.70	1.061	93.4	750	4,250	306.2	803.7	792.0	(11.69)	-1.5%
		5,000	60	12%	261.54	2.43	0.01	0.03	2.47	385.0	36.66	7.07	0.09	(0.04)	7.12	463.6	0.48	0.62	0.70	1.061	98.4	750	4,250	306.2	803.7	868.3	64.56	8.0%
		846	26	5%	261.54	2.43	0.01	0.03	2.47	282.4	36.66	7.07	0.09	(0.04)	7.12	221.4	0.48	0.62	0.70	1.061	24.7	750	96	46.2	347.7	292.3	(55.37)	-15.9%
					[$/cust]	[c/kWh]	[c/kWh]	[c/kWh]	[c/kWh]								[$/kW]											
Dgen	**Eganville**	5,000	10	69%	**21.35**	**2.32**	**0.17**	**0.12**	**2.61**	151.9	**36.66**	**7.07**	**0.37**	**(0.04)**	**7.40**	110.6	**0.48**	0.62	0.7	**1.061**	73.0	750	4,250	306.2	572.9	489.8	(83.05)	-14.5%
	E-billed	5,000	20	35%	21.35	2.32	0.17	0.12	2.61	151.9	36.66	7.07	0.37	(0.04)	7.40	184.6	0.48	0.62	0.70	1.061	78.1	750	4,250	306.2	572.9	568.9	(4.00)	-0.7%
		5,000	30	23%	21.35	2.32	0.17	0.12	2.61	151.9	36.66	7.07	0.37	(0.04)	7.40	258.5	0.48	0.62	0.70	1.061	83.2	750	4,250	306.2	572.9	647.9	75.05	13.1%
		5,000	40	17%	21.35	2.32	0.17	0.12	2.61	151.9	36.66	7.07	0.37	(0.04)	7.40	332.5	0.48	0.62	0.70	1.061	88.3	750	4,250	306.2	572.9	727.0	154.10	26.9%
		5,000	50	14%	21.35	2.32	0.17	0.12	2.61	151.9	36.66	7.07	0.37	(0.04)	7.40	406.4	0.48	0.62	0.70	1.061	93.4	750	4,250	306.2	572.9	806.0	233.15	40.7%
		5,000	60	12%	21.35	2.32	0.17	0.12	2.61	151.9	36.66	7.07	0.37	(0.04)	7.40	480.4	0.48	0.62	0.70	1.061	98.4	750	4,250	306.2	572.9	885.1	312.20	54.5%
		6	1	1%	21.35	2.32	0.17	0.12	2.61	21.5	36.66	7.07	0.37	(0.04)	7.40	45.5	0.48	0.62	0.70	1.061	0.7	6	-	0.3	22.0	46.5	24.57	111.9%

New Rate Class: GSe - Low Use Secondary

Total Bill Impacts of Proposed Distribution Rates [new RTSR+TLF]: Threshold of 600 kWhs

Classes		Scenario	May 2007 Incl Rate Riders						May 2008 Incl Rate Riders						Non-Dx Compoent				Other Reg	Commodity Bands			Existing	New	$ Incr	% Incr
			Existing Dx Rates					Existing Dx	New Dx Rates					New Dx	RTSR new	WMSC	DRC	TLF new	New	Band 1	Band 2	New	Total Bill	Total Bill	Total Bill	Total Bill
																				600.0						
																				5.0	5.9					
New Class	Old Class	kWh	$/cust	base	Rider1	Rider2	VarChg	[$/month]	$/cust	base	Rider2	Rider3	VarChg	[$/month]	c/kWh	c/kWh	c/kWh		$	kWhs	kWhs		[$/month]	[$/month]	$	%
GSe	**F1**	50	**-**	**2.37**	**0.08**	**0.10**	**2.55**	1.3	**6.19**	**3.39**	**0.09**	**(0.06)**	**3.42**	7.9	**0.67**	0.62	0.7	**1.092**	1.1	50	-	2.7	5.2	11.7	6.5	125.7%
		75	-	2.37	0.08	0.10	2.55	1.9	6.19	3.39	0.09	(0.06)	3.42	8.8	0.67	0.62	0.7	1.092	1.6	75	-	4.1	7.8	14.4	6.7	85.8%
		100	-	2.37	0.08	0.10	2.55	2.6	6.19	3.39	0.09	(0.06)	3.42	9.6	0.67	0.62	0.7	1.092	2.1	100	-	5.5	10.4	17.2	6.8	65.9%
		125	-	2.37	0.08	0.10	2.55	3.2	6.19	3.39	0.09	(0.06)	3.42	10.5	0.67	0.62	0.7	1.092	2.6	125	-	6.8	12.9	19.9	7.0	53.9%
		150	-	2.37	0.08	0.10	2.55	3.8	6.19	3.39	0.09	(0.06)	3.42	11.3	0.67	0.62	0.7	1.092	3.2	150	-	8.2	15.5	22.7	7.1	45.9%
		200	-	2.37	0.08	0.10	2.55	5.1	6.19	3.39	0.09	(0.06)	3.42	13.0	0.67	0.62	0.7	1.092	4.2	200	-	10.9	20.7	28.2	7.5	36.0%
		400	-	2.37	0.08	0.10	2.55	10.2	6.19	3.39	0.09	(0.06)	3.42	19.9	0.67	0.62	0.7	1.092	8.4	400	-	21.8	41.4	50.1	8.7	21.0%

Main Acnt	Assume 1000 kWh F1 with RRRP being mapped to R2				136.0			
		Main	Low Useold	LowUse New		Old Bill	New Bill	
Main+LowUse	50	136.0	5.2	11.7		141.17	147.68	4.6%
	75	136.0	7.8	14.4		143.76	150.43	4.6%
	100	136.0	10.4	17.2		146.35	153.18	4.7%
	125	136.0	12.9	19.9		148.94	155.92	4.7%
	150	136.0	15.5	22.7		151.53	158.67	4.7%
	200	136.0	20.7	28.2		156.71	164.17	4.8%
	400	136.0	41.4	50.1		177.43	186.14	4.9%

New Class	Old Class	kWh	$/cust	base	Rider1	Rider2	VarChg	Existing Dx [$/month]	$/cust	base	Rider2	Rider3	VarChg	New Dx [$/month]	RTSR new	WMSC	DRC	TLF new	Other Reg New $	Band 1	Band 2	New	Existing Total Bill	New Total Bill	$ Incr	% Incr
GSe	**F3**	50	**-**	**3.20**	**0.02**	**0.05**	**3.27**	1.6	**6.19**	**3.39**	**0.09**	**(0.06)**	**3.42**	7.9	**0.67**	0.62	0.7	**1.092**	1.1	50	-	2.7	5.4	11.7	6.3	115.8%
		75	-	3.20	0.02	0.05	3.27	2.5	6.19	3.39	0.09	(0.06)	3.42	8.8	0.67	0.62	0.70	1.092	1.6	75	-	4.1	8.1	14.4	6.3	77.6%
	F3, G3	100	-	3.20	0.02	0.05	3.27	3.3	6.19	3.39	0.09	(0.06)	3.42	9.6	0.67	0.62	0.70	1.092	2.1	100	-	5.5	10.8	17.2	6.3	58.6%
		125	-	3.20	0.02	0.05	3.27	4.1	6.19	3.39	0.09	(0.06)	3.42	10.5	0.67	0.62	0.70	1.092	2.6	125	-	6.8	13.5	19.9	6.4	47.2%
		150	-	3.20	0.02	0.05	3.27	4.9	6.19	3.39	0.09	(0.06)	3.42	11.3	0.67	0.62	0.70	1.092	3.2	150	-	8.2	16.3	22.7	6.4	39.5%
		200	-	3.20	0.02	0.05	3.27	6.5	6.19	3.39	0.09	(0.06)	3.42	13.0	0.67	0.62	0.70	1.092	4.2	200	-	10.9	21.7	28.2	6.5	30.0%
		400	-	3.20	0.02	0.05	3.27	13.1	6.19	3.39	0.09	(0.06)	3.42	19.9	0.67	0.62	0.70	1.092	8.4	400	-	21.8	43.3	50.1	6.8	15.7%

Main Acnt	Assume 2000 kWh G3 being mapped to GSe				274.1			
		Main	Low Useold	LowUse New		Old Bill	New Bill	
Main+LowUse	50	274.1	5.4	11.7		279.51	285.78	2.2%
	75	274.1	8.1	14.4		282.21	288.52	2.2%
	100	274.1	10.8	17.2		284.92	291.27	2.2%
	125	274.1	13.5	19.9		287.63	294.02	2.2%
	150	274.1	16.3	22.7		290.34	296.76	2.2%
	200	274.1	21.7	28.2		295.76	302.26	2.2%
	400	274.1	43.3	50.1		317.43	324.24	2.1%

New Class	Old Class	kWh	$/cust	base	Rider1	Rider2	VarChg	Existing Dx [$/month]	$/cust	base	Rider2	Rider3	VarChg	New Dx [$/month]	RTSR new	WMSC	DRC	TLF new	Other Reg New $	Band 1	Band 2	New	Existing Total Bill	New Total Bill	$ Incr	% Incr
GSe	**G1**	50	**-**	**3.25**	**0.09**	**0.09**	**3.43**	1.7	**6.19**	**3.39**	**0.09**	**(0.06)**	**3.42**	7.9	**0.67**	0.62	0.7	**1.092**	1.1	50	-	2.7	5.6	11.7	6.1	108.6%
		75	-	3.25	0.09	0.09	3.43	2.6	6.19	3.39	0.09	(0.06)	3.42	8.8	0.67	0.62	0.70	1.092	1.6	75	-	4.1	8.4	14.4	6.0	71.8%
	R1,R2,R3	100	-	3.25	0.09	0.09	3.43	3.4	6.19	3.39	0.09	(0.06)	3.42	9.6	0.67	0.62	0.70	1.092	2.1	100	-	5.5	11.2	17.2	6.0	53.3%
	R4,G1	125	-	3.25	0.09	0.09	3.43	4.3	6.19	3.39	0.09	(0.06)	3.42	10.5	0.67	0.62	0.70	1.092	2.6	125	-	6.8	14.0	19.9	5.9	42.3%
		150	-	3.25	0.09	0.09	3.43	5.1	6.19	3.39	0.09	(0.06)	3.42	11.3	0.67	0.62	0.70	1.092	3.2	150	-	8.2	16.8	22.7	5.9	34.9%
		200	-	3.25	0.09	0.09	3.43	6.9	6.19	3.39	0.09	(0.06)	3.42	13.0	0.67	0.62	0.70	1.092	4.2	200	-	10.9	22.4	28.2	5.8	25.7%
		400	-	3.25	0.09	0.09	3.43	13.7	6.19	3.39	0.09	(0.06)	3.42	19.9	0.67	0.62	0.70	1.092	8.4	400	-	21.8	44.8	50.1	5.3	11.9%

Main Acnt	Assume 1000 kWh R2 being mapped to R2				137.1			
		Main	Low Useold	LowUse New		Old Bill	New Bill	
Main+LowUse	50	137.1	5.6	11.7		142.75	148.83	4.3%
	75	137.1	8.4	14.4		145.55	151.58	4.1%
	100	137.1	11.2	17.2		148.35	154.32	4.0%
	125	137.1	14.0	19.9		151.15	157.07	3.9%
	150	137.1	16.8	22.7		153.95	159.82	3.8%
	200	137.1	22.4	28.2		159.55	165.31	3.6%
	400	137.1	44.8	50.1		181.97	187.29	2.9%

ADDENDUM ON CHANGES TO ACQUIRED LDCs RATE SCHEDULE

As a result of updates to the evidence needed to reflect the recovery of the costs associated with the transformer ownership allowance as described in Exhibit H, Tab 12, Schedule 49, the volumetric charges for all Acquired LDCs General Service 50 kW or Greater (Demand-Billed) customers has to be increased by $0.07/kW.

As an example, for Ailsa Craig, the Distribution Volumetric Rate should be $9.07/kW, instead of $9.00 currently shown in Exhibit G2, Tab 6, Schedule 1, page 3.

The same change to the distribution volumetric rate applies to all Acquired LDC rate schedules provided in Exhibits G2, Tab 6 to Tab 93.

In the case of Caledon's rate schedules provided in Exhibit G2, Tab 18, Schedule 1, the $0.07 adder applies to General Service OH – Demand Billed (50 kW or greater) and General Service CH – Demand Billed (50 kW or greater).

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Hydro-System of the Village of Ailsa Craig
Effective Date: May 1, 2008

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

APPLICATION

The application of these rates and charges shall be in accordance with The Licence of The Distributor and any Codes, Guidelines or Orders of The Board, and amendments thereto as approved by The Board, which may be applicable to the administration of this schedule.
No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code, Guideline or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.
This schedule does not contain any rates and charges relating to the electricity commodity (e.g. the Regulated Price Plan).

EFFECTIVE DATES

DISTRIBUTION RATES - May 1, 2008 for all consumption or deemed consumption services used on or after that date.

MISCELLANEOUS CHARGES - May 1, 2008 for all charges billed to customers on or after that date.
RETAIL TRANSMISSION RATES - May 1, 2008 for all consumption or deemed consumption services used on or after that date.
LOSS FACTOR ADJUSTMENT – for all consumption or deemed consumption services billed following May 1, 2008 or later

SERVICE CLASSIFICATIONS

Residential
This classification refers to all service supplied to single-family dwelling units for domestic or household purpose. Multi-unit residential establishments such as apartment buildings supplied through one service (bulk metered) will normally be classified as General Service, but, at Hydro One's discretion, up to four residential units may be classified as residential. Where electricity service is provided to combined residential and business (including agricultural usage) and the wiring does not provide for separate metering, the classification shall be at the discretion of Hydro One based on such considerations as the estimated predominant consumption.
Further servicing details are available in the utility's Conditions of Service.

General Service
This classification refers to all service supplied to premises other than those classified as Residential or Lighting. Some General Service accounts are energy(kWh)-billed, and some are demand(kW)-billed. Further servicing details are available in the utility's Conditions of Service.

Unmetered Scattered Load
This classification refers to certain instances where connections can be provided without metering. These loads are generally small in size and consistent in magnitude of load. Hydro One reserves the right to review all cases and may require that a meter be installed at its sole discretion. Services that can be unmetered include cable TV amplifiers, telephone switching devices, phone booths, bus shelters, rail way crossing signals, traffic signals, and other small fixed loads.
Further servicing details are available in the utility's Conditions of Service (including in the "Unmetered Connections" section).

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Hydro-System of the Village of Ailsa Craig
Effective Date: May 1, 2008

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

Street Lighting

This classification refers to accounts for the distribution and supply of electrical energy for street lighting. Street lights are devices owned by or operated for the road authority and/or the municipal corporation. These street lights in fact belong to the Street Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Sentinel Lighting

This classification refers to accounts for a separate service to a sentinel light. These sentinel lights in fact belong to the Sentinel Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Urban Density Classification

Customers who meet the Urban Density Criteria of being in an area containing 3,000 or more customers with a line density of at least 60 customers per kilometre, will be mapped to an Urban customer classification.

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Hydro-System of the Village of Ailsa Craig
Effective Date: May 1, 2008

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

MONTHLY RATES AND CHARGES

Residential - R1 Ailsa Craig

Service Charge	$	12.13
Distribution Volumetric Rate	$ / kWh	0.0185
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0011
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0004)
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0047
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0046
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service Less Than 50 kW (Energy-Billed) - GSe Ailsa Craig

Service Charge	$	20.76
Distribution Volumetric Rate	$ / kWh	0.0234
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0009
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0006)
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0035
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0032
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service 50 kW or Greater (Demand-Billed) - GSd Ailsa Craig

Service Charge	$	24.36
Distribution Volumetric Rate	$ / kW	9.00
Regulatory Asset Recovery - Rider #2	$ / kW	0.27
Regulatory Asset Recovery - Rider #3	$ / kW	(0.22)
Retail Transmission Rate - Network Service Rate (4)	$ / kW	1.11
Retail Transmission Rate - Line and Transformation Connection Service Rate (4)	$ / kW	1.00
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Hydro-System of the Village of Ailsa Craig
Effective Date: May 1, 2008

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

Unmetered, Scattered Load

Service Charge	$	12.33
Distribution Volumetric Rate	$ / kWh	0.0200
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0009
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0006)
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0035
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0032
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

(3) For energy-only metered customers, the billing determinant is the customer's metered energy consumption adjusted by the total loss factor as approved by the Board for Acquired LDC customers.
(4) For demand billed customers, appropriate loss factors must be applied to the applicable tariffs. Also the billing determinant for the Line and Transformation Connection Services rate is the customer's peak demand in the billing period. The billing determinant for the Network Services rate is: for non-interval-metered customers, the peak demand in the billing period, and for interval-metered customers, the peak demand between 7 AM and 7 PM local time on IESO business days

Customer-Supplied Transformation Allowance

Applicable to customers providing their own transformers

Demand-billed	$ / kW	0.60
Energy-billed	$ / kWh	0.0014

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
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Hydro-System of the Village of Ailsa Craig
Effective Date: May 1, 2008

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Loss Factors

Residential	1.085
General Service Less Than 50 kW (Energy-Billed)	1.092
General Service 50 kW or Greater (Demand-Billed)	1.061
Unmetered Scattered Load	1.092

Transformer Loss Allowance

Applicable to customers requiring a billing adjustment for transformer losses as the result of being metered on the primary side of a transformer. The following uniform values shall be applied to measured demand and energy to calculate transformer losses for voltages up to and including 50 kV (as metered on the primary side):

(a) 1.5% for transformer installations up to an individual bank capacity of 400 kVA,
(b) 1.0% for bank capacities over 400 kVA.

Alternatively, transformer losses may be determined from transformer test data, and measured demand and energy adjusted accordingly

For services which are not demand metered, an assumed demand of 50% of the transformer capacity will be used to calculate the loss allowance. Where several transformers are involved, the bank capacity is assumed to be the arithmetic sum of all transformer capacities

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Hydro-System of the Village of Ailsa Craig
Effective Date: May 1, 2008

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

MISCELLANEOUS CHARGES

Specific Service Charges: Standard Amounts

Rate Code	Specific Service Charge - Standard Name	Calculation Method			
		2006 Rate Handbook	Standard Formula	Other Formula	Time and Materials
1	Temporary Service	$500			
2	Dispute Meter Test	$30 plus Measurement Canada fees			
3	Collection of account – no disconnection/load limiter	$30			
4	Collection/Disconnect/load limiter/reconnect (at meter) trip – regular hours	$65			
5	Collection/Disconnect/load limiter/reconnect (at meter) trip – after regular hours	$185			
6	Collection/Disconnect/load limiter/reconnect (at pole) trip – regular hours	$185			
7	Collection/Disconnect/load limiter/reconnect (at pole) trip – after regular hours	$415			
8	Account Set-up Charge	$30			
9	Arrears Certificate	$15			
10	NSF Cheque Charge	$15 + bank charges			
11	Easement Charge for Unregistered Rights	$15			
12	Late Payment Charge	1.5%/month			
13a	Retailer Services – Establishing Service Agreements (refer to Handbook for all charges)	$100/agreement/Retailer +$20/month/Retailer +$0.50/month/customer + other			
13b	Retailer Services – Other (includes Bill Ready for Retailers and Service Transactions Requests) as per the Handbook, Chapter 12	$0.30/month/customer + $0.25/request for request fee + $0.50/request for process fee			
14	Special Meter Reads	$30			
15	Service Layout Fee – Basic		$495		
16	Service Layout Fee – Complex		$690		
17	Crossing Application – Pipeline		$2,445		
18	Crossing Application – Water		$3,045		
19	Crossing Application – Railroad		$2,945		
20	Line Staking – per meter		$3.70		
21	Central Metering – New service < 45 kW		$115		
22	Conversion to Central Metering < 45 kW		$915		
23	Conversion to Central Metering > 45 kW		$800		
24	Tingle Voltage Test – In Excess of 4 Hours (per hour – average 2 additional hours)		$125		
25	Standby Administration Charge per month		$440		
26	Sentinel Lights Rental Rate per month			$7.10	
27	Sentinel Pole Rental Rate per month			$4.15	
28	Joint Use for Cable and Telecom companies per pole			$22.35	
29	Joint Use for LDCs per pole			$28.61	

Hydro One Networks Inc.
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Effective Date: May 1, 2007

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APPLICATION

The application of these rates and charges shall be in accordance with The Licence of The Distributor and any Codes, Guidelines or Orders of The Board, and amendments thereto as approved by The Board, which may be applicable to the administration of this schedule.
No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code, Guideline or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.
This schedule does not contain any rates and charges relating to the electricity commodity (e.g. the Regulated Price Plan).

EFFECTIVE DATES

DISTRIBUTION RATES - May 1, 2007 for all consumption or deemed consumption services used on or after that date.

MISCELLANEOUS CHARGES - May 1, 2007 for all charges billed to customers on or after that date.
RETAIL TRANSMISSION RATES - May 1, 2007 for all consumption or deemed consumption services used on or after that date.
LOSS FACTOR ADJUSTMENT – May 1, 2007

SERVICE CLASSIFICATIONS

Residential
This classification (note 1) refers to all service supplied to single-family dwelling units for domestic or household purpose. Multi-unit residential establishments such as apartment buildings supplied through one service (bulk metered) will normally be classified as General Service, but, at Hydro One's discretion, up to four residential units may be classified as residential. Where electricity service is provided to combined residential and business (including agricultural usage) and the wiring does not provide for separate metering, the classification shall be at the discretion of Hydro One based on such considerations as the estimated predominant consumption.
Further servicing details are available in the utility's Conditions of Service.

General Service
This classification (note 1) refers to all service supplied to premises other than those classified as Residential or Lighting. Some General Service accounts are energy(kWh)-billed, and some are demand(kW)-billed. Further servicing details are available in the utility's Conditions of Service. Also, see note 2.

Unmetered Scattered Load
This classification refers to certain instances where connections can be provided without metering. These loads are generally small in size and consistent in magnitude of load. Hydro One reserves the right to review all cases and may require that a meter be installed at its sole discretion. Services that can be unmetered include cable TV amplifiers, telephone switching devices, phone booths, bus shelters, rail way crossing signals, traffic signals, and other small fixed loads.
Further servicing details are available in the utility's Conditions of Service (including in the "Unmetered Connections" section).

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Hydro-System of the Village of Ailsa Craig
Effective Date: May 1, 2007

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Street Lighting

This classification refers to accounts for the distribution and supply of electrical energy for street lighting. Street lights are devices owned by or operated for the road authority and/or the municipal corporation. These street lights in fact belong to the Street Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Sentinel Lighting

This classification refers to accounts for a separate service to a sentinel light. These sentinel lights in fact belong to the Sentinel Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Interim Demand-Side Management Time-of-Use

This is potentially applicable to Demand-billed General Service accounts. See Note 2 below.

Note (1): Classification descriptions are paraphrases from the document "Hydro One Networks Inc. - Distribution Customers Conditions of Service - August 2004"

Note (2):

Interim Demand-Side Management Time-of-Use Rates: demand charges will be based on demand during the on-peak periods.

Criteria: Customers' electricity consumption (kW) in the off-peak period is at least twice the electricity consumption (kW) during the on-peak period.

Definition of Time Periods: The on-peak hours will be between 0700 hours to 1900 hours Eastern Standard Time during the winter (standard time) on IESO business days and 0600 hours to 1800 hours Eastern Standard Time during the summer (daylight savings time) on IESO business days. The off-peak period constitutes all of the remaining hours.

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
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MONTHLY RATES AND CHARGES

Residential

Service Charge	$	10.51
Distribution Volumetric Rate	$ / kWh	0.0082
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0035
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0011
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0055
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0047
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service - Energy Billed (less than 50 kW)

Service Charge	$	17.31
Distribution Volumetric Rate	$ / kWh	0.0132
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0017
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0009
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0050
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0043
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service - Demand Billed (50 kW or greater)

Service Charge	$	17.31
Distribution Volumetric Rate	$ / kW	4.19
Regulatory Asset Recovery - Rider #1	$ / kW	0.52
Regulatory Asset Recovery - Rider #2	$ / kW	0.27
Retail Transmission Rate - Network Service Rate (4)	$ / kW	1.94
Retail Transmission Rate - Line and Transformation Connection Service Rate (4)	$ / kW	1.61
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Hydro-System of the Village of Ailsa Craig
Effective Date: May 1, 2007

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

Unmetered, Scattered Load

Service Charge	$	8.20
Distribution Volumetric Rate	$ / kWh	0.0132
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0017
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0009
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0050
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0043
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

(3) For energy-only metered customers, the billing determinant is the customer’s metered energy consumption adjusted by the total loss factor as approved by the Board for Acquired LDC customers.
(4) For demand billed customers, appropriate loss factors must be applied to the applicable tariffs. Also the billing determinant for the Line and Transformation Connection Services rate is the customer’s peak demand in the billing period. The billing determinant for the Network Services rate is: for non-interval-metered customers, the peak demand in the billing period, and for interval-metered customers, the peak demand between 7 AM and 7 PM local time on IESO business days

Interim Demand-Side Management Time-of-Use

See the "Service Classifications" section of this schedule.

Customer-Supplied Transformation Allowance

Applicable to demand-billed customers providing their own transformers
Primary Voltage under 50 kV (per kW)

Single Phase	$ / kW	0.20
Three Phase	$ / kW	0.60

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
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Effective Date: May 1, 2007

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Loss Factors

Supply Facilities Loss Factor	1.0045
Distribution Loss Factors	
Customer less than 5,000 kW	1.0500
Customer greater than or equal to 5,000 kW	1.0100
Total Loss Factors	
Customer less than 5,000 kW	1.0545
Customer greater than or equal to 5,000 kW	1.0145

Transformer Loss Allowance

Applicable to customers requiring a billing adjustment for transformer losses as the result of being metered on the primary side of a transformer. The following uniform values shall be applied to measured demand and energy to calculate transformer losses for voltages up to and including 50 kV (as metered on the primary side):

(a) 1.5% for transformer installations up to an individual bank capacity of 400 kVA,
(b) 1.0% for bank capacities over 400 kVA.

Alternatively, transformer losses may be determined from transformer test data, and measured demand and energy adjusted accordingly

For services which are not demand metered, an assumed demand of 50% of the transformer capacity will be used to calculate the loss allowance. Where several transformers are involved, the bank capacity is assumed to be the arithmetic sum of all transformer capacities

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Hydro-System of the Village of Ailsa Craig
Effective Date: May 1, 2007

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

MISCELLANEOUS CHARGES

Specific Service Charges: Standard Amounts

Rate Code	Specific Service Charge - Standard Name	Calculation Method			
		2006 Rate Handbook	Standard Formula	Other Formula	Time and Materials
1	Temporary Service	$500			
2	Dispute Meter Test	$30 plus Measurement Canada fees			
3	Collection of account – no disconnection/load limiter	$30			
4	Collection/Disconnect/load limiter/reconnect (at meter) trip – regular hours	$65			
5	Collection/Disconnect/load limiter/reconnect (at meter) trip – after regular hours	$185			
6	Collection/Disconnect/load limiter/reconnect (at pole) trip – regular hours	$185			
7	Collection/Disconnect/load limiter/reconnect (at pole) trip – after regular hours	$415			
8	Account Set-up Charge	$30			
9	Arrears Certificate	$15			
10	NSF Cheque Charge	$15 + bank charges			
11	Easement Charge for Unregistered Rights	$15			
12	Late Payment Charge	1.5%/month			
13a	Retailer Services – Establishing Service Agreements (refer to Handbook for all charges)	$100/agreement/Retailer +$20/month/Retailer +$0.50/month/customer + other			
13b	Retailer Services – Other (includes Bill Ready for Retailers and Service Transactions Requests) as per the Handbook, Chapter 12	$0.30/month/customer + $0.25/request for request fee + $0.50/request for process fee			
14	Special Meter Reads	$30			
15	Billing Suspension and Terminations in Trailer Parks		$130		
16	Service Layout Fee – Basic		$405		
17	Service Layout Fee – Complex		$580		

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Hydro-System of the Village of Ailsa Craig
Effective Date: May 1, 2007

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

18	Crossing Application – Pipeline		$2,065		
19	Crossing Application – Water		$2,525		
20	Crossing Application – Railroad		$2,565		
21	Line Staking – per meter		$3.10		
22	Central Metering – New service < 45 kW		$115		
23	Conversion to Central Metering < 45 kW		$795		
24	Conversion to Central Metering > 45 kW		$680		
25	Tingle Voltage Test – In Excess of 4 Hours (per hour – average 2 additional hours)		$105		
26	Standby Administration Charge per month (interim)		$375		
27	Sentinel Lights Rental Rate per month – Mercury Vapor			$7.00	
28	Guaranteed Units from Jan 01/91 to Aug 01/91			$26.50 / month	
29	Guaranteed Units from Jan 01/87 to Dec 31/90			$23.50 / month	
30	Joint Use for Cable and Telecom companies per pole			$22.35	
31	Joint Use for LDCs per pole			$28.61	

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Village of Arkona Public Utilities Commission
Effective Date: May 1, 2008

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

APPLICATION

The application of these rates and charges shall be in accordance with The Licence of The Distributor and any Codes, Guidelines or Orders of The Board, and amendments thereto as approved by The Board, which may be applicable to the administration of this schedule.
No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code, Guideline or Order of the Board, and amendments thereto as approved by the Board, or as specified herein
This schedule does not contain any rates and charges relating to the electricity commodity (e.g. the Regulated Price Plan).

EFFECTIVE DATES

DISTRIBUTION RATES - May 1, 2008 for all consumption or deemed consumption services used on or after that date.

MISCELLANEOUS CHARGES - May 1, 2008 for all charges billed to customers on or after that date.
RETAIL TRANSMISSION RATES - May 1, 2008 for all consumption or deemed consumption services used on or after that date.
LOSS FACTOR ADJUSTMENT – for all consumption or deemed consumption services billed following May 1, 2008 or later

SERVICE CLASSIFICATIONS

Residential
This classification refers to all service supplied to single-family dwelling units for domestic or household purpose. Multi-unit residential establishments such as apartment buildings supplied through one service (bulk metered) will normally be classified as General Service, but, at Hydro One's discretion, up to four residential units may be classified as residential. Where electricity service is provided to combined residential and business (including agricultural usage) and the wiring does not provide for separate metering, the classification shall be at the discretion of Hydro One based on such considerations as the estimated predominant consumption.
Further servicing details are available in the utility's Conditions of Service.

General Service
This classification refers to all service supplied to premises other than those classified as Residential or Lighting. Some General Service accounts are energy(kWh)-billed, and some are demand(kW)-billed. Further servicing details are available in the utility's Conditions of Service.

Unmetered Scattered Load
This classification refers to certain instances where connections can be provided without metering. These loads are generally small in size and consistent in magnitude of load. Hydro One reserves the right to review all cases and may require that a meter be installed at its sole discretion. Services that can be unmetered include cable TV amplifiers, telephone switching devices, phone booths, bus shelters, rail way crossing signals, traffic signals, and other small fixed loads.
Further servicing details are available in the utility's Conditions of Service (including in the "Unmetered Connections" section).

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Village of Arkona Public Utilities Commission
Effective Date: May 1, 2008

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

Street Lighting

This classification refers to accounts for the distribution and supply of electrical energy for street lighting. Street lights are devices owned by or operated for the road authority and/or the municipal corporation. These street lights in fact belong to the Street Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Sentinel Lighting

This classification refers to accounts for a separate service to a sentinel light. These sentinel lights in fact belong to the Sentinel Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Urban Density Classification

Customers who meet the Urban Density Criteria of being in an area containing 3,000 or more customers with a line density of at least 60 customers per kilometre, will be mapped to an Urban customer classification.

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Village of Arkona Public Utilities Commission
Effective Date: May 1, 2008

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

MONTHLY RATES AND CHARGES

Residential - R1 Arkona

Service Charge	$	8.30
Distribution Volumetric Rate	$ / kWh	0.0150
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0033
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0004)
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0047
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0046
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service Less Than 50 kW (Energy-Billed) - GSe Arkona

Service Charge	$	10.29
Distribution Volumetric Rate	$ / kWh	0.0198
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0036
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0006)
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0035
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0032
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service 50 kW or Greater (Demand-Billed) - GSd Arkona

Service Charge	$	13.89
Distribution Volumetric Rate	$ / kW	9.22
Regulatory Asset Recovery - Rider #2	$ / kW	0.83
Regulatory Asset Recovery - Rider #3	$ / kW	(0.22)
Retail Transmission Rate - Network Service Rate (4)	$ / kW	1.11
Retail Transmission Rate - Line and Transformation Connection Service Rate (4)	$ / kW	1.00
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Village of Arkona Public Utilities Commission
Effective Date: May 1, 2008

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

Unmetered, Scattered Load

Service Charge	$	7.09
Distribution Volumetric Rate	$ / kWh	0.0200
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0036
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0006)
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0035
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0032
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

(3) For energy-only metered customers, the billing determinant is the customer's metered energy consumption adjusted by the total loss factor as approved by the Board for Acquired LDC customers.
(4) For demand billed customers, appropriate loss factors must be applied to the applicable tariffs. Also the billing determinant for the Line and Transformation Connection Services rate is the customer's peak demand in the billing period. The billing determinant for the Network Services rate is: for non-interval-metered customers, the peak demand in the billing period, and for interval-metered customers, the peak demand between 7 AM and 7 PM local time on IESO business days

Customer-Supplied Transformation Allowance

Applicable to customers providing their own transformers

Demand-billed	$ / kW	0.60
Energy-billed	$ / kWh	0.0014

Hydro One Networks Inc.
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Effective Date: May 1, 2008

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Loss Factors

Residential	1.085
General Service Less Than 50 kW (Energy-Billed)	1.092
General Service 50 kW or Greater (Demand-Billed)	1.061
Unmetered Scattered Load	1.092

Transformer Loss Allowance

Applicable to customers requiring a billing adjustment for transformer losses as the result of being metered on the primary side of a transformer. The following uniform values shall be applied to measured demand and energy to calculate transformer losses for voltages up to and including 50 kV (as metered on the primary side):

(a) 1.5% for transformer installations up to an individual bank capacity of 400 kVA,
(b) 1.0% for bank capacities over 400 kVA.

Alternatively, transformer losses may be determined from transformer test data, and measured demand and energy adjusted accordingly

For services which are not demand metered, an assumed demand of 50% of the transformer capacity will be used to calculate the loss allowance. Where several transformers are involved, the bank capacity is assumed to be the arithmetic sum of all transformer capacities

Hydro One Networks Inc.
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MISCELLANEOUS CHARGES

Specific Service Charges: Standard Amounts

Rate Code	Specific Service Charge - Standard Name	Calculation Method			
		2006 Rate Handbook	Standard Formula	Other Formula	Time and Materials
1	Temporary Service	$500			
2	Dispute Meter Test	$30 plus Measurement Canada fees			
3	Collection of account – no disconnection/load limiter	$30			
4	Collection/Disconnect/load limiter/reconnect (at meter) trip – regular hours	$65			
5	Collection/Disconnect/load limiter/reconnect (at meter) trip – after regular hours	$185			
6	Collection/Disconnect/load limiter/reconnect (at pole) trip – regular hours	$185			
7	Collection/Disconnect/load limiter/reconnect (at pole) trip – after regular hours	$415			
8	Account Set-up Charge	$30			
9	Arrears Certificate	$15			
10	NSF Cheque Charge	$15 + bank charges			
11	Easement Charge for Unregistered Rights	$15			
12	Late Payment Charge	1.5%/month			
13a	Retailer Services – Establishing Service Agreements (refer to Handbook for all charges)	$100/agreement/Retailer +$20/month/Retailer +$0.50/month/customer + other			
13b	Retailer Services – Other (includes Bill Ready for Retailers and Service Transactions Requests) as per the Handbook, Chapter 12	$0.30/month/customer + $0.25/request for request fee + $0.50/request for process fee			
14	Special Meter Reads	$30			
15	Service Layout Fee – Basic		$495		
16	Service Layout Fee – Complex		$690		
17	Crossing Application – Pipeline		$2,445		
18	Crossing Application – Water		$3,045		
19	Crossing Application – Railroad		$2,945		
20	Line Staking – per meter		$3.70		
21	Central Metering – New service < 45 kW		$115		
22	Conversion to Central Metering < 45 kW		$915		
23	Conversion to Central Metering > 45 kW		$800		
24	Tingle Voltage Test – In Excess of 4 Hours (per hour – average 2 additional hours)		$125		
25	Standby Administration Charge per month		$440		
26	Sentinel Lights Rental Rate per month			$7.10	
27	Sentinel Pole Rental Rate per month			$4.15	
28	Joint Use for Cable and Telecom companies per pole			$22.35	
29	Joint Use for LDCs per pole			$28.61	

Hydro One Networks Inc.
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Village of Arkona Public Utilities Commission
Effective Date: May 1, 2007

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APPLICATION

The application of these rates and charges shall be in accordance with The Licence of The Distributor and any Codes, Guidelines or Orders of The Board, and amendments thereto as approved by The Board, which may be applicable to the administration of this schedule.
No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code, Guideline or Order of the Board, and amendments thereto as approved by the Board, or as specified herein
This schedule does not contain any rates and charges relating to the electricity commodity (e.g. the Regulated Price Plan).

EFFECTIVE DATES

DISTRIBUTION RATES - May 1, 2007 for all consumption or deemed consumption services used on or after that date.

MISCELLANEOUS CHARGES - May 1, 2007 for all charges billed to customers on or after that date.
RETAIL TRANSMISSION RATES - May 1, 2007 for all consumption or deemed consumption services used on or after that date.
LOSS FACTOR ADJUSTMENT – May 1, 2007

SERVICE CLASSIFICATIONS

Residential
This classification (note 1) refers to all service supplied to single-family dwelling units for domestic or household purpose. Multi-unit residential establishments such as apartment buildings supplied through one service (bulk metered) will normally be classified as General Service, but, at Hydro One's discretion, up to four residential units may be classified as residential. Where electricity service is provided to combined residential and business (including agricultural usage) and the wiring does not provide for separate metering, the classification shall be at the discretion of Hydro One based on such considerations as the estimated predominant consumption.
Further servicing details are available in the utility's Conditions of Service.

General Service
This classification (note 1) refers to all service supplied to premises other than those classified as Residential or Lighting. Some General Service accounts are energy(kWh)-billed, and some are demand(kW)-billed. Further servicing details are available in the utility's Conditions of Service. Also, see note 2.

Unmetered Scattered Load
This classification refers to certain instances where connections can be provided without metering. These loads are generally small in size and consistent in magnitude of load. Hydro One reserves the right to review all cases and may require that a meter be installed at its sole discretion. Services that can be unmetered include cable TV amplifiers, telephone switching devices, phone booths, bus shelters, rail way crossing signals, traffic signals, and other small fixed loads.
Further servicing details are available in the utility's Conditions of Service (including in the "Unmetered Connections" section).

Hydro One Networks Inc.
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Effective Date: May 1, 2007

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Street Lighting
This classification refers to accounts for the distribution and supply of electrical energy for street lighting. Street lights are devices owned by or operated for the road authority and/or the municipal corporation. These street lights in fact belong to the Street Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Sentinel Lighting
This classification refers to accounts for a separate service to a sentinel light. These sentinel lights in fact belong to the Sentinel Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Interim Demand-Side Management Time-of-Use
This is potentially applicable to Demand-billed General Service accounts. See Note 2 below.

Note (1): Classification descriptions are paraphrases from the document "Hydro One Networks Inc. - Distribution Customers Conditions of Service - August 2004"
Note (2):
Interim Demand-Side Management Time-of-Use Rates: demand charges will be based on demand during the on-peak periods.
Criteria: Customers' electricity consumption (kW) in the off-peak period is at least twice the electricity consumption (kW) during the on-peak period.
Definition of Time Periods: The on-peak hours will be between 0700 hours to 1900 hours Eastern Standard Time during the winter (standard time) on IESO business days and 0600 hours to 1800 hours Eastern Standard Time during the summer (daylight savings time) on IESO business days. The off-peak period constitutes all of the remaining hours.

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MONTHLY RATES AND CHARGES

Residential

Service Charge	$	5.84
Distribution Volumetric Rate	$ / kWh	0.0026
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0068
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0033
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0055
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0047
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service - Energy Billed (less than 50 kW)

Service Charge	$	3.20
Distribution Volumetric Rate	$ / kWh	0.0086
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0051
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0036
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0050
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0043
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service - Demand Billed (50 kW or greater)

Service Charge	$	3.20
Distribution Volumetric Rate	$ / kW	1.98
Regulatory Asset Recovery - Rider #1	$ / kW	1.62
Regulatory Asset Recovery - Rider #2	$ / kW	0.83
Retail Transmission Rate - Network Service Rate (4)	$ / kW	1.94
Retail Transmission Rate - Line and Transformation Connection Service Rate (4)	$ / kW	1.61
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

Hydro One Networks Inc.
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Unmetered, Scattered Load

Service Charge	$	1.14
Distribution Volumetric Rate	$ / kWh	0.0086
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0051
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0036
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0050
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0043
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

(3) For energy-only metered customers, the billing determinant is the customer’s metered energy consumption adjusted by the total loss factor as approved by the Board for Acquired LDC customers.
(4) For demand billed customers, appropriate loss factors must be applied to the applicable tariffs. Also the billing determinant for the Line and Transformation Connection Services rate is the customer’s peak demand in the billing period. The billing determinant for the Network Services rate is: for non-interval-metered customers, the peak demand in the billing period, and for interval-metered customers, the peak demand between 7 AM and 7 PM local time on IESO business days

Interim Demand-Side Management Time-of-Use

See the "Service Classifications" section of this schedule.

Customer-Supplied Transformation Allowance

Applicable to demand-billed customers providing their own transformers
Primary Voltage under 50 kV (per kW)

Single Phase	$ / kW	0.20
Three Phase	$ / kW	0.60

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Loss Factors

Supply Facilities Loss Factor	1.0045
Distribution Loss Factors	
Customer less than 5,000 kW	1.0500
Customer greater than or equal to 5,000 kW	1.0100
Total Loss Factors	
Customer less than 5,000 kW	1.0545
Customer greater than or equal to 5,000 kW	1.0145

Transformer Loss Allowance

Applicable to customers requiring a billing adjustment for transformer losses as the result of being metered on the primary side of a transformer. The following uniform values shall be applied to measured demand and energy to calculate transformer losses for voltages up to and including 50 kV (as metered on the primary side):

(a) 1.5% for transformer installations up to an individual bank capacity of 400 kVA,
(b) 1.0% for bank capacities over 400 kVA.

Alternatively, transformer losses may be determined from transformer test data, and measured demand and energy adjusted accordingly

For services which are not demand metered, an assumed demand of 50% of the transformer capacity will be used to calculate the loss allowance. Where several transformers are involved, the bank capacity is assumed to be the arithmetic sum of all transformer capacities

Hydro One Networks Inc.
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MISCELLANEOUS CHARGES

Specific Service Charges: Standard Amounts

Rate Code	Specific Service Charge - Standard Name	Calculation Method			
		2006 Rate Handbook	Standard Formula	Other Formula	Time and Materials
1	Temporary Service	$500			
2	Dispute Meter Test	$30 plus Measurement Canada fees			
3	Collection of account – no disconnection/load limiter	$30			
4	Collection/Disconnect/load limiter/reconnect (at meter) trip – regular hours	$65			
5	Collection/Disconnect/load limiter/reconnect (at meter) trip – after regular hours	$185			
6	Collection/Disconnect/load limiter/reconnect (at pole) trip – regular hours	$185			
7	Collection/Disconnect/load limiter/reconnect (at pole) trip – after regular hours	$415			
8	Account Set-up Charge	$30			
9	Arrears Certificate	$15			
10	NSF Cheque Charge	$15 + bank charges			
11	Easement Charge for Unregistered Rights	$15			
12	Late Payment Charge	1.5%/month			
13a	Retailer Services – Establishing Service Agreements (refer to Handbook for all charges)	$100/agreement/Retailer +$20/month/Retailer +$0.50/month/customer + other			
13b	Retailer Services – Other (includes Bill Ready for Retailers and Service Transactions Requests) as per the Handbook, Chapter 12	$0.30/month/customer + $0.25/request for request fee + $0.50/request for process fee			
14	Special Meter Reads	$30			
15	Billing Suspension and Terminations in Trailer Parks		$130		
16	Service Layout Fee – Basic		$405		
17	Service Layout Fee – Complex		$580		

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18	Crossing Application – Pipeline		$2,065		
19	Crossing Application – Water		$2,525		
20	Crossing Application – Railroad		$2,565		
21	Line Staking – per meter		$3.10		
22	Central Metering – New service < 45 kW		$115		
23	Conversion to Central Metering < 45 kW		$795		
24	Conversion to Central Metering > 45 kW		$680		
25	Tingle Voltage Test – In Excess of 4 Hours (per hour – average 2 additional hours)		$105		
26	Standby Administration Charge per month (interim)		$375		
27	Sentinel Lights Rental Rate per month – Mercury Vapor			$7.00	
28	Guaranteed Units from Jan 01/91 to Aug 01/91			$26.50 / month	
29	Guaranteed Units from Jan 01/87 to Dec 31/90			$23.50 / month	
30	Joint Use for Cable and Telecom companies per pole			$22.35	
31	Joint Use for LDCs per pole			$28.61	

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Hydro-Electric Commission of the Town of Arnprior
Effective Date: May 1, 2008

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

APPLICATION

The application of these rates and charges shall be in accordance with The Licence of The Distributor and any Codes, Guidelines or Orders of The Board, and amendments thereto as approved by The Board, which may be applicable to the administration of this schedule.
No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code, Guideline or Order of the Board, and amendments thereto as approved by the Board, or as specified herein
This schedule does not contain any rates and charges relating to the electricity commodity (e.g. the Regulated Price Plan).

EFFECTIVE DATES

DISTRIBUTION RATES - May 1, 2008 for all consumption or deemed consumption services used on or after that date.

MISCELLANEOUS CHARGES - May 1, 2008 for all charges billed to customers on or after that date.
RETAIL TRANSMISSION RATES - May 1, 2008 for all consumption or deemed consumption services used on or after that date.
LOSS FACTOR ADJUSTMENT – for all consumption or deemed consumption services billed following May 1, 2008 or later

SERVICE CLASSIFICATIONS

Residential
This classification refers to all service supplied to single-family dwelling units for domestic or household purpose. Multi-unit residential establishments such as apartment buildings supplied through one service (bulk metered) will normally be classified as General Service, but, at Hydro One’s discretion, up to four residential units may be classified as residential. Where electricity service is provided to combined residential and business (including agricultural usage) and the wiring does not provide for separate metering, the classification shall be at the discretion of Hydro One based on such considerations as the estimated predominant consumption.
Further servicing details are available in the utility’s Conditions of Service.

General Service
This classification refers to all service supplied to premises other than those classified as Residential or Lighting. Some General Service accounts are energy(kWh)-billed, and some are demand(kW)-billed. Further servicing details are available in the utility’s Conditions of Service.

Unmetered Scattered Load
This classification refers to certain instances where connections can be provided without metering. These loads are generally small in size and consistent in magnitude of load. Hydro One reserves the right to review all cases and may require that a meter be installed at its sole discretion. Services that can be unmetered include cable TV amplifiers, telephone switching devices, phone booths, bus shelters, rail way crossing signals, traffic signals, and other small fixed loads.
Further servicing details are available in the utility’s Conditions of Service (including in the "Unmetered Connections" section).

Hydro One Networks Inc.
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Large Use - see Note 1

Street Lighting

This classification refers to accounts for the distribution and supply of electrical energy for street lighting. Street lights are devices owned by or operated for the road authority and/or the municipal corporation. These street lights in fact belong to the Street Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Sentinel Lighting

This classification refers to accounts for a separate service to a sentinel light. These sentinel lights in fact belong to the Sentinel Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Urban Density Classification

Customers who meet the Urban Density Criteria of being in an area containing 3,000 or more customers with a line density of at least 60 customers per kilometre, will be mapped to an Urban customer classification.

Note (1) The former Large Use class is now part of the ST class, which is separate from the classes for customers of acquired distribution companies.
This former class refered to individual Customers whose monthly measured maximum demand (kW) averaged over the most recent 12 consecutive months is equal to or greater than 5,000 kW.

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MONTHLY RATES AND CHARGES

Residential - UR/R1 Arnprior

Service Charge	$	11.70
Distribution Volumetric Rate	$ / kWh	0.0240
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0018
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0002)
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0047
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0045
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service Less Than 50 kW (Energy-Billed) - UGe/GSe Arnprior

Service Charge	$	18.74
Distribution Volumetric Rate	$ / kWh	0.0200
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0006
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0006)
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0036
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0033
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service 50 kW or Greater (Demand-Billed) - UGd/GSd Arnprior

Service Charge	$	22.95
Distribution Volumetric Rate	$ / kW	7.33
Regulatory Asset Recovery - Rider #2	$ / kW	0.20
Regulatory Asset Recovery - Rider #3	$ / kW	(0.27)
Retail Transmission Rate - Network Service Rate (4)	$ / kW	1.41
Retail Transmission Rate - Line and Transformation Connection Service Rate (4)	$ / kW	1.27
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

Hydro One Networks Inc.
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Unmetered, Scattered Load

Service Charge	$	13.82
Distribution Volumetric Rate	$ / kWh	0.0200
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0006
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0006)
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0035
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0032
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

(3) For energy-only metered customers, the billing determinant is the customer's metered energy consumption adjusted by the total loss factor as approved by the Board for Acquired LDC customers.

(4) For demand billed customers, appropriate loss factors must be applied to the applicable tariffs. Also the billing determinant for the Line and Transformation Connection Services rate is the customer's peak demand in the billing period. The billing determinant for the Network Services rate is: for non-interval-metered customers, the peak demand in the billing period, and for interval-metered customers, the peak demand between 7 AM and 7 PM local time on IESO business days

Customer-Supplied Transformation Allowance

Applicable to customers providing their own transformers

Demand-billed	$ / kW	0.60
Energy-billed	$ / kWh	0.0014

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Loss Factors

Residential	1.078
General Service Less Than 50 kW (Energy-Billed)	1.092
General Service 50 kW or Greater (Demand-Billed)	1.061
Unmetered Scattered Load	1.092

Transformer Loss Allowance

Applicable to customers requiring a billing adjustment for transformer losses as the result of being metered on the primary side of a transformer. The following uniform values shall be applied to measured demand and energy to calculate transformer losses for voltages up to and including 50 kV (as metered on the primary side):

(a) 1.5% for transformer installations up to an individual bank capacity of 400 kVA,
(b) 1.0% for bank capacities over 400 kVA.

Alternatively, transformer losses may be determined from transformer test data, and measured demand and energy adjusted accordingly

For services which are not demand metered, an assumed demand of 50% of the transformer capacity will be used to calculate the loss allowance. Where several transformers are involved, the bank capacity is assumed to be the arithmetic sum of all transformer capacities

Hydro One Networks Inc.
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MISCELLANEOUS CHARGES

Specific Service Charges: Standard Amounts

Rate Code	Specific Service Charge - Standard Name	Calculation Method			
		2006 Rate Handbook	Standard Formula	Other Formula	Time and Materials
1	Temporary Service	$500			
2	Dispute Meter Test	$30 plus Measurement Canada fees			
3	Collection of account – no disconnection/load limiter	$30			
4	Collection/Disconnect/load limiter/reconnect (at meter) trip – regular hours	$65			
5	Collection/Disconnect/load limiter/reconnect (at meter) trip – after regular hours	$185			
6	Collection/Disconnect/load limiter/reconnect (at pole) trip – regular hours	$185			
7	Collection/Disconnect/load limiter/reconnect (at pole) trip – after regular hours	$415			
8	Account Set-up Charge	$30			
9	Arrears Certificate	$15			
10	NSF Cheque Charge	$15 + bank charges			
11	Easement Charge for Unregistered Rights	$15			
12	Late Payment Charge	1.5%/month			
13a	Retailer Services – Establishing Service Agreements (refer to Handbook for all charges)	$100/agreement/Retailer +$20/month/Retailer +$0.50/month/customer + other			
13b	Retailer Services – Other (includes Bill Ready for Retailers and Service Transactions Requests) as per the Handbook, Chapter 12	$0.30/month/customer + $0.25/request for request fee + $0.50/request for process fee			
14	Special Meter Reads	$30			
15	Service Layout Fee – Basic		$495		
16	Service Layout Fee – Complex		$690		
17	Crossing Application – Pipeline		$2,445		
18	Crossing Application – Water		$3,045		
19	Crossing Application – Railroad		$2,945		
20	Line Staking – per meter		$3.70		
21	Central Metering – New service < 45 kW		$115		
22	Conversion to Central Metering < 45 kW		$915		
23	Conversion to Central Metering > 45 kW		$800		
24	Tingle Voltage Test – In Excess of 4 Hours (per hour – average 2 additional hours)		$125		
25	Standby Administration Charge per month		$440		
26	Sentinel Lights Rental Rate per month			$7.10	
27	Sentinel Pole Rental Rate per month			$4.15	
28	Joint Use for Cable and Telecom companies per pole			$22.35	
29	Joint Use for LDCs per pole			$28.61	

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Hydro-Electric Commission of the Town of Arnprior
Effective Date: May 1, 2007

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

APPLICATION

The application of these rates and charges shall be in accordance with The Licence of The Distributor and any Codes, Guidelines or Orders of The Board, and amendments thereto as approved by The Board, which may be applicable to the administration of this schedule.
No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code, Guideline or Order of the Board, and amendments thereto as approved by the Board, or as specified herein
This schedule does not contain any rates and charges relating to the electricity commodity (e.g. the Regulated Price Plan).

EFFECTIVE DATES

DISTRIBUTION RATES - May 1, 2007 for all consumption or deemed consumption services used on or after that date.

MISCELLANEOUS CHARGES - May 1, 2007 for all charges billed to customers on or after that date.
RETAIL TRANSMISSION RATES - May 1, 2007 for all consumption or deemed consumption services used on or after that date.
LOSS FACTOR ADJUSTMENT – May 1, 2007

SERVICE CLASSIFICATIONS

Residential
This classification (note 1) refers to all service supplied to single-family dwelling units for domestic or household purpose. Multi-unit residential establishments such as apartment buildings supplied through one service (bulk metered) will normally be classified as General Service, but, at Hydro One's discretion, up to four residential units may be classified as residential. Where electricity service is provided to combined residential and business (including agricultural usage) and the wiring does not provide for separate metering, the classification shall be at the discretion of Hydro One based on such considerations as the estimated predominant consumption.
Further servicing details are available in the utility's Conditions of Service.

General Service
This classification (note 1) refers to all service supplied to premises other than those classified as Residential, Lighting or Large Use. Some General Service accounts are energy(kWh)-billed, and some are demand(kW)-billed. Further servicing details are available in the utility's Conditions of Service. Also, see note 2.

Unmetered Scattered Load
This classification refers to certain instances where connections can be provided without metering. These loads are generally small in size and consistent in magnitude of load. Hydro One reserves the right to review all cases and may require that a meter be installed at its sole discretion. Services that can be unmetered include cable TV amplifiers, telephone switching devices, phone booths, bus shelters, rail way crossing signals, traffic signals, and other small fixed loads.
Further servicing details are available in the utility's Conditions of Service (including in the "Unmetered Connections" section).

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Hydro-Electric Commission of the Town of Arnprior
Effective Date: May 1, 2007

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

Large Use

This classification refers to individual Customers whose monthly measured maximum demand (kW) averaged over the
Further servicing details are available in the utility's Conditions of Service. Also, see note 2.

Street Lighting

This classification refers to accounts for the distribution and supply of electrical energy for street lighting. Street lights are devices owned by or operated for the road authority and/or the municipal corporation. These street lights in fact belong to the Street Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Sentinel Lighting

This classification refers to accounts for a separate service to a sentinel light. These sentinel lights in fact belong to the Sentinel Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Interim Demand-Side Management Time-of-Use

This is potentially applicable to Demand-billed General Service and Large Use accounts. See Note 2 below.

Note (1): Classification descriptions are paraphrases from the document "Hydro One Networks Inc. - Distribution Customers Conditions of Service - August 2004"

Note (2):

Interim Demand-Side Management Time-of-Use Rates: demand charges will be based on demand during the on-peak periods.

Criteria: Customers' electricity consumption (kW) in the off-peak period is at least twice the electricity consumption (kW) during the on-peak period.

Definition of Time Periods: The on-peak hours will be between 0700 hours to 1900 hours Eastern Standard Time during the winter (standard time) on IESO business days and 0600 hours to 1800 hours Eastern Standard Time during the summer (daylight savings time) on IESO business days. The off-peak period constitutes all of the remaining hours.

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
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MONTHLY RATES AND CHARGES

Residential

Service Charge	$	11.54
Distribution Volumetric Rate	$ / kWh	0.0147
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0049
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0018
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0055
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0047
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service - Energy Billed (less than 50 kW)

Service Charge	$	21.38
Distribution Volumetric Rate	$ / kWh	0.0117
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0016
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0006
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0050
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0043
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service - Demand Billed (50 kW or greater)

Service Charge	$	21.38
Distribution Volumetric Rate	$ / kW	3.70
Regulatory Asset Recovery - Rider #1	$ / kW	0.50
Regulatory Asset Recovery - Rider #2	$ / kW	0.20
Retail Transmission Rate - Network Service Rate (4)	$ / kW	1.94
Retail Transmission Rate - Line and Transformation Connection Service Rate (4)	$ / kW	1.61
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

Hydro One Networks Inc.
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Unmetered, Scattered Load

Service Charge	$	10.23
Distribution Volumetric Rate	$ / kWh	0.0117
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0016
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0006
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0050
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0043
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

Large User

Service Charge	$	3,844
Distribution Volumetric Rate	$ / kW	3.62
Regulatory Asset Recovery - Rider #1	$ / kW	0.29
Regulatory Asset Recovery - Rider #2	$ / kW	0.09
Retail Transmission Rate - Network Service Rate (4)	$ / kW	2.37
Retail Transmission Rate - Line and Transformation Connection Service Rate (4)	$ / kW	2.09
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

(3) For energy-only metered customers, the billing determinant is the customer’s metered energy consumption adjusted by the total loss factor as approved by the Board for Acquired LDC customers.
(4) For demand billed customers, appropriate loss factors must be applied to the applicable tariffs. Also the billing determinant for the Line and Transformation Connection Services rate is the customer’s peak demand in the billing period. The billing determinant for the Network Services rate is: for non-interval-metered customers, the peak demand in the billing period, and for interval-metered customers, the peak demand between 7 AM and 7 PM local time on IESO business days

Interim Demand-Side Management Time-of-Use

See the "Service Classifications" section of this schedule.

Customer-Supplied Transformation Allowance

Applicable to demand-billed customers (excluding Large Users) providing their own transformers
Primary Voltage under 50 kV (per kW)

Single Phase	$ / kW	0.20
Three Phase	$ / kW	0.60

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Loss Factors

Supply Facilities Loss Factor	1.0045
Distribution Loss Factors	
Customer less than 5,000 kW	1.0500
Customer greater than or equal to 5,000 kW	1.0100
Total Loss Factors	
Customer less than 5,000 kW	1.0545
Customer greater than or equal to 5,000 kW	1.0145

Transformer Loss Allowance

Applicable to customers requiring a billing adjustment for transformer losses as the result of being metered on the primary side of a transformer. The following uniform values shall be applied to measured demand and energy to calculate transformer losses for voltages up to and including 50 kV (as metered on the primary side):

(a) 1.5% for transformer installations up to an individual bank capacity of 400 kVA,
(b) 1.0% for bank capacities over 400 kVA.

Alternatively, transformer losses may be determined from transformer test data, and measured demand and energy adjusted accordingly

For services which are not demand metered, an assumed demand of 50% of the transformer capacity will be used to calculate the loss allowance. Where several transformers are involved, the bank capacity is assumed to be the arithmetic sum of all transformer capacities

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
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Effective Date: May 1, 2007

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

MISCELLANEOUS CHARGES

Specific Service Charges: Standard Amounts

Rate Code	Specific Service Charge - Standard Name	Calculation Method			
		2006 Rate Handbook	Standard Formula	Other Formula	Time and Materials
1	Temporary Service	$500			
2	Dispute Meter Test	$30 plus Measurement Canada fees			
3	Collection of account – no disconnection/load limiter	$30			
4	Collection/Disconnect/load limiter/reconnect (at meter) trip – regular hours	$65			
5	Collection/Disconnect/load limiter/reconnect (at meter) trip – after regular hours	$185			
6	Collection/Disconnect/load limiter/reconnect (at pole) trip – regular hours	$185			
7	Collection/Disconnect/load limiter/reconnect (at pole) trip – after regular hours	$415			
8	Account Set-up Charge	$30			
9	Arrears Certificate	$15			
10	NSF Cheque Charge	$15 + bank charges			
11	Easement Charge for Unregistered Rights	$15			
12	Late Payment Charge	1.5%/month			
13a	Retailer Services – Establishing Service Agreements (refer to Handbook for all charges)	$100/agreement/Retailer +$20/month/Retailer +$0.50/month/customer + other			
13b	Retailer Services – Other (includes Bill Ready for Retailers and Service Transactions Requests) as per the Handbook, Chapter 12	$0.30/month/customer + $0.25/request for request fee + $0.50/request for process fee			
14	Special Meter Reads	$30			
15	Billing Suspension and Terminations in Trailer Parks		$130		
16	Service Layout Fee – Basic		$405		
17	Service Layout Fee – Complex		$580		

Hydro One Networks Inc.
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18	Crossing Application – Pipeline		$2,065		
19	Crossing Application – Water		$2,525		
20	Crossing Application – Railroad		$2,565		
21	Line Staking – per meter		$3.10		
22	Central Metering – New service < 45 kW		$115		
23	Conversion to Central Metering < 45 kW		$795		
24	Conversion to Central Metering > 45 kW		$680		
25	Tingle Voltage Test – In Excess of 4 Hours (per hour – average 2 additional hours)		$105		
26	Standby Administration Charge per month (interim)		$375		
27	Sentinel Lights Rental Rate per month – Mercury Vapor			$7.00	
28	Guaranteed Units from Jan 01/91 to Aug 01/91			$26.50 / month	
29	Guaranteed Units from Jan 01/87 to Dec 31/90			$23.50 / month	
30	Joint Use for Cable and Telecom companies per pole			$22.35	
31	Joint Use for LDCs per pole			$28.61	

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
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Arran-Elderslie Public Utilities Commission
Effective Date: May 1, 2008

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

APPLICATION

The application of these rates and charges shall be in accordance with The Licence of The Distributor and any Codes, Guidelines or Orders of The Board, and amendments thereto as approved by The Board, which may be applicable to the administration of this schedule.
No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code, Guideline or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.
This schedule does not contain any rates and charges relating to the electricity commodity (e.g. the Regulated Price Plan).

EFFECTIVE DATES

DISTRIBUTION RATES - May 1, 2008 for all consumption or deemed consumption services used on or after that date.

MISCELLANEOUS CHARGES - May 1, 2008 for all charges billed to customers on or after that date.
RETAIL TRANSMISSION RATES - May 1, 2008 for all consumption or deemed consumption services used on or after that date.
LOSS FACTOR ADJUSTMENT – for all consumption or deemed consumption services billed following May 1, 2008 or later

SERVICE CLASSIFICATIONS

Residential
This classification refers to all service supplied to single-family dwelling units for domestic or household purpose. Multi-unit residential establishments such as apartment buildings supplied through one service (bulk metered) will normally be classified as General Service, but, at Hydro One's discretion, up to four residential units may be classified as residential. Where electricity service is provided to combined residential and business (including agricultural usage) and the wiring does not provide for separate metering, the classification shall be at the discretion of Hydro One based on such considerations as the estimated predominant consumption.
Further servicing details are available in the utility's Conditions of Service.

General Service
This classification refers to all service supplied to premises other than those classified as Residential or Lighting. Some General Service accounts are energy(kWh)-billed, and some are demand(kW)-billed. Further servicing details are available in the utility's Conditions of Service.

Unmetered Scattered Load
This classification refers to certain instances where connections can be provided without metering. These loads are generally small in size and consistent in magnitude of load. Hydro One reserves the right to review all cases and may require that a meter be installed at its sole discretion. Services that can be unmetered include cable TV amplifiers, telephone switching devices, phone booths, bus shelters, rail way crossing signals, traffic signals, and other small fixed loads.
Further servicing details are available in the utility's Conditions of Service (including in the "Unmetered Connections" section).

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Arran-Elderslie Public Utilities Commission
Effective Date: May 1, 2008

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

Street Lighting

This classification refers to accounts for the distribution and supply of electrical energy for street lighting. Street lights are devices owned by or operated for the road authority and/or the municipal corporation. These street lights in fact belong to the Street Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Sentinel Lighting

This classification refers to accounts for a separate service to a sentinel light. These sentinel lights in fact belong to the Sentinel Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Urban Density Classification

Customers who meet the Urban Density Criteria of being in an area containing 3,000 or more customers with a line density of at least 60 customers per kilometre, will be mapped to an Urban customer classification.

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
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MONTHLY RATES AND CHARGES

Residential - R1 Arran-Elderslie

Service Charge	$	11.51
Distribution Volumetric Rate	$ / kWh	0.0190
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0015
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0004)
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0047
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0046
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service Less Than 50 kW (Energy-Billed) - GSe Arran-Elderslie

Service Charge	$	13.88
Distribution Volumetric Rate	$ / kWh	0.0190
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0009
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0006)
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0035
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0032
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service 50 kW or Greater (Demand-Billed) - GSd Arran-Elderslie

Service Charge	$	17.48
Distribution Volumetric Rate	$ / kW	8.00
Regulatory Asset Recovery - Rider #2	$ / kW	0.28
Regulatory Asset Recovery - Rider #3	$ / kW	(0.22)
Retail Transmission Rate - Network Service Rate (4)	$ / kW	1.11
Retail Transmission Rate - Line and Transformation Connection Service Rate (4)	$ / kW	1.00
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
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Arran-Elderslie Public Utilities Commission
Effective Date: May 1, 2008

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

Unmetered, Scattered Load

Service Charge	$	8.39
Distribution Volumetric Rate	$ / kWh	0.0200
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0009
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0006)
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0035
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0032
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

(3) For energy-only metered customers, the billing determinant is the customer's metered energy consumption adjusted by the total loss factor as approved by the Board for Acquired LDC customers.
(4) For demand billed customers, appropriate loss factors must be applied to the applicable tariffs. Also the billing determinant for the Line and Transformation Connection Services rate is the customer's peak demand in the billing period. The billing determinant for the Network Services rate is: for non-interval-metered customers, the peak demand in the billing period, and for interval-metered customers, the peak demand between 7 AM and 7 PM local time on IESO business days

Customer-Supplied Transformation Allowance

Applicable to customers providing their own transformers

Demand-billed	$ / kW	0.60
Energy-billed	$ / kWh	0.0014

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Loss Factors

Residential	1.085
General Service Less Than 50 kW (Energy-Billed)	1.092
General Service 50 kW or Greater (Demand-Billed)	1.061
Unmetered Scattered Load	1.092

Transformer Loss Allowance

Applicable to customers requiring a billing adjustment for transformer losses as the result of being metered on the primary side of a transformer. The following uniform values shall be applied to measured demand and energy to calculate transformer losses for voltages up to and including 50 kV (as metered on the primary side):

(a) 1.5% for transformer installations up to an individual bank capacity of 400 kVA,
(b) 1.0% for bank capacities over 400 kVA.

Alternatively, transformer losses may be determined from transformer test data, and measured demand and energy adjusted accordingly

For services which are not demand metered, an assumed demand of 50% of the transformer capacity will be used to calculate the loss allowance. Where several transformers are involved, the bank capacity is assumed to be the arithmetic sum of all transformer capacities

Hydro One Networks Inc.
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MISCELLANEOUS CHARGES

Specific Service Charges: Standard Amounts

Rate Code	Specific Service Charge - Standard Name	Calculation Method			
		2006 Rate Handbook	Standard Formula	Other Formula	Time and Materials
1	Temporary Service	$500			
2	Dispute Meter Test	$30 plus Measurement Canada fees			
3	Collection of account – no disconnection/load limiter	$30			
4	Collection/Disconnect/load limiter/reconnect (at meter) trip – regular hours	$65			
5	Collection/Disconnect/load limiter/reconnect (at meter) trip – after regular hours	$185			
6	Collection/Disconnect/load limiter/reconnect (at pole) trip – regular hours	$185			
7	Collection/Disconnect/load limiter/reconnect (at pole) trip – after regular hours	$415			
8	Account Set-up Charge	$30			
9	Arrears Certificate	$15			
10	NSF Cheque Charge	$15 + bank charges			
11	Easement Charge for Unregistered Rights	$15			
12	Late Payment Charge	1.5%/month			
13a	Retailer Services – Establishing Service Agreements (refer to Handbook for all charges)	$100/agreement/Retailer +$20/month/Retailer +$0.50/month/customer + other			
13b	Retailer Services – Other (includes Bill Ready for Retailers and Service Transactions Requests) as per the Handbook, Chapter 12	$0.30/month/customer + $0.25/request for request fee + $0.50/request for process fee			
14	Special Meter Reads	$30			
15	Service Layout Fee – Basic		$495		
16	Service Layout Fee – Complex		$690		
17	Crossing Application – Pipeline		$2,445		
18	Crossing Application – Water		$3,045		
19	Crossing Application – Railroad		$2,945		
20	Line Staking – per meter		$3.70		
21	Central Metering – New service < 45 kW		$115		
22	Conversion to Central Metering < 45 kW		$915		
23	Conversion to Central Metering > 45 kW		$800		
24	Tingle Voltage Test – In Excess of 4 Hours (per hour – average 2 additional hours)		$125		
25	Standby Administration Charge per month		$440		
26	Sentinel Lights Rental Rate per month			$7.10	
27	Sentinel Pole Rental Rate per month			$4.15	
28	Joint Use for Cable and Telecom companies per pole			$22.35	
29	Joint Use for LDCs per pole			$28.61	

Hydro One Networks Inc.
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APPLICATION

The application of these rates and charges shall be in accordance with The Licence of The Distributor and any Codes, Guidelines or Orders of The Board, and amendments thereto as approved by The Board, which may be applicable to the administration of this schedule.
No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code, Guideline or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.
This schedule does not contain any rates and charges relating to the electricity commodity (e.g. the Regulated Price Plan).

EFFECTIVE DATES

DISTRIBUTION RATES - May 1, 2007 for all consumption or deemed consumption services used on or after that date.

MISCELLANEOUS CHARGES - May 1, 2007 for all charges billed to customers on or after that date.
RETAIL TRANSMISSION RATES - May 1, 2007 for all consumption or deemed consumption services used on or after that date.
LOSS FACTOR ADJUSTMENT – May 1, 2007

SERVICE CLASSIFICATIONS

Residential
This classification (note 1) refers to all service supplied to single-family dwelling units for domestic or household purpose. Multi-unit residential establishments such as apartment buildings supplied through one service (bulk metered) will normally be classified as General Service, but, at Hydro One's discretion, up to four residential units may be classified as residential. Where electricity service is provided to combined residential and business (including agricultural usage) and the wiring does not provide for separate metering, the classification shall be at the discretion of Hydro One based on such considerations as the estimated predominant consumption.
Further servicing details are available in the utility's Conditions of Service.

General Service
This classification (note 1) refers to all service supplied to premises other than those classified as Residential or Lighting. Some General Service accounts are energy(kWh)-billed, and some are demand(kW)-billed. Further servicing details are available in the utility's Conditions of Service. Also, see note 2.

Unmetered Scattered Load
This classification refers to certain instances where connections can be provided without metering. These loads are generally small in size and consistent in magnitude of load. Hydro One reserves the right to review all cases and may require that a meter be installed at its sole discretion. Services that can be unmetered include cable TV amplifiers, telephone switching devices, phone booths, bus shelters, rail way crossing signals, traffic signals, and other small fixed loads.
Further servicing details are available in the utility's Conditions of Service (including in the "Unmetered Connections" section).

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Street Lighting

This classification refers to accounts for the distribution and supply of electrical energy for street lighting. Street lights are devices owned by or operated for the road authority and/or the municipal corporation. These street lights in fact belong to the Street Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Sentinel Lighting

This classification refers to accounts for a separate service to a sentinel light. These sentinel lights in fact belong to the Sentinel Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Interim Demand-Side Management Time-of-Use

This is potentially applicable to Demand-billed General Service accounts. See Note 2 below.

Note (1): Classification descriptions are paraphrases from the document "Hydro One Networks Inc. - Distribution Customers Conditions of Service - August 2004"

Note (2):

Interim Demand-Side Management Time-of-Use Rates: demand charges will be based on demand during the on-peak periods.

Criteria: Customers' electricity consumption (kW) in the off-peak period is at least twice the electricity consumption (kW) during the on-peak period.

Definition of Time Periods: The on-peak hours will be between 0700 hours to 1900 hours Eastern Standard Time during the winter (standard time) on IESO business days and 0600 hours to 1800 hours Eastern Standard Time during the summer (daylight savings time) on IESO business days. The off-peak period constitutes all of the remaining hours.

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Arran-Elderslie Public Utilities Commission
Effective Date: May 1, 2007

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

MONTHLY RATES AND CHARGES

Residential

Service Charge	$	9.02
Distribution Volumetric Rate	$ / kWh	0.0095
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0035
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0015
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0055
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0047
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service - Energy Billed (less than 50 kW)

Service Charge	$	8.83
Distribution Volumetric Rate	$ / kWh	0.0103
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0017
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0009
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0050
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0043
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service - Demand Billed (50 kW or greater)

Service Charge	$	8.83
Distribution Volumetric Rate	$ / kW	3.28
Regulatory Asset Recovery - Rider #1	$ / kW	0.55
Regulatory Asset Recovery - Rider #2	$ / kW	0.28
Retail Transmission Rate - Network Service Rate (4)	$ / kW	1.94
Retail Transmission Rate - Line and Transformation Connection Service Rate (4)	$ / kW	1.61
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Arran-Elderslie Public Utilities Commission
Effective Date: May 1, 2007

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Unmetered, Scattered Load

Service Charge	$	3.95
Distribution Volumetric Rate	$ / kWh	0.0103
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0017
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0009
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0050
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0043
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

(3) For energy-only metered customers, the billing determinant is the customer's metered energy consumption adjusted by the total loss factor as approved by the Board for Acquired LDC customers.
(4) For demand billed customers, appropriate loss factors must be applied to the applicable tariffs. Also the billing determinant for the Line and Transformation Connection Services rate is the customer's peak demand in the billing period. The billing determinant for the Network Services rate is: for non-interval-metered customers, the peak demand in the billing period, and for interval-metered customers, the peak demand between 7 AM and 7 PM local time on IESO business days

Interim Demand-Side Management Time-of-Use

See the "Service Classifications" section of this schedule.

Customer-Supplied Transformation Allowance

Applicable to demand-billed customers providing their own transformers
Primary Voltage under 50 kV (per kW)

Single Phase	$ / kW	0.20
Three Phase	$ / kW	0.60

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Arran-Elderslie Public Utilities Commission
Effective Date: May 1, 2007

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Loss Factors

Supply Facilities Loss Factor	1.0045
Distribution Loss Factors	
Customer less than 5,000 kW	1.0500
Customer greater than or equal to 5,000 kW	1.0100
Total Loss Factors	
Customer less than 5,000 kW	1.0545
Customer greater than or equal to 5,000 kW	1.0145

Transformer Loss Allowance

Applicable to customers requiring a billing adjustment for transformer losses as the result of being metered on the primary side of a transformer. The following uniform values shall be applied to measured demand and energy to calculate transformer losses for voltages up to and including 50 kV (as metered on the primary side):

(a) 1.5% for transformer installations up to an individual bank capacity of 400 kVA,
(b) 1.0% for bank capacities over 400 kVA.

Alternatively, transformer losses may be determined from transformer test data, and measured demand and energy adjusted accordingly

For services which are not demand metered, an assumed demand of 50% of the transformer capacity will be used to calculate the loss allowance. Where several transformers are involved, the bank capacity is assumed to be the arithmetic sum of all transformer capacities

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Arran-Elderslie Public Utilities Commission
Effective Date: May 1, 2007

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

MISCELLANEOUS CHARGES

Specific Service Charges: Standard Amounts

Rate Code	Specific Service Charge - Standard Name	Calculation Method			
		2006 Rate Handbook	Standard Formula	Other Formula	Time and Materials
1	Temporary Service	$500			
2	Dispute Meter Test	$30 plus Measurement Canada fees			
3	Collection of account – no disconnection/load limiter	$30			
4	Collection/Disconnect/load limiter/reconnect (at meter) trip – regular hours	$65			
5	Collection/Disconnect/load limiter/reconnect (at meter) trip – after regular hours	$185			
6	Collection/Disconnect/load limiter/reconnect (at pole) trip – regular hours	$185			
7	Collection/Disconnect/load limiter/reconnect (at pole) trip – after regular hours	$415			
8	Account Set-up Charge	$30			
9	Arrears Certificate	$15			
10	NSF Cheque Charge	$15 + bank charges			
11	Easement Charge for Unregistered Rights	$15			
12	Late Payment Charge	1.5%/month			
13a	Retailer Services – Establishing Service Agreements (refer to Handbook for all charges)	$100/agreement/Retailer +$20/month/Retailer +$0.50/month/customer + other			
13b	Retailer Services – Other (includes Bill Ready for Retailers and Service Transactions Requests) as per the Handbook, Chapter 12	$0.30/month/customer + $0.25/request for request fee + $0.50/request for process fee			
14	Special Meter Reads	$30			
15	Billing Suspension and Terminations in Trailer Parks		$130		
16	Service Layout Fee – Basic		$405		
17	Service Layout Fee – Complex		$580		

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
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Arran-Elderslie Public Utilities Commission
Effective Date: May 1, 2007

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18	Crossing Application – Pipeline		$2,065		
19	Crossing Application – Water		$2,525		
20	Crossing Application – Railroad		$2,565		
21	Line Staking – per meter		$3.10		
22	Central Metering – New service < 45 kW		$115		
23	Conversion to Central Metering < 45 kW		$795		
24	Conversion to Central Metering > 45 kW		$680		
25	Tingle Voltage Test – In Excess of 4 Hours (per hour – average 2 additional hours)		$105		
26	Standby Administration Charge per month (interim)		$375		
27	Sentinel Lights Rental Rate per month – Mercury Vapor			$7.00	
28	Guaranteed Units from Jan 01/91 to Aug 01/91			$26.50 / month	
29	Guaranteed Units from Jan 01/87 to Dec 31/90			$23.50 / month	
30	Joint Use for Cable and Telecom companies per pole			$22.35	
31	Joint Use for LDCs per pole			$28.61	

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Hydro-Electric Commission of the Township of Artemesia
Effective Date: May 1, 2008

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

APPLICATION

The application of these rates and charges shall be in accordance with The Licence of The Distributor and any Codes, Guidelines or Orders of The Board, and amendments thereto as approved by The Board, which may be applicable to the administration of this schedule.
No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code, Guideline or Order of the Board, and amendments thereto as approved by the Board, or as specified herein
This schedule does not contain any rates and charges relating to the electricity commodity (e.g. the Regulated Price Plan).

EFFECTIVE DATES

DISTRIBUTION RATES - May 1, 2008 for all consumption or deemed consumption services used on or after that date.

MISCELLANEOUS CHARGES - May 1, 2008 for all charges billed to customers on or after that date.
RETAIL TRANSMISSION RATES - May 1, 2008 for all consumption or deemed consumption services used on or after that date.
LOSS FACTOR ADJUSTMENT – for all consumption or deemed consumption services billed following May 1, 2008 or later

SERVICE CLASSIFICATIONS

Residential
This classification refers to all service supplied to single-family dwelling units for domestic or household purpose. Multi-unit residential establishments such as apartment buildings supplied through one service (bulk metered) will normally be classified as General Service, but, at Hydro One's discretion, up to four residential units may be classified as residential. Where electricity service is provided to combined residential and business (including agricultural usage) and the wiring does not provide for separate metering, the classification shall be at the discretion of Hydro One based on such considerations as the estimated predominant consumption.
Further servicing details are available in the utility's Conditions of Service.

General Service
This classification refers to all service supplied to premises other than those classified as Residential or Lighting. Some General Service accounts are energy(kWh)-billed, and some are demand(kW)-billed. Further servicing details are available in the utility's Conditions of Service.

Unmetered Scattered Load
This classification refers to certain instances where connections can be provided without metering. These loads are generally small in size and consistent in magnitude of load. Hydro One reserves the right to review all cases and may require that a meter be installed at its sole discretion. Services that can be unmetered include cable TV amplifiers, telephone switching devices, phone booths, bus shelters, rail way crossing signals, traffic signals, and other small fixed loads.
Further servicing details are available in the utility's Conditions of Service (including in the "Unmetered Connections" section).

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Hydro-Electric Commission of the Township of Artemesia
Effective Date: May 1, 2008

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

Street Lighting

This classification refers to accounts for the distribution and supply of electrical energy for street lighting. Street lights are devices owned by or operated for the road authority and/or the municipal corporation. These street lights in fact belong to the Street Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Sentinel Lighting

This classification refers to accounts for a separate service to a sentinel light. These sentinel lights in fact belong to the Sentinel Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Urban Density Classification

Customers who meet the Urban Density Criteria of being in an area containing 3,000 or more customers with a line density of at least 60 customers per kilometre, will be mapped to an Urban customer classification.

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Hydro-Electric Commission of the Township of Artemesia
Effective Date: May 1, 2008

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MONTHLY RATES AND CHARGES

Residential - R1 Artemesia

Service Charge	$	13.58
Distribution Volumetric Rate	$ / kWh	0.0235
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0034
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0004)
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0047
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0046
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service Less Than 50 kW (Energy-Billed) - GSe Artemesia

Service Charge	$	22.19
Distribution Volumetric Rate	$ / kWh	0.0321
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0034
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0006)
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0035
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0032
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service 50 kW or Greater (Demand-Billed) - GSd Artemesia

Service Charge	$	25.78
Distribution Volumetric Rate	$ / kW	9.22
Regulatory Asset Recovery - Rider #2	$ / kW	1.08
Regulatory Asset Recovery - Rider #3	$ / kW	(0.22)
Retail Transmission Rate - Network Service Rate (4)	$ / kW	1.11
Retail Transmission Rate - Line and Transformation Connection Service Rate (4)	$ / kW	1.00
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
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Hydro-Electric Commission of the Township of Artemesia
Effective Date: May 1, 2008

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

Unmetered, Scattered Load

Service Charge	$	13.04
Distribution Volumetric Rate	$ / kWh	0.0200
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0034
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0006)
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0035
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0032
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

(3) For energy-only metered customers, the billing determinant is the customer's metered energy consumption adjusted by the total loss factor as approved by the Board for Acquired LDC customers.
(4) For demand billed customers, appropriate loss factors must be applied to the applicable tariffs. Also the billing determinant for the Line and Transformation Connection Services rate is the customer's peak demand in the billing period. The billing determinant for the Network Services rate is: for non-interval-metered customers, the peak demand in the billing period, and for interval-metered customers, the peak demand between 7 AM and 7 PM local time on IESO business days

Customer-Supplied Transformation Allowance

Applicable to customers providing their own transformers

Demand-billed	$ / kW	0.60
Energy-billed	$ / kWh	0.0014

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
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Hydro-Electric Commission of the Township of Artemesia
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Loss Factors

Residential	1.085
General Service Less Than 50 kW (Energy-Billed)	1.092
General Service 50 kW or Greater (Demand-Billed)	1.061
Unmetered Scattered Load	1.092

Transformer Loss Allowance

Applicable to customers requiring a billing adjustment for transformer losses as the result of being metered on the primary side of a transformer. The following uniform values shall be applied to measured demand and energy to calculate transformer losses for voltages up to and including 50 kV (as metered on the primary side):

(a) 1.5% for transformer installations up to an individual bank capacity of 400 kVA,
(b) 1.0% for bank capacities over 400 kVA.

Alternatively, transformer losses may be determined from transformer test data, and measured demand and energy adjusted accordingly
For services which are not demand metered, an assumed demand of 50% of the transformer capacity will be used to calculate the loss allowance. Where several transformers are involved, the bank capacity is assumed to be the arithmetic sum of all transformer capacities

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Hydro-Electric Commission of the Township of Artemesia
Effective Date: May 1, 2008

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

MISCELLANEOUS CHARGES

Specific Service Charges: Standard Amounts

Rate Code	Specific Service Charge - Standard Name	Calculation Method			
		2006 Rate Handbook	Standard Formula	Other Formula	Time and Materials
1	Temporary Service	$500			
2	Dispute Meter Test	$30 plus Measurement Canada fees			
3	Collection of account – no disconnection/load limiter	$30			
4	Collection/Disconnect/load limiter/reconnect (at meter) trip – regular hours	$65			
5	Collection/Disconnect/load limiter/reconnect (at meter) trip – after regular hours	$185			
6	Collection/Disconnect/load limiter/reconnect (at pole) trip – regular hours	$185			
7	Collection/Disconnect/load limiter/reconnect (at pole) trip – after regular hours	$415			
8	Account Set-up Charge	$30			
9	Arrears Certificate	$15			
10	NSF Cheque Charge	$15 + bank charges			
11	Easement Charge for Unregistered Rights	$15			
12	Late Payment Charge	1.5%/month			
13a	Retailer Services – Establishing Service Agreements (refer to Handbook for all charges)	$100/agreement/Retailer +$20/month/Retailer +$0.50/month/customer + other			
13b	Retailer Services – Other (includes Bill Ready for Retailers and Service Transactions Requests) as per the Handbook, Chapter 12	$0.30/month/customer + $0.25/request for request fee + $0.50/request for process fee			
14	Special Meter Reads	$30			
15	Service Layout Fee – Basic		$495		
16	Service Layout Fee – Complex		$690		
17	Crossing Application – Pipeline		$2,445		
18	Crossing Application – Water		$3,045		
19	Crossing Application – Railroad		$2,945		
20	Line Staking – per meter		$3.70		
21	Central Metering – New service < 45 kW		$115		
22	Conversion to Central Metering < 45 kW		$915		
23	Conversion to Central Metering > 45 kW		$800		
24	Tingle Voltage Test – In Excess of 4 Hours (per hour – average 2 additional hours)		$125		
25	Standby Administration Charge per month		$440		
26	Sentinel Lights Rental Rate per month			$7.10	
27	Sentinel Pole Rental Rate per month			$4.15	
28	Joint Use for Cable and Telecom companies per pole			$22.35	
29	Joint Use for LDCs per pole			$28.61	

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Hydro-Electric Commission of the Township of Artemesia
Effective Date: May 1, 2007

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

APPLICATION

The application of these rates and charges shall be in accordance with The Licence of The Distributor and any Codes, Guidelines or Orders of The Board, and amendments thereto as approved by The Board, which may be applicable to the administration of this schedule.
No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code, Guideline or Order of the Board, and amendments thereto as approved by the Board, or as specified herein
This schedule does not contain any rates and charges relating to the electricity commodity (e.g. the Regulated Price Plan).

EFFECTIVE DATES

DISTRIBUTION RATES - May 1, 2007 for all consumption or deemed consumption services used on or after that date.

MISCELLANEOUS CHARGES - May 1, 2007 for all charges billed to customers on or after that date.
RETAIL TRANSMISSION RATES - May 1, 2007 for all consumption or deemed consumption services used on or after that date.
LOSS FACTOR ADJUSTMENT – May 1, 2007

SERVICE CLASSIFICATIONS

Residential
This classification (note 1) refers to all service supplied to single-family dwelling units for domestic or household purpose. Multi-unit residential establishments such as apartment buildings supplied through one service (bulk metered) will normally be classified as General Service, but, at Hydro One’s discretion, up to four residential units may be classified as residential. Where electricity service is provided to combined residential and business (including agricultural usage) and the wiring does not provide for separate metering, the classification shall be at the discretion of Hydro One based on such considerations as the estimated predominant consumption.
Further servicing details are available in the utility’s Conditions of Service.

General Service
This classification (note 1) refers to all service supplied to premises other than those classified as Residential or Lighting. Some General Service accounts are energy(kWh)-billed, and some are demand(kW)-billed. Further servicing details are available in the utility’s Conditions of Service. Also, see note 2.

Unmetered Scattered Load
This classification refers to certain instances where connections can be provided without metering. These loads are generally small in size and consistent in magnitude of load. Hydro One reserves the right to review all cases and may require that a meter be installed at its sole discretion. Services that can be unmetered include cable TV amplifiers, telephone switching devices, phone booths, bus shelters, rail way crossing signals, traffic signals, and other small fixed loads.
Further servicing details are available in the utility’s Conditions of Service (including in the "Unmetered Connections" section).

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Hydro-Electric Commission of the Township of Artemesia
Effective Date: May 1, 2007

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Street Lighting

This classification refers to accounts for the distribution and supply of electrical energy for street lighting. Street lights are devices owned by or operated for the road authority and/or the municipal corporation. These street lights in fact belong to the Street Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Sentinel Lighting

This classification refers to accounts for a separate service to a sentinel light. These sentinel lights in fact belong to the Sentinel Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Interim Demand-Side Management Time-of-Use

This is potentially applicable to Demand-billed General Service accounts. See Note 2 below.

Note (1): Classification descriptions are paraphrases from the document "Hydro One Networks Inc. - Distribution Customers Conditions of Service - August 2004"

Note (2):

Interim Demand-Side Management Time-of-Use Rates: demand charges will be based on demand during the on-peak periods.

Criteria: Customers' electricity consumption (kW) in the off-peak period is at least twice the electricity consumption (kW) during the on-peak period.

Definition of Time Periods: The on-peak hours will be between 0700 hours to 1900 hours Eastern Standard Time during the winter (standard time) on IESO business days and 0600 hours to 1800 hours Eastern Standard Time during the summer (daylight savings time) on IESO business days. The off-peak period constitutes all of the remaining hours.

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Hydro-Electric Commission of the Township of Artemesia
Effective Date: May 1, 2007

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

MONTHLY RATES AND CHARGES

Residential

Service Charge	$	12.73
Distribution Volumetric Rate	$ / kWh	0.0093
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0059
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0034
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0055
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0047
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service - Energy Billed (less than 50 kW)

Service Charge	$	19.62
Distribution Volumetric Rate	$ / kWh	0.0174
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0049
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0034
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0050
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0043
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service - Demand Billed (50 kW or greater)

Service Charge	$	19.62
Distribution Volumetric Rate	$ / kW	5.49
Regulatory Asset Recovery - Rider #1	$ / kW	1.55
Regulatory Asset Recovery - Rider #2	$ / kW	1.08
Retail Transmission Rate - Network Service Rate (4)	$ / kW	1.94
Retail Transmission Rate - Line and Transformation Connection Service Rate (4)	$ / kW	1.61
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Hydro-Electric Commission of the Township of Artemesia
Effective Date: May 1, 2007

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

Unmetered, Scattered Load

Service Charge	$	9.34
Distribution Volumetric Rate	$ / kWh	0.0174
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0049
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0034
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0050
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0043
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

(3) For energy-only metered customers, the billing determinant is the customer's metered energy consumption adjusted by the total loss factor as approved by the Board for Acquired LDC customers.
(4) For demand billed customers, appropriate loss factors must be applied to the applicable tariffs. Also the billing determinant for the Line and Transformation Connection Services rate is the customer's peak demand in the billing period. The billing determinant for the Network Services rate is: for non-interval-metered customers, the peak demand in the billing period, and for interval-metered customers, the peak demand between 7 AM and 7 PM local time on IESO business days

Interim Demand-Side Management Time-of-Use

See the "Service Classifications" section of this schedule.

Customer-Supplied Transformation Allowance

Applicable to demand-billed customers providing their own transformers
Primary Voltage under 50 kV (per kW)

Single Phase	$ / kW	0.20
Three Phase	$ / kW	0.60

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Hydro-Electric Commission of the Township of Artemesia
Effective Date: May 1, 2007

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

Loss Factors

Supply Facilities Loss Factor	1.0045
Distribution Loss Factors	
Customer less than 5,000 kW	1.0500
Customer greater than or equal to 5,000 kW	1.0100
Total Loss Factors	
Customer less than 5,000 kW	1.0545
Customer greater than or equal to 5,000 kW	1.0145

Transformer Loss Allowance

Applicable to customers requiring a billing adjustment for transformer losses as the result of being metered on the primary side of a transformer. The following uniform values shall be applied to measured demand and energy to calculate transformer losses for voltages up to and including 50 kV (as metered on the primary side):

(a) 1.5% for transformer installations up to an individual bank capacity of 400 kVA,
(b) 1.0% for bank capacities over 400 kVA.

Alternatively, transformer losses may be determined from transformer test data, and measured demand and energy adjusted accordingly

For services which are not demand metered, an assumed demand of 50% of the transformer capacity will be used to calculate the loss allowance. Where several transformers are involved, the bank capacity is assumed to be the arithmetic sum of all transformer capacities

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Hydro-Electric Commission of the Township of Artemesia
Effective Date: May 1, 2007

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

MISCELLANEOUS CHARGES

Specific Service Charges: Standard Amounts

Rate Code	Specific Service Charge - Standard Name	Calculation Method			
		2006 Rate Handbook	Standard Formula	Other Formula	Time and Materials
1	Temporary Service	$500			
2	Dispute Meter Test	$30 plus Measurement Canada fees			
3	Collection of account – no disconnection/load limiter	$30			
4	Collection/Disconnect/load limiter/reconnect (at meter) trip – regular hours	$65			
5	Collection/Disconnect/load limiter/reconnect (at meter) trip – after regular hours	$185			
6	Collection/Disconnect/load limiter/reconnect (at pole) trip – regular hours	$185			
7	Collection/Disconnect/load limiter/reconnect (at pole) trip – after regular hours	$415			
8	Account Set-up Charge	$30			
9	Arrears Certificate	$15			
10	NSF Cheque Charge	$15 + bank charges			
11	Easement Charge for Unregistered Rights	$15			
12	Late Payment Charge	1.5%/month			
13a	Retailer Services – Establishing Service Agreements (refer to Handbook for all charges)	$100/agreement/Retailer +$20/month/Retailer +$0.50/month/customer + other			
13b	Retailer Services – Other (includes Bill Ready for Retailers and Service Transactions Requests) as per the Handbook, Chapter 12	$0.30/month/customer + $0.25/request for request fee + $0.50/request for process fee			
14	Special Meter Reads	$30			
15	Billing Suspension and Terminations in Trailer Parks		$130		
16	Service Layout Fee – Basic		$405		
17	Service Layout Fee – Complex		$580		

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Hydro-Electric Commission of the Township of Artemesia
Effective Date: May 1, 2007

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18	Crossing Application – Pipeline		$2,065		
19	Crossing Application – Water		$2,525		
20	Crossing Application – Railroad		$2,565		
21	Line Staking – per meter		$3.10		
22	Central Metering – New service < 45 kW		$115		
23	Conversion to Central Metering < 45 kW		$795		
24	Conversion to Central Metering > 45 kW		$680		
25	Tingle Voltage Test – In Excess of 4 Hours (per hour – average 2 additional hours)		$105		
26	Standby Administration Charge per month (interim)		$375		
27	Sentinel Lights Rental Rate per month – Mercury Vapor			$7.00	
28	Guaranteed Units from Jan 01/91 to Aug 01/91			$26.50 / month	
29	Guaranteed Units from Jan 01/87 to Dec 31/90			$23.50 / month	
30	Joint Use for Cable and Telecom companies per pole			$22.35	
31	Joint Use for LDCs per pole			$28.61	

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Bancroft Public Utilities Commission
Effective Date: May 1, 2008

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

APPLICATION

The application of these rates and charges shall be in accordance with The Licence of The Distributor and any Codes, Guidelines or Orders of The Board, and amendments thereto as approved by The Board, which may be applicable to the administration of this schedule.
No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code, Guideline or Order of the Board, and amendments thereto as approved by the Board, or as specified herein
This schedule does not contain any rates and charges relating to the electricity commodity (e.g. the Regulated Price Plan).

EFFECTIVE DATES

DISTRIBUTION RATES - May 1, 2008 for all consumption or deemed consumption services used on or after that date.

MISCELLANEOUS CHARGES - May 1, 2008 for all charges billed to customers on or after that date.
RETAIL TRANSMISSION RATES - May 1, 2008 for all consumption or deemed consumption services used on or after that date.
LOSS FACTOR ADJUSTMENT – for all consumption or deemed consumption services billed following May 1, 2008 or later

SERVICE CLASSIFICATIONS

Residential
This classification refers to all service supplied to single-family dwelling units for domestic or household purpose. Multi-unit residential establishments such as apartment buildings supplied through one service (bulk metered) will normally be classified as General Service, but, at Hydro One's discretion, up to four residential units may be classified as residential. Where electricity service is provided to combined residential and business (including agricultural usage) and the wiring does not provide for separate metering, the classification shall be at the discretion of Hydro One based on such considerations as the estimated predominant consumption.
Further servicing details are available in the utility's Conditions of Service.

General Service
This classification refers to all service supplied to premises other than those classified as Residential or Lighting. Some General Service accounts are energy(kWh)-billed, and some are demand(kW)-billed. Further servicing details are available in the utility's Conditions of Service.

Unmetered Scattered Load
This classification refers to certain instances where connections can be provided without metering. These loads are generally small in size and consistent in magnitude of load. Hydro One reserves the right to review all cases and may require that a meter be installed at its sole discretion. Services that can be unmetered include cable TV amplifiers, telephone switching devices, phone booths, bus shelters, rail way crossing signals, traffic signals, and other small fixed loads.
Further servicing details are available in the utility's Conditions of Service (including in the "Unmetered Connections" section).

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Bancroft Public Utilities Commission
Effective Date: May 1, 2008

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

Street Lighting

This classification refers to accounts for the distribution and supply of electrical energy for street lighting. Street lights are devices owned by or operated for the road authority and/or the municipal corporation. These street lights in fact belong to the Street Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Sentinel Lighting

This classification refers to accounts for a separate service to a sentinel light. These sentinel lights in fact belong to the Sentinel Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Urban Density Classification

Customers who meet the Urban Density Criteria of being in an area containing 3,000 or more customers with a line density of at least 60 customers per kilometre, will be mapped to an Urban customer classification.

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Bancroft Public Utilities Commission
Effective Date: May 1, 2008

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

MONTHLY RATES AND CHARGES

Residential - R1 Bancroft

Service Charge	$	14.39
Distribution Volumetric Rate	$ / kWh	0.0210
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0012
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0004)
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0047
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0046
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service Less Than 50 kW (Energy-Billed) - GSe Bancroft

Service Charge	$	25.99
Distribution Volumetric Rate	$ / kWh	0.0230
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0008
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0006)
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0035
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0032
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service 50 kW or Greater (Demand-Billed) - GSd Bancroft

Service Charge	$	29.59
Distribution Volumetric Rate	$ / kW	8.50
Regulatory Asset Recovery - Rider #2	$ / kW	0.24
Regulatory Asset Recovery - Rider #3	$ / kW	(0.22)
Retail Transmission Rate - Network Service Rate (4)	$ / kW	1.11
Retail Transmission Rate - Line and Transformation Connection Service Rate (4)	$ / kW	1.00
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
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Bancroft Public Utilities Commission
Effective Date: May 1, 2008

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Unmetered, Scattered Load

Service Charge	$	14.45
Distribution Volumetric Rate	$ / kWh	0.0200
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0008
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0006)
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0035
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0032
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

(3) For energy-only metered customers, the billing determinant is the customer's metered energy consumption adjusted by the total loss factor as approved by the Board for Acquired LDC customers.
(4) For demand billed customers, appropriate loss factors must be applied to the applicable tariffs. Also the billing determinant for the Line and Transformation Connection Services rate is the customer's peak demand in the billing period. The billing determinant for the Network Services rate is: for non-interval-metered customers, the peak demand in the billing period, and for interval-metered customers, the peak demand between 7 AM and 7 PM local time on IESO business days

Customer-Supplied Transformation Allowance

Applicable to customers providing their own transformers		
Demand-billed	$ / kW	0.60
Energy-billed	$ / kWh	0.0014

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
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Loss Factors

Residential	1.085
General Service Less Than 50 kW (Energy-Billed)	1.092
General Service 50 kW or Greater (Demand-Billed)	1.061
Unmetered Scattered Load	1.092

Transformer Loss Allowance

Applicable to customers requiring a billing adjustment for transformer losses as the result of being metered on the primary side of a transformer. The following uniform values shall be applied to measured demand and energy to calculate transformer losses for voltages up to and including 50 kV (as metered on the primary side):

(a) 1.5% for transformer installations up to an individual bank capacity of 400 kVA,
(b) 1.0% for bank capacities over 400 kVA.

Alternatively, transformer losses may be determined from transformer test data, and measured demand and energy adjusted accordingly

For services which are not demand metered, an assumed demand of 50% of the transformer capacity will be used to calculate the loss allowance. Where several transformers are involved, the bank capacity is assumed to be the arithmetic sum of all transformer capacities

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Bancroft Public Utilities Commission
Effective Date: May 1, 2008

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

MISCELLANEOUS CHARGES

Specific Service Charges: Standard Amounts

Rate Code	Specific Service Charge - Standard Name	Calculation Method			
		2006 Rate Handbook	Standard Formula	Other Formula	Time and Materials
1	Temporary Service	$500			
2	Dispute Meter Test	$30 plus Measurement Canada fees			
3	Collection of account – no disconnection/load limiter	$30			
4	Collection/Disconnect/load limiter/reconnect (at meter) trip – regular hours	$65			
5	Collection/Disconnect/load limiter/reconnect (at meter) trip – after regular hours	$185			
6	Collection/Disconnect/load limiter/reconnect (at pole) trip – regular hours	$185			
7	Collection/Disconnect/load limiter/reconnect (at pole) trip – after regular hours	$415			
8	Account Set-up Charge	$30			
9	Arrears Certificate	$15			
10	NSF Cheque Charge	$15 + bank charges			
11	Easement Charge for Unregistered Rights	$15			
12	Late Payment Charge	1.5%/month			
13a	Retailer Services – Establishing Service Agreements (refer to Handbook for all charges)	$100/agreement/Retailer +$20/month/Retailer +$0.50/month/customer + other			
13b	Retailer Services – Other (includes Bill Ready for Retailers and Service Transactions Requests) as per the Handbook, Chapter 12	$0.30/month/customer + $0.25/request for request fee + $0.50/request for process fee			
14	Special Meter Reads	$30			
15	Service Layout Fee – Basic		$495		
16	Service Layout Fee – Complex		$690		
17	Crossing Application – Pipeline		$2,445		
18	Crossing Application – Water		$3,045		
19	Crossing Application – Railroad		$2,945		
20	Line Staking – per meter		$3.70		
21	Central Metering – New service < 45 kW		$115		
22	Conversion to Central Metering < 45 kW		$915		
23	Conversion to Central Metering > 45 kW		$800		
24	Tingle Voltage Test – In Excess of 4 Hours (per hour – average 2 additional hours)		$125		
25	Standby Administration Charge per month		$440		
26	Sentinel Lights Rental Rate per month			$7.10	
27	Sentinel Pole Rental Rate per month			$4.15	
28	Joint Use for Cable and Telecom companies per pole			$22.35	
29	Joint Use for LDCs per pole			$28.61	

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Bancroft Public Utilities Commission
Effective Date: May 1, 2007

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APPLICATION

The application of these rates and charges shall be in accordance with The Licence of The Distributor and any Codes, Guidelines or Orders of The Board, and amendments thereto as approved by The Board, which may be applicable to the administration of this schedule.
No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code, Guideline or Order of the Board, and amendments thereto as approved by the Board, or as specified herein
This schedule does not contain any rates and charges relating to the electricity commodity (e.g. the Regulated Price Plan).

EFFECTIVE DATES

DISTRIBUTION RATES - May 1, 2007 for all consumption or deemed consumption services used on or after that date.

MISCELLANEOUS CHARGES - May 1, 2007 for all charges billed to customers on or after that date.
RETAIL TRANSMISSION RATES - May 1, 2007 for all consumption or deemed consumption services used on or after that date.
LOSS FACTOR ADJUSTMENT – May 1, 2007

SERVICE CLASSIFICATIONS

Residential
This classification (note 1) refers to all service supplied to single-family dwelling units for domestic or household purpose. Multi-unit residential establishments such as apartment buildings supplied through one service (bulk metered) will normally be classified as General Service, but, at Hydro One's discretion, up to four residential units may be classified as residential. Where electricity service is provided to combined residential and business (including agricultural usage) and the wiring does not provide for separate metering, the classification shall be at the discretion of Hydro One based on such considerations as the estimated predominant consumption.
Further servicing details are available in the utility's Conditions of Service.

General Service
This classification (note 1) refers to all service supplied to premises other than those classified as Residential or Lighting. Some General Service accounts are energy(kWh)-billed, and some are demand(kW)-billed. Further servicing details are available in the utility's Conditions of Service. Also, see note 2.

Unmetered Scattered Load
This classification refers to certain instances where connections can be provided without metering. These loads are generally small in size and consistent in magnitude of load. Hydro One reserves the right to review all cases and may require that a meter be installed at its sole discretion. Services that can be unmetered include cable TV amplifiers, telephone switching devices, phone booths, bus shelters, rail way crossing signals, traffic signals, and other small fixed loads.
Further servicing details are available in the utility's Conditions of Service (including in the "Unmetered Connections" section).

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Bancroft Public Utilities Commission
Effective Date: May 1, 2007

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

Street Lighting

This classification refers to accounts for the distribution and supply of electrical energy for street lighting. Street lights are devices owned by or operated for the road authority and/or the municipal corporation. These street lights in fact belong to the Street Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Sentinel Lighting

This classification refers to accounts for a separate service to a sentinel light. These sentinel lights in fact belong to the Sentinel Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Interim Demand-Side Management Time-of-Use

This is potentially applicable to Demand-billed General Service accounts. See Note 2 below.

Note (1): Classification descriptions are paraphrases from the document "Hydro One Networks Inc. - Distribution Customers Conditions of Service - August 2004"

Note (2):

Interim Demand-Side Management Time-of-Use Rates: demand charges will be based on demand during the on-peak periods.

Criteria: Customers' electricity consumption (kW) in the off-peak period is at least twice the electricity consumption (kW) during the on-peak period.

Definition of Time Periods: The on-peak hours will be between 0700 hours to 1900 hours Eastern Standard Time during the winter (standard time) on IESO business days and 0600 hours to 1800 hours Eastern Standard Time during the summer (daylight savings time) on IESO business days. The off-peak period constitutes all of the remaining hours.

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Bancroft Public Utilities Commission
Effective Date: May 1, 2007

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

MONTHLY RATES AND CHARGES

Residential

Service Charge	$	13.48
Distribution Volumetric Rate	$ / kWh	0.0095
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0034
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0012
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0055
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0047
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service - Energy Billed (less than 50 kW)

Service Charge	$	24.41
Distribution Volumetric Rate	$ / kWh	0.0118
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0017
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0008
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0050
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0043
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service - Demand Billed (50 kW or greater)

Service Charge	$	24.41
Distribution Volumetric Rate	$ / kW	3.70
Regulatory Asset Recovery - Rider #1	$ / kW	0.54
Regulatory Asset Recovery - Rider #2	$ / kW	0.24
Retail Transmission Rate - Network Service Rate (4)	$ / kW	1.94
Retail Transmission Rate - Line and Transformation Connection Service Rate (4)	$ / kW	1.61
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Bancroft Public Utilities Commission
Effective Date: May 1, 2007

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

Unmetered, Scattered Load

Service Charge	$	11.73
Distribution Volumetric Rate	$ / kWh	0.0118
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0017
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0008
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0050
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0043
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

(3) For energy-only metered customers, the billing determinant is the customer's metered energy consumption adjusted by the total loss factor as approved by the Board for Acquired LDC customers.
(4) For demand billed customers, appropriate loss factors must be applied to the applicable tariffs. Also the billing determinant for the Line and Transformation Connection Services rate is the customer's peak demand in the billing period. The billing determinant for the Network Services rate is: for non-interval-metered customers, the peak demand in the billing period, and for interval-metered customers, the peak demand between 7 AM and 7 PM local time on IESO business days

Interim Demand-Side Management Time-of-Use

See the "Service Classifications" section of this schedule.

Customer-Supplied Transformation Allowance

Applicable to demand-billed customers providing their own transformers
Primary Voltage under 50 kV (per kW)

Single Phase	$ / kW	0.20
Three Phase	$ / kW	0.60

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
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Bancroft Public Utilities Commission
Effective Date: May 1, 2007

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

Loss Factors

Supply Facilities Loss Factor	1.0045
Distribution Loss Factors	
Customer less than 5,000 kW	1.0500
Customer greater than or equal to 5,000 kW	1.0100
Total Loss Factors	
Customer less than 5,000 kW	1.0545
Customer greater than or equal to 5,000 kW	1.0145

Transformer Loss Allowance

Applicable to customers requiring a billing adjustment for transformer losses as the result of being metered on the primary side of a transformer. The following uniform values shall be applied to measured demand and energy to calculate transformer losses for voltages up to and including 50 kV (as metered on the primary side):

(a) 1.5% for transformer installations up to an individual bank capacity of 400 kVA,
(b) 1.0% for bank capacities over 400 kVA.

Alternatively, transformer losses may be determined from transformer test data, and measured demand and energy adjusted accordingly

For services which are not demand metered, an assumed demand of 50% of the transformer capacity will be used to calculate the loss allowance. Where several transformers are involved, the bank capacity is assumed to be the arithmetic sum of all transformer capacities

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Bancroft Public Utilities Commission
Effective Date: May 1, 2007

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

MISCELLANEOUS CHARGES

Specific Service Charges: Standard Amounts

Rate Code	Specific Service Charge - Standard Name	Calculation Method			
		2006 Rate Handbook	Standard Formula	Other Formula	Time and Materials
1	Temporary Service	$500			
2	Dispute Meter Test	$30 plus Measurement Canada fees			
3	Collection of account – no disconnection/load limiter	$30			
4	Collection/Disconnect/load limiter/reconnect (at meter) trip – regular hours	$65			
5	Collection/Disconnect/load limiter/reconnect (at meter) trip – after regular hours	$185			
6	Collection/Disconnect/load limiter/reconnect (at pole) trip – regular hours	$185			
7	Collection/Disconnect/load limiter/reconnect (at pole) trip – after regular hours	$415			
8	Account Set-up Charge	$30			
9	Arrears Certificate	$15			
10	NSF Cheque Charge	$15 + bank charges			
11	Easement Charge for Unregistered Rights	$15			
12	Late Payment Charge	1.5%/month			
13a	Retailer Services – Establishing Service Agreements (refer to Handbook for all charges)	$100/agreement/Retailer +$20/month/Retailer +$0.50/month/customer + other			
13b	Retailer Services – Other (includes Bill Ready for Retailers and Service Transactions Requests) as per the Handbook, Chapter 12	$0.30/month/customer + $0.25/request for request fee + $0.50/request for process fee			
14	Special Meter Reads	$30			
15	Billing Suspension and Terminations in Trailer Parks		$130		
16	Service Layout Fee – Basic		$405		
17	Service Layout Fee – Complex		$580		

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Bancroft Public Utilities Commission
Effective Date: May 1, 2007

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

18	Crossing Application – Pipeline		$2,065		
19	Crossing Application – Water		$2,525		
20	Crossing Application – Railroad		$2,565		
21	Line Staking – per meter		$3.10		
22	Central Metering – New service < 45 kW		$115		
23	Conversion to Central Metering < 45 kW		$795		
24	Conversion to Central Metering > 45 kW		$680		
25	Tingle Voltage Test – In Excess of 4 Hours (per hour – average 2 additional hours)		$105		
26	Standby Administration Charge per month (interim)		$375		
27	Sentinel Lights Rental Rate per month – Mercury Vapor			$7.00	
28	Guaranteed Units from Jan 01/91 to Aug 01/91			$26.50 / month	
29	Guaranteed Units from Jan 01/87 to Dec 31/90			$23.50 / month	
30	Joint Use for Cable and Telecom companies per pole			$22.35	
31	Joint Use for LDCs per pole			$28.61	

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Bath Hydro Electric System
Effective Date: May 1, 2008

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

APPLICATION

The application of these rates and charges shall be in accordance with The Licence of The Distributor and any Codes, Guidelines or Orders of The Board, and amendments thereto as approved by The Board, which may be applicable to the administration of this schedule.
No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code, Guideline or Order of the Board, and amendments thereto as approved by the Board, or as specified herein
This schedule does not contain any rates and charges relating to the electricity commodity (e.g. the Regulated Price Plan).

EFFECTIVE DATES

DISTRIBUTION RATES - May 1, 2008 for all consumption or deemed consumption services used on or after that date.

MISCELLANEOUS CHARGES - May 1, 2008 for all charges billed to customers on or after that date.
RETAIL TRANSMISSION RATES - May 1, 2008 for all consumption or deemed consumption services used on or after that date.
LOSS FACTOR ADJUSTMENT – for all consumption or deemed consumption services billed following May 1, 2008 or later

SERVICE CLASSIFICATIONS

Residential
This classification refers to all service supplied to single-family dwelling units for domestic or household purpose. Multi-unit residential establishments such as apartment buildings supplied through one service (bulk metered) will normally be classified as General Service, but, at Hydro One's discretion, up to four residential units may be classified as residential. Where electricity service is provided to combined residential and business (including agricultural usage) and the wiring does not provide for separate metering, the classification shall be at the discretion of Hydro One based on such considerations as the estimated predominant consumption.
Further servicing details are available in the utility's Conditions of Service.

General Service
This classification refers to all service supplied to premises other than those classified as Residential or Lighting. Some General Service accounts are energy(kWh)-billed, and some are demand(kW)-billed. Further servicing details are available in the utility's Conditions of Service.

Unmetered Scattered Load
This classification refers to certain instances where connections can be provided without metering. These loads are generally small in size and consistent in magnitude of load. Hydro One reserves the right to review all cases and may require that a meter be installed at its sole discretion. Services that can be unmetered include cable TV amplifiers, telephone switching devices, phone booths, bus shelters, rail way crossing signals, traffic signals, and other small fixed loads.
Further servicing details are available in the utility's Conditions of Service (including in the "Unmetered Connections" section).

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Bath Hydro Electric System
Effective Date: May 1, 2008

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

Street Lighting

This classification refers to accounts for the distribution and supply of electrical energy for street lighting. Street lights are devices owned by or operated for the road authority and/or the municipal corporation. These street lights in fact belong to the Street Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Sentinel Lighting

This classification refers to accounts for a separate service to a sentinel light. These sentinel lights in fact belong to the Sentinel Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Urban Density Classification

Customers who meet the Urban Density Criteria of being in an area containing 3,000 or more customers with a line density of at least 60 customers per kilometre, will be mapped to an Urban customer classification.

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Bath Hydro Electric System
Effective Date: May 1, 2008

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MONTHLY RATES AND CHARGES

Residential - R1 Bath

Service Charge	$	14.42
Distribution Volumetric Rate	$ / kWh	0.0235
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0038
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0004)
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0047
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0046
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service Less Than 50 kW (Energy-Billed) - GSe Bath

Service Charge	$	15.43
Distribution Volumetric Rate	$ / kWh	0.0255
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0024
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0006)
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0035
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0032
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service 50 kW or Greater (Demand-Billed) - GSd Bath

Service Charge	$	19.03
Distribution Volumetric Rate	$ / kW	9.00
Regulatory Asset Recovery - Rider #2	$ / kW	0.63
Regulatory Asset Recovery - Rider #3	$ / kW	(0.22)
Retail Transmission Rate - Network Service Rate (4)	$ / kW	1.11
Retail Transmission Rate - Line and Transformation Connection Service Rate (4)	$ / kW	1.00
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

Hydro One Networks Inc.
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Unmetered, Scattered Load

Service Charge	$	9.16
Distribution Volumetric Rate	$ / kWh	0.0200
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0024
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0006)
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0035
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0032
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

(3) For energy-only metered customers, the billing determinant is the customer's metered energy consumption adjusted by the total loss factor as approved by the Board for Acquired LDC customers.

(4) For demand billed customers, appropriate loss factors must be applied to the applicable tariffs. Also the billing determinant for the Line and Transformation Connection Services rate is the customer's peak demand in the billing period. The billing determinant for the Network Services rate is: for non-interval-metered customers, the peak demand in the billing period, and for interval-metered customers, the peak demand between 7 AM and 7 PM local time on IESO business days

Customer-Supplied Transformation Allowance

Applicable to customers providing their own transformers

Demand-billed	$ / kW	0.60
Energy-billed	$ / kWh	0.0014

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Loss Factors

Residential	1.085
General Service Less Than 50 kW (Energy-Billed)	1.092
General Service 50 kW or Greater (Demand-Billed)	1.061
Unmetered Scattered Load	1.092

Transformer Loss Allowance

Applicable to customers requiring a billing adjustment for transformer losses as the result of being metered on the primary side of a transformer. The following uniform values shall be applied to measured demand and energy to calculate transformer losses for voltages up to and including 50 kV (as metered on the primary side):

(a) 1.5% for transformer installations up to an individual bank capacity of 400 kVA,
(b) 1.0% for bank capacities over 400 kVA.

Alternatively, transformer losses may be determined from transformer test data, and measured demand and energy adjusted accordingly

For services which are not demand metered, an assumed demand of 50% of the transformer capacity will be used to calculate the loss allowance. Where several transformers are involved, the bank capacity is assumed to be the arithmetic sum of all transformer capacities

Hydro One Networks Inc.
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Effective Date: May 1, 2008

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

MISCELLANEOUS CHARGES

Specific Service Charges: Standard Amounts

Rate Code	Specific Service Charge - Standard Name	Calculation Method			
		2006 Rate Handbook	Standard Formula	Other Formula	Time and Materials
1	Temporary Service	$500			
2	Dispute Meter Test	$30 plus Measurement Canada fees			
3	Collection of account – no disconnection/load limiter	$30			
4	Collection/Disconnect/load limiter/reconnect (at meter) trip – regular hours	$65			
5	Collection/Disconnect/load limiter/reconnect (at meter) trip – after regular hours	$185			
6	Collection/Disconnect/load limiter/reconnect (at pole) trip – regular hours	$185			
7	Collection/Disconnect/load limiter/reconnect (at pole) trip – after regular hours	$415			
8	Account Set-up Charge	$30			
9	Arrears Certificate	$15			
10	NSF Cheque Charge	$15 + bank charges			
11	Easement Charge for Unregistered Rights	$15			
12	Late Payment Charge	1.5%/month			
13a	Retailer Services – Establishing Service Agreements (refer to Handbook for all charges)	$100/agreement/Retailer +$20/month/Retailer +$0.50/month/customer + other			
13b	Retailer Services – Other (includes Bill Ready for Retailers and Service Transactions Requests) as per the Handbook, Chapter 12	$0.30/month/customer + $0.25/request for request fee + $0.50/request for process fee			
14	Special Meter Reads	$30			
15	Service Layout Fee – Basic		$495		
16	Service Layout Fee – Complex		$690		
17	Crossing Application – Pipeline		$2,445		
18	Crossing Application – Water		$3,045		
19	Crossing Application – Railroad		$2,945		
20	Line Staking – per meter		$3.70		
21	Central Metering – New service < 45 kW		$115		
22	Conversion to Central Metering < 45 kW		$915		
23	Conversion to Central Metering > 45 kW		$800		
24	Tingle Voltage Test – In Excess of 4 Hours (per hour – average 2 additional hours)		$125		
25	Standby Administration Charge per month		$440		
26	Sentinel Lights Rental Rate per month			$7.10	
27	Sentinel Pole Rental Rate per month			$4.15	
28	Joint Use for Cable and Telecom companies per pole			$22.35	
29	Joint Use for LDCs per pole			$28.61	

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Bath Hydro Electric System
Effective Date: May 1, 2007

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

APPLICATION

The application of these rates and charges shall be in accordance with The Licence of The Distributor and any Codes, Guidelines or Orders of The Board, and amendments thereto as approved by The Board, which may be applicable to the administration of this schedule.
No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code, Guideline or Order of the Board, and amendments thereto as approved by the Board, or as specified herein
This schedule does not contain any rates and charges relating to the electricity commodity (e.g. the Regulated Price Plan).

EFFECTIVE DATES

DISTRIBUTION RATES - May 1, 2007 for all consumption or deemed consumption services used on or after that date.

MISCELLANEOUS CHARGES - May 1, 2007 for all charges billed to customers on or after that date.
RETAIL TRANSMISSION RATES - May 1, 2007 for all consumption or deemed consumption services used on or after that date.
LOSS FACTOR ADJUSTMENT – May 1, 2007

SERVICE CLASSIFICATIONS

Residential
This classification (note 1) refers to all service supplied to single-family dwelling units for domestic or household purpose. Multi-unit residential establishments such as apartment buildings supplied through one service (bulk metered) will normally be classified as General Service, but, at Hydro One’s discretion, up to four residential units may be classified as residential. Where electricity service is provided to combined residential and business (including agricultural usage) and the wiring does not provide for separate metering, the classification shall be at the discretion of Hydro One based on such considerations as the estimated predominant consumption.
Further servicing details are available in the utility’s Conditions of Service.

General Service
This classification (note 1) refers to all service supplied to premises other than those classified as Residential or Lighting. Some General Service accounts are energy(kWh)-billed, and some are demand(kW)-billed. Further servicing details are available in the utility’s Conditions of Service. Also, see note 2.

Unmetered Scattered Load
This classification refers to certain instances where connections can be provided without metering. These loads are generally small in size and consistent in magnitude of load. Hydro One reserves the right to review all cases and may require that a meter be installed at its sole discretion. Services that can be unmetered include cable TV amplifiers, telephone switching devices, phone booths, bus shelters, rail way crossing signals, traffic signals, and other small fixed loads.
Further servicing details are available in the utility’s Conditions of Service (including in the "Unmetered Connections" section).

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
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Bath Hydro Electric System
Effective Date: May 1, 2007

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

Street Lighting

This classification refers to accounts for the distribution and supply of electrical energy for street lighting. Street lights are devices owned by or operated for the road authority and/or the municipal corporation. These street lights in fact belong to the Street Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Sentinel Lighting

This classification refers to accounts for a separate service to a sentinel light. These sentinel lights in fact belong to the Sentinel Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Interim Demand-Side Management Time-of-Use

This is potentially applicable to Demand-billed General Service accounts. See Note 2 below.

Note (1): Classification descriptions are paraphrases from the document "Hydro One Networks Inc. - Distribution Customers Conditions of Service - August 2004"

Note (2):

Interim Demand-Side Management Time-of-Use Rates: demand charges will be based on demand during the on-peak periods.

Criteria: Customers' electricity consumption (kW) in the off-peak period is at least twice the electricity consumption (kW) during the on-peak period.

Definition of Time Periods: The on-peak hours will be between 0700 hours to 1900 hours Eastern Standard Time during the winter (standard time) on IESO business days and 0600 hours to 1800 hours Eastern Standard Time during the summer (daylight savings time) on IESO business days. The off-peak period constitutes all of the remaining hours.

Hydro One Networks Inc.
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MONTHLY RATES AND CHARGES

Residential

Service Charge	$	13.38
Distribution Volumetric Rate	$ / kWh	0.0086
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0068
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0038
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0055
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0047
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service - Energy Billed (less than 50 kW)

Service Charge	$	10.65
Distribution Volumetric Rate	$ / kWh	0.0147
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0029
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0024
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0050
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0043
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service - Demand Billed (50 kW or greater)

Service Charge	$	10.65
Distribution Volumetric Rate	$ / kW	3.77
Regulatory Asset Recovery - Rider #1	$ / kW	0.93
Regulatory Asset Recovery - Rider #2	$ / kW	0.63
Retail Transmission Rate - Network Service Rate (4)	$ / kW	1.94
Retail Transmission Rate - Line and Transformation Connection Service Rate (4)	$ / kW	1.61
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

Hydro One Networks Inc.
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Unmetered, Scattered Load

Service Charge	$	4.86
Distribution Volumetric Rate	$ / kWh	0.0147
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0029
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0024
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0050
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0043
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

(3) For energy-only metered customers, the billing determinant is the customer's metered energy consumption adjusted by the total loss factor as approved by the Board for Acquired LDC customers.
(4) For demand billed customers, appropriate loss factors must be applied to the applicable tariffs. Also the billing determinant for the Line and Transformation Connection Services rate is the customer's peak demand in the billing period. The billing determinant for the Network Services rate is: for non-interval-metered customers, the peak demand in the billing period, and for interval-metered customers, the peak demand between 7 AM and 7 PM local time on IESO business days

Interim Demand-Side Management Time-of-Use

See the "Service Classifications" section of this schedule.

Customer-Supplied Transformation Allowance

Applicable to demand-billed customers providing their own transformers
Primary Voltage under 50 kV (per kW)

Single Phase	$ / kW	0.20
Three Phase	$ / kW	0.60

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Loss Factors

Supply Facilities Loss Factor	1.0045
Distribution Loss Factors	
Customer less than 5,000 kW	1.0500
Customer greater than or equal to 5,000 kW	1.0100
Total Loss Factors	
Customer less than 5,000 kW	1.0545
Customer greater than or equal to 5,000 kW	1.0145

Transformer Loss Allowance

Applicable to customers requiring a billing adjustment for transformer losses as the result of being metered on the primary side of a transformer. The following uniform values shall be applied to measured demand and energy to calculate transformer losses for voltages up to and including 50 kV (as metered on the primary side):

(a) 1.5% for transformer installations up to an individual bank capacity of 400 kVA,
(b) 1.0% for bank capacities over 400 kVA.

Alternatively, transformer losses may be determined from transformer test data, and measured demand and energy adjusted accordingly

For services which are not demand metered, an assumed demand of 50% of the transformer capacity will be used to calculate the loss allowance. Where several transformers are involved, the bank capacity is assumed to be the arithmetic sum of all transformer capacities

Hydro One Networks Inc.
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Bath Hydro Electric System
Effective Date: May 1, 2007

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MISCELLANEOUS CHARGES

Specific Service Charges: Standard Amounts

Rate Code	Specific Service Charge - Standard Name	Calculation Method			
		2006 Rate Handbook	Standard Formula	Other Formula	Time and Materials
1	Temporary Service	$500			
2	Dispute Meter Test	$30 plus Measurement Canada fees			
3	Collection of account – no disconnection/load limiter	$30			
4	Collection/Disconnect/load limiter/reconnect (at meter) trip – regular hours	$65			
5	Collection/Disconnect/load limiter/reconnect (at meter) trip – after regular hours	$185			
6	Collection/Disconnect/load limiter/reconnect (at pole) trip – regular hours	$185			
7	Collection/Disconnect/load limiter/reconnect (at pole) trip – after regular hours	$415			
8	Account Set-up Charge	$30			
9	Arrears Certificate	$15			
10	NSF Cheque Charge	$15 + bank charges			
11	Easement Charge for Unregistered Rights	$15			
12	Late Payment Charge	1.5%/month			
13a	Retailer Services – Establishing Service Agreements (refer to Handbook for all charges)	$100/agreement/Retailer +$20/month/Retailer +$0.50/month/customer + other			
13b	Retailer Services – Other (includes Bill Ready for Retailers and Service Transactions Requests) as per the Handbook, Chapter 12	$0.30/month/customer + $0.25/request for request fee + $0.50/request for process fee			
14	Special Meter Reads	$30			
15	Billing Suspension and Terminations in Trailer Parks		$130		
16	Service Layout Fee – Basic		$405		
17	Service Layout Fee – Complex		$580		

Hydro One Networks Inc.
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Effective Date: May 1, 2007

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

18	Crossing Application – Pipeline		$2,065		
19	Crossing Application – Water		$2,525		
20	Crossing Application – Railroad		$2,565		
21	Line Staking – per meter		$3.10		
22	Central Metering – New service < 45 kW		$115		
23	Conversion to Central Metering < 45 kW		$795		
24	Conversion to Central Metering > 45 kW		$680		
25	Tingle Voltage Test – In Excess of 4 Hours (per hour – average 2 additional hours)		$105		
26	Standby Administration Charge per month (interim)		$375		
27	Sentinel Lights Rental Rate per month – Mercury Vapor			$7.00	
28	Guaranteed Units from Jan 01/91 to Aug 01/91			$26.50 / month	
29	Guaranteed Units from Jan 01/87 to Dec 31/90			$23.50 / month	
30	Joint Use for Cable and Telecom companies per pole			$22.35	
31	Joint Use for LDCs per pole			$28.61	

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Blandford-Blenheim Public Utilities Commission
Effective Date: May 1, 2008

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

APPLICATION

The application of these rates and charges shall be in accordance with The Licence of The Distributor and any Codes, Guidelines or Orders of The Board, and amendments thereto as approved by The Board, which may be applicable to the administration of this schedule.
No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code, Guideline or Order of the Board, and amendments thereto as approved by the Board, or as specified herein
This schedule does not contain any rates and charges relating to the electricity commodity (e.g. the Regulated Price Plan).

EFFECTIVE DATES

DISTRIBUTION RATES - May 1, 2008 for all consumption or deemed consumption services used on or after that date.

MISCELLANEOUS CHARGES - May 1, 2008 for all charges billed to customers on or after that date.
RETAIL TRANSMISSION RATES - May 1, 2008 for all consumption or deemed consumption services used on or after that date.
LOSS FACTOR ADJUSTMENT – for all consumption or deemed consumption services billed following May 1, 2008 or later

SERVICE CLASSIFICATIONS

Residential
This classification refers to all service supplied to single-family dwelling units for domestic or household purpose. Multi-unit residential establishments such as apartment buildings supplied through one service (bulk metered) will normally be classified as General Service, but, at Hydro One's discretion, up to four residential units may be classified as residential. Where electricity service is provided to combined residential and business (including agricultural usage) and the wiring does not provide for separate metering, the classification shall be at the discretion of Hydro One based on such considerations as the estimated predominant consumption.
Further servicing details are available in the utility's Conditions of Service.

General Service
This classification refers to all service supplied to premises other than those classified as Residential or Lighting. Some General Service accounts are energy(kWh)-billed, and some are demand(kW)-billed. Further servicing details are available in the utility's Conditions of Service.

Unmetered Scattered Load
This classification refers to certain instances where connections can be provided without metering. These loads are generally small in size and consistent in magnitude of load. Hydro One reserves the right to review all cases and may require that a meter be installed at its sole discretion. Services that can be unmetered include cable TV amplifiers, telephone switching devices, phone booths, bus shelters, rail way crossing signals, traffic signals, and other small fixed loads.
Further servicing details are available in the utility's Conditions of Service (including in the "Unmetered Connections" section).

Hydro One Networks Inc.
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Effective Date: May 1, 2008

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

Street Lighting

This classification refers to accounts for the distribution and supply of electrical energy for street lighting. Street lights are devices owned by or operated for the road authority and/or the municipal corporation. These street lights in fact belong to the Street Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Sentinel Lighting

This classification refers to accounts for a separate service to a sentinel light. These sentinel lights in fact belong to the Sentinel Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Urban Density Classification

Customers who meet the Urban Density Criteria of being in an area containing 3,000 or more customers with a line density of at least 60 customers per kilometre, will be mapped to an Urban customer classification.

Hydro One Networks Inc.
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Effective Date: May 1, 2008

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

MONTHLY RATES AND CHARGES

Residential - R1 Blandford-Blenheim

Service Charge	$	12.85
Distribution Volumetric Rate	$ / kWh	0.0230
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0033
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0004)
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0047
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0046
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service Less Than 50 kW (Energy-Billed) - GSe Blandford-Blenheim

Service Charge	$	25.13
Distribution Volumetric Rate	$ / kWh	0.0240
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0020
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0006)
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0035
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0032
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service 50 kW or Greater (Demand-Billed) - GSd Blandford-Blenheim

Service Charge	$	28.73
Distribution Volumetric Rate	$ / kW	8.90
Regulatory Asset Recovery - Rider #2	$ / kW	0.65
Regulatory Asset Recovery - Rider #3	$ / kW	(0.22)
Retail Transmission Rate - Network Service Rate (4)	$ / kW	1.11
Retail Transmission Rate - Line and Transformation Connection Service Rate (4)	$ / kW	1.00
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
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Blandford-Blenheim Public Utilities Commission
Effective Date: May 1, 2008

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

Unmetered, Scattered Load

Service Charge	$	14.51
Distribution Volumetric Rate	$ / kWh	0.0200
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0020
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0006)
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0035
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0032
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

(3) For energy-only metered customers, the billing determinant is the customer’s metered energy consumption adjusted by the total loss factor as approved by the Board for Acquired LDC customers.
(4) For demand billed customers, appropriate loss factors must be applied to the applicable tariffs. Also the billing determinant for the Line and Transformation Connection Services rate is the customer’s peak demand in the billing period. The billing determinant for the Network Services rate is: for non-interval-metered customers, the peak demand in the billing period, and for interval-metered customers, the peak demand between 7 AM and 7 PM local time on IESO business days

Customer-Supplied Transformation Allowance

Applicable to customers providing their own transformers		
Demand-billed	$ / kW	0.60
Energy-billed	$ / kWh	0.0014

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
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Blandford-Blenheim Public Utilities Commission
Effective Date: May 1, 2008

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

Loss Factors

Residential	1.085
General Service Less Than 50 kW (Energy-Billed)	1.092
General Service 50 kW or Greater (Demand-Billed)	1.061
Unmetered Scattered Load	1.092

Transformer Loss Allowance

Applicable to customers requiring a billing adjustment for transformer losses as the result of being metered on the primary side of a transformer. The following uniform values shall be applied to measured demand and energy to calculate transformer losses for voltages up to and including 50 kV (as metered on the primary side):

(a) 1.5% for transformer installations up to an individual bank capacity of 400 kVA,
(b) 1.0% for bank capacities over 400 kVA.

Alternatively, transformer losses may be determined from transformer test data, and measured demand and energy adjusted accordingly

For services which are not demand metered, an assumed demand of 50% of the transformer capacity will be used to calculate the loss allowance. Where several transformers are involved, the bank capacity is assumed to be the arithmetic sum of all transformer capacities

Hydro One Networks Inc.
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MISCELLANEOUS CHARGES

Specific Service Charges: Standard Amounts

Rate Code	Specific Service Charge - Standard Name	Calculation Method			
		2006 Rate Handbook	Standard Formula	Other Formula	Time and Materials
1	Temporary Service	$500			
2	Dispute Meter Test	$30 plus Measurement Canada fees			
3	Collection of account – no disconnection/load limiter	$30			
4	Collection/Disconnect/load limiter/reconnect (at meter) trip – regular hours	$65			
5	Collection/Disconnect/load limiter/reconnect (at meter) trip – after regular hours	$185			
6	Collection/Disconnect/load limiter/reconnect (at pole) trip – regular hours	$185			
7	Collection/Disconnect/load limiter/reconnect (at pole) trip – after regular hours	$415			
8	Account Set-up Charge	$30			
9	Arrears Certificate	$15			
10	NSF Cheque Charge	$15 + bank charges			
11	Easement Charge for Unregistered Rights	$15			
12	Late Payment Charge	1.5%/month			
13a	Retailer Services – Establishing Service Agreements (refer to Handbook for all charges)	$100/agreement/Retailer +$20/month/Retailer +$0.50/month/customer + other			
13b	Retailer Services – Other (includes Bill Ready for Retailers and Service Transactions Requests) as per the Handbook, Chapter 12	$0.30/month/customer + $0.25/request for request fee + $0.50/request for process fee			
14	Special Meter Reads	$30			
15	Service Layout Fee – Basic		$495		
16	Service Layout Fee – Complex		$690		
17	Crossing Application – Pipeline		$2,445		
18	Crossing Application – Water		$3,045		
19	Crossing Application – Railroad		$2,945		
20	Line Staking – per meter		$3.70		
21	Central Metering – New service < 45 kW		$115		
22	Conversion to Central Metering < 45 kW		$915		
23	Conversion to Central Metering > 45 kW		$800		
24	Tingle Voltage Test – In Excess of 4 Hours (per hour – average 2 additional hours)		$125		
25	Standby Administration Charge per month		$440		
26	Sentinel Lights Rental Rate per month			$7.10	
27	Sentinel Pole Rental Rate per month			$4.15	
28	Joint Use for Cable and Telecom companies per pole			$22.35	
29	Joint Use for LDCs per pole			$28.61	

Hydro One Networks Inc.
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Effective Date: May 1, 2007

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

APPLICATION

The application of these rates and charges shall be in accordance with The Licence of The Distributor and any Codes, Guidelines or Orders of The Board, and amendments thereto as approved by The Board, which may be applicable to the administration of this schedule.
No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code, Guideline or Order of the Board, and amendments thereto as approved by the Board, or as specified herein
This schedule does not contain any rates and charges relating to the electricity commodity (e.g. the Regulated Price Plan).

EFFECTIVE DATES

DISTRIBUTION RATES - May 1, 2007 for all consumption or deemed consumption services used on or after that date.

MISCELLANEOUS CHARGES - May 1, 2007 for all charges billed to customers on or after that date.
RETAIL TRANSMISSION RATES - May 1, 2007 for all consumption or deemed consumption services used on or after that date.
LOSS FACTOR ADJUSTMENT – May 1, 2007

SERVICE CLASSIFICATIONS

Residential
This classification (note 1) refers to all service supplied to single-family dwelling units for domestic or household purpose. Multi-unit residential establishments such as apartment buildings supplied through one service (bulk metered) will normally be classified as General Service, but, at Hydro One's discretion, up to four residential units may be classified as residential. Where electricity service is provided to combined residential and business (including agricultural usage) and the wiring does not provide for separate metering, the classification shall be at the discretion of Hydro One based on such considerations as the estimated predominant consumption.
Further servicing details are available in the utility's Conditions of Service.

General Service
This classification (note 1) refers to all service supplied to premises other than those classified as Residential or Lighting. Some General Service accounts are energy(kWh)-billed, and some are demand(kW)-billed. Further servicing details are available in the utility's Conditions of Service. Also, see note 2.

Unmetered Scattered Load
This classification refers to certain instances where connections can be provided without metering. These loads are generally small in size and consistent in magnitude of load. Hydro One reserves the right to review all cases and may require that a meter be installed at its sole discretion. Services that can be unmetered include cable TV amplifiers, telephone switching devices, phone booths, bus shelters, rail way crossing signals, traffic signals, and other small fixed loads.
Further servicing details are available in the utility's Conditions of Service (including in the "Unmetered Connections" section).

Hydro One Networks Inc.
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Street Lighting

This classification refers to accounts for the distribution and supply of electrical energy for street lighting. Street lights are devices owned by or operated for the road authority and/or the municipal corporation. These street lights in fact belong to the Street Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Sentinel Lighting

This classification refers to accounts for a separate service to a sentinel light. These sentinel lights in fact belong to the Sentinel Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Interim Demand-Side Management Time-of-Use

This is potentially applicable to Demand-billed General Service accounts. See Note 2 below.

Note (1): Classification descriptions are paraphrases from the document "Hydro One Networks Inc. - Distribution Customers Conditions of Service - August 2004"

Note (2):

Interim Demand-Side Management Time-of-Use Rates: demand charges will be based on demand during the on-peak periods.

Criteria: Customers' electricity consumption (kW) in the off-peak period is at least twice the electricity consumption (kW) during the on-peak period.

Definition of Time Periods: The on-peak hours will be between 0700 hours to 1900 hours Eastern Standard Time during the winter (standard time) on IESO business days and 0600 hours to 1800 hours Eastern Standard Time during the summer (daylight savings time) on IESO business days. The off-peak period constitutes all of the remaining hours.

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MONTHLY RATES AND CHARGES

Residential

Service Charge	$	11.63
Distribution Volumetric Rate	$ / kWh	0.0090
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0063
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0033
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0055
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0047
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service - Energy Billed (less than 50 kW)

Service Charge	$	23.85
Distribution Volumetric Rate	$ / kWh	0.0114
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0028
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0020
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0050
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0043
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service - Demand Billed (50 kW or greater)

Service Charge	$	23.85
Distribution Volumetric Rate	$ / kW	3.63
Regulatory Asset Recovery - Rider #1	$ / kW	0.91
Regulatory Asset Recovery - Rider #2	$ / kW	0.65
Retail Transmission Rate - Network Service Rate (4)	$ / kW	1.94
Retail Transmission Rate - Line and Transformation Connection Service Rate (4)	$ / kW	1.61
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

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Unmetered, Scattered Load

Service Charge	$	11.46
Distribution Volumetric Rate	$ / kWh	0.0114
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0028
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0020
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0050
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0043
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

(3) For energy-only metered customers, the billing determinant is the customer’s metered energy consumption adjusted by the total loss factor as approved by the Board for Acquired LDC customers.

(4) For demand billed customers, appropriate loss factors must be applied to the applicable tariffs. Also the billing determinant for the Line and Transformation Connection Services rate is the customer’s peak demand in the billing period. The billing determinant for the Network Services rate is: for non-interval-metered customers, the peak demand in the billing period, and for interval-metered customers, the peak demand between 7 AM and 7 PM local time on IESO business days

Interim Demand-Side Management Time-of-Use

See the "Service Classifications" section of this schedule.

Customer-Supplied Transformation Allowance

Applicable to demand-billed customers providing their own transformers
Primary Voltage under 50 kV (per kW)

Single Phase	$ / kW	0.20
Three Phase	$ / kW	0.60

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Loss Factors

Supply Facilities Loss Factor	1.0045
Distribution Loss Factors	
Customer less than 5,000 kW	1.0500
Customer greater than or equal to 5,000 kW	1.0100
Total Loss Factors	
Customer less than 5,000 kW	1.0545
Customer greater than or equal to 5,000 kW	1.0145

Transformer Loss Allowance

Applicable to customers requiring a billing adjustment for transformer losses as the result of being metered on the primary side of a transformer. The following uniform values shall be applied to measured demand and energy to calculate transformer losses for voltages up to and including 50 kV (as metered on the primary side):

(a) 1.5% for transformer installations up to an individual bank capacity of 400 kVA,
(b) 1.0% for bank capacities over 400 kVA.

Alternatively, transformer losses may be determined from transformer test data, and measured demand and energy adjusted accordingly

For services which are not demand metered, an assumed demand of 50% of the transformer capacity will be used to calculate the loss allowance. Where several transformers are involved, the bank capacity is assumed to be the arithmetic sum of all transformer capacities

Hydro One Networks Inc.
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MISCELLANEOUS CHARGES

Specific Service Charges: Standard Amounts

Rate Code	Specific Service Charge - Standard Name	Calculation Method			
		2006 Rate Handbook	Standard Formula	Other Formula	Time and Materials
1	Temporary Service	$500			
2	Dispute Meter Test	$30 plus Measurement Canada fees			
3	Collection of account – no disconnection/load limiter	$30			
4	Collection/Disconnect/load limiter/reconnect (at meter) trip – regular hours	$65			
5	Collection/Disconnect/load limiter/reconnect (at meter) trip – after regular hours	$185			
6	Collection/Disconnect/load limiter/reconnect (at pole) trip – regular hours	$185			
7	Collection/Disconnect/load limiter/reconnect (at pole) trip – after regular hours	$415			
8	Account Set-up Charge	$30			
9	Arrears Certificate	$15			
10	NSF Cheque Charge	$15 + bank charges			
11	Easement Charge for Unregistered Rights	$15			
12	Late Payment Charge	1.5%/month			
13a	Retailer Services – Establishing Service Agreements (refer to Handbook for all charges)	$100/agreement/Retailer +$20/month/Retailer +$0.50/month/customer + other			
13b	Retailer Services – Other (includes Bill Ready for Retailers and Service Transactions Requests) as per the Handbook, Chapter 12	$0.30/month/customer + $0.25/request for request fee + $0.50/request for process fee			
14	Special Meter Reads	$30			
15	Billing Suspension and Terminations in Trailer Parks		$130		
16	Service Layout Fee – Basic		$405		
17	Service Layout Fee – Complex		$580		

Hydro One Networks Inc.
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18	Crossing Application – Pipeline		$2,065		
19	Crossing Application – Water		$2,525		
20	Crossing Application – Railroad		$2,565		
21	Line Staking – per meter		$3.10		
22	Central Metering – New service < 45 kW		$115		
23	Conversion to Central Metering < 45 kW		$795		
24	Conversion to Central Metering > 45 kW		$680		
25	Tingle Voltage Test – In Excess of 4 Hours (per hour – average 2 additional hours)		$105		
26	Standby Administration Charge per month (interim)		$375		
27	Sentinel Lights Rental Rate per month – Mercury Vapor			$7.00	
28	Guaranteed Units from Jan 01/91 to Aug 01/91			$26.50 / month	
29	Guaranteed Units from Jan 01/87 to Dec 31/90			$23.50 / month	
30	Joint Use for Cable and Telecom companies per pole			$22.35	
31	Joint Use for LDCs per pole			$28.61	

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
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Hydro-Electric Commission of the Village of Blyth
Effective Date: May 1, 2008

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APPLICATION

The application of these rates and charges shall be in accordance with The Licence of The Distributor and any Codes, Guidelines or Orders of The Board, and amendments thereto as approved by The Board, which may be applicable to the administration of this schedule.
No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code, Guideline or Order of the Board, and amendments thereto as approved by the Board, or as specified herein
This schedule does not contain any rates and charges relating to the electricity commodity (e.g. the Regulated Price Plan).

EFFECTIVE DATES

DISTRIBUTION RATES - May 1, 2008 for all consumption or deemed consumption services used on or after that date.

MISCELLANEOUS CHARGES - May 1, 2008 for all charges billed to customers on or after that date.
RETAIL TRANSMISSION RATES - May 1, 2008 for all consumption or deemed consumption services used on or after that date.
LOSS FACTOR ADJUSTMENT – for all consumption or deemed consumption services billed following May 1, 2008 or later

SERVICE CLASSIFICATIONS

Residential
This classification refers to all service supplied to single-family dwelling units for domestic or household purpose. Multi-unit residential establishments such as apartment buildings supplied through one service (bulk metered) will normally be classified as General Service, but, at Hydro One's discretion, up to four residential units may be classified as residential. Where electricity service is provided to combined residential and business (including agricultural usage) and the wiring does not provide for separate metering, the classification shall be at the discretion of Hydro One based on such considerations as the estimated predominant consumption.
Further servicing details are available in the utility's Conditions of Service.

General Service
This classification refers to all service supplied to premises other than those classified as Residential or Lighting. Some General Service accounts are energy(kWh)-billed, and some are demand(kW)-billed. Further servicing details are available in the utility's Conditions of Service.

Unmetered Scattered Load
This classification refers to certain instances where connections can be provided without metering. These loads are generally small in size and consistent in magnitude of load. Hydro One reserves the right to review all cases and may require that a meter be installed at its sole discretion. Services that can be unmetered include cable TV amplifiers, telephone switching devices, phone booths, bus shelters, rail way crossing signals, traffic signals, and other small fixed loads.
Further servicing details are available in the utility's Conditions of Service (including in the "Unmetered Connections" section).

Hydro One Networks Inc.
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Street Lighting

This classification refers to accounts for the distribution and supply of electrical energy for street lighting. Street lights are devices owned by or operated for the road authority and/or the municipal corporation. These street lights in fact belong to the Street Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Sentinel Lighting

This classification refers to accounts for a separate service to a sentinel light. These sentinel lights in fact belong to the Sentinel Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Urban Density Classification

Customers who meet the Urban Density Criteria of being in an area containing 3,000 or more customers with a line density of at least 60 customers per kilometre, will be mapped to an Urban customer classification.

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MONTHLY RATES AND CHARGES

Residential - R1 Blyth

Service Charge	$	9.96
Distribution Volumetric Rate	$ / kWh	0.0200
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0027
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0004)
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0047
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0046
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service Less Than 50 kW (Energy-Billed) - GSe Blyth

Service Charge	$	23.68
Distribution Volumetric Rate	$ / kWh	0.0220
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0020
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0006)
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0035
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0032
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service 50 kW or Greater (Demand-Billed) - GSd Blyth

Service Charge	$	27.28
Distribution Volumetric Rate	$ / kW	8.50
Regulatory Asset Recovery - Rider #2	$ / kW	0.64
Regulatory Asset Recovery - Rider #3	$ / kW	(0.22)
Retail Transmission Rate - Network Service Rate (4)	$ / kW	1.11
Retail Transmission Rate - Line and Transformation Connection Service Rate (4)	$ / kW	1.00
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

Hydro One Networks Inc.

TARIFF OF RATES AND CHARGES

for the Service Area Formerly Served by

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Unmetered, Scattered Load

Service Charge	$	13.79
Distribution Volumetric Rate	$ / kWh	0.0200
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0020
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0006)
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0035
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0032
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

(3) For energy-only metered customers, the billing determinant is the customer's metered energy consumption adjusted by the total loss factor as approved by the Board for Acquired LDC customers.

(4) For demand billed customers, appropriate loss factors must be applied to the applicable tariffs. Also the billing determinant for the Line and Transformation Connection Services rate is the customer's peak demand in the billing period. The billing determinant for the Network Services rate is: for non-interval-metered customers, the peak demand in the billing period, and for interval-metered customers, the peak demand between 7 AM and 7 PM local time on IESO business days

Customer-Supplied Transformation Allowance

Applicable to customers providing their own transformers		
Demand-billed	$ / kW	0.60
Energy-billed	$ / kWh	0.0014

Hydro One Networks Inc.
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Loss Factors

Residential	1.085
General Service Less Than 50 kW (Energy-Billed)	1.092
General Service 50 kW or Greater (Demand-Billed)	1.061
Unmetered Scattered Load	1.092

Transformer Loss Allowance

Applicable to customers requiring a billing adjustment for transformer losses as the result of being metered on the primary side of a transformer. The following uniform values shall be applied to measured demand and energy to calculate transformer losses for voltages up to and including 50 kV (as metered on the primary side):

(a) 1.5% for transformer installations up to an individual bank capacity of 400 kVA,
(b) 1.0% for bank capacities over 400 kVA.

Alternatively, transformer losses may be determined from transformer test data, and measured demand and energy adjusted accordingly
For services which are not demand metered, an assumed demand of 50% of the transformer capacity will be used to calculate the loss allowance. Where several transformers are involved, the bank capacity is assumed to be the arithmetic sum of all transformer capacities

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MISCELLANEOUS CHARGES

Specific Service Charges: Standard Amounts

Rate Code	Specific Service Charge - Standard Name	Calculation Method			
		2006 Rate Handbook	Standard Formula	Other Formula	Time and Materials
1	Temporary Service	$500			
2	Dispute Meter Test	$30 plus Measurement Canada fees			
3	Collection of account – no disconnection/load limiter	$30			
4	Collection/Disconnect/load limiter/reconnect (at meter) trip – regular hours	$65			
5	Collection/Disconnect/load limiter/reconnect (at meter) trip – after regular hours	$185			
6	Collection/Disconnect/load limiter/reconnect (at pole) trip – regular hours	$185			
7	Collection/Disconnect/load limiter/reconnect (at pole) trip – after regular hours	$415			
8	Account Set-up Charge	$30			
9	Arrears Certificate	$15			
10	NSF Cheque Charge	$15 + bank charges			
11	Easement Charge for Unregistered Rights	$15			
12	Late Payment Charge	1.5%/month			
13a	Retailer Services – Establishing Service Agreements (refer to Handbook for all charges)	$100/agreement/Retailer +$20/month/Retailer +$0.50/month/customer + other			
13b	Retailer Services – Other (includes Bill Ready for Retailers and Service Transactions Requests) as per the Handbook, Chapter 12	$0.30/month/customer + $0.25/request for request fee + $0.50/request for process fee			
14	Special Meter Reads	$30			
15	Service Layout Fee – Basic		$495		
16	Service Layout Fee – Complex		$690		
17	Crossing Application – Pipeline		$2,445		
18	Crossing Application – Water		$3,045		
19	Crossing Application – Railroad		$2,945		
20	Line Staking – per meter		$3.70		
21	Central Metering – New service < 45 kW		$115		
22	Conversion to Central Metering < 45 kW		$915		
23	Conversion to Central Metering > 45 kW		$800		
24	Tingle Voltage Test – In Excess of 4 Hours (per hour – average 2 additional hours)		$125		
25	Standby Administration Charge per month		$440		
26	Sentinel Lights Rental Rate per month			$7.10	
27	Sentinel Pole Rental Rate per month			$4.15	
28	Joint Use for Cable and Telecom companies per pole			$22.35	
29	Joint Use for LDCs per pole			$28.61	

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TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Hydro-Electric Commission of the Village of Blyth
Effective Date: May 1, 2007

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

APPLICATION

The application of these rates and charges shall be in accordance with The Licence of The Distributor and any Codes, Guidelines or Orders of The Board, and amendments thereto as approved by The Board, which may be applicable to the administration of this schedule.
No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code, Guideline or Order of the Board, and amendments thereto as approved by the Board, or as specified herein
This schedule does not contain any rates and charges relating to the electricity commodity (e.g. the Regulated Price Plan).

EFFECTIVE DATES

DISTRIBUTION RATES - May 1, 2007 for all consumption or deemed consumption services used on or after that date.

MISCELLANEOUS CHARGES - May 1, 2007 for all charges billed to customers on or after that date.
RETAIL TRANSMISSION RATES - May 1, 2007 for all consumption or deemed consumption services used on or after that date.
LOSS FACTOR ADJUSTMENT – May 1, 2007

SERVICE CLASSIFICATIONS

Residential
This classification (note 1) refers to all service supplied to single-family dwelling units for domestic or household purpose. Multi-unit residential establishments such as apartment buildings supplied through one service (bulk metered) will normally be classified as General Service, but, at Hydro One's discretion, up to four residential units may be classified as residential. Where electricity service is provided to combined residential and business (including agricultural usage) and the wiring does not provide for separate metering, the classification shall be at the discretion of Hydro One based on such considerations as the estimated predominant consumption.
Further servicing details are available in the utility's Conditions of Service.

General Service
This classification (note 1) refers to all service supplied to premises other than those classified as Residential or Lighting. Some General Service accounts are energy(kWh)-billed, and some are demand(kW)-billed. Further servicing details are available in the utility's Conditions of Service. Also, see note 2.

Unmetered Scattered Load
This classification refers to certain instances where connections can be provided without metering. These loads are generally small in size and consistent in magnitude of load. Hydro One reserves the right to review all cases and may require that a meter be installed at its sole discretion. Services that can be unmetered include cable TV amplifiers, telephone switching devices, phone booths, bus shelters, rail way crossing signals, traffic signals, and other small fixed loads.
Further servicing details are available in the utility's Conditions of Service (including in the "Unmetered Connections" section).

Hydro One Networks Inc.
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Hydro-Electric Commission of the Village of Blyth
Effective Date: May 1, 2007

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Street Lighting

This classification refers to accounts for the distribution and supply of electrical energy for street lighting. Street lights are devices owned by or operated for the road authority and/or the municipal corporation. These street lights in fact belong to the Street Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Sentinel Lighting

This classification refers to accounts for a separate service to a sentinel light. These sentinel lights in fact belong to the Sentinel Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Interim Demand-Side Management Time-of-Use

This is potentially applicable to Demand-billed General Service accounts. See Note 2 below.

Note (1): Classification descriptions are paraphrases from the document "Hydro One Networks Inc. - Distribution Customers Conditions of Service - August 2004"

Note (2):

Interim Demand-Side Management Time-of-Use Rates: demand charges will be based on demand during the on-peak periods.

Criteria: Customers' electricity consumption (kW) in the off-peak period is at least twice the electricity consumption (kW) during the on-peak period.

Definition of Time Periods: The on-peak hours will be between 0700 hours to 1900 hours Eastern Standard Time during the winter (standard time) on IESO business days and 0600 hours to 1800 hours Eastern Standard Time during the summer (daylight savings time) on IESO business days. The off-peak period constitutes all of the remaining hours.

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
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Effective Date: May 1, 2007

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MONTHLY RATES AND CHARGES

Residential

Service Charge	$	7.19
Distribution Volumetric Rate	$ / kWh	0.0091
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0054
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0027
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0055
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0047
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service - Energy Billed (less than 50 kW)

Service Charge	$	21.63
Distribution Volumetric Rate	$ / kWh	0.0105
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0026
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0020
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0050
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0043
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service - Demand Billed (50 kW or greater)

Service Charge	$	21.63
Distribution Volumetric Rate	$ / kW	3.37
Regulatory Asset Recovery - Rider #1	$ / kW	0.82
Regulatory Asset Recovery - Rider #2	$ / kW	0.64
Retail Transmission Rate - Network Service Rate (4)	$ / kW	1.94
Retail Transmission Rate - Line and Transformation Connection Service Rate (4)	$ / kW	1.61
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
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Effective Date: May 1, 2007

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Unmetered, Scattered Load

Service Charge	$	10.35
Distribution Volumetric Rate	$ / kWh	0.0105
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0026
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0020
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0050
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0043
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

(3) For energy-only metered customers, the billing determinant is the customer’s metered energy consumption adjusted by the total loss factor as approved by the Board for Acquired LDC customers.
(4) For demand billed customers, appropriate loss factors must be applied to the applicable tariffs. Also the billing determinant for the Line and Transformation Connection Services rate is the customer’s peak demand in the billing period. The billing determinant for the Network Services rate is: for non-interval-metered customers, the peak demand in the billing period, and for interval-metered customers, the peak demand between 7 AM and 7 PM local time on IESO business days

Interim Demand-Side Management Time-of-Use

See the "Service Classifications" section of this schedule.

Customer-Supplied Transformation Allowance

Applicable to demand-billed customers providing their own transformers
Primary Voltage under 50 kV (per kW)

Single Phase	$ / kW	0.20
Three Phase	$ / kW	0.60

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Loss Factors

Supply Facilities Loss Factor	1.0045
Distribution Loss Factors	
Customer less than 5,000 kW	1.0500
Customer greater than or equal to 5,000 kW	1.0100
Total Loss Factors	
Customer less than 5,000 kW	1.0545
Customer greater than or equal to 5,000 kW	1.0145

Transformer Loss Allowance

Applicable to customers requiring a billing adjustment for transformer losses as the result of being metered on the primary side of a transformer. The following uniform values shall be applied to measured demand and energy to calculate transformer losses for voltages up to and including 50 kV (as metered on the primary side):

(a) 1.5% for transformer installations up to an individual bank capacity of 400 kVA,
(b) 1.0% for bank capacities over 400 kVA.

Alternatively, transformer losses may be determined from transformer test data, and measured demand and energy adjusted accordingly

For services which are not demand metered, an assumed demand of 50% of the transformer capacity will be used to calculate the loss allowance. Where several transformers are involved, the bank capacity is assumed to be the arithmetic sum of all transformer capacities

Hydro One Networks Inc.
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MISCELLANEOUS CHARGES

Specific Service Charges: Standard Amounts

Rate Code	Specific Service Charge - Standard Name	Calculation Method			
		2006 Rate Handbook	Standard Formula	Other Formula	Time and Materials
1	Temporary Service	$500			
2	Dispute Meter Test	$30 plus Measurement Canada fees			
3	Collection of account – no disconnection/load limiter	$30			
4	Collection/Disconnect/load limiter/reconnect (at meter) trip – regular hours	$65			
5	Collection/Disconnect/load limiter/reconnect (at meter) trip – after regular hours	$185			
6	Collection/Disconnect/load limiter/reconnect (at pole) trip – regular hours	$185			
7	Collection/Disconnect/load limiter/reconnect (at pole) trip – after regular hours	$415			
8	Account Set-up Charge	$30			
9	Arrears Certificate	$15			
10	NSF Cheque Charge	$15 + bank charges			
11	Easement Charge for Unregistered Rights	$15			
12	Late Payment Charge	1.5%/month			
13a	Retailer Services – Establishing Service Agreements (refer to Handbook for all charges)	$100/agreement/Retailer +$20/month/Retailer +$0.50/month/customer + other			
13b	Retailer Services – Other (includes Bill Ready for Retailers and Service Transactions Requests) as per the Handbook, Chapter 12	$0.30/month/customer + $0.25/request for request fee + $0.50/request for process fee			
14	Special Meter Reads	$30			
15	Billing Suspension and Terminations in Trailer Parks		$130		
16	Service Layout Fee – Basic		$405		
17	Service Layout Fee – Complex		$580		

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18	Crossing Application – Pipeline		$2,065		
19	Crossing Application – Water		$2,525		
20	Crossing Application – Railroad		$2,565		
21	Line Staking – per meter		$3.10		
22	Central Metering – New service < 45 kW		$115		
23	Conversion to Central Metering < 45 kW		$795		
24	Conversion to Central Metering > 45 kW		$680		
25	Tingle Voltage Test – In Excess of 4 Hours (per hour – average 2 additional hours)		$105		
26	Standby Administration Charge per month (interim)		$375		
27	Sentinel Lights Rental Rate per month – Mercury Vapor			$7.00	
28	Guaranteed Units from Jan 01/91 to Aug 01/91			$26.50 / month	
29	Guaranteed Units from Jan 01/87 to Dec 31/90			$23.50 / month	
30	Joint Use for Cable and Telecom companies per pole			$22.35	
31	Joint Use for LDCs per pole			$28.61	

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APPLICATION

The application of these rates and charges shall be in accordance with The Licence of The Distributor and any Codes, Guidelines or Orders of The Board, and amendments thereto as approved by The Board, which may be applicable to the administration of this schedule.
No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code, Guideline or Order of the Board, and amendments thereto as approved by the Board, or as specified herein
This schedule does not contain any rates and charges relating to the electricity commodity (e.g. the Regulated Price Plan).

EFFECTIVE DATES

DISTRIBUTION RATES - May 1, 2008 for all consumption or deemed consumption services used on or after that date.

MISCELLANEOUS CHARGES - May 1, 2008 for all charges billed to customers on or after that date.
RETAIL TRANSMISSION RATES - May 1, 2008 for all consumption or deemed consumption services used on or after that date.
LOSS FACTOR ADJUSTMENT – for all consumption or deemed consumption services billed following May 1, 2008 or later

SERVICE CLASSIFICATIONS

Residential
This classification refers to all service supplied to single-family dwelling units for domestic or household purpose. Multi-unit residential establishments such as apartment buildings supplied through one service (bulk metered) will normally be classified as General Service, but, at Hydro One's discretion, up to four residential units may be classified as residential. Where electricity service is provided to combined residential and business (including agricultural usage) and the wiring does not provide for separate metering, the classification shall be at the discretion of Hydro One based on such considerations as the estimated predominant consumption.
Further servicing details are available in the utility's Conditions of Service.

General Service
This classification refers to all service supplied to premises other than those classified as Residential or Lighting. Some General Service accounts are energy(kWh)-billed, and some are demand(kW)-billed. Further servicing details are available in the utility's Conditions of Service.

Unmetered Scattered Load
This classification refers to certain instances where connections can be provided without metering. These loads are generally small in size and consistent in magnitude of load. Hydro One reserves the right to review all cases and may require that a meter be installed at its sole discretion. Services that can be unmetered include cable TV amplifiers, telephone switching devices, phone booths, bus shelters, rail way crossing signals, traffic signals, and other small fixed loads.
Further servicing details are available in the utility's Conditions of Service (including in the "Unmetered Connections" section).

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
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Bobcaygeon Hydro Electric Commission
Effective Date: May 1, 2008

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Street Lighting

This classification refers to accounts for the distribution and supply of electrical energy for street lighting. Street lights are devices owned by or operated for the road authority and/or the municipal corporation. These street lights in fact belong to the Street Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Sentinel Lighting

This classification refers to accounts for a separate service to a sentinel light. These sentinel lights in fact belong to the Sentinel Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Urban Density Classification

Customers who meet the Urban Density Criteria of being in an area containing 3,000 or more customers with a line density of at least 60 customers per kilometre, will be mapped to an Urban customer classification.

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
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Effective Date: May 1, 2008

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MONTHLY RATES AND CHARGES

Residential - R1 Bobcaygeon

Service Charge	$	15.14
Distribution Volumetric Rate	$ / kWh	0.0205
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0010
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0004)
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0047
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0046
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service Less Than 50 kW (Energy-Billed) - GSe Bobcaygeon

Service Charge	$	25.29
Distribution Volumetric Rate	$ / kWh	0.0250
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0009
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0006)
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0035
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0032
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service 50 kW or Greater (Demand-Billed) - GSd Bobcaygeon

Service Charge	$	28.89
Distribution Volumetric Rate	$ / kW	9.22
Regulatory Asset Recovery - Rider #2	$ / kW	0.27
Regulatory Asset Recovery - Rider #3	$ / kW	(0.22)
Retail Transmission Rate - Network Service Rate (4)	$ / kW	1.11
Retail Transmission Rate - Line and Transformation Connection Service Rate (4)	$ / kW	1.00
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

Hydro One Networks Inc.
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Unmetered, Scattered Load

Service Charge	$	14.59
Distribution Volumetric Rate	$ / kWh	0.0200
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0009
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0006)
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0035
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0032
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

(3) For energy-only metered customers, the billing determinant is the customer's metered energy consumption adjusted by the total loss factor as approved by the Board for Acquired LDC customers.
(4) For demand billed customers, appropriate loss factors must be applied to the applicable tariffs. Also the billing determinant for the Line and Transformation Connection Services rate is the customer's peak demand in the billing period. The billing determinant for the Network Services rate is: for non-interval-metered customers, the peak demand in the billing period, and for interval-metered customers, the peak demand between 7 AM and 7 PM local time on IESO business days

Customer-Supplied Transformation Allowance

Applicable to customers providing their own transformers

Demand-billed	$ / kW	0.60
Energy-billed	$ / kWh	0.0014

Hydro One Networks Inc.
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Loss Factors

Residential	1.085
General Service Less Than 50 kW (Energy-Billed)	1.092
General Service 50 kW or Greater (Demand-Billed)	1.061
Unmetered Scattered Load	1.092

Transformer Loss Allowance

Applicable to customers requiring a billing adjustment for transformer losses as the result of being metered on the primary side of a transformer. The following uniform values shall be applied to measured demand and energy to calculate transformer losses for voltages up to and including 50 kV (as metered on the primary side):

(a) 1.5% for transformer installations up to an individual bank capacity of 400 kVA,
(b) 1.0% for bank capacities over 400 kVA.

Alternatively, transformer losses may be determined from transformer test data, and measured demand and energy adjusted accordingly

For services which are not demand metered, an assumed demand of 50% of the transformer capacity will be used to calculate the loss allowance. Where several transformers are involved, the bank capacity is assumed to be the arithmetic sum of all transformer capacities

Hydro One Networks Inc.
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MISCELLANEOUS CHARGES

Specific Service Charges: Standard Amounts

Rate Code	Specific Service Charge - Standard Name	Calculation Method			
		2006 Rate Handbook	Standard Formula	Other Formula	Time and Materials
1	Temporary Service	$500			
2	Dispute Meter Test	$30 plus Measurement Canada fees			
3	Collection of account – no disconnection/load limiter	$30			
4	Collection/Disconnect/load limiter/reconnect (at meter) trip – regular hours	$65			
5	Collection/Disconnect/load limiter/reconnect (at meter) trip – after regular hours	$185			
6	Collection/Disconnect/load limiter/reconnect (at pole) trip – regular hours	$185			
7	Collection/Disconnect/load limiter/reconnect (at pole) trip – after regular hours	$415			
8	Account Set-up Charge	$30			
9	Arrears Certificate	$15			
10	NSF Cheque Charge	$15 + bank charges			
11	Easement Charge for Unregistered Rights	$15			
12	Late Payment Charge	1.5%/month			
13a	Retailer Services – Establishing Service Agreements (refer to Handbook for all charges)	$100/agreement/Retailer +$20/month/Retailer +$0.50/month/customer + other			
13b	Retailer Services – Other (includes Bill Ready for Retailers and Service Transactions Requests) as per the Handbook, Chapter 12	$0.30/month/customer + $0.25/request for request fee + $0.50/request for process fee			
14	Special Meter Reads	$30			
15	Service Layout Fee – Basic		$495		
16	Service Layout Fee – Complex		$690		
17	Crossing Application – Pipeline		$2,445		
18	Crossing Application – Water		$3,045		
19	Crossing Application – Railroad		$2,945		
20	Line Staking – per meter		$3.70		
21	Central Metering – New service < 45 kW		$115		
22	Conversion to Central Metering < 45 kW		$915		
23	Conversion to Central Metering > 45 kW		$800		
24	Tingle Voltage Test – In Excess of 4 Hours (per hour – average 2 additional hours)		$125		
25	Standby Administration Charge per month		$440		
26	Sentinel Lights Rental Rate per month			$7.10	
27	Sentinel Pole Rental Rate per month			$4.15	
28	Joint Use for Cable and Telecom companies per pole			$22.35	
29	Joint Use for LDCs per pole			$28.61	

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APPLICATION

The application of these rates and charges shall be in accordance with The Licence of The Distributor and any Codes, Guidelines or Orders of The Board, and amendments thereto as approved by The Board, which may be applicable to the administration of this schedule.
No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code, Guideline or Order of the Board, and amendments thereto as approved by the Board, or as specified herein
This schedule does not contain any rates and charges relating to the electricity commodity (e.g. the Regulated Price Plan).

EFFECTIVE DATES

DISTRIBUTION RATES - May 1, 2007 for all consumption or deemed consumption services used on or after that date.

MISCELLANEOUS CHARGES - May 1, 2007 for all charges billed to customers on or after that date.
RETAIL TRANSMISSION RATES - May 1, 2007 for all consumption or deemed consumption services used on or after that date.
LOSS FACTOR ADJUSTMENT – May 1, 2007

SERVICE CLASSIFICATIONS

Residential
This classification (note 1) refers to all service supplied to single-family dwelling units for domestic or household purpose. Multi-unit residential establishments such as apartment buildings supplied through one service (bulk metered) will normally be classified as General Service, but, at Hydro One's discretion, up to four residential units may be classified as residential. Where electricity service is provided to combined residential and business (including agricultural usage) and the wiring does not provide for separate metering, the classification shall be at the discretion of Hydro One based on such considerations as the estimated predominant consumption.
Further servicing details are available in the utility's Conditions of Service.

General Service
This classification (note 1) refers to all service supplied to premises other than those classified as Residential or Lighting. Some General Service accounts are energy(kWh)-billed, and some are demand(kW)-billed. Further servicing details are available in the utility's Conditions of Service. Also, see note 2.

Unmetered Scattered Load
This classification refers to certain instances where connections can be provided without metering. These loads are generally small in size and consistent in magnitude of load. Hydro One reserves the right to review all cases and may require that a meter be installed at its sole discretion. Services that can be unmetered include cable TV amplifiers, telephone switching devices, phone booths, bus shelters, rail way crossing signals, traffic signals, and other small fixed loads.
Further servicing details are available in the utility's Conditions of Service (including in the "Unmetered Connections" section).

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Street Lighting

This classification refers to accounts for the distribution and supply of electrical energy for street lighting. Street lights are devices owned by or operated for the road authority and/or the municipal corporation. These street lights in fact belong to the Street Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Sentinel Lighting

This classification refers to accounts for a separate service to a sentinel light. These sentinel lights in fact belong to the Sentinel Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Interim Demand-Side Management Time-of-Use

This is potentially applicable to Demand-billed General Service accounts. See Note 2 below.

Note (1): Classification descriptions are paraphrases from the document "Hydro One Networks Inc. - Distribution Customers Conditions of Service - August 2004"

Note (2):

Interim Demand-Side Management Time-of-Use Rates: demand charges will be based on demand during the on-peak periods.

Criteria: Customers' electricity consumption (kW) in the off-peak period is at least twice the electricity consumption (kW) during the on-peak period.

Definition of Time Periods: The on-peak hours will be between 0700 hours to 1900 hours Eastern Standard Time during the winter (standard time) on IESO business days and 0600 hours to 1800 hours Eastern Standard Time during the summer (daylight savings time) on IESO business days. The off-peak period constitutes all of the remaining hours.

Hydro One Networks Inc.
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MONTHLY RATES AND CHARGES

Residential

Service Charge	$	14.47
Distribution Volumetric Rate	$ / kWh	0.0097
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0028
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0010
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0055
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0047
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service - Energy Billed (less than 50 kW)

Service Charge	$	23.20
Distribution Volumetric Rate	$ / kWh	0.0138
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0018
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0009
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0050
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0043
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service - Demand Billed (50 kW or greater)

Service Charge	$	23.20
Distribution Volumetric Rate	$ / kW	4.35
Regulatory Asset Recovery - Rider #1	$ / kW	0.58
Regulatory Asset Recovery - Rider #2	$ / kW	0.27
Retail Transmission Rate - Network Service Rate (4)	$ / kW	1.94
Retail Transmission Rate - Line and Transformation Connection Service Rate (4)	$ / kW	1.61
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Bobcaygeon Hydro Electric Commission
Effective Date: May 1, 2007

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

Unmetered, Scattered Load

Service Charge	$	11.14
Distribution Volumetric Rate	$ / kWh	0.0138
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0018
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0009
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0050
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0043
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

(3) For energy-only metered customers, the billing determinant is the customer’s metered energy consumption adjusted by the total loss factor as approved by the Board for Acquired LDC customers.
(4) For demand billed customers, appropriate loss factors must be applied to the applicable tariffs. Also the billing determinant for the Line and Transformation Connection Services rate is the customer’s peak demand in the billing period. The billing determinant for the Network Services rate is: for non-interval-metered customers, the peak demand in the billing period, and for interval-metered customers, the peak demand between 7 AM and 7 PM local time on IESO business days

Interim Demand-Side Management Time-of-Use

See the "Service Classifications" section of this schedule.

Customer-Supplied Transformation Allowance

Applicable to demand-billed customers providing their own transformers
Primary Voltage under 50 kV (per kW)

Single Phase	$ / kW	0.20
Three Phase	$ / kW	0.60

Hydro One Networks Inc.
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Bobcaygeon Hydro Electric Commission
Effective Date: May 1, 2007

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

Loss Factors

Supply Facilities Loss Factor	1.0045
Distribution Loss Factors	
Customer less than 5,000 kW	1.0500
Customer greater than or equal to 5,000 kW	1.0100
Total Loss Factors	
Customer less than 5,000 kW	1.0545
Customer greater than or equal to 5,000 kW	1.0145

Transformer Loss Allowance

Applicable to customers requiring a billing adjustment for transformer losses as the result of being metered on the primary side of a transformer. The following uniform values shall be applied to measured demand and energy to calculate transformer losses for voltages up to and including 50 kV (as metered on the primary side):

(a) 1.5% for transformer installations up to an individual bank capacity of 400 kVA,
(b) 1.0% for bank capacities over 400 kVA.

Alternatively, transformer losses may be determined from transformer test data, and measured demand and energy adjusted accordingly

For services which are not demand metered, an assumed demand of 50% of the transformer capacity will be used to calculate the loss allowance. Where several transformers are involved, the bank capacity is assumed to be the arithmetic sum of all transformer capacities

Hydro One Networks Inc.
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This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

MISCELLANEOUS CHARGES

Specific Service Charges: Standard Amounts

Rate Code	Specific Service Charge - Standard Name	Calculation Method			
		2006 Rate Handbook	Standard Formula	Other Formula	Time and Materials
1	Temporary Service	$500			
2	Dispute Meter Test	$30 plus Measurement Canada fees			
3	Collection of account – no disconnection/load limiter	$30			
4	Collection/Disconnect/load limiter/reconnect (at meter) trip – regular hours	$65			
5	Collection/Disconnect/load limiter/reconnect (at meter) trip – after regular hours	$185			
6	Collection/Disconnect/load limiter/reconnect (at pole) trip – regular hours	$185			
7	Collection/Disconnect/load limiter/reconnect (at pole) trip – after regular hours	$415			
8	Account Set-up Charge	$30			
9	Arrears Certificate	$15			
10	NSF Cheque Charge	$15 + bank charges			
11	Easement Charge for Unregistered Rights	$15			
12	Late Payment Charge	1.5%/month			
13a	Retailer Services – Establishing Service Agreements (refer to Handbook for all charges)	$100/agreement/Retailer +$20/month/Retailer +$0.50/month/customer + other			
13b	Retailer Services – Other (includes Bill Ready for Retailers and Service Transactions Requests) as per the Handbook, Chapter 12	$0.30/month/customer + $0.25/request for request fee + $0.50/request for process fee			
14	Special Meter Reads	$30			
15	Billing Suspension and Terminations in Trailer Parks		$130		
16	Service Layout Fee – Basic		$405		
17	Service Layout Fee – Complex		$580		

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18	Crossing Application – Pipeline		$2,065		
19	Crossing Application – Water		$2,525		
20	Crossing Application – Railroad		$2,565		
21	Line Staking – per meter		$3.10		
22	Central Metering – New service < 45 kW		$115		
23	Conversion to Central Metering < 45 kW		$795		
24	Conversion to Central Metering > 45 kW		$680		
25	Tingle Voltage Test – In Excess of 4 Hours (per hour – average 2 additional hours)		$105		
26	Standby Administration Charge per month (interim)		$375		
27	Sentinel Lights Rental Rate per month – Mercury Vapor			$7.00	
28	Guaranteed Units from Jan 01/91 to Aug 01/91			$26.50 / month	
29	Guaranteed Units from Jan 01/87 to Dec 31/90			$23.50 / month	
30	Joint Use for Cable and Telecom companies per pole			$22.35	
31	Joint Use for LDCs per pole			$28.61	

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Brighton Public Utilities Commission
Effective Date: May 1, 2008

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

APPLICATION

The application of these rates and charges shall be in accordance with The Licence of The Distributor and any Codes, Guidelines or Orders of The Board, and amendments thereto as approved by The Board, which may be applicable to the administration of this schedule.
No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code, Guideline or Order of the Board, and amendments thereto as approved by the Board, or as specified herein
This schedule does not contain any rates and charges relating to the electricity commodity (e.g. the Regulated Price Plan).

EFFECTIVE DATES

DISTRIBUTION RATES - May 1, 2008 for all consumption or deemed consumption services used on or after that date.

MISCELLANEOUS CHARGES - May 1, 2008 for all charges billed to customers on or after that date.
RETAIL TRANSMISSION RATES - May 1, 2008 for all consumption or deemed consumption services used on or after that date.
LOSS FACTOR ADJUSTMENT – for all consumption or deemed consumption services billed following May 1, 2008 or later

SERVICE CLASSIFICATIONS

Residential
This classification refers to all service supplied to single-family dwelling units for domestic or household purpose. Multi-unit residential establishments such as apartment buildings supplied through one service (bulk metered) will normally be classified as General Service, but, at Hydro One's discretion, up to four residential units may be classified as residential. Where electricity service is provided to combined residential and business (including agricultural usage) and the wiring does not provide for separate metering, the classification shall be at the discretion of Hydro One based on such considerations as the estimated predominant consumption.
Further servicing details are available in the utility's Conditions of Service.

General Service
This classification refers to all service supplied to premises other than those classified as Residential or Lighting. Some General Service accounts are energy(kWh)-billed, and some are demand(kW)-billed. Further servicing details are available in the utility's Conditions of Service.

Unmetered Scattered Load
This classification refers to certain instances where connections can be provided without metering. These loads are generally small in size and consistent in magnitude of load. Hydro One reserves the right to review all cases and may require that a meter be installed at its sole discretion. Services that can be unmetered include cable TV amplifiers, telephone switching devices, phone booths, bus shelters, rail way crossing signals, traffic signals, and other small fixed loads.
Further servicing details are available in the utility's Conditions of Service (including in the "Unmetered Connections" section).

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Brighton Public Utilities Commission
Effective Date: May 1, 2008

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Street Lighting

This classification refers to accounts for the distribution and supply of electrical energy for street lighting. Street lights are devices owned by or operated for the road authority and/or the municipal corporation. These street lights in fact belong to the Street Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Sentinel Lighting

This classification refers to accounts for a separate service to a sentinel light. These sentinel lights in fact belong to the Sentinel Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Urban Density Classification

Customers who meet the Urban Density Criteria of being in an area containing 3,000 or more customers with a line density of at least 60 customers per kilometre, will be mapped to an Urban customer classification.

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MONTHLY RATES AND CHARGES

Residential - R1 Brighton

Service Charge	$	12.86
Distribution Volumetric Rate	$ / kWh	0.0220
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0011
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0004)
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0047
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0046
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service Less Than 50 kW (Energy-Billed) - GSe Brighton

Service Charge	$	24.37
Distribution Volumetric Rate	$ / kWh	0.0250
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0008
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0006)
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0035
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0032
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service 50 kW or Greater (Demand-Billed) - GSd Brighton

Service Charge	$	27.96
Distribution Volumetric Rate	$ / kW	9.22
Regulatory Asset Recovery - Rider #2	$ / kW	0.25
Regulatory Asset Recovery - Rider #3	$ / kW	(0.22)
Retail Transmission Rate - Network Service Rate (4)	$ / kW	1.11
Retail Transmission Rate - Line and Transformation Connection Service Rate (4)	$ / kW	1.00
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

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Unmetered, Scattered Load

Service Charge	$	13.63
Distribution Volumetric Rate	$ / kWh	0.0200
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0008
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0006)
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0035
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0032
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

(3) For energy-only metered customers, the billing determinant is the customer's metered energy consumption adjusted by the total loss factor as approved by the Board for Acquired LDC customers.

(4) For demand billed customers, appropriate loss factors must be applied to the applicable tariffs. Also the billing determinant for the Line and Transformation Connection Services rate is the customer's peak demand in the billing period. The billing determinant for the Network Services rate is: for non-interval-metered customers, the peak demand in the billing period, and for interval-metered customers, the peak demand between 7 AM and 7 PM local time on IESO business days

Customer-Supplied Transformation Allowance

Applicable to customers providing their own transformers

Demand-billed	$ / kW	0.60
Energy-billed	$ / kWh	0.0014

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Loss Factors

Residential	1.085
General Service Less Than 50 kW (Energy-Billed)	1.092
General Service 50 kW or Greater (Demand-Billed)	1.061
Unmetered Scattered Load	1.092

Transformer Loss Allowance

Applicable to customers requiring a billing adjustment for transformer losses as the result of being metered on the primary side of a transformer. The following uniform values shall be applied to measured demand and energy to calculate transformer losses for voltages up to and including 50 kV (as metered on the primary side):

(a) 1.5% for transformer installations up to an individual bank capacity of 400 kVA,
(b) 1.0% for bank capacities over 400 kVA.

Alternatively, transformer losses may be determined from transformer test data, and measured demand and energy adjusted accordingly

For services which are not demand metered, an assumed demand of 50% of the transformer capacity will be used to calculate the loss allowance. Where several transformers are involved, the bank capacity is assumed to be the arithmetic sum of all transformer capacities

Hydro One Networks Inc.
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This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

MISCELLANEOUS CHARGES

Specific Service Charges: Standard Amounts

Rate Code	Specific Service Charge - Standard Name	Calculation Method			
		2006 Rate Handbook	Standard Formula	Other Formula	Time and Materials
1	Temporary Service	$500			
2	Dispute Meter Test	$30 plus Measurement Canada fees			
3	Collection of account – no disconnection/load limiter	$30			
4	Collection/Disconnect/load limiter/reconnect (at meter) trip – regular hours	$65			
5	Collection/Disconnect/load limiter/reconnect (at meter) trip – after regular hours	$185			
6	Collection/Disconnect/load limiter/reconnect (at pole) trip – regular hours	$185			
7	Collection/Disconnect/load limiter/reconnect (at pole) trip – after regular hours	$415			
8	Account Set-up Charge	$30			
9	Arrears Certificate	$15			
10	NSF Cheque Charge	$15 + bank charges			
11	Easement Charge for Unregistered Rights	$15			
12	Late Payment Charge	1.5%/month			
13a	Retailer Services – Establishing Service Agreements (refer to Handbook for all charges)	$100/agreement/Retailer +$20/month/Retailer +$0.50/month/customer + other			
13b	Retailer Services – Other (includes Bill Ready for Retailers and Service Transactions Requests) as per the Handbook, Chapter 12	$0.30/month/customer + $0.25/request for request fee + $0.50/request for process fee			
14	Special Meter Reads	$30			
15	Service Layout Fee – Basic		$495		
16	Service Layout Fee – Complex		$690		
17	Crossing Application – Pipeline		$2,445		
18	Crossing Application – Water		$3,045		
19	Crossing Application – Railroad		$2,945		
20	Line Staking – per meter		$3.70		
21	Central Metering – New service < 45 kW		$115		
22	Conversion to Central Metering < 45 kW		$915		
23	Conversion to Central Metering > 45 kW		$800		
24	Tingle Voltage Test – In Excess of 4 Hours (per hour – average 2 additional hours)		$125		
25	Standby Administration Charge per month		$440		
26	Sentinel Lights Rental Rate per month			$7.10	
27	Sentinel Pole Rental Rate per month			$4.15	
28	Joint Use for Cable and Telecom companies per pole			$22.35	
29	Joint Use for LDCs per pole			$28.61	

Hydro One Networks Inc.
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APPLICATION

The application of these rates and charges shall be in accordance with The Licence of The Distributor and any Codes, Guidelines or Orders of The Board, and amendments thereto as approved by The Board, which may be applicable to the administration of this schedule.
No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code, Guideline or Order of the Board, and amendments thereto as approved by the Board, or as specified herein
This schedule does not contain any rates and charges relating to the electricity commodity (e.g. the Regulated Price Plan).

EFFECTIVE DATES

DISTRIBUTION RATES - May 1, 2007 for all consumption or deemed consumption services used on or after that date.

MISCELLANEOUS CHARGES - May 1, 2007 for all charges billed to customers on or after that date.
RETAIL TRANSMISSION RATES - May 1, 2007 for all consumption or deemed consumption services used on or after that date.
LOSS FACTOR ADJUSTMENT – May 1, 2007

SERVICE CLASSIFICATIONS

Residential
This classification (note 1) refers to all service supplied to single-family dwelling units for domestic or household purpose. Multi-unit residential establishments such as apartment buildings supplied through one service (bulk metered) will normally be classified as General Service, but, at Hydro One’s discretion, up to four residential units may be classified as residential. Where electricity service is provided to combined residential and business (including agricultural usage) and the wiring does not provide for separate metering, the classification shall be at the discretion of Hydro One based on such considerations as the estimated predominant consumption.
Further servicing details are available in the utility’s Conditions of Service.

General Service
This classification (note 1) refers to all service supplied to premises other than those classified as Residential or Lighting. Some General Service accounts are energy(kWh)-billed, and some are demand(kW)-billed. Further servicing details are available in the utility’s Conditions of Service. Also, see note 2.

Unmetered Scattered Load
This classification refers to certain instances where connections can be provided without metering. These loads are generally small in size and consistent in magnitude of load. Hydro One reserves the right to review all cases and may require that a meter be installed at its sole discretion. Services that can be unmetered include cable TV amplifiers, telephone switching devices, phone booths, bus shelters, rail way crossing signals, traffic signals, and other small fixed loads.
Further servicing details are available in the utility’s Conditions of Service (including in the "Unmetered Connections" section).

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Street Lighting

This classification refers to accounts for the distribution and supply of electrical energy for street lighting. Street lights are devices owned by or operated for the road authority and/or the municipal corporation. These street lights in fact belong to the Street Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Sentinel Lighting

This classification refers to accounts for a separate service to a sentinel light. These sentinel lights in fact belong to the Sentinel Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Interim Demand-Side Management Time-of-Use

This is potentially applicable to Demand-billed General Service accounts. See Note 2 below.

Note (1): Classification descriptions are paraphrases from the document "Hydro One Networks Inc. - Distribution Customers Conditions of Service - August 2004"

Note (2):

Interim Demand-Side Management Time-of-Use Rates: demand charges will be based on demand during the on-peak periods.

Criteria: Customers' electricity consumption (kW) in the off-peak period is at least twice the electricity consumption (kW) during the on-peak period.

Definition of Time Periods: The on-peak hours will be between 0700 hours to 1900 hours Eastern Standard Time during the winter (standard time) on IESO business days and 0600 hours to 1800 hours Eastern Standard Time during the summer (daylight savings time) on IESO business days. The off-peak period constitutes all of the remaining hours.

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MONTHLY RATES AND CHARGES

Residential

Service Charge	$	11.61
Distribution Volumetric Rate	$ / kWh	0.0107
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0037
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0011
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0055
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0047
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service - Energy Billed (less than 50 kW)

Service Charge	$	22.90
Distribution Volumetric Rate	$ / kWh	0.0135
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0020
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0008
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0050
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0043
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service - Demand Billed (50 kW or greater)

Service Charge	$	22.90
Distribution Volumetric Rate	$ / kW	4.24
Regulatory Asset Recovery - Rider #1	$ / kW	0.65
Regulatory Asset Recovery - Rider #2	$ / kW	0.25
Retail Transmission Rate - Network Service Rate (4)	$ / kW	1.94
Retail Transmission Rate - Line and Transformation Connection Service Rate (4)	$ / kW	1.61
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

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Unmetered, Scattered Load

Service Charge	$	10.99
Distribution Volumetric Rate	$ / kWh	0.0135
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0020
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0008
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0050
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0043
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

(3) For energy-only metered customers, the billing determinant is the customer’s metered energy consumption adjusted by the total loss factor as approved by the Board for Acquired LDC customers.
(4) For demand billed customers, appropriate loss factors must be applied to the applicable tariffs. Also the billing determinant for the Line and Transformation Connection Services rate is the customer’s peak demand in the billing period. The billing determinant for the Network Services rate is: for non-interval-metered customers, the peak demand in the billing period, and for interval-metered customers, the peak demand between 7 AM and 7 PM local time on IESO business days

Interim Demand-Side Management Time-of-Use

See the "Service Classifications" section of this schedule.

Customer-Supplied Transformation Allowance

Applicable to demand-billed customers providing their own transformers
Primary Voltage under 50 kV (per kW)

Single Phase	$ / kW	0.20
Three Phase	$ / kW	0.60

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Loss Factors

Supply Facilities Loss Factor	1.0045
Distribution Loss Factors	
Customer less than 5,000 kW	1.0500
Customer greater than or equal to 5,000 kW	1.0100
Total Loss Factors	
Customer less than 5,000 kW	1.0545
Customer greater than or equal to 5,000 kW	1.0145

Transformer Loss Allowance

Applicable to customers requiring a billing adjustment for transformer losses as the result of being metered on the primary side of a transformer. The following uniform values shall be applied to measured demand and energy to calculate transformer losses for voltages up to and including 50 kV (as metered on the primary side):

(a) 1.5% for transformer installations up to an individual bank capacity of 400 kVA,
(b) 1.0% for bank capacities over 400 kVA.

Alternatively, transformer losses may be determined from transformer test data, and measured demand and energy adjusted accordingly

For services which are not demand metered, an assumed demand of 50% of the transformer capacity will be used to calculate the loss allowance. Where several transformers are involved, the bank capacity is assumed to be the arithmetic sum of all transformer capacities

Hydro One Networks Inc.
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MISCELLANEOUS CHARGES

Specific Service Charges: Standard Amounts

Rate Code	Specific Service Charge - Standard Name	Calculation Method			
		2006 Rate Handbook	Standard Formula	Other Formula	Time and Materials
1	Temporary Service	$500			
2	Dispute Meter Test	$30 plus Measurement Canada fees			
3	Collection of account – no disconnection/load limiter	$30			
4	Collection/Disconnect/load limiter/reconnect (at meter) trip – regular hours	$65			
5	Collection/Disconnect/load limiter/reconnect (at meter) trip – after regular hours	$185			
6	Collection/Disconnect/load limiter/reconnect (at pole) trip – regular hours	$185			
7	Collection/Disconnect/load limiter/reconnect (at pole) trip – after regular hours	$415			
8	Account Set-up Charge	$30			
9	Arrears Certificate	$15			
10	NSF Cheque Charge	$15 + bank charges			
11	Easement Charge for Unregistered Rights	$15			
12	Late Payment Charge	1.5%/month			
13a	Retailer Services – Establishing Service Agreements (refer to Handbook for all charges)	$100/agreement/Retailer +$20/month/Retailer +$0.50/month/customer + other			
13b	Retailer Services – Other (includes Bill Ready for Retailers and Service Transactions Requests) as per the Handbook, Chapter 12	$0.30/month/customer + $0.25/request for request fee + $0.50/request for process fee			
14	Special Meter Reads	$30			
15	Billing Suspension and Terminations in Trailer Parks		$130		
16	Service Layout Fee – Basic		$405		
17	Service Layout Fee – Complex		$580		

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Brighton Public Utilities Commission
Effective Date: May 1, 2007

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

18	Crossing Application – Pipeline		$2,065		
19	Crossing Application – Water		$2,525		
20	Crossing Application – Railroad		$2,565		
21	Line Staking – per meter		$3.10		
22	Central Metering – New service < 45 kW		$115		
23	Conversion to Central Metering < 45 kW		$795		
24	Conversion to Central Metering > 45 kW		$680		
25	Tingle Voltage Test – In Excess of 4 Hours (per hour – average 2 additional hours)		$105		
26	Standby Administration Charge per month (interim)		$375		
27	Sentinel Lights Rental Rate per month – Mercury Vapor			$7.00	
28	Guaranteed Units from Jan 01/91 to Aug 01/91			$26.50 / month	
29	Guaranteed Units from Jan 01/87 to Dec 31/90			$23.50 / month	
30	Joint Use for Cable and Telecom companies per pole			$22.35	
31	Joint Use for LDCs per pole			$28.61	

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Brockville Public Utilities Commission
Effective Date: May 1, 2008

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

APPLICATION

The application of these rates and charges shall be in accordance with The Licence of The Distributor and any Codes, Guidelines or Orders of The Board, and amendments thereto as approved by The Board, which may be applicable to the administration of this schedule.
No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code, Guideline or Order of the Board, and amendments thereto as approved by the Board, or as specified herein
This schedule does not contain any rates and charges relating to the electricity commodity (e.g. the Regulated Price Plan).

EFFECTIVE DATES

DISTRIBUTION RATES - May 1, 2008 for all consumption or deemed consumption services used on or after that date.

MISCELLANEOUS CHARGES - May 1, 2008 for all charges billed to customers on or after that date.
RETAIL TRANSMISSION RATES - May 1, 2008 for all consumption or deemed consumption services used on or after that date.
LOSS FACTOR ADJUSTMENT – for all consumption or deemed consumption services billed following May 1, 2008 or later

SERVICE CLASSIFICATIONS

Residential
This classification refers to all service supplied to single-family dwelling units for domestic or household purpose. Multi-unit residential establishments such as apartment buildings supplied through one service (bulk metered) will normally be classified as General Service, but, at Hydro One's discretion, up to four residential units may be classified as residential. Where electricity service is provided to combined residential and business (including agricultural usage) and the wiring does not provide for separate metering, the classification shall be at the discretion of Hydro One based on such considerations as the estimated predominant consumption.
Further servicing details are available in the utility's Conditions of Service.

General Service
This classification refers to all service supplied to premises other than those classified as Residential or Lighting. Some General Service accounts are energy(kWh)-billed, and some are demand(kW)-billed. Further servicing details are available in the utility's Conditions of Service.

Unmetered Scattered Load
This classification refers to certain instances where connections can be provided without metering. These loads are generally small in size and consistent in magnitude of load. Hydro One reserves the right to review all cases and may require that a meter be installed at its sole discretion. Services that can be unmetered include cable TV amplifiers, telephone switching devices, phone booths, bus shelters, rail way crossing signals, traffic signals, and other small fixed loads.
Further servicing details are available in the utility's Conditions of Service (including in the "Unmetered Connections" section).

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Brockville Public Utilities Commission
Effective Date: May 1, 2008

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

Large Use - see Note 1

Street Lighting

This classification refers to accounts for the distribution and supply of electrical energy for street lighting. Street lights are devices owned by or operated for the road authority and/or the municipal corporation. These street lights in fact belong to the Street Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Sentinel Lighting

This classification refers to accounts for a separate service to a sentinel light. These sentinel lights in fact belong to the Sentinel Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Urban Density Classification

Customers who meet the Urban Density Criteria of being in an area containing 3,000 or more customers with a line density of at least 60 customers per kilometre, will be mapped to an Urban customer classification.

Note (1) The former Large Use class is now part of the ST class, which is separate from the classes for customers of acquired distribution companies.
This former class refered to individual Customers whose monthly measured maximum demand (kW) averaged over the most recent 12 consecutive months is equal to or greater than 5,000 kW.

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Brockville Public Utilities Commission
Effective Date: May 1, 2008

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

MONTHLY RATES AND CHARGES

Residential - UR/R1 Brockville

Service Charge	$	12.50
Distribution Volumetric Rate	$ / kWh	0.0240
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0016
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0002)
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0047
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0045
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service Less Than 50 kW (Energy-Billed) - UGe/GSe Brockville

Service Charge	$	18.67
Distribution Volumetric Rate	$ / kWh	0.0200
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0004
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0006)
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0036
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0033
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service 50 kW or Greater (Demand-Billed) - UGd/GSd Brockville

Service Charge	$	22.89
Distribution Volumetric Rate	$ / kW	6.70
Regulatory Asset Recovery - Rider #2	$ / kW	0.12
Regulatory Asset Recovery - Rider #3	$ / kW	(0.27)
Retail Transmission Rate - Network Service Rate (4)	$ / kW	1.41
Retail Transmission Rate - Line and Transformation Connection Service Rate (4)	$ / kW	1.27
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Brockville Public Utilities Commission
Effective Date: May 1, 2008

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

Unmetered, Scattered Load

Service Charge	$	13.79
Distribution Volumetric Rate	$ / kWh	0.0200
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0004
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0006)
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0035
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0032
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

(3) For energy-only metered customers, the billing determinant is the customer's metered energy consumption adjusted by the total loss factor as approved by the Board for Acquired LDC customers.
(4) For demand billed customers, appropriate loss factors must be applied to the applicable tariffs. Also the billing determinant for the Line and Transformation Connection Services rate is the customer's peak demand in the billing period. The billing determinant for the Network Services rate is: for non-interval-metered customers, the peak demand in the billing period, and for interval-metered customers, the peak demand between 7 AM and 7 PM local time on IESO business days

Customer-Supplied Transformation Allowance

Applicable to customers providing their own transformers

Demand-billed	$ / kW	0.60
Energy-billed	$ / kWh	0.0014

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Brockville Public Utilities Commission
Effective Date: May 1, 2008

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

Loss Factors

Residential	1.078
General Service Less Than 50 kW (Energy-Billed)	1.092
General Service 50 kW or Greater (Demand-Billed)	1.061
Unmetered Scattered Load	1.092

Transformer Loss Allowance

Applicable to customers requiring a billing adjustment for transformer losses as the result of being metered on the primary side of a transformer. The following uniform values shall be applied to measured demand and energy to calculate transformer losses for voltages up to and including 50 kV (as metered on the primary side):

(a) 1.5% for transformer installations up to an individual bank capacity of 400 kVA,
(b) 1.0% for bank capacities over 400 kVA.

Alternatively, transformer losses may be determined from transformer test data, and measured demand and energy adjusted accordingly

For services which are not demand metered, an assumed demand of 50% of the transformer capacity will be used to calculate the loss allowance. Where several transformers are involved, the bank capacity is assumed to be the arithmetic sum of all transformer capacities

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Brockville Public Utilities Commission
Effective Date: May 1, 2008

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

MISCELLANEOUS CHARGES

Specific Service Charges: Standard Amounts

Rate Code	Specific Service Charge - Standard Name	Calculation Method			
		2006 Rate Handbook	Standard Formula	Other Formula	Time and Materials
1	Temporary Service	$500			
2	Dispute Meter Test	$30 plus Measurement Canada fees			
3	Collection of account – no disconnection/load limiter	$30			
4	Collection/Disconnect/load limiter/reconnect (at meter) trip – regular hours	$65			
5	Collection/Disconnect/load limiter/reconnect (at meter) trip – after regular hours	$185			
6	Collection/Disconnect/load limiter/reconnect (at pole) trip – regular hours	$185			
7	Collection/Disconnect/load limiter/reconnect (at pole) trip – after regular hours	$415			
8	Account Set-up Charge	$30			
9	Arrears Certificate	$15			
10	NSF Cheque Charge	$15 + bank charges			
11	Easement Charge for Unregistered Rights	$15			
12	Late Payment Charge	1.5%/month			
13a	Retailer Services – Establishing Service Agreements (refer to Handbook for all charges)	$100/agreement/Retailer +$20/month/Retailer +$0.50/month/customer + other			
13b	Retailer Services – Other (includes Bill Ready for Retailers and Service Transactions Requests) as per the Handbook, Chapter 12	$0.30/month/customer + $0.25/request for request fee + $0.50/request for process fee			
14	Special Meter Reads	$30			
15	Service Layout Fee – Basic		$495		
16	Service Layout Fee – Complex		$690		
17	Crossing Application – Pipeline		$2,445		
18	Crossing Application – Water		$3,045		
19	Crossing Application – Railroad		$2,945		
20	Line Staking – per meter		$3.70		
21	Central Metering – New service < 45 kW		$115		
22	Conversion to Central Metering < 45 kW		$915		
23	Conversion to Central Metering > 45 kW		$800		
24	Tingle Voltage Test – In Excess of 4 Hours (per hour – average 2 additional hours)		$125		
25	Standby Administration Charge per month		$440		
26	Sentinel Lights Rental Rate per month			$7.10	
27	Sentinel Pole Rental Rate per month			$4.15	
28	Joint Use for Cable and Telecom companies per pole			$22.35	
29	Joint Use for LDCs per pole			$28.61	

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Brockville Public Utilities Commission
Effective Date: May 1, 2007

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

APPLICATION

The application of these rates and charges shall be in accordance with The Licence of The Distributor and any Codes, Guidelines or Orders of The Board, and amendments thereto as approved by The Board, which may be applicable to the administration of this schedule.
No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code, Guideline or Order of the Board, and amendments thereto as approved by the Board, or as specified herein
This schedule does not contain any rates and charges relating to the electricity commodity (e.g. the Regulated Price Plan).

EFFECTIVE DATES

DISTRIBUTION RATES - May 1, 2007 for all consumption or deemed consumption services used on or after that date.

MISCELLANEOUS CHARGES - May 1, 2007 for all charges billed to customers on or after that date.
RETAIL TRANSMISSION RATES - May 1, 2007 for all consumption or deemed consumption services used on or after that date.
LOSS FACTOR ADJUSTMENT – May 1, 2007

SERVICE CLASSIFICATIONS

Residential
This classification (note 1) refers to all service supplied to single-family dwelling units for domestic or household purpose. Multi-unit residential establishments such as apartment buildings supplied through one service (bulk metered) will normally be classified as General Service, but, at Hydro One's discretion, up to four residential units may be classified as residential. Where electricity service is provided to combined residential and business (including agricultural usage) and the wiring does not provide for separate metering, the classification shall be at the discretion of Hydro One based on such considerations as the estimated predominant consumption.
Further servicing details are available in the utility's Conditions of Service.

General Service
This classification (note 1) refers to all service supplied to premises other than those classified as Residential, Lighting or Large Use. Some General Service accounts are energy(kWh)-billed, and some are demand(kW)-billed. Further servicing details are available in the utility's Conditions of Service. Also, see note 2.

Unmetered Scattered Load
This classification refers to certain instances where connections can be provided without metering. These loads are generally small in size and consistent in magnitude of load. Hydro One reserves the right to review all cases and may require that a meter be installed at its sole discretion. Services that can be unmetered include cable TV amplifiers, telephone switching devices, phone booths, bus shelters, rail way crossing signals, traffic signals, and other small fixed loads.
Further servicing details are available in the utility's Conditions of Service (including in the "Unmetered Connections" section).

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Brockville Public Utilities Commission
Effective Date: May 1, 2007

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

Large Use

This classification refers to individual Customers whose monthly measured maximum demand (kW) averaged over the Further servicing details are available in the utility’s Conditions of Service. Also, see note 2.

Street Lighting

This classification refers to accounts for the distribution and supply of electrical energy for street lighting. Street lights are devices owned by or operated for the road authority and/or the municipal corporation. These street lights in fact belong to the Street Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility’s Conditions of Service.

Sentinel Lighting

This classification refers to accounts for a separate service to a sentinel light. These sentinel lights in fact belong to the Sentinel Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility’s Conditions of Service.

Interim Demand-Side Management Time-of-Use

This is potentially applicable to Demand-billed General Service and Large Use accounts. See Note 2 below.

Note (1): Classification descriptions are paraphrases from the document "Hydro One Networks Inc. - Distribution Customers Conditions of Service - August 2004"

Note (2):

Interim Demand-Side Management Time-of-Use Rates: demand charges will be based on demand during the on-peak periods.

Criteria: Customers' electricity consumption (kW) in the off-peak period is at least twice the electricity consumption (kW) during the on-peak period.

Definition of Time Periods: The on-peak hours will be between 0700 hours to 1900 hours Eastern Standard Time during the winter (standard time) on IESO business days and 0600 hours to 1800 hours Eastern Standard Time during the summer (daylight savings time) on IESO business days. The off-peak period constitutes all of the remaining hours.

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Brockville Public Utilities Commission
Effective Date: May 1, 2007

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

MONTHLY RATES AND CHARGES

Residential

Service Charge	$	12.33
Distribution Volumetric Rate	$ / kWh	0.0093
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0048
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0016
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0055
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0047
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service - Energy Billed (less than 50 kW)

Service Charge	$	21.65
Distribution Volumetric Rate	$ / kWh	0.0078
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0013
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0004
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0050
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0043
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service - Demand Billed (50 kW or greater)

Service Charge	$	21.65
Distribution Volumetric Rate	$ / kW	2.49
Regulatory Asset Recovery - Rider #1	$ / kW	0.41
Regulatory Asset Recovery - Rider #2	$ / kW	0.12
Retail Transmission Rate - Network Service Rate (4)	$ / kW	1.94
Retail Transmission Rate - Line and Transformation Connection Service Rate (4)	$ / kW	1.61
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Brockville Public Utilities Commission
Effective Date: May 1, 2007

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

Unmetered, Scattered Load

Service Charge	$	10.37
Distribution Volumetric Rate	$ / kWh	0.0078
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0013
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0004
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0050
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0043
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

Large User

Service Charge	$	2,608
Distribution Volumetric Rate	$ / kW	3.91
Regulatory Asset Recovery - Rider #1	$ / kW	0.33
Regulatory Asset Recovery - Rider #2	$ / kW	0.21
Retail Transmission Rate - Network Service Rate (4)	$ / kW	2.37
Retail Transmission Rate - Line and Transformation Connection Service Rate (4)	$ / kW	2.09
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

(3) For energy-only metered customers, the billing determinant is the customer's metered energy consumption adjusted by the total loss factor as approved by the Board for Acquired LDC customers.
(4) For demand billed customers, appropriate loss factors must be applied to the applicable tariffs. Also the billing determinant for the Line and Transformation Connection Services rate is the customer's peak demand in the billing period. The billing determinant for the Network Services rate is: for non-interval-metered customers, the peak demand in the billing period, and for interval-metered customers, the peak demand between 7 AM and 7 PM local time on IESO business days

Interim Demand-Side Management Time-of-Use

See the "Service Classifications" section of this schedule.

Customer-Supplied Transformation Allowance

Applicable to demand-billed customers (excluding Large Users) providing their own transformers
Primary Voltage under 50 kV (per kW)

Single Phase	$ / kW	0.20
Three Phase	$ / kW	0.60

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Brockville Public Utilities Commission
Effective Date: May 1, 2007

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

Loss Factors

Supply Facilities Loss Factor	1.0045
Distribution Loss Factors	
Customer less than 5,000 kW	1.0500
Customer greater than or equal to 5,000 kW	1.0100
Total Loss Factors	
Customer less than 5,000 kW	1.0545
Customer greater than or equal to 5,000 kW	1.0145

Transformer Loss Allowance

Applicable to customers requiring a billing adjustment for transformer losses as the result of being metered on the primary side of a transformer. The following uniform values shall be applied to measured demand and energy to calculate transformer losses for voltages up to and including 50 kV (as metered on the primary side):

(a) 1.5% for transformer installations up to an individual bank capacity of 400 kVA,
(b) 1.0% for bank capacities over 400 kVA.

Alternatively, transformer losses may be determined from transformer test data, and measured demand and energy adjusted accordingly

For services which are not demand metered, an assumed demand of 50% of the transformer capacity will be used to calculate the loss allowance. Where several transformers are involved, the bank capacity is assumed to be the arithmetic sum of all transformer capacities

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Brockville Public Utilities Commission
Effective Date: May 1, 2007

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

MISCELLANEOUS CHARGES

Specific Service Charges: Standard Amounts

Rate Code	Specific Service Charge - Standard Name	Calculation Method			
		2006 Rate Handbook	Standard Formula	Other Formula	Time and Materials
1	Temporary Service	$500			
2	Dispute Meter Test	$30 plus Measurement Canada fees			
3	Collection of account – no disconnection/load limiter	$30			
4	Collection/Disconnect/load limiter/reconnect (at meter) trip – regular hours	$65			
5	Collection/Disconnect/load limiter/reconnect (at meter) trip – after regular hours	$185			
6	Collection/Disconnect/load limiter/reconnect (at pole) trip – regular hours	$185			
7	Collection/Disconnect/load limiter/reconnect (at pole) trip – after regular hours	$415			
8	Account Set-up Charge	$30			
9	Arrears Certificate	$15			
10	NSF Cheque Charge	$15 + bank charges			
11	Easement Charge for Unregistered Rights	$15			
12	Late Payment Charge	1.5%/month			
13a	Retailer Services – Establishing Service Agreements (refer to Handbook for all charges)	$100/agreement/Retailer +$20/month/Retailer +$0.50/month/customer + other			
13b	Retailer Services – Other (includes Bill Ready for Retailers and Service Transactions Requests) as per the Handbook, Chapter 12	$0.30/month/customer + $0.25/request for request fee + $0.50/request for process fee			
14	Special Meter Reads	$30			
15	Billing Suspension and Terminations in Trailer Parks		$130		
16	Service Layout Fee – Basic		$405		
17	Service Layout Fee – Complex		$580		

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Brockville Public Utilities Commission
Effective Date: May 1, 2007

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

18	Crossing Application – Pipeline		$2,065		
19	Crossing Application – Water		$2,525		
20	Crossing Application – Railroad		$2,565		
21	Line Staking – per meter		$3.10		
22	Central Metering – New service < 45 kW		$115		
23	Conversion to Central Metering < 45 kW		$795		
24	Conversion to Central Metering > 45 kW		$680		
25	Tingle Voltage Test – In Excess of 4 Hours (per hour – average 2 additional hours)		$105		
26	Standby Administration Charge per month (interim)		$375		
27	Sentinel Lights Rental Rate per month – Mercury Vapor			$7.00	
28	Guaranteed Units from Jan 01/91 to Aug 01/91			$26.50 / month	
29	Guaranteed Units from Jan 01/87 to Dec 31/90			$23.50 / month	
30	Joint Use for Cable and Telecom companies per pole			$22.35	
31	Joint Use for LDCs per pole			$28.61	

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Caledon Hydro Corporation
Effective May 1, 2008

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

APPLICATION

The application of these rates and charges shall be in accordance with The Licence of The Distributor and any Codes, Guidelines or Orders of The Board, and amendments thereto as approved by The Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code, Guideline or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

This schedule does not contain any rates and charges relating to the electricity commodity (e.g. the Regulated Price Plan).

EFFECTIVE DATES

DISTRIBUTION RATES - May 1, 2008 for all consumption or deemed consumption services used on or after that date

MISCELLANEOUS CHARGES - May 1, 2008 for all charges billed to customers on or after that date.

RETAIL TRANSMISSION RATES - May 1, 2008 for all consumption or deemed consumption services used on or after that date

LOSS FACTOR ADJUSTMENT – for all consumption or deemed consumption services billed following May 1, 2008 or later

SERVICE CLASSIFICATIONS

Residential

This classification refers to all service supplied to single-family dwelling units for domestic or household purpose. Multi-unit residential establishments such as apartment buildings supplied through one service (bulk metered) will normally be classified as General Service, but, at Hydro One’s discretion, up to four residential units may be classified as residential. Where electricity service is provided to combined residential and business (including agricultural usage) and the wiring does not provide for separate metering, the classification shall be at the discretion of Hydro One based on such considerations as the estimated predominant consumption. Further servicing details are available in the utility’s Conditions of Service.

Residential CH-02 is for customers located in the town of Bolton and who were in the area of the former pre-expanded municipally-owned utility.

Residential OH-01 is for the areas of the former Ontario Hydro Urban class rates (outside the town of Bolton).

Residential OH-06 is for the former Ontario Hydro R2 class rates (outside the town of Bolton).

Residential OH-07 is for the former Ontario Hydro R4 class rates (outside the town of Bolton).

General Service

This classification refers to all service supplied to premises other than those classified as Residential, Lighting or Large Use. Some General Service accounts are energy(kWh)-billed, and some are demand(kW)-billed. Further servicing details are available in the utility’s Conditions of Service. Also, see note 2.

General Service GS-OH is for the former Ontario Hydro General Service class rates (outside the town of Bolton).

General Service GS-CH is for customers located in the town of Bolton and who were in the area of the former pre-expanded municipally-owned utility.

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Unmetered Scattered Load

This classification refers to certain instances where connections can be provided without metering. These loads are generally small in size and consistent in magnitude of load. Hydro One reserves the right to review all cases and may require that a meter be installed at its sole discretion. Services that can be unmetered include cable TV amplifiers, telephone switching devices, phone booths, bus shelters, rail way crossing signals, traffic signals, and other small fixed loads.

Large Use - see Note 1

Street Lighting

This classification refers to accounts for the distribution and supply of electrical energy for street lighting. Street lights are devices owned by or operated for the road authority and/or the municipal corporation. These street lights in fact belong to the Street Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Sentinel Lighting

This classification refers to accounts for a separate service to a sentinel light. These sentinel lights in fact belong to the Sentinel Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Customer Class Reclassification

Customers in Residential OH 01 will be mapped to Urban customer classification.
Customers in Residential CH 02 will be mapped to R1 customer classification.
Customers in Residential OH 06 will be mapped to R2 customer classification.
Customers in Residential OH 07 will be mapped to Seasonal customer classification.

Note (1)
The former Large Use class is now part of the ST class, which is separate from the classes for customers of acquired distribution companies.
This former class refered to individual Customers whose monthly measured maximum demand (kW) averaged over the most recent 12 consecutive months was equal to or greater than 5,000 kW.

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MONTHLY RATES AND CHARGES

Residential CH 02

Service Charge	$	15.96
Distribution Volumetric Rate	$ / kWh	0.0210
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0008
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0004)
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0047
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0046
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

Residential OH 01

Service Charge	$	16.95
Distribution Volumetric Rate	$ / kWh	0.0215
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0016
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0002)
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0047
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0045
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

Residential OH 06

Service Charge	$	30.64
Distribution Volumetric Rate	$ / kWh	0.0220
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0011
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0005)
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0046
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0043
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

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Residential OH 07

Service Charge	$	33.18
Distribution Volumetric Rate	$ / kWh	0.0320
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0025
Regulatory Asset Recovery - Rider #3	$ / kWh	0.0002
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0044
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0043
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service OH - Energy Billed (less than 50 kW)

Service Charge	$	26.70
Distribution Volumetric Rate	$ / kWh	0.0290
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0007
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0006)
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0035
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0032
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service OH - Demand Billed (50 kW or greater)

Service Charge	$	30.30
Distribution Volumetric Rate	$ / kW	9.22
Regulatory Asset Recovery - Rider #2	$ / kW	0.24
Regulatory Asset Recovery - Rider #3	$ / kW	(0.22)
Retail Transmission Rate - Network Service Rate (4)	$ / kW	1.11
Retail Transmission Rate - Line and Transformation Connection Service Rate (4)	$ / kW	1.00
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

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General Service CH - Energy Billed (less than 50 kW)

Service Charge	$	26.04
Distribution Volumetric Rate	$ / kWh	0.0290
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0008
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0006)
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0035
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0032
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service CH - Demand Billed (50 kW or greater)

Service Charge	$	29.64
Distribution Volumetric Rate	$ / kW	9.22
Regulatory Asset Recovery - Rider #2	$ / kW	0.27
Regulatory Asset Recovery - Rider #3	$ / kW	(0.22)
Retail Transmission Rate - Network Service Rate (4)	$ / kW	1.11
Retail Transmission Rate - Line and Transformation Connection Service Rate (4)	$ / kW	1.00
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

Unmetered, Scattered Load

Service Charge	$	14.47
Distribution Volumetric Rate	$ / kWh	0.0200
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0008
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0006)
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0035
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0032
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

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Notes:

(3) For energy-only metered customers, the billing determinant is the customer's metered energy consumption adjusted by the total loss factor as approved by the Board for Acquired LDC customers.
(4) For demand billed customers, appropriate loss factors must be applied to the applicable tariffs. Also the billing determinant for the Line and Transformation Connection Services rate is the customer's peak demand in the billing period. The billing determinant for the Network Services rate is: for non-interval-metered customers, the peak demand in the billing period, and for interval-metered customers, the peak demand between 7 AM and 7 PM local time on IESO business days

Customer-Supplied Transformation Allowance

Applicable to customers providing their own transformers

Demand-billed	$ / kW	0.600
Energy-billed	$ / kWh	0.00140

Loss Factors

Residential CH 02	1.085
Residential OH 01	1.078
Residential OH 06	1.092
Residential OH 07	1.092
General Service OH - Energy Billed (less than 50 kW)	1.092
General Service OH - Demand Billed (50 kW or greater)	1.061
General Service CH - Energy Billed (less than 50 kW)	1.092
General Service CH - Demand Billed (50 kW or greater)	1.061
Unmetered, Scattered Load	1.092

Transformer Loss Allowance

Applicable to customers requiring a billing adjustment for transformer losses as the result of being metered on the primary side of a transformer. The following uniform values shall be applied to measured demand and energy to calculate transformer losses for voltages up to and including 50 kV (as metered on the primary side):

(a) 1.5% for transformer installations up to an individual bank capacity of 400 kVA,
(b) 1.0% for bank capacities over 400 kVA.

Alternatively, transformer losses may be determined from transformer test data, and measured demand and energy adjusted accordingly
For services which are not demand metered, an assumed demand of 50% of the transformer capacity will be used to calculate the loss allowance. Where several transformers are involved, the bank capacity is assumed to be the arithmetic sum of all transformer capacities

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MISCELLANEOUS CHARGES

Specific Service Charges: Standard Amounts

Rate Code	Specific Service Charge - Standard Name	Calculation Method			
		2006 Rate Handbook	Standard Formula	Other Formula	Time and Materials
1	Temporary Service	$500			
2	Dispute Meter Test	$30 plus Measurement Canada fees			
3	Collection of account – no disconnection/load limiter	$30			
4	Collection/Disconnect/load limiter/reconnect (at meter) trip – regular hours	$65			
5	Collection/Disconnect/load limiter/reconnect (at meter) trip – after regular hours	$185			
6	Collection/Disconnect/load limiter/reconnect (at pole) trip – regular hours	$185			
7	Collection/Disconnect/load limiter/reconnect (at pole) trip – after regular hours	$415			
8	Account Set-up Charge	$30			
9	Arrears Certificate	$15			
10	NSF Cheque Charge	$15 + bank charges			
11	Easement Charge for Unregistered Rights	$15			
12	Late Payment Charge	1.5%/month			
13a	Retailer Services – Establishing Service Agreements (refer to Handbook for all charges)	$100/agreement/Retailer +$20/month/Retailer +$0.50/month/customer + other			
13b	Retailer Services – Other (includes Bill Ready for Retailers and Service Transactions Requests) as per the Handbook, Chapter 12	$0.30/month/customer + $0.25/request for request fee + $0.50/request for process fee			
14	Special Meter Reads	$30			
15	Service Layout Fee – Basic		$495		
16	Service Layout Fee – Complex		$690		
17	Crossing Application – Pipeline		$2,445		
18	Crossing Application – Water		$3,045		
19	Crossing Application – Railroad		$2,945		
20	Line Staking – per meter		$3.70		
21	Central Metering – New service < 45 kW		$115		
22	Conversion to Central Metering < 45 kW		$915		
23	Conversion to Central Metering > 45 kW		$800		
24	Tingle Voltage Test – In Excess of 4 Hours (per hour – average 2 additional hours)		$125		
25	Standby Administration Charge per month		$440		
26	Sentinel Lights Rental Rate per month			$7.10	
27	Sentinel Pole Rental Rate per month			$4.15	
28	Joint Use for Cable and Telecom companies per pole			$22.35	
29	Joint Use for LDCs per pole			$28.61	

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APPLICATION

The application of these rates and charges shall be in accordance with The Licence of The Distributor and any Codes, Guidelines or Orders of The Board, and amendments thereto as approved by The Board, which may be applicable to the administration of this schedule.
No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code, Guideline or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.
This schedule does not contain any rates and charges relating to the electricity commodity (e.g. the Regulated Price Plan).

EFFECTIVE DATES

DISTRIBUTION RATES - May 1, 2007 for all consumption or deemed consumption services used on or after that date.
MISCELLANEOUS CHARGES - May 1, 2007 for all charges billed to customers on or after that date.
RETAIL TRANSMISSION RATES - May 1, 2007 for all consumption or deemed consumption services used on or after that date.
LOSS FACTOR ADJUSTMENT – May 1, 2007

SERVICE CLASSIFICATIONS

Residential
This classification (note 1) refers to all service supplied to single-family dwelling units for domestic or household purpose. Multi-unit residential establishments such as apartment buildings supplied through one service (bulk metered) will normally be classified as General Service, but, at Hydro One's discretion, up to four residential units may be classified as residential. Where electricity service is provided to combined residential and business (including agricultural usage) and the wiring does not provide for separate metering, the classification shall be at the discretion of Hydro One based on such considerations as the estimated predominant consumption. Further servicing details are available in the utility's Conditions of Service.
Residential CH-02 is for customers located in the town of Bolton and who were in the area of the former pre-expanded municipally-owned utility.
Residential OH-01 is for the areas of the former Ontario Hydro Urban class rates (outside the town of Bolton).
Residential OH-06 is for the former Ontario Hydro R2 class rates (outside the town of Bolton).
Residential OH-07 is for the former Ontario Hydro R4 class rates (outside the town of Bolton).

General Service
This classification (note 1) refers to all service supplied to premises other than those classified as Residential, Lighting or Large Use. Some General Service accounts are energy(kWh)-billed, and some are demand(kW)-billed. Further servicing details are available in the utility's Conditions of Service. Also, see note 2.
General Service GS-05 is for the former Ontario Hydro Farm class rates (outside the town of Bolton).
General Service GS-OH is for the former Ontario Hydro General Service class rates (outside the town of Bolton).
General Service GS-CH is for customers located in the town of Bolton and who were in the area of the former pre-expanded municipally-owned utility.

Unmetered Scattered Load
This classification refers to certain instances where connections can be provided without metering. These loads are generally small in size and consistent in magnitude of load. Hydro One reserves the right to review all cases and may require that a meter be installed at its sole discretion. Services that can be unmetered include cable TV amplifiers, telephone switching devices, phone booths, bus shelters, rail way crossing signals, traffic signals, and other small fixed loads.
Further servicing details are available in the utility's Conditions of Service (including in the "Unmetered Connections" section).

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Large Use

This classification refers to individual Customers whose monthly measured maximum demand (kW) averaged over the most recent 12 consecutive months is equal or greater than 5,000 kW.
This Large User class is applicable only to a large user in the former Town of Bolton.
Further servicing details are available in the utility's Conditions of Service. Also, see note 2.

Street Lighting

This classification refers to accounts for the distribution and supply of electrical energy for street lighting. Street lights are devices owned by or operated for the road authority and/or the municipal corporation. These street lights in fact belong to the Street Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Sentinel Lighting

This classification refers to accounts for a separate service to a sentinel light. These sentinel lights in fact belong to the Sentinel Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Interim Demand-Side Management Time-of-Use

This is potentially applicable to Demand-billed General Service and Large Use accounts. See Note 2 below.

Note (1): Classification descriptions are paraphrases from the document "Hydro One Networks Inc. - Distribution Customers Conditions of Service - August 2004"
Note (2):

Interim Demand-Side Management Time-of-Use Rates: demand charges will be based on demand during the on-peak periods.

Criteria: Customers' electricity consumption (kW) in the off-peak period is at least twice the electricity consumption (kW) during the on-peak period.

Definition of Time Periods: The on-peak hours will be between 0700 hours to 1900 hours Eastern Standard Time during the winter (standard time) on IESO business days and 0600 hours to 1800 hours Eastern Standard Time during the summer (daylight savings time) on IESO business days. The off-peak period constitutes all of the remaining hours.

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MONTHLY RATES AND CHARGES

Residential CH 02

Service Charge	$	15.19
Distribution Volumetric Rate	$ / kWh	0.0102
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0028
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0008
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0055
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0047
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

Residential OH 01

Service Charge	$	18.52
Distribution Volumetric Rate	$ / kWh	0.0057
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0042
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0016
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0055
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0047
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

Residential OH 06

Service Charge	$	34.85
Distribution Volumetric Rate	$ / kWh	0.0050
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0025
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0011
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0055
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0047
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

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Residential OH 07

Service Charge	$	38.78
Distribution Volumetric Rate	$ / kWh	0.0104
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0043
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0025
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0055
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0047
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service 05 - Energy Billed (less than 50 kW)

Service Charge	$	23.34
Distribution Volumetric Rate	$ / kWh	0.0219
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0022
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0020
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0050
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0043
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service 05 - Demand Billed (50 kW or greater)

Service Charge	$	23.34
Distribution Volumetric Rate	$ / kW	6.9600
Regulatory Asset Recovery - Rider #1	$ / kW	0.6900
Regulatory Asset Recovery - Rider #2	$ / kW	0.6400
Retail Transmission Rate - Network Service Rate (4)	$ / kW	1.9400
Retail Transmission Rate - Line and Transformation Connection Service Rate (4)	$ / kW	1.61
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service OH - Energy Billed (less than 50 kW)

Service Charge	$	25.56
Distribution Volumetric Rate	$ / kWh	0.0170
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0016
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0007
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0050
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0043
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

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General Service OH - Demand Billed (50 kW or greater)

Service Charge	$	25.56
Distribution Volumetric Rate	$ / kW	5.35
Regulatory Asset Recovery - Rider #1	$ / kW	0.51
Regulatory Asset Recovery - Rider #2	$ / kW	0.24
Retail Transmission Rate - Network Service Rate (4)	$ / kW	1.94
Retail Transmission Rate - Line and Transformation Connection Service Rate (4)	$ / kW	1.61
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service CH - Energy Billed (less than 50 kW)

Service Charge	$	24.21
Distribution Volumetric Rate	$ / kWh	0.0180
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0014
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0008
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0050
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0043
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service CH - Demand Billed (50 kW or greater)

Service Charge	$	24.21
Distribution Volumetric Rate	$ / kW	5.73
Regulatory Asset Recovery - Rider #1	$ / kW	0.45
Regulatory Asset Recovery - Rider #2	$ / kW	0.27
Retail Transmission Rate - Network Service Rate (4)	$ / kW	1.94
Retail Transmission Rate - Line and Transformation Connection Service Rate (4)	$ / kW	1.61
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

Unmetered, Scattered Load

Service Charge	$	11.63
Distribution Volumetric Rate	$ / kWh	0.0180
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0014
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0008
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0050
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0043
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

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Large User

Service Charge	$	4,279
Distribution Volumetric Rate	$ / kW	5.22
Regulatory Asset Recovery - Rider #1	$ / kW	0.20
Regulatory Asset Recovery - Rider #2	$ / kW	0.16
Retail Transmission Rate - Network Service Rate (4)	$ / kW	2.37
Retail Transmission Rate - Line and Transformation Connection Service Rate (4)	$ / kW	2.09
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

Notes:

(3) For energy-only metered customers, the billing determinant is the customer’s metered energy consumption adjusted by the total loss factor as approved by the Board for Acquired LDC customers.

(4) For demand billed customers, appropriate loss factors must be applied to the applicable tariffs. Also the billing determinant for the Line and Transformation Connection Services rate is the customer’s peak demand in the billing period. The billing determinant for the Network Services rate is: for non-interval-metered customers, the peak demand in the billing period, and for interval-metered customers, the peak demand between 7 AM and 7 PM local time on IESO business days

Interim Demand-Side Management Time-of-Use

See the "Service Classifications" section of this schedule.

Customer-Supplied Transformation Allowance

Applicable to demand-billed customers (excluding Large Users) providing their own transformers
Primary Voltage under 50 kV (per kW)

Single Phase	$ / kW	0.20
Three Phase	$ / kW	0.60

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Loss Factors

Supply Facilities Loss Factor	1.0045
Distribution Loss Factors	
Customer less than 5,000 kW	1.0500
Customer greater than or equal to 5,000 kW	1.0100
Total Loss Factors	
Customer less than 5,000 kW	1.0545
Customer greater than or equal to 5,000 kW	1.0145

Transformer Loss Allowance

Applicable to customers requiring a billing adjustment for transformer losses as the result of being metered on the primary side of a transformer. The following uniform values shall be applied to measured demand and energy to calculate transformer losses for voltages up to and including 50 kV (as metered on the primary side):

(a) 1.5% for transformer installations up to an individual bank capacity of 400 kVA,
(b) 1.0% for bank capacities over 400 kVA.

Alternatively, transformer losses may be determined from transformer test data, and measured demand and energy adjusted accordingly

For services which are not demand metered, an assumed demand of 50% of the transformer capacity will be used to calculate the loss allowance. Where several transformers are involved, the bank capacity is assumed to be the arithmetic sum of all transformer capacities

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Caledon Hydro Corporation
Effective May 1, 2007

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

MISCELLANEOUS CHARGES

Specific Service Charges: Standard Amounts

Rate Code	Specific Service Charge - Standard Name	Calculation Method			
		2006 Rate Handbook	Standard Formula	Other Formula	Time and Materials
1	Temporary Service	$500			
2	Dispute Meter Test	$30 plus Measurement Canada fees			
3	Collection of account – no disconnection/load limiter	$30			
4	Collection/Disconnect/load limiter/reconnect (at meter) trip – regular hours	$65			
5	Collection/Disconnect/load limiter/reconnect (at meter) trip – after regular hours	$185			
6	Collection/Disconnect/load limiter/reconnect (at pole) trip – regular hours	$185			
7	Collection/Disconnect/load limiter/reconnect (at pole) trip – after regular hours	$415			
8	Account Set-up Charge	$30			
9	Arrears Certificate	$15			
10	NSF Cheque Charge	$15 + bank charges			
11	Easement Charge for Unregistered Rights	$15			
12	Late Payment Charge	1.5%/month			
13a	Retailer Services – Establishing Service Agreements (refer to Handbook for all charges)	$100/agreement/Retailer +$20/month/Retailer +$0.50/month/customer + other			
13b	Retailer Services – Other (includes Bill Ready for Retailers and Service Transactions Requests) as per the Handbook, Chapter 12	$0.30/month/customer + $0.25/request for request fee + $0.50/request for process fee			
14	Special Meter Reads	$30			
15	Billing Suspension and Terminations in Trailer Parks		$130		
16	Service Layout Fee – Basic		$405		
17	Service Layout Fee – Complex		$580		

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Caledon Hydro Corporation
Effective May 1, 2007

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18	Crossing Application – Pipeline		$2,065		
19	Crossing Application – Water		$2,525		
20	Crossing Application – Railroad		$2,565		
21	Line Staking – per meter		$3.10		
22	Central Metering – New service < 45 kW		$115		
23	Conversion to Central Metering < 45 kW		$795		
24	Conversion to Central Metering > 45 kW		$680		
25	Tingle Voltage Test – In Excess of 4 Hours (per hour – average 2 additional hours)		$105		
26	Standby Administration Charge per month (interim)		$375		
27	Sentinel Lights Rental Rate per month – Mercury Vapor			$7.00	
28	Guaranteed Units from Jan 01/91 to Aug 01/91			$26.50 / month	
29	Guaranteed Units from Jan 01/87 to Dec 31/90			$23.50 / month	
30	Joint Use for Cable and Telecom companies per pole			$22.35	
31	Joint Use for LDCs per pole			$28.61	

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Campbellford/Seymour Public Utilities Commission
Effective Date: May 1, 2008

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

APPLICATION

The application of these rates and charges shall be in accordance with The Licence of The Distributor and any Codes, Guidelines or Orders of The Board, and amendments thereto as approved by The Board, which may be applicable to the administration of this schedule.
No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code, Guideline or Order of the Board, and amendments thereto as approved by the Board, or as specified herein
This schedule does not contain any rates and charges relating to the electricity commodity (e.g. the Regulated Price Plan).

EFFECTIVE DATES

DISTRIBUTION RATES - May 1, 2008 for all consumption or deemed consumption services used on or after that date.

MISCELLANEOUS CHARGES - May 1, 2008 for all charges billed to customers on or after that date.
RETAIL TRANSMISSION RATES - May 1, 2008 for all consumption or deemed consumption services used on or after that date.
LOSS FACTOR ADJUSTMENT – for all consumption or deemed consumption services billed following May 1, 2008 or later

SERVICE CLASSIFICATIONS

Residential
This classification refers to all service supplied to single-family dwelling units for domestic or household purpose. Multi-unit residential establishments such as apartment buildings supplied through one service (bulk metered) will normally be classified as General Service, but, at Hydro One's discretion, up to four residential units may be classified as residential. Where electricity service is provided to combined residential and business (including agricultural usage) and the wiring does not provide for separate metering, the classification shall be at the discretion of Hydro One based on such considerations as the estimated predominant consumption.
Further servicing details are available in the utility's Conditions of Service.

General Service
This classification refers to all service supplied to premises other than those classified as Residential or Lighting. Some General Service accounts are energy(kWh)-billed, and some are demand(kW)-billed. Further servicing details are available in the utility's Conditions of Service.

Unmetered Scattered Load
This classification refers to certain instances where connections can be provided without metering. These loads are generally small in size and consistent in magnitude of load. Hydro One reserves the right to review all cases and may require that a meter be installed at its sole discretion. Services that can be unmetered include cable TV amplifiers, telephone switching devices, phone booths, bus shelters, rail way crossing signals, traffic signals, and other small fixed loads.
Further servicing details are available in the utility's Conditions of Service (including in the "Unmetered Connections" section).

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Campbellford/Seymour Public Utilities Commission
Effective Date: May 1, 2008

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

Street Lighting

This classification refers to accounts for the distribution and supply of electrical energy for street lighting. Street lights are devices owned by or operated for the road authority and/or the municipal corporation. These street lights in fact belong to the Street Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Sentinel Lighting

This classification refers to accounts for a separate service to a sentinel light. These sentinel lights in fact belong to the Sentinel Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Urban Density Classification

Customers who meet the Urban Density Criteria of being in an area containing 3,000 or more customers with a line density of at least 60 customers per kilometre, will be mapped to an Urban customer classification.

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Campbellford/Seymour Public Utilities Commission
Effective Date: May 1, 2008

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

MONTHLY RATES AND CHARGES

Residential - R1 Campbellford-Seymour

Service Charge	$	13.69
Distribution Volumetric Rate	$ / kWh	0.0225
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0012
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0004)
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0047
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0046
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service Less Than 50 kW (Energy-Billed) - GSe Campbellford-Seymour

Service Charge	$	20.04
Distribution Volumetric Rate	$ / kWh	0.0215
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0005
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0006)
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0035
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0032
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service 50 kW or Greater (Demand-Billed) - GSd Campbellford-Seymour

Service Charge	$	23.64
Distribution Volumetric Rate	$ / kW	8.50
Regulatory Asset Recovery - Rider #2	$ / kW	0.17
Regulatory Asset Recovery - Rider #3	$ / kW	(0.22)
Retail Transmission Rate - Network Service Rate (4)	$ / kW	1.11
Retail Transmission Rate - Line and Transformation Connection Service Rate (4)	$ / kW	1.00
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Campbellford/Seymour Public Utilities Commission
Effective Date: May 1, 2008

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

Unmetered, Scattered Load

Service Charge	$	11.47
Distribution Volumetric Rate	$ / kWh	0.0200
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0005
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0006)
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0035
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0032
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

(3) For energy-only metered customers, the billing determinant is the customer's metered energy consumption adjusted by the total loss factor as approved by the Board for Acquired LDC customers.
(4) For demand billed customers, appropriate loss factors must be applied to the applicable tariffs. Also the billing determinant for the Line and Transformation Connection Services rate is the customer's peak demand in the billing period. The billing determinant for the Network Services rate is: for non-interval-metered customers, the peak demand in the billing period, and for interval-metered customers, the peak demand between 7 AM and 7 PM local time on IESO business days

Customer-Supplied Transformation Allowance

Applicable to customers providing their own transformers

Demand-billed	$ / kW	0.60
Energy-billed	$ / kWh	0.0014

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Campbellford/Seymour Public Utilities Commission
Effective Date: May 1, 2008

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

Loss Factors

Residential	1.085
General Service Less Than 50 kW (Energy-Billed)	1.092
General Service 50 kW or Greater (Demand-Billed)	1.061
Unmetered Scattered Load	1.092

Transformer Loss Allowance

Applicable to customers requiring a billing adjustment for transformer losses as the result of being metered on the primary side of a transformer. The following uniform values shall be applied to measured demand and energy to calculate transformer losses for voltages up to and including 50 kV (as metered on the primary side):

(a) 1.5% for transformer installations up to an individual bank capacity of 400 kVA,
(b) 1.0% for bank capacities over 400 kVA.

Alternatively, transformer losses may be determined from transformer test data, and measured demand and energy adjusted accordingly

For services which are not demand metered, an assumed demand of 50% of the transformer capacity will be used to calculate the loss allowance. Where several transformers are involved, the bank capacity is assumed to be the arithmetic sum of all transformer capacities

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Campbellford/Seymour Public Utilities Commission
Effective Date: May 1, 2008

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

MISCELLANEOUS CHARGES

Specific Service Charges: Standard Amounts

Rate Code	Specific Service Charge - Standard Name	Calculation Method			
		2006 Rate Handbook	Standard Formula	Other Formula	Time and Materials
1	Temporary Service	$500			
2	Dispute Meter Test	$30 plus Measurement Canada fees			
3	Collection of account – no disconnection/load limiter	$30			
4	Collection/Disconnect/load limiter/reconnect (at meter) trip – regular hours	$65			
5	Collection/Disconnect/load limiter/reconnect (at meter) trip – after regular hours	$185			
6	Collection/Disconnect/load limiter/reconnect (at pole) trip – regular hours	$185			
7	Collection/Disconnect/load limiter/reconnect (at pole) trip – after regular hours	$415			
8	Account Set-up Charge	$30			
9	Arrears Certificate	$15			
10	NSF Cheque Charge	$15 + bank charges			
11	Easement Charge for Unregistered Rights	$15			
12	Late Payment Charge	1.5%/month			
13a	Retailer Services – Establishing Service Agreements (refer to Handbook for all charges)	$100/agreement/Retailer +$20/month/Retailer +$0.50/month/customer + other			
13b	Retailer Services – Other (includes Bill Ready for Retailers and Service Transactions Requests) as per the Handbook, Chapter 12	$0.30/month/customer + $0.25/request for request fee + $0.50/request for process fee			
14	Special Meter Reads	$30			
15	Service Layout Fee – Basic		$495		
16	Service Layout Fee – Complex		$690		
17	Crossing Application – Pipeline		$2,445		
18	Crossing Application – Water		$3,045		
19	Crossing Application – Railroad		$2,945		
20	Line Staking – per meter		$3.70		
21	Central Metering – New service < 45 kW		$115		
22	Conversion to Central Metering < 45 kW		$915		
23	Conversion to Central Metering > 45 kW		$800		
24	Tingle Voltage Test – In Excess of 4 Hours (per hour – average 2 additional hours)		$125		
25	Standby Administration Charge per month		$440		
26	Sentinel Lights Rental Rate per month			$7.10	
27	Sentinel Pole Rental Rate per month			$4.15	
28	Joint Use for Cable and Telecom companies per pole			$22.35	
29	Joint Use for LDCs per pole			$28.61	

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Campbellford/Seymour Public Utilities Commission
Effective Date: May 1, 2007

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

APPLICATION

The application of these rates and charges shall be in accordance with The Licence of The Distributor and any Codes, Guidelines or Orders of The Board, and amendments thereto as approved by The Board, which may be applicable to the administration of this schedule.
No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code, Guideline or Order of the Board, and amendments thereto as approved by the Board, or as specified herein
This schedule does not contain any rates and charges relating to the electricity commodity (e.g. the Regulated Price Plan).

EFFECTIVE DATES

DISTRIBUTION RATES - May 1, 2007 for all consumption or deemed consumption services used on or after that date.

MISCELLANEOUS CHARGES - May 1, 2007 for all charges billed to customers on or after that date.
RETAIL TRANSMISSION RATES - May 1, 2007 for all consumption or deemed consumption services used on or after that date.
LOSS FACTOR ADJUSTMENT – May 1, 2007

SERVICE CLASSIFICATIONS

Residential
This classification (note 1) refers to all service supplied to single-family dwelling units for domestic or household purpose. Multi-unit residential establishments such as apartment buildings supplied through one service (bulk metered) will normally be classified as General Service, but, at Hydro One's discretion, up to four residential units may be classified as residential. Where electricity service is provided to combined residential and business (including agricultural usage) and the wiring does not provide for separate metering, the classification shall be at the discretion of Hydro One based on such considerations as the estimated predominant consumption.
Further servicing details are available in the utility's Conditions of Service.

General Service
This classification (note 1) refers to all service supplied to premises other than those classified as Residential or Lighting. Some General Service accounts are energy(kWh)-billed, and some are demand(kW)-billed. Further servicing details are available in the utility's Conditions of Service. Also, see note 2.

Unmetered Scattered Load
This classification refers to certain instances where connections can be provided without metering. These loads are generally small in size and consistent in magnitude of load. Hydro One reserves the right to review all cases and may require that a meter be installed at its sole discretion. Services that can be unmetered include cable TV amplifiers, telephone switching devices, phone booths, bus shelters, rail way crossing signals, traffic signals, and other small fixed loads.
Further servicing details are available in the utility's Conditions of Service (including in the "Unmetered Connections" section).

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Campbellford/Seymour Public Utilities Commission
Effective Date: May 1, 2007

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

Street Lighting

This classification refers to accounts for the distribution and supply of electrical energy for street lighting. Street lights are devices owned by or operated for the road authority and/or the municipal corporation. These street lights in fact belong to the Street Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Sentinel Lighting

This classification refers to accounts for a separate service to a sentinel light. These sentinel lights in fact belong to the Sentinel Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Interim Demand-Side Management Time-of-Use

This is potentially applicable to Demand-billed General Service accounts. See Note 2 below.

Note (1): Classification descriptions are paraphrases from the document "Hydro One Networks Inc. - Distribution Customers Conditions of Service - August 2004"

Note (2):

Interim Demand-Side Management Time-of-Use Rates: demand charges will be based on demand during the on-peak periods.

Criteria: Customers' electricity consumption (kW) in the off-peak period is at least twice the electricity consumption (kW) during the on-peak period.

Definition of Time Periods: The on-peak hours will be between 0700 hours to 1900 hours Eastern Standard Time during the winter (standard time) on IESO business days and 0600 hours to 1800 hours Eastern Standard Time during the summer (daylight savings time) on IESO business days. The off-peak period constitutes all of the remaining hours.

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Campbellford/Seymour Public Utilities Commission
Effective Date: May 1, 2007

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

MONTHLY RATES AND CHARGES

Residential

Service Charge	$	12.30
Distribution Volumetric Rate	$ / kWh	0.0107
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0041
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0012
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0055
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0047
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service - Energy Billed (less than 50 kW)

Service Charge	$	16.19
Distribution Volumetric Rate	$ / kWh	0.0119
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0017
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0005
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0050
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0043
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service - Demand Billed (50 kW or greater)

Service Charge	$	16.19
Distribution Volumetric Rate	$ / kW	3.77
Regulatory Asset Recovery - Rider #1	$ / kW	0.53
Regulatory Asset Recovery - Rider #2	$ / kW	0.17
Retail Transmission Rate - Network Service Rate (4)	$ / kW	1.94
Retail Transmission Rate - Line and Transformation Connection Service Rate (4)	$ / kW	1.61
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Campbellford/Seymour Public Utilities Commission
Effective Date: May 1, 2007

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

Unmetered, Scattered Load

Service Charge	$	7.63
Distribution Volumetric Rate	$ / kWh	0.0119
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0017
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0005
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0050
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0043
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

(3) For energy-only metered customers, the billing determinant is the customer’s metered energy consumption adjusted by the total loss factor as approved by the Board for Acquired LDC customers.
(4) For demand billed customers, appropriate loss factors must be applied to the applicable tariffs. Also the billing determinant for the Line and Transformation Connection Services rate is the customer’s peak demand in the billing period. The billing determinant for the Network Services rate is: for non-interval-metered customers, the peak demand in the billing period, and for interval-metered customers, the peak demand between 7 AM and 7 PM local time on IESO business days

Interim Demand-Side Management Time-of-Use

See the "Service Classifications" section of this schedule.

Customer-Supplied Transformation Allowance

Applicable to demand-billed customers providing their own transformers
Primary Voltage under 50 kV (per kW)

Single Phase	$ / kW	0.20
Three Phase	$ / kW	0.60

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Campbellford/Seymour Public Utilities Commission
Effective Date: May 1, 2007

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

Loss Factors

Supply Facilities Loss Factor	1.0045
Distribution Loss Factors	
Customer less than 5,000 kW	1.0500
Customer greater than or equal to 5,000 kW	1.0100
Total Loss Factors	
Customer less than 5,000 kW	1.0545
Customer greater than or equal to 5,000 kW	1.0145

Transformer Loss Allowance

Applicable to customers requiring a billing adjustment for transformer losses as the result of being metered on the primary side of a transformer. The following uniform values shall be applied to measured demand and energy to calculate transformer losses for voltages up to and including 50 kV (as metered on the primary side):

(a) 1.5% for transformer installations up to an individual bank capacity of 400 kVA,
(b) 1.0% for bank capacities over 400 kVA.

Alternatively, transformer losses may be determined from transformer test data, and measured demand and energy adjusted accordingly

For services which are not demand metered, an assumed demand of 50% of the transformer capacity will be used to calculate the loss allowance. Where several transformers are involved, the bank capacity is assumed to be the arithmetic sum of all transformer capacities

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Campbellford/Seymour Public Utilities Commission
Effective Date: May 1, 2007

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

MISCELLANEOUS CHARGES

Specific Service Charges: Standard Amounts

Rate Code	Specific Service Charge - Standard Name	Calculation Method			
		2006 Rate Handbook	Standard Formula	Other Formula	Time and Materials
1	Temporary Service	$500			
2	Dispute Meter Test	$30 plus Measurement Canada fees			
3	Collection of account – no disconnection/load limiter	$30			
4	Collection/Disconnect/load limiter/reconnect (at meter) trip – regular hours	$65			
5	Collection/Disconnect/load limiter/reconnect (at meter) trip – after regular hours	$185			
6	Collection/Disconnect/load limiter/reconnect (at pole) trip – regular hours	$185			
7	Collection/Disconnect/load limiter/reconnect (at pole) trip – after regular hours	$415			
8	Account Set-up Charge	$30			
9	Arrears Certificate	$15			
10	NSF Cheque Charge	$15 + bank charges			
11	Easement Charge for Unregistered Rights	$15			
12	Late Payment Charge	1.5%/month			
13a	Retailer Services – Establishing Service Agreements (refer to Handbook for all charges)	$100/agreement/Retailer +$20/month/Retailer +$0.50/month/customer + other			
13b	Retailer Services – Other (includes Bill Ready for Retailers and Service Transactions Requests) as per the Handbook, Chapter 12	$0.30/month/customer + $0.25/request for request fee + $0.50/request for process fee			
14	Special Meter Reads	$30			
15	Billing Suspension and Terminations in Trailer Parks		$130		
16	Service Layout Fee – Basic		$405		
17	Service Layout Fee – Complex		$580		

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Campbellford/Seymour Public Utilities Commission
Effective Date: May 1, 2007

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

18	Crossing Application – Pipeline		$2,065		
19	Crossing Application – Water		$2,525		
20	Crossing Application – Railroad		$2,565		
21	Line Staking – per meter		$3.10		
22	Central Metering – New service < 45 kW		$115		
23	Conversion to Central Metering < 45 kW		$795		
24	Conversion to Central Metering > 45 kW		$680		
25	Tingle Voltage Test – In Excess of 4 Hours (per hour – average 2 additional hours)		$105		
26	Standby Administration Charge per month (interim)		$375		
27	Sentinel Lights Rental Rate per month – Mercury Vapor			$7.00	
28	Guaranteed Units from Jan 01/91 to Aug 01/91			$26.50 / month	
29	Guaranteed Units from Jan 01/87 to Dec 31/90			$23.50 / month	
30	Joint Use for Cable and Telecom companies per pole			$22.35	
31	Joint Use for LDCs per pole			$28.61	

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Hydro Electric Commission of the Town of Carleton Place
Effective Date: May 1, 2008

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

APPLICATION

The application of these rates and charges shall be in accordance with The Licence of The Distributor and any Codes, Guidelines or Orders of The Board, and amendments thereto as approved by The Board, which may be applicable to the administration of this schedule.
No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code, Guideline or Order of the Board, and amendments thereto as approved by the Board, or as specified herein
This schedule does not contain any rates and charges relating to the electricity commodity (e.g. the Regulated Price Plan).

EFFECTIVE DATES

DISTRIBUTION RATES - May 1, 2008 for all consumption or deemed consumption services used on or after that date.

MISCELLANEOUS CHARGES - May 1, 2008 for all charges billed to customers on or after that date.
RETAIL TRANSMISSION RATES - May 1, 2008 for all consumption or deemed consumption services used on or after that date.
LOSS FACTOR ADJUSTMENT – for all consumption or deemed consumption services billed following May 1, 2008 or later

SERVICE CLASSIFICATIONS

Residential
This classification refers to all service supplied to single-family dwelling units for domestic or household purpose. Multi-unit residential establishments such as apartment buildings supplied through one service (bulk metered) will normally be classified as General Service, but, at Hydro One's discretion, up to four residential units may be classified as residential. Where electricity service is provided to combined residential and business (including agricultural usage) and the wiring does not provide for separate metering, the classification shall be at the discretion of Hydro One based on such considerations as the estimated predominant consumption.
Further servicing details are available in the utility's Conditions of Service.

General Service
This classification refers to all service supplied to premises other than those classified as Residential or Lighting. Some General Service accounts are energy(kWh)-billed, and some are demand(kW)-billed. Further servicing details are available in the utility's Conditions of Service.

Unmetered Scattered Load
This classification refers to certain instances where connections can be provided without metering. These loads are generally small in size and consistent in magnitude of load. Hydro One reserves the right to review all cases and may require that a meter be installed at its sole discretion. Services that can be unmetered include cable TV amplifiers, telephone switching devices, phone booths, bus shelters, rail way crossing signals, traffic signals, and other small fixed loads.
Further servicing details are available in the utility's Conditions of Service (including in the "Unmetered Connections" section).

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Hydro Electric Commission of the Town of Carleton Place
Effective Date: May 1, 2008

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Street Lighting

This classification refers to accounts for the distribution and supply of electrical energy for street lighting. Street lights are devices owned by or operated for the road authority and/or the municipal corporation. These street lights in fact belong to the Street Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Sentinel Lighting

This classification refers to accounts for a separate service to a sentinel light. These sentinel lights in fact belong to the Sentinel Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Urban Density Classification

Customers who meet the Urban Density Criteria of being in an area containing 3,000 or more customers with a line density of at least 60 customers per kilometre, will be mapped to an Urban customer classification.

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
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MONTHLY RATES AND CHARGES

Residential - UR/R1 Carleton Place

Service Charge	$	14.04
Distribution Volumetric Rate	$ / kWh	0.0240
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0015
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0002)
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0047
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0045
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service Less Than 50 kW (Energy-Billed) - UGe/GSe Carleton Place

Service Charge	$	20.17
Distribution Volumetric Rate	$ / kWh	0.0200
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0007
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0006)
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0036
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0033
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service 50 kW or Greater (Demand-Billed) - UGd/GSd Carleton Place

Service Charge	$	24.39
Distribution Volumetric Rate	$ / kW	7.33
Regulatory Asset Recovery - Rider #2	$ / kW	0.22
Regulatory Asset Recovery - Rider #3	$ / kW	(0.27)
Retail Transmission Rate - Network Service Rate (4)	$ / kW	1.41
Retail Transmission Rate - Line and Transformation Connection Service Rate (4)	$ / kW	1.27
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

Hydro One Networks Inc.
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Unmetered, Scattered Load

Service Charge	$	14.54
Distribution Volumetric Rate	$ / kWh	0.0200
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0007
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0006)
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0035
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0032
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

(3) For energy-only metered customers, the billing determinant is the customer's metered energy consumption adjusted by the total loss factor as approved by the Board for Acquired LDC customers.
(4) For demand billed customers, appropriate loss factors must be applied to the applicable tariffs. Also the billing determinant for the Line and Transformation Connection Services rate is the customer's peak demand in the billing period. The billing determinant for the Network Services rate is: for non-interval-metered customers, the peak demand in the billing period, and for interval-metered customers, the peak demand between 7 AM and 7 PM local time on IESO business days

Customer-Supplied Transformation Allowance

Applicable to customers providing their own transformers

Demand-billed	$ / kW	0.60
Energy-billed	$ / kWh	0.0014

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Loss Factors

Residential	1.078
General Service Less Than 50 kW (Energy-Billed)	1.092
General Service 50 kW or Greater (Demand-Billed)	1.061
Unmetered Scattered Load	1.092

Transformer Loss Allowance

Applicable to customers requiring a billing adjustment for transformer losses as the result of being metered on the primary side of a transformer. The following uniform values shall be applied to measured demand and energy to calculate transformer losses for voltages up to and including 50 kV (as metered on the primary side):

(a) 1.5% for transformer installations up to an individual bank capacity of 400 kVA,
(b) 1.0% for bank capacities over 400 kVA.

Alternatively, transformer losses may be determined from transformer test data, and measured demand and energy adjusted accordingly
For services which are not demand metered, an assumed demand of 50% of the transformer capacity will be used to calculate the loss allowance. Where several transformers are involved, the bank capacity is assumed to be the arithmetic sum of all transformer capacities

Hydro One Networks Inc.
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MISCELLANEOUS CHARGES

Specific Service Charges: Standard Amounts

Rate Code	Specific Service Charge - Standard Name	Calculation Method			
		2006 Rate Handbook	Standard Formula	Other Formula	Time and Materials
1	Temporary Service	$500			
2	Dispute Meter Test	$30 plus Measurement Canada fees			
3	Collection of account – no disconnection/load limiter	$30			
4	Collection/Disconnect/load limiter/reconnect (at meter) trip – regular hours	$65			
5	Collection/Disconnect/load limiter/reconnect (at meter) trip – after regular hours	$185			
6	Collection/Disconnect/load limiter/reconnect (at pole) trip – regular hours	$185			
7	Collection/Disconnect/load limiter/reconnect (at pole) trip – after regular hours	$415			
8	Account Set-up Charge	$30			
9	Arrears Certificate	$15			
10	NSF Cheque Charge	$15 + bank charges			
11	Easement Charge for Unregistered Rights	$15			
12	Late Payment Charge	1.5%/month			
13a	Retailer Services – Establishing Service Agreements (refer to Handbook for all charges)	$100/agreement/Retailer +$20/month/Retailer +$0.50/month/customer + other			
13b	Retailer Services – Other (includes Bill Ready for Retailers and Service Transactions Requests) as per the Handbook, Chapter 12	$0.30/month/customer + $0.25/request for request fee + $0.50/request for process fee			
14	Special Meter Reads	$30			
15	Service Layout Fee – Basic		$495		
16	Service Layout Fee – Complex		$690		
17	Crossing Application – Pipeline		$2,445		
18	Crossing Application – Water		$3,045		
19	Crossing Application – Railroad		$2,945		
20	Line Staking – per meter		$3.70		
21	Central Metering – New service < 45 kW		$115		
22	Conversion to Central Metering < 45 kW		$915		
23	Conversion to Central Metering > 45 kW		$800		
24	Tingle Voltage Test – In Excess of 4 Hours (per hour – average 2 additional hours)		$125		
25	Standby Administration Charge per month		$440		
26	Sentinel Lights Rental Rate per month			$7.10	
27	Sentinel Pole Rental Rate per month			$4.15	
28	Joint Use for Cable and Telecom companies per pole			$22.35	
29	Joint Use for LDCs per pole			$28.61	

Hydro One Networks Inc.
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Effective Date: May 1, 2007

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APPLICATION

The application of these rates and charges shall be in accordance with The Licence of The Distributor and any Codes, Guidelines or Orders of The Board, and amendments thereto as approved by The Board, which may be applicable to the administration of this schedule.
No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code, Guideline or Order of the Board, and amendments thereto as approved by the Board, or as specified herein
This schedule does not contain any rates and charges relating to the electricity commodity (e.g. the Regulated Price Plan).

EFFECTIVE DATES

DISTRIBUTION RATES - May 1, 2007 for all consumption or deemed consumption services used on or after that date.

MISCELLANEOUS CHARGES - May 1, 2007 for all charges billed to customers on or after that date.
RETAIL TRANSMISSION RATES - May 1, 2007 for all consumption or deemed consumption services used on or after that date.
LOSS FACTOR ADJUSTMENT – May 1, 2007

SERVICE CLASSIFICATIONS

Residential
This classification (note 1) refers to all service supplied to single-family dwelling units for domestic or household purpose. Multi-unit residential establishments such as apartment buildings supplied through one service (bulk metered) will normally be classified as General Service, but, at Hydro One’s discretion, up to four residential units may be classified as residential. Where electricity service is provided to combined residential and business (including agricultural usage) and the wiring does not provide for separate metering, the classification shall be at the discretion of Hydro One based on such considerations as the estimated predominant consumption.
Further servicing details are available in the utility’s Conditions of Service.

General Service
This classification (note 1) refers to all service supplied to premises other than those classified as Residential or Lighting. Some General Service accounts are energy(kWh)-billed, and some are demand(kW)-billed. Further servicing details are available in the utility’s Conditions of Service. Also, see note 2.

Unmetered Scattered Load
This classification refers to certain instances where connections can be provided without metering. These loads are generally small in size and consistent in magnitude of load. Hydro One reserves the right to review all cases and may require that a meter be installed at its sole discretion. Services that can be unmetered include cable TV amplifiers, telephone switching devices, phone booths, bus shelters, rail way crossing signals, traffic signals, and other small fixed loads.
Further servicing details are available in the utility’s Conditions of Service (including in the "Unmetered Connections" section).

Hydro One Networks Inc.
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Street Lighting

This classification refers to accounts for the distribution and supply of electrical energy for street lighting. Street lights are devices owned by or operated for the road authority and/or the municipal corporation. These street lights in fact belong to the Street Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Sentinel Lighting

This classification refers to accounts for a separate service to a sentinel light. These sentinel lights in fact belong to the Sentinel Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Interim Demand-Side Management Time-of-Use

This is potentially applicable to Demand-billed General Service accounts. See Note 2 below.

Note (1): Classification descriptions are paraphrases from the document "Hydro One Networks Inc. - Distribution Customers Conditions of Service - August 2004"

Note (2):

Interim Demand-Side Management Time-of-Use Rates: demand charges will be based on demand during the on-peak periods.

Criteria: Customers' electricity consumption (kW) in the off-peak period is at least twice the electricity consumption (kW) during the on-peak period.

Definition of Time Periods: The on-peak hours will be between 0700 hours to 1900 hours Eastern Standard Time during the winter (standard time) on IESO business days and 0600 hours to 1800 hours Eastern Standard Time during the summer (daylight savings time) on IESO business days. The off-peak period constitutes all of the remaining hours.

Hydro One Networks Inc.
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MONTHLY RATES AND CHARGES

Residential

Service Charge	$	14.17
Distribution Volumetric Rate	$ / kWh	0.0179
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0038
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0015
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0055
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0047
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service - Energy Billed (less than 50 kW)

Service Charge	$	23.65
Distribution Volumetric Rate	$ / kWh	0.0168
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0013
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0007
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0050
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0043
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service - Demand Billed (50 kW or greater)

Service Charge	$	23.65
Distribution Volumetric Rate	$ / kW	5.31
Regulatory Asset Recovery - Rider #1	$ / kW	0.42
Regulatory Asset Recovery - Rider #2	$ / kW	0.22
Retail Transmission Rate - Network Service Rate (4)	$ / kW	1.94
Retail Transmission Rate - Line and Transformation Connection Service Rate (4)	$ / kW	1.61
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

Hydro One Networks Inc.
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Unmetered, Scattered Load

Service Charge	$	11.36
Distribution Volumetric Rate	$ / kWh	0.0168
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0013
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0007
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0050
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0043
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

(3) For energy-only metered customers, the billing determinant is the customer's metered energy consumption adjusted by the total loss factor as approved by the Board for Acquired LDC customers.

(4) For demand billed customers, appropriate loss factors must be applied to the applicable tariffs. Also the billing determinant for the Line and Transformation Connection Services rate is the customer's peak demand in the billing period. The billing determinant for the Network Services rate is: for non-interval-metered customers, the peak demand in the billing period, and for interval-metered customers, the peak demand between 7 AM and 7 PM local time on IESO business days

Interim Demand-Side Management Time-of-Use

See the "Service Classifications" section of this schedule.

Customer-Supplied Transformation Allowance

Applicable to demand-billed customers providing their own transformers
Primary Voltage under 50 kV (per kW)

Single Phase	$ / kW	0.20
Three Phase	$ / kW	0.60

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Loss Factors

Supply Facilities Loss Factor	1.0045
Distribution Loss Factors	
Customer less than 5,000 kW	1.0500
Customer greater than or equal to 5,000 kW	1.0100
Total Loss Factors	
Customer less than 5,000 kW	1.0545
Customer greater than or equal to 5,000 kW	1.0145

Transformer Loss Allowance

Applicable to customers requiring a billing adjustment for transformer losses as the result of being metered on the primary side of a transformer. The following uniform values shall be applied to measured demand and energy to calculate transformer losses for voltages up to and including 50 kV (as metered on the primary side):

(a) 1.5% for transformer installations up to an individual bank capacity of 400 kVA,
(b) 1.0% for bank capacities over 400 kVA.

Alternatively, transformer losses may be determined from transformer test data, and measured demand and energy adjusted accordingly

For services which are not demand metered, an assumed demand of 50% of the transformer capacity will be used to calculate the loss allowance. Where several transformers are involved, the bank capacity is assumed to be the arithmetic sum of all transformer capacities

Hydro One Networks Inc.
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MISCELLANEOUS CHARGES

Specific Service Charges: Standard Amounts

Rate Code	Specific Service Charge - Standard Name	Calculation Method			
		2006 Rate Handbook	Standard Formula	Other Formula	Time and Materials
1	Temporary Service	$500			
2	Dispute Meter Test	$30 plus Measurement Canada fees			
3	Collection of account – no disconnection/load limiter	$30			
4	Collection/Disconnect/load limiter/reconnect (at meter) trip – regular hours	$65			
5	Collection/Disconnect/load limiter/reconnect (at meter) trip – after regular hours	$185			
6	Collection/Disconnect/load limiter/reconnect (at pole) trip – regular hours	$185			
7	Collection/Disconnect/load limiter/reconnect (at pole) trip – after regular hours	$415			
8	Account Set-up Charge	$30			
9	Arrears Certificate	$15			
10	NSF Cheque Charge	$15 + bank charges			
11	Easement Charge for Unregistered Rights	$15			
12	Late Payment Charge	1.5%/month			
13a	Retailer Services – Establishing Service Agreements (refer to Handbook for all charges)	$100/agreement/Retailer +$20/month/Retailer +$0.50/month/customer + other			
13b	Retailer Services – Other (includes Bill Ready for Retailers and Service Transactions Requests) as per the Handbook, Chapter 12	$0.30/month/customer + $0.25/request for request fee + $0.50/request for process fee			
14	Special Meter Reads	$30			
15	Billing Suspension and Terminations in Trailer Parks		$130		
16	Service Layout Fee – Basic		$405		
17	Service Layout Fee – Complex		$580		

Hydro One Networks Inc.
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18	Crossing Application – Pipeline		$2,065		
19	Crossing Application – Water		$2,525		
20	Crossing Application – Railroad		$2,565		
21	Line Staking – per meter		$3.10		
22	Central Metering – New service < 45 kW		$115		
23	Conversion to Central Metering < 45 kW		$795		
24	Conversion to Central Metering > 45 kW		$680		
25	Tingle Voltage Test – In Excess of 4 Hours (per hour – average 2 additional hours)		$105		
26	Standby Administration Charge per month (interim)		$375		
27	Sentinel Lights Rental Rate per month – Mercury Vapor			$7.00	
28	Guaranteed Units from Jan 01/91 to Aug 01/91			$26.50 / month	
29	Guaranteed Units from Jan 01/87 to Dec 31/90			$23.50 / month	
30	Joint Use for Cable and Telecom companies per pole			$22.35	
31	Joint Use for LDCs per pole			$28.61	

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
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Cavan-Millbrook-North Monaghan Public Utilities Commission
Effective Date: May 1, 2008

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APPLICATION

The application of these rates and charges shall be in accordance with The Licence of The Distributor and any Codes, Guidelines or Orders of The Board, and amendments thereto as approved by The Board, which may be applicable to the administration of this schedule.
No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code, Guideline or Order of the Board, and amendments thereto as approved by the Board, or as specified herein
This schedule does not contain any rates and charges relating to the electricity commodity (e.g. the Regulated Price Plan).

EFFECTIVE DATES

DISTRIBUTION RATES - May 1, 2008 for all consumption or deemed consumption services used on or after that date.

MISCELLANEOUS CHARGES - May 1, 2008 for all charges billed to customers on or after that date.
RETAIL TRANSMISSION RATES - May 1, 2008 for all consumption or deemed consumption services used on or after that date.
LOSS FACTOR ADJUSTMENT – for all consumption or deemed consumption services billed following May 1, 2008 or later

SERVICE CLASSIFICATIONS

Residential
This classification refers to all service supplied to single-family dwelling units for domestic or household purpose. Multi-unit residential establishments such as apartment buildings supplied through one service (bulk metered) will normally be classified as General Service, but, at Hydro One's discretion, up to four residential units may be classified as residential. Where electricity service is provided to combined residential and business (including agricultural usage) and the wiring does not provide for separate metering, the classification shall be at the discretion of Hydro One based on such considerations as the estimated predominant consumption.
Further servicing details are available in the utility's Conditions of Service.

General Service
This classification refers to all service supplied to premises other than those classified as Residential or Lighting. Some General Service accounts are energy(kWh)-billed, and some are demand(kW)-billed. Further servicing details are available in the utility's Conditions of Service.

Unmetered Scattered Load
This classification refers to certain instances where connections can be provided without metering. These loads are generally small in size and consistent in magnitude of load. Hydro One reserves the right to review all cases and may require that a meter be installed at its sole discretion. Services that can be unmetered include cable TV amplifiers, telephone switching devices, phone booths, bus shelters, rail way crossing signals, traffic signals, and other small fixed loads.
Further servicing details are available in the utility's Conditions of Service (including in the "Unmetered Connections" section).

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Street Lighting

This classification refers to accounts for the distribution and supply of electrical energy for street lighting. Street lights are devices owned by or operated for the road authority and/or the municipal corporation. These street lights in fact belong to the Street Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Sentinel Lighting

This classification refers to accounts for a separate service to a sentinel light. These sentinel lights in fact belong to the Sentinel Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Urban Density Classification

Customers who meet the Urban Density Criteria of being in an area containing 3,000 or more customers with a line density of at least 60 customers per kilometre, will be mapped to an Urban customer classification.

Hydro One Networks Inc.
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MONTHLY RATES AND CHARGES

Residential - R1 Cavan-Millbrook-North Monaghan

Service Charge	$	16.01
Distribution Volumetric Rate	$ / kWh	0.0271
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0040
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0004)
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0047
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0046
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service Less Than 50 kW (Energy-Billed) - GSe Cavan-Millbrook-North Monaghan

Service Charge	$	24.52
Distribution Volumetric Rate	$ / kWh	0.0280
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0026
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0006)
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0035
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0032
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service 50 kW or Greater (Demand-Billed) - GSd Cavan-Millbrook-North Monaghan

Service Charge	$	28.12
Distribution Volumetric Rate	$ / kW	9.22
Regulatory Asset Recovery - Rider #2	$ / kW	0.81
Regulatory Asset Recovery - Rider #3	$ / kW	(0.22)
Retail Transmission Rate - Network Service Rate (4)	$ / kW	1.11
Retail Transmission Rate - Line and Transformation Connection Service Rate (4)	$ / kW	1.00
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

Hydro One Networks Inc.
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Unmetered, Scattered Load

Service Charge	$	13.71
Distribution Volumetric Rate	$ / kWh	0.0200
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0026
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0006)
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0035
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0032
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

(3) For energy-only metered customers, the billing determinant is the customer's metered energy consumption adjusted by the total loss factor as approved by the Board for Acquired LDC customers.
(4) For demand billed customers, appropriate loss factors must be applied to the applicable tariffs. Also the billing determinant for the Line and Transformation Connection Services rate is the customer's peak demand in the billing period. The billing determinant for the Network Services rate is: for non-interval-metered customers, the peak demand in the billing period, and for interval-metered customers, the peak demand between 7 AM and 7 PM local time on IESO business days

Customer-Supplied Transformation Allowance

Applicable to customers providing their own transformers

Demand-billed	$ / kW	0.60
Energy-billed	$ / kWh	0.0014

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Cavan-Millbrook-North Monaghan Public Utilities Commission
Effective Date: May 1, 2008

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

Loss Factors

Residential	1.085
General Service Less Than 50 kW (Energy-Billed)	1.092
General Service 50 kW or Greater (Demand-Billed)	1.061
Unmetered Scattered Load	1.092

Transformer Loss Allowance

Applicable to customers requiring a billing adjustment for transformer losses as the result of being metered on the primary side of a transformer. The following uniform values shall be applied to measured demand and energy to calculate transformer losses for voltages up to and including 50 kV (as metered on the primary side):

(a) 1.5% for transformer installations up to an individual bank capacity of 400 kVA,

(b) 1.0% for bank capacities over 400 kVA.

Alternatively, transformer losses may be determined from transformer test data, and measured demand and energy adjusted accordingly

For services which are not demand metered, an assumed demand of 50% of the transformer capacity will be used to calculate the loss allowance. Where several transformers are involved, the bank capacity is assumed to be the arithmetic sum of all transformer capacities

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
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Effective Date: May 1, 2008

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MISCELLANEOUS CHARGES

Specific Service Charges: Standard Amounts

Rate Code	Specific Service Charge - Standard Name	Calculation Method			
		2006 Rate Handbook	Standard Formula	Other Formula	Time and Materials
1	Temporary Service	$500			
2	Dispute Meter Test	$30 plus Measurement Canada fees			
3	Collection of account – no disconnection/load limiter	$30			
4	Collection/Disconnect/load limiter/reconnect (at meter) trip – regular hours	$65			
5	Collection/Disconnect/load limiter/reconnect (at meter) trip – after regular hours	$185			
6	Collection/Disconnect/load limiter/reconnect (at pole) trip – regular hours	$185			
7	Collection/Disconnect/load limiter/reconnect (at pole) trip – after regular hours	$415			
8	Account Set-up Charge	$30			
9	Arrears Certificate	$15			
10	NSF Cheque Charge	$15 + bank charges			
11	Easement Charge for Unregistered Rights	$15			
12	Late Payment Charge	1.5%/month			
13a	Retailer Services – Establishing Service Agreements (refer to Handbook for all charges)	$100/agreement/Retailer +$20/month/Retailer +$0.50/month/customer + other			
13b	Retailer Services – Other (includes Bill Ready for Retailers and Service Transactions Requests) as per the Handbook, Chapter 12	$0.30/month/customer + $0.25/request for request fee + $0.50/request for process fee			
14	Special Meter Reads	$30			
15	Service Layout Fee – Basic		$495		
16	Service Layout Fee – Complex		$690		
17	Crossing Application – Pipeline		$2,445		
18	Crossing Application – Water		$3,045		
19	Crossing Application – Railroad		$2,945		
20	Line Staking – per meter		$3.70		
21	Central Metering – New service < 45 kW		$115		
22	Conversion to Central Metering < 45 kW		$915		
23	Conversion to Central Metering > 45 kW		$800		
24	Tingle Voltage Test – In Excess of 4 Hours (per hour – average 2 additional hours)		$125		
25	Standby Administration Charge per month		$440		
26	Sentinel Lights Rental Rate per month			$7.10	
27	Sentinel Pole Rental Rate per month			$4.15	
28	Joint Use for Cable and Telecom companies per pole			$22.35	
29	Joint Use for LDCs per pole			$28.61	

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
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Cavan-Millbrook-North Monaghan Public Utilities Commission
Effective Date: May 1, 2007

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

APPLICATION

The application of these rates and charges shall be in accordance with The Licence of The Distributor and any Codes, Guidelines or Orders of The Board, and amendments thereto as approved by The Board, which may be applicable to the administration of this schedule.
No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code, Guideline or Order of the Board, and amendments thereto as approved by the Board, or as specified herein
This schedule does not contain any rates and charges relating to the electricity commodity (e.g. the Regulated Price Plan).

EFFECTIVE DATES

DISTRIBUTION RATES - May 1, 2007 for all consumption or deemed consumption services used on or after that date.

MISCELLANEOUS CHARGES - May 1, 2007 for all charges billed to customers on or after that date.
RETAIL TRANSMISSION RATES - May 1, 2007 for all consumption or deemed consumption services used on or after that date.
LOSS FACTOR ADJUSTMENT – May 1, 2007

SERVICE CLASSIFICATIONS

Residential
This classification (note 1) refers to all service supplied to single-family dwelling units for domestic or household purpose. Multi-unit residential establishments such as apartment buildings supplied through one service (bulk metered) will normally be classified as General Service, but, at Hydro One's discretion, up to four residential units may be classified as residential. Where electricity service is provided to combined residential and business (including agricultural usage) and the wiring does not provide for separate metering, the classification shall be at the discretion of Hydro One based on such considerations as the estimated predominant consumption.
Further servicing details are available in the utility's Conditions of Service.

General Service
This classification (note 1) refers to all service supplied to premises other than those classified as Residential or Lighting. Some General Service accounts are energy(kWh)-billed, and some are demand(kW)-billed. Further servicing details are available in the utility's Conditions of Service. Also, see note 2.

Unmetered Scattered Load
This classification refers to certain instances where connections can be provided without metering. These loads are generally small in size and consistent in magnitude of load. Hydro One reserves the right to review all cases and may require that a meter be installed at its sole discretion. Services that can be unmetered include cable TV amplifiers, telephone switching devices, phone booths, bus shelters, rail way crossing signals, traffic signals, and other small fixed loads.
Further servicing details are available in the utility's Conditions of Service (including in the "Unmetered Connections" section).

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
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Cavan-Millbrook-North Monaghan Public Utilities Commission
Effective Date: May 1, 2007

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Street Lighting

This classification refers to accounts for the distribution and supply of electrical energy for street lighting. Street lights are devices owned by or operated for the road authority and/or the municipal corporation. These street lights in fact belong to the Street Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Sentinel Lighting

This classification refers to accounts for a separate service to a sentinel light. These sentinel lights in fact belong to the Sentinel Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Interim Demand-Side Management Time-of-Use

This is potentially applicable to Demand-billed General Service accounts. See Note 2 below.

Note (1): Classification descriptions are paraphrases from the document "Hydro One Networks Inc. - Distribution Customers Conditions of Service - August 2004"

Note (2):

Interim Demand-Side Management Time-of-Use Rates: demand charges will be based on demand during the on-peak periods.

Criteria: Customers' electricity consumption (kW) in the off-peak period is at least twice the electricity consumption (kW) during the on-peak period.

Definition of Time Periods: The on-peak hours will be between 0700 hours to 1900 hours Eastern Standard Time during the winter (standard time) on IESO business days and 0600 hours to 1800 hours Eastern Standard Time during the summer (daylight savings time) on IESO business days. The off-peak period constitutes all of the remaining hours.

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MONTHLY RATES AND CHARGES

Residential

Service Charge	$	15.01
Distribution Volumetric Rate	$ / kWh	0.0134
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0068
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0040
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0055
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0047
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service - Energy Billed (less than 50 kW)

Service Charge	$	22.28
Distribution Volumetric Rate	$ / kWh	0.0150
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0033
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0026
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0050
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0043
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service - Demand Billed (50 kW or greater)

Service Charge	$	22.28
Distribution Volumetric Rate	$ / kW	4.67
Regulatory Asset Recovery - Rider #1	$ / kW	1.06
Regulatory Asset Recovery - Rider #2	$ / kW	0.81
Retail Transmission Rate - Network Service Rate (4)	$ / kW	1.94
Retail Transmission Rate - Line and Transformation Connection Service Rate (4)	$ / kW	1.61
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

Hydro One Networks Inc.
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Unmetered, Scattered Load

Service Charge	$	10.68
Distribution Volumetric Rate	$ / kWh	0.0150
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0033
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0026
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0050
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0043
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

(3) For energy-only metered customers, the billing determinant is the customer’s metered energy consumption adjusted by the total loss factor as approved by the Board for Acquired LDC customers.

(4) For demand billed customers, appropriate loss factors must be applied to the applicable tariffs. Also the billing determinant for the Line and Transformation Connection Services rate is the customer’s peak demand in the billing period. The billing determinant for the Network Services rate is: for non-interval-metered customers, the peak demand in the billing period, and for interval-metered customers, the peak demand between 7 AM and 7 PM local time on IESO business days

Interim Demand-Side Management Time-of-Use

See the "Service Classifications" section of this schedule.

Customer-Supplied Transformation Allowance

Applicable to demand-billed customers providing their own transformers
Primary Voltage under 50 kV (per kW)

Single Phase	$ / kW	0.20
Three Phase	$ / kW	0.60

Hydro One Networks Inc.
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Loss Factors

Supply Facilities Loss Factor	1.0045
Distribution Loss Factors	
Customer less than 5,000 kW	1.0500
Customer greater than or equal to 5,000 kW	1.0100
Total Loss Factors	
Customer less than 5,000 kW	1.0545
Customer greater than or equal to 5,000 kW	1.0145

Transformer Loss Allowance

Applicable to customers requiring a billing adjustment for transformer losses as the result of being metered on the primary side of a transformer. The following uniform values shall be applied to measured demand and energy to calculate transformer losses for voltages up to and including 50 kV (as metered on the primary side):

(a) 1.5% for transformer installations up to an individual bank capacity of 400 kVA,
(b) 1.0% for bank capacities over 400 kVA.

Alternatively, transformer losses may be determined from transformer test data, and measured demand and energy adjusted accordingly

For services which are not demand metered, an assumed demand of 50% of the transformer capacity will be used to calculate the loss allowance. Where several transformers are involved, the bank capacity is assumed to be the arithmetic sum of all transformer capacities

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
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MISCELLANEOUS CHARGES

Specific Service Charges: Standard Amounts

Rate Code	Specific Service Charge - Standard Name	Calculation Method			
		2006 Rate Handbook	Standard Formula	Other Formula	Time and Materials
1	Temporary Service	$500			
2	Dispute Meter Test	$30 plus Measurement Canada fees			
3	Collection of account – no disconnection/load limiter	$30			
4	Collection/Disconnect/load limiter/reconnect (at meter) trip – regular hours	$65			
5	Collection/Disconnect/load limiter/reconnect (at meter) trip – after regular hours	$185			
6	Collection/Disconnect/load limiter/reconnect (at pole) trip – regular hours	$185			
7	Collection/Disconnect/load limiter/reconnect (at pole) trip – after regular hours	$415			
8	Account Set-up Charge	$30			
9	Arrears Certificate	$15			
10	NSF Cheque Charge	$15 + bank charges			
11	Easement Charge for Unregistered Rights	$15			
12	Late Payment Charge	1.5%/month			
13a	Retailer Services – Establishing Service Agreements (refer to Handbook for all charges)	$100/agreement/Retailer +$20/month/Retailer +$0.50/month/customer + other			
13b	Retailer Services – Other (includes Bill Ready for Retailers and Service Transactions Requests) as per the Handbook, Chapter 12	$0.30/month/customer + $0.25/request for request fee + $0.50/request for process fee			
14	Special Meter Reads	$30			
15	Billing Suspension and Terminations in Trailer Parks		$130		
16	Service Layout Fee – Basic		$405		
17	Service Layout Fee – Complex		$580		

Hydro One Networks Inc.
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18	Crossing Application – Pipeline		$2,065		
19	Crossing Application – Water		$2,525		
20	Crossing Application – Railroad		$2,565		
21	Line Staking – per meter		$3.10		
22	Central Metering – New service < 45 kW		$115		
23	Conversion to Central Metering < 45 kW		$795		
24	Conversion to Central Metering > 45 kW		$680		
25	Tingle Voltage Test – In Excess of 4 Hours (per hour – average 2 additional hours)		$105		
26	Standby Administration Charge per month (interim)		$375		
27	Sentinel Lights Rental Rate per month – Mercury Vapor			$7.00	
28	Guaranteed Units from Jan 01/91 to Aug 01/91			$26.50 / month	
29	Guaranteed Units from Jan 01/87 to Dec 31/90			$23.50 / month	
30	Joint Use for Cable and Telecom companies per pole			$22.35	
31	Joint Use for LDCs per pole			$28.61	

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Centre Hastings Hydro Electric Commission
Effective Date: May 1, 2008

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

APPLICATION

The application of these rates and charges shall be in accordance with The Licence of The Distributor and any Codes, Guidelines or Orders of The Board, and amendments thereto as approved by The Board, which may be applicable to the administration of this schedule.
No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code, Guideline or Order of the Board, and amendments thereto as approved by the Board, or as specified herein
This schedule does not contain any rates and charges relating to the electricity commodity (e.g. the Regulated Price Plan).

EFFECTIVE DATES

DISTRIBUTION RATES - May 1, 2008 for all consumption or deemed consumption services used on or after that date.

MISCELLANEOUS CHARGES - May 1, 2008 for all charges billed to customers on or after that date.
RETAIL TRANSMISSION RATES - May 1, 2008 for all consumption or deemed consumption services used on or after that date.
LOSS FACTOR ADJUSTMENT – for all consumption or deemed consumption services billed following May 1, 2008 or later

SERVICE CLASSIFICATIONS

Residential
This classification refers to all service supplied to single-family dwelling units for domestic or household purpose. Multi-unit residential establishments such as apartment buildings supplied through one service (bulk metered) will normally be classified as General Service, but, at Hydro One's discretion, up to four residential units may be classified as residential. Where electricity service is provided to combined residential and business (including agricultural usage) and the wiring does not provide for separate metering, the classification shall be at the discretion of Hydro One based on such considerations as the estimated predominant consumption.
Further servicing details are available in the utility's Conditions of Service.

General Service
This classification refers to all service supplied to premises other than those classified as Residential or Lighting. Some General Service accounts are energy(kWh)-billed, and some are demand(kW)-billed. Further servicing details are available in the utility's Conditions of Service.

Unmetered Scattered Load
This classification refers to certain instances where connections can be provided without metering. These loads are generally small in size and consistent in magnitude of load. Hydro One reserves the right to review all cases and may require that a meter be installed at its sole discretion. Services that can be unmetered include cable TV amplifiers, telephone switching devices, phone booths, bus shelters, rail way crossing signals, traffic signals, and other small fixed loads.
Further servicing details are available in the utility's Conditions of Service (including in the "Unmetered Connections" section).

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Centre Hastings Hydro Electric Commission
Effective Date: May 1, 2008

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

Street Lighting

This classification refers to accounts for the distribution and supply of electrical energy for street lighting. Street lights are devices owned by or operated for the road authority and/or the municipal corporation. These street lights in fact belong to the Street Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Sentinel Lighting

This classification refers to accounts for a separate service to a sentinel light. These sentinel lights in fact belong to the Sentinel Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Urban Density Classification

Customers who meet the Urban Density Criteria of being in an area containing 3,000 or more customers with a line density of at least 60 customers per kilometre, will be mapped to an Urban customer classification.

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
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MONTHLY RATES AND CHARGES

Residential - R1 Centre Hastings

Service Charge	$	12.84
Distribution Volumetric Rate	$ / kWh	0.0200
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0011
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0004)
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0047
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0046
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service Less Than 50 kW (Energy-Billed) - GSe Centre Hastings

Service Charge	$	21.50
Distribution Volumetric Rate	$ / kWh	0.0194
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0006
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0006)
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0035
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0032
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service 50 kW or Greater (Demand-Billed) - GSd Centre Hastings

Service Charge	$	25.09
Distribution Volumetric Rate	$ / kW	7.70
Regulatory Asset Recovery - Rider #2	$ / kW	0.20
Regulatory Asset Recovery - Rider #3	$ / kW	(0.22)
Retail Transmission Rate - Network Service Rate (4)	$ / kW	1.11
Retail Transmission Rate - Line and Transformation Connection Service Rate (4)	$ / kW	1.00
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

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Unmetered, Scattered Load

Service Charge	$	12.20
Distribution Volumetric Rate	$ / kWh	0.0200
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0006
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0006)
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0035
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0032
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

(3) For energy-only metered customers, the billing determinant is the customer’s metered energy consumption adjusted by the total loss factor as approved by the Board for Acquired LDC customers.
(4) For demand billed customers, appropriate loss factors must be applied to the applicable tariffs. Also the billing determinant for the Line and Transformation Connection Services rate is the customer’s peak demand in the billing period. The billing determinant for the Network Services rate is: for non-interval-metered customers, the peak demand in the billing period, and for interval-metered customers, the peak demand between 7 AM and 7 PM local time on IESO business days

Customer-Supplied Transformation Allowance

Applicable to customers providing their own transformers

Demand-billed	$ / kW	0.60
Energy-billed	$ / kWh	0.0014

Hydro One Networks Inc.
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This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

Loss Factors

Residential	1.085
General Service Less Than 50 kW (Energy-Billed)	1.092
General Service 50 kW or Greater (Demand-Billed)	1.061
Unmetered Scattered Load	1.092

Transformer Loss Allowance

Applicable to customers requiring a billing adjustment for transformer losses as the result of being metered on the primary side of a transformer. The following uniform values shall be applied to measured demand and energy to calculate transformer losses for voltages up to and including 50 kV (as metered on the primary side):

(a) 1.5% for transformer installations up to an individual bank capacity of 400 kVA,

(b) 1.0% for bank capacities over 400 kVA.

Alternatively, transformer losses may be determined from transformer test data, and measured demand and energy adjusted accordingly

For services which are not demand metered, an assumed demand of 50% of the transformer capacity will be used to calculate the loss allowance. Where several transformers are involved, the bank capacity is assumed to be the arithmetic sum of all transformer capacities

Hydro One Networks Inc.
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MISCELLANEOUS CHARGES

Specific Service Charges: Standard Amounts

Rate Code	Specific Service Charge - Standard Name	Calculation Method			
		2006 Rate Handbook	Standard Formula	Other Formula	Time and Materials
1	Temporary Service	$500			
2	Dispute Meter Test	$30 plus Measurement Canada fees			
3	Collection of account – no disconnection/load limiter	$30			
4	Collection/Disconnect/load limiter/reconnect (at meter) trip – regular hours	$65			
5	Collection/Disconnect/load limiter/reconnect (at meter) trip – after regular hours	$185			
6	Collection/Disconnect/load limiter/reconnect (at pole) trip – regular hours	$185			
7	Collection/Disconnect/load limiter/reconnect (at pole) trip – after regular hours	$415			
8	Account Set-up Charge	$30			
9	Arrears Certificate	$15			
10	NSF Cheque Charge	$15 + bank charges			
11	Easement Charge for Unregistered Rights	$15			
12	Late Payment Charge	1.5%/month			
13a	Retailer Services – Establishing Service Agreements (refer to Handbook for all charges)	$100/agreement/Retailer +$20/month/Retailer +$0.50/month/customer + other			
13b	Retailer Services – Other (includes Bill Ready for Retailers and Service Transactions Requests) as per the Handbook, Chapter 12	$0.30/month/customer + $0.25/request for request fee + $0.50/request for process fee			
14	Special Meter Reads	$30			
15	Service Layout Fee – Basic		$495		
16	Service Layout Fee – Complex		$690		
17	Crossing Application – Pipeline		$2,445		
18	Crossing Application – Water		$3,045		
19	Crossing Application – Railroad		$2,945		
20	Line Staking – per meter		$3.70		
21	Central Metering – New service < 45 kW		$115		
22	Conversion to Central Metering < 45 kW		$915		
23	Conversion to Central Metering > 45 kW		$800		
24	Tingle Voltage Test – In Excess of 4 Hours (per hour – average 2 additional hours)		$125		
25	Standby Administration Charge per month		$440		
26	Sentinel Lights Rental Rate per month			$7.10	
27	Sentinel Pole Rental Rate per month			$4.15	
28	Joint Use for Cable and Telecom companies per pole			$22.35	
29	Joint Use for LDCs per pole			$28.61	

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TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Centre Hastings Hydro Electric Commission
Effective Date: May 1, 2007

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

APPLICATION

The application of these rates and charges shall be in accordance with The Licence of The Distributor and any Codes, Guidelines or Orders of The Board, and amendments thereto as approved by The Board, which may be applicable to the administration of this schedule.
No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code, Guideline or Order of the Board, and amendments thereto as approved by the Board, or as specified herein
This schedule does not contain any rates and charges relating to the electricity commodity (e.g. the Regulated Price Plan).

EFFECTIVE DATES

DISTRIBUTION RATES - May 1, 2007 for all consumption or deemed consumption services used on or after that date.

MISCELLANEOUS CHARGES - May 1, 2007 for all charges billed to customers on or after that date.
RETAIL TRANSMISSION RATES - May 1, 2007 for all consumption or deemed consumption services used on or after that date.
LOSS FACTOR ADJUSTMENT – May 1, 2007

SERVICE CLASSIFICATIONS

Residential
This classification (note 1) refers to all service supplied to single-family dwelling units for domestic or household purpose. Multi-unit residential establishments such as apartment buildings supplied through one service (bulk metered) will normally be classified as General Service, but, at Hydro One's discretion, up to four residential units may be classified as residential. Where electricity service is provided to combined residential and business (including agricultural usage) and the wiring does not provide for separate metering, the classification shall be at the discretion of Hydro One based on such considerations as the estimated predominant consumption.
Further servicing details are available in the utility's Conditions of Service.

General Service
This classification (note 1) refers to all service supplied to premises other than those classified as Residential or Lighting. Some General Service accounts are energy(kWh)-billed, and some are demand(kW)-billed. Further servicing details are available in the utility's Conditions of Service. Also, see note 2.

Unmetered Scattered Load
This classification refers to certain instances where connections can be provided without metering. These loads are generally small in size and consistent in magnitude of load. Hydro One reserves the right to review all cases and may require that a meter be installed at its sole discretion. Services that can be unmetered include cable TV amplifiers, telephone switching devices, phone booths, bus shelters, rail way crossing signals, traffic signals, and other small fixed loads.
Further servicing details are available in the utility's Conditions of Service (including in the "Unmetered Connections" section).

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Centre Hastings Hydro Electric Commission
Effective Date: May 1, 2007

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

Street Lighting
This classification refers to accounts for the distribution and supply of electrical energy for street lighting. Street lights are devices owned by or operated for the road authority and/or the municipal corporation. These street lights in fact belong to the Street Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Sentinel Lighting
This classification refers to accounts for a separate service to a sentinel light. These sentinel lights in fact belong to the Sentinel Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Interim Demand-Side Management Time-of-Use
This is potentially applicable to Demand-billed General Service accounts. See Note 2 below.

Note (1): Classification descriptions are paraphrases from the document "Hydro One Networks Inc. - Distribution Customers Conditions of Service - August 2004"
Note (2):
Interim Demand-Side Management Time-of-Use Rates: demand charges will be based on demand during the on-peak periods.
Criteria: Customers' electricity consumption (kW) in the off-peak period is at least twice the electricity consumption (kW) during the on-peak period.
Definition of Time Periods: The on-peak hours will be between 0700 hours to 1900 hours Eastern Standard Time during the winter (standard time) on IESO business days and 0600 hours to 1800 hours Eastern Standard Time during the summer (daylight savings time) on IESO business days. The off-peak period constitutes all of the remaining hours.

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Centre Hastings Hydro Electric Commission
Effective Date: May 1, 2007

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

MONTHLY RATES AND CHARGES

Residential

Service Charge	$	11.67
Distribution Volumetric Rate	$ / kWh	0.0096
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0029
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0011
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0055
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0047
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service - Energy Billed (less than 50 kW)

Service Charge	$	18.38
Distribution Volumetric Rate	$ / kWh	0.0097
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0014
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0006
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0050
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0043
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service - Demand Billed (50 kW or greater)

Service Charge	$	18.38
Distribution Volumetric Rate	$ / kW	3.07
Regulatory Asset Recovery - Rider #1	$ / kW	0.45
Regulatory Asset Recovery - Rider #2	$ / kW	0.20
Retail Transmission Rate - Network Service Rate (4)	$ / kW	1.94
Retail Transmission Rate - Line and Transformation Connection Service Rate (4)	$ / kW	1.61
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Centre Hastings Hydro Electric Commission
Effective Date: May 1, 2007

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Unmetered, Scattered Load

Service Charge	$	8.73
Distribution Volumetric Rate	$ / kWh	0.0097
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0014
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0006
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0050
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0043
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

(3) For energy-only metered customers, the billing determinant is the customer’s metered energy consumption adjusted by the total loss factor as approved by the Board for Acquired LDC customers.

(4) For demand billed customers, appropriate loss factors must be applied to the applicable tariffs. Also the billing determinant for the Line and Transformation Connection Services rate is the customer’s peak demand in the billing period. The billing determinant for the Network Services rate is: for non-interval-metered customers, the peak demand in the billing period, and for interval-metered customers, the peak demand between 7 AM and 7 PM local time on IESO business days

Interim Demand-Side Management Time-of-Use

See the "Service Classifications" section of this schedule.

Customer-Supplied Transformation Allowance

Applicable to demand-billed customers providing their own transformers
Primary Voltage under 50 kV (per kW)

Single Phase	$ / kW	0.20
Three Phase	$ / kW	0.60

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
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Centre Hastings Hydro Electric Commission
Effective Date: May 1, 2007

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

Loss Factors

Supply Facilities Loss Factor	1.0045
Distribution Loss Factors	
Customer less than 5,000 kW	1.0500
Customer greater than or equal to 5,000 kW	1.0100
Total Loss Factors	
Customer less than 5,000 kW	1.0545
Customer greater than or equal to 5,000 kW	1.0145

Transformer Loss Allowance

Applicable to customers requiring a billing adjustment for transformer losses as the result of being metered on the primary side of a transformer. The following uniform values shall be applied to measured demand and energy to calculate transformer losses for voltages up to and including 50 kV (as metered on the primary side):

(a) 1.5% for transformer installations up to an individual bank capacity of 400 kVA,
(b) 1.0% for bank capacities over 400 kVA.

Alternatively, transformer losses may be determined from transformer test data, and measured demand and energy adjusted accordingly

For services which are not demand metered, an assumed demand of 50% of the transformer capacity will be used to calculate the loss allowance. Where several transformers are involved, the bank capacity is assumed to be the arithmetic sum of all transformer capacities

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Centre Hastings Hydro Electric Commission
Effective Date: May 1, 2007

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

MISCELLANEOUS CHARGES

Specific Service Charges: Standard Amounts

Rate Code	Specific Service Charge - Standard Name	Calculation Method			
		2006 Rate Handbook	Standard Formula	Other Formula	Time and Materials
1	Temporary Service	$500			
2	Dispute Meter Test	$30 plus Measurement Canada fees			
3	Collection of account – no disconnection/load limiter	$30			
4	Collection/Disconnect/load limiter/reconnect (at meter) trip – regular hours	$65			
5	Collection/Disconnect/load limiter/reconnect (at meter) trip – after regular hours	$185			
6	Collection/Disconnect/load limiter/reconnect (at pole) trip – regular hours	$185			
7	Collection/Disconnect/load limiter/reconnect (at pole) trip – after regular hours	$415			
8	Account Set-up Charge	$30			
9	Arrears Certificate	$15			
10	NSF Cheque Charge	$15 + bank charges			
11	Easement Charge for Unregistered Rights	$15			
12	Late Payment Charge	1.5%/month			
13a	Retailer Services – Establishing Service Agreements (refer to Handbook for all charges)	$100/agreement/Retailer +$20/month/Retailer +$0.50/month/customer + other			
13b	Retailer Services – Other (includes Bill Ready for Retailers and Service Transactions Requests) as per the Handbook, Chapter 12	$0.30/month/customer + $0.25/request for request fee + $0.50/request for process fee			
14	Special Meter Reads	$30			
15	Billing Suspension and Terminations in Trailer Parks		$130		
16	Service Layout Fee – Basic		$405		
17	Service Layout Fee – Complex		$580		

Hydro One Networks Inc.
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18	Crossing Application – Pipeline		$2,065		
19	Crossing Application – Water		$2,525		
20	Crossing Application – Railroad		$2,565		
21	Line Staking – per meter		$3.10		
22	Central Metering – New service < 45 kW		$115		
23	Conversion to Central Metering < 45 kW		$795		
24	Conversion to Central Metering > 45 kW		$680		
25	Tingle Voltage Test – In Excess of 4 Hours (per hour – average 2 additional hours)		$105		
26	Standby Administration Charge per month (interim)		$375		
27	Sentinel Lights Rental Rate per month – Mercury Vapor			$7.00	
28	Guaranteed Units from Jan 01/91 to Aug 01/91			$26.50 / month	
29	Guaranteed Units from Jan 01/87 to Dec 31/90			$23.50 / month	
30	Joint Use for Cable and Telecom companies per pole			$22.35	
31	Joint Use for LDCs per pole			$28.61	

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Village of Chalk River Hydro Electric System
Effective Date: May 1, 2008

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

APPLICATION

The application of these rates and charges shall be in accordance with The Licence of The Distributor and any Codes, Guidelines or Orders of The Board, and amendments thereto as approved by The Board, which may be applicable to the administration of this schedule.
No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code, Guideline or Order of the Board, and amendments thereto as approved by the Board, or as specified herein
This schedule does not contain any rates and charges relating to the electricity commodity (e.g. the Regulated Price Plan).

EFFECTIVE DATES

DISTRIBUTION RATES - May 1, 2008 for all consumption or deemed consumption services used on or after that date.

MISCELLANEOUS CHARGES - May 1, 2008 for all charges billed to customers on or after that date.
RETAIL TRANSMISSION RATES - May 1, 2008 for all consumption or deemed consumption services used on or after that date.
LOSS FACTOR ADJUSTMENT – for all consumption or deemed consumption services billed following May 1, 2008 or later

SERVICE CLASSIFICATIONS

Residential
This classification refers to all service supplied to single-family dwelling units for domestic or household purpose. Multi-unit residential establishments such as apartment buildings supplied through one service (bulk metered) will normally be classified as General Service, but, at Hydro One's discretion, up to four residential units may be classified as residential. Where electricity service is provided to combined residential and business (including agricultural usage) and the wiring does not provide for separate metering, the classification shall be at the discretion of Hydro One based on such considerations as the estimated predominant consumption.
Further servicing details are available in the utility's Conditions of Service.

General Service
This classification refers to all service supplied to premises other than those classified as Residential or Lighting. Some General Service accounts are energy(kWh)-billed, and some are demand(kW)-billed. Further servicing details are available in the utility's Conditions of Service.

Unmetered Scattered Load
This classification refers to certain instances where connections can be provided without metering. These loads are generally small in size and consistent in magnitude of load. Hydro One reserves the right to review all cases and may require that a meter be installed at its sole discretion. Services that can be unmetered include cable TV amplifiers, telephone switching devices, phone booths, bus shelters, rail way crossing signals, traffic signals, and other small fixed loads.
Further servicing details are available in the utility's Conditions of Service (including in the "Unmetered Connections" section).

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Village of Chalk River Hydro Electric System
Effective Date: May 1, 2008

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Street Lighting

This classification refers to accounts for the distribution and supply of electrical energy for street lighting. Street lights are devices owned by or operated for the road authority and/or the municipal corporation. These street lights in fact belong to the Street Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Sentinel Lighting

This classification refers to accounts for a separate service to a sentinel light. These sentinel lights in fact belong to the Sentinel Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Urban Density Classification

Customers who meet the Urban Density Criteria of being in an area containing 3,000 or more customers with a line density of at least 60 customers per kilometre, will be mapped to an Urban customer classification.

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Village of Chalk River Hydro Electric System
Effective Date: May 1, 2008

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

MONTHLY RATES AND CHARGES

Residential - R1 Chalk River

Service Charge	$	15.25
Distribution Volumetric Rate	$ / kWh	0.0271
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0042
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0004)
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0047
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0046
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service Less Than 50 kW (Energy-Billed) - GSe Chalk River

Service Charge	$	23.76
Distribution Volumetric Rate	$ / kWh	0.0318
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0034
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0006)
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0035
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0032
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service 50 kW or Greater (Demand-Billed) - GSd Chalk River

Service Charge	$	27.36
Distribution Volumetric Rate	$ / kW	9.22
Regulatory Asset Recovery - Rider #2	$ / kW	1.07
Regulatory Asset Recovery - Rider #3	$ / kW	(0.22)
Retail Transmission Rate - Network Service Rate (4)	$ / kW	1.11
Retail Transmission Rate - Line and Transformation Connection Service Rate (4)	$ / kW	1.00
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
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Village of Chalk River Hydro Electric System
Effective Date: May 1, 2008

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Unmetered, Scattered Load

Service Charge	$	13.83
Distribution Volumetric Rate	$ / kWh	0.0200
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0034
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0006)
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0035
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0032
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

(3) For energy-only metered customers, the billing determinant is the customer’s metered energy consumption adjusted by the total loss factor as approved by the Board for Acquired LDC customers.
(4) For demand billed customers, appropriate loss factors must be applied to the applicable tariffs. Also the billing determinant for the Line and Transformation Connection Services rate is the customer’s peak demand in the billing period. The billing determinant for the Network Services rate is: for non-interval-metered customers, the peak demand in the billing period, and for interval-metered customers, the peak demand between 7 AM and 7 PM local time on IESO business days

Customer-Supplied Transformation Allowance

Applicable to customers providing their own transformers

Demand-billed	$ / kW	0.60
Energy-billed	$ / kWh	0.0014

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
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Village of Chalk River Hydro Electric System
Effective Date: May 1, 2008

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Loss Factors

Residential	1.085
General Service Less Than 50 kW (Energy-Billed)	1.092
General Service 50 kW or Greater (Demand-Billed)	1.061
Unmetered Scattered Load	1.092

Transformer Loss Allowance

Applicable to customers requiring a billing adjustment for transformer losses as the result of being metered on the primary side of a transformer. The following uniform values shall be applied to measured demand and energy to calculate transformer losses for voltages up to and including 50 kV (as metered on the primary side):

(a) 1.5% for transformer installations up to an individual bank capacity of 400 kVA,
(b) 1.0% for bank capacities over 400 kVA.

Alternatively, transformer losses may be determined from transformer test data, and measured demand and energy adjusted accordingly

For services which are not demand metered, an assumed demand of 50% of the transformer capacity will be used to calculate the loss allowance. Where several transformers are involved, the bank capacity is assumed to be the arithmetic sum of all transformer capacities

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Village of Chalk River Hydro Electric System
Effective Date: May 1, 2008

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

MISCELLANEOUS CHARGES

Specific Service Charges: Standard Amounts

Rate Code	Specific Service Charge - Standard Name	Calculation Method			
		2006 Rate Handbook	Standard Formula	Other Formula	Time and Materials
1	Temporary Service	$500			
2	Dispute Meter Test	$30 plus Measurement Canada fees			
3	Collection of account – no disconnection/load limiter	$30			
4	Collection/Disconnect/load limiter/reconnect (at meter) trip – regular hours	$65			
5	Collection/Disconnect/load limiter/reconnect (at meter) trip – after regular hours	$185			
6	Collection/Disconnect/load limiter/reconnect (at pole) trip – regular hours	$185			
7	Collection/Disconnect/load limiter/reconnect (at pole) trip – after regular hours	$415			
8	Account Set-up Charge	$30			
9	Arrears Certificate	$15			
10	NSF Cheque Charge	$15 + bank charges			
11	Easement Charge for Unregistered Rights	$15			
12	Late Payment Charge	1.5%/month			
13a	Retailer Services – Establishing Service Agreements (refer to Handbook for all charges)	$100/agreement/Retailer +$20/month/Retailer +$0.50/month/customer + other			
13b	Retailer Services – Other (includes Bill Ready for Retailers and Service Transactions Requests) as per the Handbook, Chapter 12	$0.30/month/customer + $0.25/request for request fee + $0.50/request for process fee			
14	Special Meter Reads	$30			
15	Service Layout Fee – Basic		$495		
16	Service Layout Fee – Complex		$690		
17	Crossing Application – Pipeline		$2,445		
18	Crossing Application – Water		$3,045		
19	Crossing Application – Railroad		$2,945		
20	Line Staking – per meter		$3.70		
21	Central Metering – New service < 45 kW		$115		
22	Conversion to Central Metering < 45 kW		$915		
23	Conversion to Central Metering > 45 kW		$800		
24	Tingle Voltage Test – In Excess of 4 Hours (per hour – average 2 additional hours)		$125		
25	Standby Administration Charge per month		$440		
26	Sentinel Lights Rental Rate per month			$7.10	
27	Sentinel Pole Rental Rate per month			$4.15	
28	Joint Use for Cable and Telecom companies per pole			$22.35	
29	Joint Use for LDCs per pole			$28.61	

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
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Effective Date: May 1, 2007

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APPLICATION

The application of these rates and charges shall be in accordance with The Licence of The Distributor and any Codes, Guidelines or Orders of The Board, and amendments thereto as approved by The Board, which may be applicable to the administration of this schedule.
No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code, Guideline or Order of the Board, and amendments thereto as approved by the Board, or as specified herein
This schedule does not contain any rates and charges relating to the electricity commodity (e.g. the Regulated Price Plan).

EFFECTIVE DATES

DISTRIBUTION RATES - May 1, 2007 for all consumption or deemed consumption services used on or after that date.

MISCELLANEOUS CHARGES - May 1, 2007 for all charges billed to customers on or after that date.
RETAIL TRANSMISSION RATES - May 1, 2007 for all consumption or deemed consumption services used on or after that date.
LOSS FACTOR ADJUSTMENT – May 1, 2007

SERVICE CLASSIFICATIONS

Residential
This classification (note 1) refers to all service supplied to single-family dwelling units for domestic or household purpose. Multi-unit residential establishments such as apartment buildings supplied through one service (bulk metered) will normally be classified as General Service, but, at Hydro One's discretion, up to four residential units may be classified as residential. Where electricity service is provided to combined residential and business (including agricultural usage) and the wiring does not provide for separate metering, the classification shall be at the discretion of Hydro One based on such considerations as the estimated predominant consumption.
Further servicing details are available in the utility's Conditions of Service.

General Service
This classification (note 1) refers to all service supplied to premises other than those classified as Residential or Lighting. Some General Service accounts are energy(kWh)-billed, and some are demand(kW)-billed. Further servicing details are available in the utility's Conditions of Service. Also, see note 2.

Unmetered Scattered Load
This classification refers to certain instances where connections can be provided without metering. These loads are generally small in size and consistent in magnitude of load. Hydro One reserves the right to review all cases and may require that a meter be installed at its sole discretion. Services that can be unmetered include cable TV amplifiers, telephone switching devices, phone booths, bus shelters, rail way crossing signals, traffic signals, and other small fixed loads.
Further servicing details are available in the utility's Conditions of Service (including in the "Unmetered Connections" section).

Hydro One Networks Inc.
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Street Lighting

This classification refers to accounts for the distribution and supply of electrical energy for street lighting. Street lights are devices owned by or operated for the road authority and/or the municipal corporation. These street lights in fact belong to the Street Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Sentinel Lighting

This classification refers to accounts for a separate service to a sentinel light. These sentinel lights in fact belong to the Sentinel Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Interim Demand-Side Management Time-of-Use

This is potentially applicable to Demand-billed General Service accounts. See Note 2 below.

Note (1): Classification descriptions are paraphrases from the document "Hydro One Networks Inc. - Distribution Customers Conditions of Service - August 2004"

Note (2):

Interim Demand-Side Management Time-of-Use Rates: demand charges will be based on demand during the on-peak periods.

Criteria: Customers' electricity consumption (kW) in the off-peak period is at least twice the electricity consumption (kW) during the on-peak period.

Definition of Time Periods: The on-peak hours will be between 0700 hours to 1900 hours Eastern Standard Time during the winter (standard time) on IESO business days and 0600 hours to 1800 hours Eastern Standard Time during the summer (daylight savings time) on IESO business days. The off-peak period constitutes all of the remaining hours.

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Village of Chalk River Hydro Electric System
Effective Date: May 1, 2007

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

MONTHLY RATES AND CHARGES

Residential

Service Charge	$	14.03
Distribution Volumetric Rate	$ / kWh	0.0137
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0061
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0042
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0055
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0047
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service - Energy Billed (less than 50 kW)

Service Charge	$	21.33
Distribution Volumetric Rate	$ / kWh	0.0179
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0039
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0034
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0050
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0043
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service - Demand Billed (50 kW or greater)

Service Charge	$	21.33
Distribution Volumetric Rate	$ / kW	5.70
Regulatory Asset Recovery - Rider #1	$ / kW	1.23
Regulatory Asset Recovery - Rider #2	$ / kW	1.07
Retail Transmission Rate - Network Service Rate (4)	$ / kW	1.94
Retail Transmission Rate - Line and Transformation Connection Service Rate (4)	$ / kW	1.61
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Village of Chalk River Hydro Electric System
Effective Date: May 1, 2007

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

Unmetered, Scattered Load

Service Charge	$	10.20
Distribution Volumetric Rate	$ / kWh	0.0179
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0039
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0034
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0050
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0043
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

(3) For energy-only metered customers, the billing determinant is the customer’s metered energy consumption adjusted by the total loss factor as approved by the Board for Acquired LDC customers.

(4) For demand billed customers, appropriate loss factors must be applied to the applicable tariffs. Also the billing determinant for the Line and Transformation Connection Services rate is the customer’s peak demand in the billing period. The billing determinant for the Network Services rate is: for non-interval-metered customers, the peak demand in the billing period, and for interval-metered customers, the peak demand between 7 AM and 7 PM local time on IESO business days

Interim Demand-Side Management Time-of-Use

See the "Service Classifications" section of this schedule.

Customer-Supplied Transformation Allowance

Applicable to demand-billed customers providing their own transformers
Primary Voltage under 50 kV (per kW)

Single Phase	$ / kW	0.20
Three Phase	$ / kW	0.60

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
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Village of Chalk River Hydro Electric System
Effective Date: May 1, 2007

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Loss Factors

Supply Facilities Loss Factor	1.0045
Distribution Loss Factors	
Customer less than 5,000 kW	1.0500
Customer greater than or equal to 5,000 kW	1.0100
Total Loss Factors	
Customer less than 5,000 kW	1.0545
Customer greater than or equal to 5,000 kW	1.0145

Transformer Loss Allowance

Applicable to customers requiring a billing adjustment for transformer losses as the result of being metered on the primary side of a transformer. The following uniform values shall be applied to measured demand and energy to calculate transformer losses for voltages up to and including 50 kV (as metered on the primary side):

(a) 1.5% for transformer installations up to an individual bank capacity of 400 kVA,
(b) 1.0% for bank capacities over 400 kVA.

Alternatively, transformer losses may be determined from transformer test data, and measured demand and energy adjusted accordingly

For services which are not demand metered, an assumed demand of 50% of the transformer capacity will be used to calculate the loss allowance. Where several transformers are involved, the bank capacity is assumed to be the arithmetic sum of all transformer capacities

Hydro One Networks Inc.
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MISCELLANEOUS CHARGES

Specific Service Charges: Standard Amounts

Rate Code	Specific Service Charge - Standard Name	Calculation Method			
		2006 Rate Handbook	Standard Formula	Other Formula	Time and Materials
1	Temporary Service	$500			
2	Dispute Meter Test	$30 plus Measurement Canada fees			
3	Collection of account – no disconnection/load limiter	$30			
4	Collection/Disconnect/load limiter/reconnect (at meter) trip – regular hours	$65			
5	Collection/Disconnect/load limiter/reconnect (at meter) trip – after regular hours	$185			
6	Collection/Disconnect/load limiter/reconnect (at pole) trip – regular hours	$185			
7	Collection/Disconnect/load limiter/reconnect (at pole) trip – after regular hours	$415			
8	Account Set-up Charge	$30			
9	Arrears Certificate	$15			
10	NSF Cheque Charge	$15 + bank charges			
11	Easement Charge for Unregistered Rights	$15			
12	Late Payment Charge	1.5%/month			
13a	Retailer Services – Establishing Service Agreements (refer to Handbook for all charges)	$100/agreement/Retailer +$20/month/Retailer +$0.50/month/customer + other			
13b	Retailer Services – Other (includes Bill Ready for Retailers and Service Transactions Requests) as per the Handbook, Chapter 12	$0.30/month/customer + $0.25/request for request fee + $0.50/request for process fee			
14	Special Meter Reads	$30			
15	Billing Suspension and Terminations in Trailer Parks		$130		
16	Service Layout Fee – Basic		$405		
17	Service Layout Fee – Complex		$580		

Hydro One Networks Inc.
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18	Crossing Application – Pipeline		$2,065		
19	Crossing Application – Water		$2,525		
20	Crossing Application – Railroad		$2,565		
21	Line Staking – per meter		$3.10		
22	Central Metering – New service < 45 kW		$115		
23	Conversion to Central Metering < 45 kW		$795		
24	Conversion to Central Metering > 45 kW		$680		
25	Tingle Voltage Test – In Excess of 4 Hours (per hour – average 2 additional hours)		$105		
26	Standby Administration Charge per month (interim)		$375		
27	Sentinel Lights Rental Rate per month – Mercury Vapor			$7.00	
28	Guaranteed Units from Jan 01/91 to Aug 01/91			$26.50 / month	
29	Guaranteed Units from Jan 01/87 to Dec 31/90			$23.50 / month	
30	Joint Use for Cable and Telecom companies per pole			$22.35	
31	Joint Use for LDCs per pole			$28.61	

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Township of Champlain Public Utilities Commission
Effective Date: May 1, 2008

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

APPLICATION

The application of these rates and charges shall be in accordance with The Licence of The Distributor and any Codes, Guidelines or Orders of The Board, and amendments thereto as approved by The Board, which may be applicable to the administration of this schedule.
No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code, Guideline or Order of the Board, and amendments thereto as approved by the Board, or as specified herein
This schedule does not contain any rates and charges relating to the electricity commodity (e.g. the Regulated Price Plan).

EFFECTIVE DATES

DISTRIBUTION RATES - May 1, 2008 for all consumption or deemed consumption services used on or after that date.

MISCELLANEOUS CHARGES - May 1, 2008 for all charges billed to customers on or after that date.
RETAIL TRANSMISSION RATES - May 1, 2008 for all consumption or deemed consumption services used on or after that date.
LOSS FACTOR ADJUSTMENT – for all consumption or deemed consumption services billed following May 1, 2008 or later

SERVICE CLASSIFICATIONS

Residential
This classification refers to all service supplied to single-family dwelling units for domestic or household purpose. Multi-unit residential establishments such as apartment buildings supplied through one service (bulk metered) will normally be classified as General Service, but, at Hydro One's discretion, up to four residential units may be classified as residential. Where electricity service is provided to combined residential and business (including agricultural usage) and the wiring does not provide for separate metering, the classification shall be at the discretion of Hydro One based on such considerations as the estimated predominant consumption.
Further servicing details are available in the utility's Conditions of Service.

General Service
This classification refers to all service supplied to premises other than those classified as Residential or Lighting. Some General Service accounts are energy(kWh)-billed, and some are demand(kW)-billed. Further servicing details are available in the utility's Conditions of Service.

Unmetered Scattered Load
This classification refers to certain instances where connections can be provided without metering. These loads are generally small in size and consistent in magnitude of load. Hydro One reserves the right to review all cases and may require that a meter be installed at its sole discretion. Services that can be unmetered include cable TV amplifiers, telephone switching devices, phone booths, bus shelters, rail way crossing signals, traffic signals, and other small fixed loads.
Further servicing details are available in the utility's Conditions of Service (including in the "Unmetered Connections" section).

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
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Township of Champlain Public Utilities Commission
Effective Date: May 1, 2008

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

Street Lighting

This classification refers to accounts for the distribution and supply of electrical energy for street lighting. Street lights are devices owned by or operated for the road authority and/or the municipal corporation. These street lights in fact belong to the Street Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Sentinel Lighting

This classification refers to accounts for a separate service to a sentinel light. These sentinel lights in fact belong to the Sentinel Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Urban Density Classification

Customers who meet the Urban Density Criteria of being in an area containing 3,000 or more customers with a line density of at least 60 customers per kilometre, will be mapped to an Urban customer classification.

Hydro One Networks Inc.
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MONTHLY RATES AND CHARGES

Residential - R1 Champlain

Service Charge	$	12.17
Distribution Volumetric Rate	$ / kWh	0.0200
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0023
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0004)
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0047
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0046
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service Less Than 50 kW (Energy-Billed) - GSe Champlain

Service Charge	$	22.94
Distribution Volumetric Rate	$ / kWh	0.0205
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0015
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0006)
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0035
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0032
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service 50 kW or Greater (Demand-Billed) - GSd Champlain

Service Charge	$	26.54
Distribution Volumetric Rate	$ / kW	8.00
Regulatory Asset Recovery - Rider #2	$ / kW	0.49
Regulatory Asset Recovery - Rider #3	$ / kW	(0.22)
Retail Transmission Rate - Network Service Rate (4)	$ / kW	1.11
Retail Transmission Rate - Line and Transformation Connection Service Rate (4)	$ / kW	1.00
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

Hydro One Networks Inc.
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Unmetered, Scattered Load

Service Charge	$	12.92
Distribution Volumetric Rate	$ / kWh	0.0200
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0015
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0006)
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0035
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0032
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

(3) For energy-only metered customers, the billing determinant is the customer’s metered energy consumption adjusted by the total loss factor as approved by the Board for Acquired LDC customers.
(4) For demand billed customers, appropriate loss factors must be applied to the applicable tariffs. Also the billing determinant for the Line and Transformation Connection Services rate is the customer’s peak demand in the billing period. The billing determinant for the Network Services rate is: for non-interval-metered customers, the peak demand in the billing period, and for interval-metered customers, the peak demand between 7 AM and 7 PM local time on IESO business days

Customer-Supplied Transformation Allowance

Applicable to customers providing their own transformers

Demand-billed	$ / kW	0.60
Energy-billed	$ / kWh	0.0014

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Loss Factors

Residential	1.085
General Service Less Than 50 kW (Energy-Billed)	1.092
General Service 50 kW or Greater (Demand-Billed)	1.061
Unmetered Scattered Load	1.092

Transformer Loss Allowance

Applicable to customers requiring a billing adjustment for transformer losses as the result of being metered on the primary side of a transformer. The following uniform values shall be applied to measured demand and energy to calculate transformer losses for voltages up to and including 50 kV (as metered on the primary side):

(a) 1.5% for transformer installations up to an individual bank capacity of 400 kVA,
(b) 1.0% for bank capacities over 400 kVA.

Alternatively, transformer losses may be determined from transformer test data, and measured demand and energy adjusted accordingly

For services which are not demand metered, an assumed demand of 50% of the transformer capacity will be used to calculate the loss allowance. Where several transformers are involved, the bank capacity is assumed to be the arithmetic sum of all transformer capacities

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
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This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

MISCELLANEOUS CHARGES

Specific Service Charges: Standard Amounts

Rate Code	Specific Service Charge - Standard Name	Calculation Method			
		2006 Rate Handbook	Standard Formula	Other Formula	Time and Materials
1	Temporary Service	$500			
2	Dispute Meter Test	$30 plus Measurement Canada fees			
3	Collection of account – no disconnection/load limiter	$30			
4	Collection/Disconnect/load limiter/reconnect (at meter) trip – regular hours	$65			
5	Collection/Disconnect/load limiter/reconnect (at meter) trip – after regular hours	$185			
6	Collection/Disconnect/load limiter/reconnect (at pole) trip – regular hours	$185			
7	Collection/Disconnect/load limiter/reconnect (at pole) trip – after regular hours	$415			
8	Account Set-up Charge	$30			
9	Arrears Certificate	$15			
10	NSF Cheque Charge	$15 + bank charges			
11	Easement Charge for Unregistered Rights	$15			
12	Late Payment Charge	1.5%/month			
13a	Retailer Services – Establishing Service Agreements (refer to Handbook for all charges)	$100/agreement/Retailer +$20/month/Retailer +$0.50/month/customer + other			
13b	Retailer Services – Other (includes Bill Ready for Retailers and Service Transactions Requests) as per the Handbook, Chapter 12	$0.30/month/customer + $0.25/request for request fee + $0.50/request for process fee			
14	Special Meter Reads	$30			
15	Service Layout Fee – Basic		$495		
16	Service Layout Fee – Complex		$690		
17	Crossing Application – Pipeline		$2,445		
18	Crossing Application – Water		$3,045		
19	Crossing Application – Railroad		$2,945		
20	Line Staking – per meter		$3.70		
21	Central Metering – New service < 45 kW		$115		
22	Conversion to Central Metering < 45 kW		$915		
23	Conversion to Central Metering > 45 kW		$800		
24	Tingle Voltage Test – In Excess of 4 Hours (per hour – average 2 additional hours)		$125		
25	Standby Administration Charge per month		$440		
26	Sentinel Lights Rental Rate per month			$7.10	
27	Sentinel Pole Rental Rate per month			$4.15	
28	Joint Use for Cable and Telecom companies per pole			$22.35	
29	Joint Use for LDCs per pole			$28.61	

Hydro One Networks Inc.
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APPLICATION

The application of these rates and charges shall be in accordance with The Licence of The Distributor and any Codes, Guidelines or Orders of The Board, and amendments thereto as approved by The Board, which may be applicable to the administration of this schedule.
No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code, Guideline or Order of the Board, and amendments thereto as approved by the Board, or as specified herein
This schedule does not contain any rates and charges relating to the electricity commodity (e.g. the Regulated Price Plan).

EFFECTIVE DATES

DISTRIBUTION RATES - May 1, 2007 for all consumption or deemed consumption services used on or after that date.

MISCELLANEOUS CHARGES - May 1, 2007 for all charges billed to customers on or after that date.
RETAIL TRANSMISSION RATES - May 1, 2007 for all consumption or deemed consumption services used on or after that date.
LOSS FACTOR ADJUSTMENT – May 1, 2007

SERVICE CLASSIFICATIONS

Residential
This classification (note 1) refers to all service supplied to single-family dwelling units for domestic or household purpose. Multi-unit residential establishments such as apartment buildings supplied through one service (bulk metered) will normally be classified as General Service, but, at Hydro One’s discretion, up to four residential units may be classified as residential. Where electricity service is provided to combined residential and business (including agricultural usage) and the wiring does not provide for separate metering, the classification shall be at the discretion of Hydro One based on such considerations as the estimated predominant consumption.
Further servicing details are available in the utility’s Conditions of Service.

General Service
This classification (note 1) refers to all service supplied to premises other than those classified as Residential or Lighting. Some General Service accounts are energy(kWh)-billed, and some are demand(kW)-billed. Further servicing details are available in the utility’s Conditions of Service. Also, see note 2.

Unmetered Scattered Load
This classification refers to certain instances where connections can be provided without metering. These loads are generally small in size and consistent in magnitude of load. Hydro One reserves the right to review all cases and may require that a meter be installed at its sole discretion. Services that can be unmetered include cable TV amplifiers, telephone switching devices, phone booths, bus shelters, rail way crossing signals, traffic signals, and other small fixed loads.
Further servicing details are available in the utility’s Conditions of Service (including in the "Unmetered Connections" section).

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Street Lighting

This classification refers to accounts for the distribution and supply of electrical energy for street lighting. Street lights are devices owned by or operated for the road authority and/or the municipal corporation. These street lights in fact belong to the Street Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Sentinel Lighting

This classification refers to accounts for a separate service to a sentinel light. These sentinel lights in fact belong to the Sentinel Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Interim Demand-Side Management Time-of-Use

This is potentially applicable to Demand-billed General Service accounts. See Note 2 below.

Note (1): Classification descriptions are paraphrases from the document "Hydro One Networks Inc. - Distribution Customers Conditions of Service - August 2004"
Note (2):

Interim Demand-Side Management Time-of-Use Rates: demand charges will be based on demand during the on-peak periods.
Criteria: Customers' electricity consumption (kW) in the off-peak period is at least twice the electricity consumption (kW) during the on-peak period.
Definition of Time Periods: The on-peak hours will be between 0700 hours to 1900 hours Eastern Standard Time during the winter (standard time) on IESO business days and 0600 hours to 1800 hours Eastern Standard Time during the summer (daylight savings time) on IESO business days. The off-peak period constitutes all of the remaining hours.

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MONTHLY RATES AND CHARGES

Residential

Service Charge	$	10.36
Distribution Volumetric Rate	$ / kWh	0.0088
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0045
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0023
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0055
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0047
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service - Energy Billed (less than 50 kW)

Service Charge	$	20.59
Distribution Volumetric Rate	$ / kWh	0.0091
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0026
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0015
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0050
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0043
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service - Demand Billed (50 kW or greater)

Service Charge	$	20.59
Distribution Volumetric Rate	$ / kW	2.88
Regulatory Asset Recovery - Rider #1	$ / kW	0.84
Regulatory Asset Recovery - Rider #2	$ / kW	0.49
Retail Transmission Rate - Network Service Rate (4)	$ / kW	1.94
Retail Transmission Rate - Line and Transformation Connection Service Rate (4)	$ / kW	1.61
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

Hydro One Networks Inc.
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Unmetered, Scattered Load

Service Charge	$	9.83
Distribution Volumetric Rate	$ / kWh	0.0091
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0026
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0015
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0050
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0043
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

(3) For energy-only metered customers, the billing determinant is the customer's metered energy consumption adjusted by the total loss factor as approved by the Board for Acquired LDC customers.
(4) For demand billed customers, appropriate loss factors must be applied to the applicable tariffs. Also the billing determinant for the Line and Transformation Connection Services rate is the customer's peak demand in the billing period. The billing determinant for the Network Services rate is: for non-interval-metered customers, the peak demand in the billing period, and for interval-metered customers, the peak demand between 7 AM and 7 PM local time on IESO business days

Interim Demand-Side Management Time-of-Use

See the "Service Classifications" section of this schedule.

Customer-Supplied Transformation Allowance

Applicable to demand-billed customers providing their own transformers
Primary Voltage under 50 kV (per kW)

Single Phase	$ / kW	0.20
Three Phase	$ / kW	0.60

Hydro One Networks Inc.
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Loss Factors

Supply Facilities Loss Factor	1.0045
Distribution Loss Factors	
Customer less than 5,000 kW	1.0500
Customer greater than or equal to 5,000 kW	1.0100
Total Loss Factors	
Customer less than 5,000 kW	1.0545
Customer greater than or equal to 5,000 kW	1.0145

Transformer Loss Allowance

Applicable to customers requiring a billing adjustment for transformer losses as the result of being metered on the primary side of a transformer. The following uniform values shall be applied to measured demand and energy to calculate transformer losses for voltages up to and including 50 kV (as metered on the primary side):

(a) 1.5% for transformer installations up to an individual bank capacity of 400 kVA,
(b) 1.0% for bank capacities over 400 kVA.

Alternatively, transformer losses may be determined from transformer test data, and measured demand and energy adjusted accordingly

For services which are not demand metered, an assumed demand of 50% of the transformer capacity will be used to calculate the loss allowance. Where several transformers are involved, the bank capacity is assumed to be the arithmetic sum of all transformer capacities

Hydro One Networks Inc.
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MISCELLANEOUS CHARGES

Specific Service Charges: Standard Amounts

Rate Code	Specific Service Charge - Standard Name	Calculation Method			
		2006 Rate Handbook	Standard Formula	Other Formula	Time and Materials
1	Temporary Service	$500			
2	Dispute Meter Test	$30 plus Measurement Canada fees			
3	Collection of account – no disconnection/load limiter	$30			
4	Collection/Disconnect/load limiter/reconnect (at meter) trip – regular hours	$65			
5	Collection/Disconnect/load limiter/reconnect (at meter) trip – after regular hours	$185			
6	Collection/Disconnect/load limiter/reconnect (at pole) trip – regular hours	$185			
7	Collection/Disconnect/load limiter/reconnect (at pole) trip – after regular hours	$415			
8	Account Set-up Charge	$30			
9	Arrears Certificate	$15			
10	NSF Cheque Charge	$15 + bank charges			
11	Easement Charge for Unregistered Rights	$15			
12	Late Payment Charge	1.5%/month			
13a	Retailer Services – Establishing Service Agreements (refer to Handbook for all charges)	$100/agreement/Retailer +$20/month/Retailer +$0.50/month/customer + other			
13b	Retailer Services – Other (includes Bill Ready for Retailers and Service Transactions Requests) as per the Handbook, Chapter 12	$0.30/month/customer + $0.25/request for request fee + $0.50/request for process fee			
14	Special Meter Reads	$30			
15	Billing Suspension and Terminations in Trailer Parks		$130		
16	Service Layout Fee – Basic		$405		
17	Service Layout Fee – Complex		$580		

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Township of Champlain Public Utilities Commission
Effective Date: May 1, 2007

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

18	Crossing Application – Pipeline		$2,065		
19	Crossing Application – Water		$2,525		
20	Crossing Application – Railroad		$2,565		
21	Line Staking – per meter		$3.10		
22	Central Metering – New service < 45 kW		$115		
23	Conversion to Central Metering < 45 kW		$795		
24	Conversion to Central Metering > 45 kW		$680		
25	Tingle Voltage Test – In Excess of 4 Hours (per hour – average 2 additional hours)		$105		
26	Standby Administration Charge per month (interim)		$375		
27	Sentinel Lights Rental Rate per month – Mercury Vapor			$7.00	
28	Guaranteed Units from Jan 01/91 to Aug 01/91			$26.50 / month	
29	Guaranteed Units from Jan 01/87 to Dec 31/90			$23.50 / month	
30	Joint Use for Cable and Telecom companies per pole			$22.35	
31	Joint Use for LDCs per pole			$28.61	

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Clarence-Rockland Hydro Electric Commission
Effective Date: May 1, 2008

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

APPLICATION

The application of these rates and charges shall be in accordance with The Licence of The Distributor and any Codes, Guidelines or Orders of The Board, and amendments thereto as approved by The Board, which may be applicable to the administration of this schedule.
No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code, Guideline or Order of the Board, and amendments thereto as approved by the Board, or as specified herein
This schedule does not contain any rates and charges relating to the electricity commodity (e.g. the Regulated Price Plan).

EFFECTIVE DATES

DISTRIBUTION RATES - May 1, 2008 for all consumption or deemed consumption services used on or after that date.

MISCELLANEOUS CHARGES - May 1, 2008 for all charges billed to customers on or after that date.
RETAIL TRANSMISSION RATES - May 1, 2008 for all consumption or deemed consumption services used on or after that date.
LOSS FACTOR ADJUSTMENT – for all consumption or deemed consumption services billed following May 1, 2008 or later

SERVICE CLASSIFICATIONS

Residential
This classification refers to all service supplied to single-family dwelling units for domestic or household purpose. Multi-unit residential establishments such as apartment buildings supplied through one service (bulk metered) will normally be classified as General Service, but, at Hydro One's discretion, up to four residential units may be classified as residential. Where electricity service is provided to combined residential and business (including agricultural usage) and the wiring does not provide for separate metering, the classification shall be at the discretion of Hydro One based on such considerations as the estimated predominant consumption.
Further servicing details are available in the utility's Conditions of Service.

General Service
This classification refers to all service supplied to premises other than those classified as Residential or Lighting. Some General Service accounts are energy(kWh)-billed, and some are demand(kW)-billed. Further servicing details are available in the utility's Conditions of Service.

Unmetered Scattered Load
This classification refers to certain instances where connections can be provided without metering. These loads are generally small in size and consistent in magnitude of load. Hydro One reserves the right to review all cases and may require that a meter be installed at its sole discretion. Services that can be unmetered include cable TV amplifiers, telephone switching devices, phone booths, bus shelters, rail way crossing signals, traffic signals, and other small fixed loads.
Further servicing details are available in the utility's Conditions of Service (including in the "Unmetered Connections" section).

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Clarence-Rockland Hydro Electric Commission
Effective Date: May 1, 2008

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

Street Lighting

This classification refers to accounts for the distribution and supply of electrical energy for street lighting. Street lights are devices owned by or operated for the road authority and/or the municipal corporation. These street lights in fact belong to the Street Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Sentinel Lighting

This classification refers to accounts for a separate service to a sentinel light. These sentinel lights in fact belong to the Sentinel Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Urban Density Classification

Customers who meet the Urban Density Criteria of being in an area containing 3,000 or more customers with a line density of at least 60 customers per kilometre, will be mapped to an Urban customer classification.

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Clarence-Rockland Hydro Electric Commission
Effective Date: May 1, 2008

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

MONTHLY RATES AND CHARGES

Residential - R1 Rockland

Service Charge	$	11.41
Distribution Volumetric Rate	$ / kWh	0.0230
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0037
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0004)
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0047
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0046
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service Less Than 50 kW (Energy-Billed) - GSe Rockland

Service Charge	$	13.27
Distribution Volumetric Rate	$ / kWh	0.0180
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0022
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0006)
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0035
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0032
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service 50 kW or Greater (Demand-Billed) - GSd Rockland

Service Charge	$	16.87
Distribution Volumetric Rate	$ / kW	7.25
Regulatory Asset Recovery - Rider #2	$ / kW	0.57
Regulatory Asset Recovery - Rider #3	$ / kW	(0.22)
Retail Transmission Rate - Network Service Rate (4)	$ / kW	1.11
Retail Transmission Rate - Line and Transformation Connection Service Rate (4)	$ / kW	1.00
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Clarence-Rockland Hydro Electric Commission
Effective Date: May 1, 2008

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

Unmetered, Scattered Load

Service Charge	$	8.59
Distribution Volumetric Rate	$ / kWh	0.0200
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0022
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0006)
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0035
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0032
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

(3) For energy-only metered customers, the billing determinant is the customer’s metered energy consumption adjusted by the total loss factor as approved by the Board for Acquired LDC customers.
(4) For demand billed customers, appropriate loss factors must be applied to the applicable tariffs. Also the billing determinant for the Line and Transformation Connection Services rate is the customer’s peak demand in the billing period. The billing determinant for the Network Services rate is: for non-interval-metered customers, the peak demand in the billing period, and for interval-metered customers, the peak demand between 7 AM and 7 PM local time on IESO business days

Customer-Supplied Transformation Allowance

Applicable to customers providing their own transformers		
Demand-billed	$ / kW	0.60
Energy-billed	$ / kWh	0.0014

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Clarence-Rockland Hydro Electric Commission
Effective Date: May 1, 2008

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

Loss Factors

Residential	1.085
General Service Less Than 50 kW (Energy-Billed)	1.092
General Service 50 kW or Greater (Demand-Billed)	1.061
Unmetered Scattered Load	1.092

Transformer Loss Allowance

Applicable to customers requiring a billing adjustment for transformer losses as the result of being metered on the primary side of a transformer. The following uniform values shall be applied to measured demand and energy to calculate transformer losses for voltages up to and including 50 kV (as metered on the primary side):

(a) 1.5% for transformer installations up to an individual bank capacity of 400 kVA,
(b) 1.0% for bank capacities over 400 kVA.

Alternatively, transformer losses may be determined from transformer test data, and measured demand and energy adjusted accordingly

For services which are not demand metered, an assumed demand of 50% of the transformer capacity will be used to calculate the loss allowance. Where several transformers are involved, the bank capacity is assumed to be the arithmetic sum of all transformer capacities

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Clarence-Rockland Hydro Electric Commission
Effective Date: May 1, 2008

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

MISCELLANEOUS CHARGES

Specific Service Charges: Standard Amounts

Rate Code	Specific Service Charge - Standard Name	Calculation Method			
		2006 Rate Handbook	Standard Formula	Other Formula	Time and Materials
1	Temporary Service	$500			
2	Dispute Meter Test	$30 plus Measurement Canada fees			
3	Collection of account – no disconnection/load limiter	$30			
4	Collection/Disconnect/load limiter/reconnect (at meter) trip – regular hours	$65			
5	Collection/Disconnect/load limiter/reconnect (at meter) trip – after regular hours	$185			
6	Collection/Disconnect/load limiter/reconnect (at pole) trip – regular hours	$185			
7	Collection/Disconnect/load limiter/reconnect (at pole) trip – after regular hours	$415			
8	Account Set-up Charge	$30			
9	Arrears Certificate	$15			
10	NSF Cheque Charge	$15 + bank charges			
11	Easement Charge for Unregistered Rights	$15			
12	Late Payment Charge	1.5%/month			
13a	Retailer Services – Establishing Service Agreements (refer to Handbook for all charges)	$100/agreement/Retailer +$20/month/Retailer +$0.50/month/customer + other			
13b	Retailer Services – Other (includes Bill Ready for Retailers and Service Transactions Requests) as per the Handbook, Chapter 12	$0.30/month/customer + $0.25/request for request fee + $0.50/request for process fee			
14	Special Meter Reads	$30			
15	Service Layout Fee – Basic		$495		
16	Service Layout Fee – Complex		$690		
17	Crossing Application – Pipeline		$2,445		
18	Crossing Application – Water		$3,045		
19	Crossing Application – Railroad		$2,945		
20	Line Staking – per meter		$3.70		
21	Central Metering – New service < 45 kW		$115		
22	Conversion to Central Metering < 45 kW		$915		
23	Conversion to Central Metering > 45 kW		$800		
24	Tingle Voltage Test – In Excess of 4 Hours (per hour – average 2 additional hours)		$125		
25	Standby Administration Charge per month		$440		
26	Sentinel Lights Rental Rate per month			$7.10	
27	Sentinel Pole Rental Rate per month			$4.15	
28	Joint Use for Cable and Telecom companies per pole			$22.35	
29	Joint Use for LDCs per pole			$28.61	

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Rockland Hydro Electric Commission
Effective Date: May 1, 2007

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

APPLICATION

The application of these rates and charges shall be in accordance with The Licence of The Distributor and any Codes, Guidelines or Orders of The Board, and amendments thereto as approved by The Board, which may be applicable to the administration of this schedule.
No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code, Guideline or Order of the Board, and amendments thereto as approved by the Board, or as specified herein
This schedule does not contain any rates and charges relating to the electricity commodity (e.g. the Regulated Price Plan).

EFFECTIVE DATES

DISTRIBUTION RATES - May 1, 2007 for all consumption or deemed consumption services used on or after that date.

MISCELLANEOUS CHARGES - May 1, 2007 for all charges billed to customers on or after that date.
RETAIL TRANSMISSION RATES - May 1, 2007 for all consumption or deemed consumption services used on or after that date.
LOSS FACTOR ADJUSTMENT – May 1, 2007

SERVICE CLASSIFICATIONS

Residential
This classification (note 1) refers to all service supplied to single-family dwelling units for domestic or household purpose. Multi-unit residential establishments such as apartment buildings supplied through one service (bulk metered) will normally be classified as General Service, but, at Hydro One's discretion, up to four residential units may be classified as residential. Where electricity service is provided to combined residential and business (including agricultural usage) and the wiring does not provide for separate metering, the classification shall be at the discretion of Hydro One based on such considerations as the estimated predominant consumption.
Further servicing details are available in the utility's Conditions of Service.

General Service
This classification (note 1) refers to all service supplied to premises other than those classified as Residential or Lighting. Some General Service accounts are energy(kWh)-billed, and some are demand(kW)-billed. Further servicing details are available in the utility's Conditions of Service. Also, see note 2.

Unmetered Scattered Load
This classification refers to certain instances where connections can be provided without metering. These loads are generally small in size and consistent in magnitude of load. Hydro One reserves the right to review all cases and may require that a meter be installed at its sole discretion. Services that can be unmetered include cable TV amplifiers, telephone switching devices, phone booths, bus shelters, rail way crossing signals, traffic signals, and other small fixed loads.
Further servicing details are available in the utility's Conditions of Service (including in the "Unmetered Connections" section).

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Rockland Hydro Electric Commission
Effective Date: May 1, 2007

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

Street Lighting

This classification refers to accounts for the distribution and supply of electrical energy for street lighting. Street lights are devices owned by or operated for the road authority and/or the municipal corporation. These street lights in fact belong to the Street Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Sentinel Lighting

This classification refers to accounts for a separate service to a sentinel light. These sentinel lights in fact belong to the Sentinel Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Interim Demand-Side Management Time-of-Use

This is potentially applicable to Demand-billed General Service accounts. See Note 2 below.

Note (1): Classification descriptions are paraphrases from the document "Hydro One Networks Inc. - Distribution Customers Conditions of Service - August 2004"

Note (2):

Interim Demand-Side Management Time-of-Use Rates: demand charges will be based on demand during the on-peak periods.

Criteria: Customers' electricity consumption (kW) in the off-peak period is at least twice the electricity consumption (kW) during the on-peak period.

Definition of Time Periods: The on-peak hours will be between 0700 hours to 1900 hours Eastern Standard Time during the winter (standard time) on IESO business days and 0600 hours to 1800 hours Eastern Standard Time during the summer (daylight savings time) on IESO business days. The off-peak period constitutes all of the remaining hours.

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Rockland Hydro Electric Commission
Effective Date: May 1, 2007

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

MONTHLY RATES AND CHARGES

Residential

Service Charge	$	9.41
Distribution Volumetric Rate	$ / kWh	0.0092
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0065
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0037
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0055
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0047
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service - Energy Billed (less than 50 kW)

Service Charge	$	7.27
Distribution Volumetric Rate	$ / kWh	0.0100
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0017
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0022
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0050
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0043
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service - Demand Billed (50 kW or greater)

Service Charge	$	7.27
Distribution Volumetric Rate	$ / kW	2.59
Regulatory Asset Recovery - Rider #1	$ / kW	0.53
Regulatory Asset Recovery - Rider #2	$ / kW	0.57
Retail Transmission Rate - Network Service Rate (4)	$ / kW	1.94
Retail Transmission Rate - Line and Transformation Connection Service Rate (4)	$ / kW	1.61
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Rockland Hydro Electric Commission
Effective Date: May 1, 2007

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

Unmetered, Scattered Load

Service Charge	$	3.16
Distribution Volumetric Rate	$ / kWh	0.0100
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0017
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0022
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0050
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0043
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

(3) For energy-only metered customers, the billing determinant is the customer’s metered energy consumption adjusted by the total loss factor as approved by the Board for Acquired LDC customers.
(4) For demand billed customers, appropriate loss factors must be applied to the applicable tariffs. Also the billing determinant for the Line and Transformation Connection Services rate is the customer’s peak demand in the billing period. The billing determinant for the Network Services rate is: for non-interval-metered customers, the peak demand in the billing period, and for interval-metered customers, the peak demand between 7 AM and 7 PM local time on IESO business days

Interim Demand-Side Management Time-of-Use

See the "Service Classifications" section of this schedule.

Customer-Supplied Transformation Allowance

Applicable to demand-billed customers providing their own transformers
Primary Voltage under 50 kV (per kW)

Single Phase	$ / kW	0.20
Three Phase	$ / kW	0.60

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Rockland Hydro Electric Commission
Effective Date: May 1, 2007

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

Loss Factors

Supply Facilities Loss Factor	1.0045
Distribution Loss Factors	
Customer less than 5,000 kW	1.0500
Customer greater than or equal to 5,000 kW	1.0100
Total Loss Factors	
Customer less than 5,000 kW	1.0545
Customer greater than or equal to 5,000 kW	1.0145

Transformer Loss Allowance

Applicable to customers requiring a billing adjustment for transformer losses as the result of being metered on the primary side of a transformer. The following uniform values shall be applied to measured demand and energy to calculate transformer losses for voltages up to and including 50 kV (as metered on the primary side):

(a) 1.5% for transformer installations up to an individual bank capacity of 400 kVA,
(b) 1.0% for bank capacities over 400 kVA.

Alternatively, transformer losses may be determined from transformer test data, and measured demand and energy adjusted accordingly

For services which are not demand metered, an assumed demand of 50% of the transformer capacity will be used to calculate the loss allowance. Where several transformers are involved, the bank capacity is assumed to be the arithmetic sum of all transformer capacities

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Rockland Hydro Electric Commission
Effective Date: May 1, 2007

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

MISCELLANEOUS CHARGES

Specific Service Charges: Standard Amounts

Rate Code	Specific Service Charge - Standard Name	Calculation Method			
		2006 Rate Handbook	Standard Formula	Other Formula	Time and Materials
1	Temporary Service	$500			
2	Dispute Meter Test	$30 plus Measurement Canada fees			
3	Collection of account – no disconnection/load limiter	$30			
4	Collection/Disconnect/load limiter/reconnect (at meter) trip – regular hours	$65			
5	Collection/Disconnect/load limiter/reconnect (at meter) trip – after regular hours	$185			
6	Collection/Disconnect/load limiter/reconnect (at pole) trip – regular hours	$185			
7	Collection/Disconnect/load limiter/reconnect (at pole) trip – after regular hours	$415			
8	Account Set-up Charge	$30			
9	Arrears Certificate	$15			
10	NSF Cheque Charge	$15 + bank charges			
11	Easement Charge for Unregistered Rights	$15			
12	Late Payment Charge	1.5%/month			
13a	Retailer Services – Establishing Service Agreements (refer to Handbook for all charges)	$100/agreement/Retailer +$20/month/Retailer +$0.50/month/customer + other			
13b	Retailer Services – Other (includes Bill Ready for Retailers and Service Transactions Requests) as per the Handbook, Chapter 12	$0.30/month/customer + $0.25/request for request fee + $0.50/request for process fee			
14	Special Meter Reads	$30			
15	Billing Suspension and Terminations in Trailer Parks		$130		
16	Service Layout Fee – Basic		$405		
17	Service Layout Fee – Complex		$580		

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Rockland Hydro Electric Commission
Effective Date: May 1, 2007

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

18	Crossing Application – Pipeline		$2,065		
19	Crossing Application – Water		$2,525		
20	Crossing Application – Railroad		$2,565		
21	Line Staking – per meter		$3.10		
22	Central Metering – New service < 45 kW		$115		
23	Conversion to Central Metering < 45 kW		$795		
24	Conversion to Central Metering > 45 kW		$680		
25	Tingle Voltage Test – In Excess of 4 Hours (per hour – average 2 additional hours)		$105		
26	Standby Administration Charge per month (interim)		$375		
27	Sentinel Lights Rental Rate per month – Mercury Vapor			$7.00	
28	Guaranteed Units from Jan 01/91 to Aug 01/91			$26.50 / month	
29	Guaranteed Units from Jan 01/87 to Dec 31/90			$23.50 / month	
30	Joint Use for Cable and Telecom companies per pole			$22.35	
31	Joint Use for LDCs per pole			$28.61	

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Village of Cobden Hydro System
Effective Date: May 1, 2008

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

APPLICATION

The application of these rates and charges shall be in accordance with The Licence of The Distributor and any Codes, Guidelines or Orders of The Board, and amendments thereto as approved by The Board, which may be applicable to the administration of this schedule.
No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code, Guideline or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.
This schedule does not contain any rates and charges relating to the electricity commodity (e.g. the Regulated Price Plan).

EFFECTIVE DATES

DISTRIBUTION RATES - May 1, 2008 for all consumption or deemed consumption services used on or after that date.

MISCELLANEOUS CHARGES - May 1, 2008 for all charges billed to customers on or after that date.
RETAIL TRANSMISSION RATES - May 1, 2008 for all consumption or deemed consumption services used on or after that date.
LOSS FACTOR ADJUSTMENT – for all consumption or deemed consumption services billed following May 1, 2008 or later

SERVICE CLASSIFICATIONS

Residential
This classification refers to all service supplied to single-family dwelling units for domestic or household purpose. Multi-unit residential establishments such as apartment buildings supplied through one service (bulk metered) will normally be classified as General Service, but, at Hydro One's discretion, up to four residential units may be classified as residential. Where electricity service is provided to combined residential and business (including agricultural usage) and the wiring does not provide for separate metering, the classification shall be at the discretion of Hydro One based on such considerations as the estimated predominant consumption.
Further servicing details are available in the utility's Conditions of Service.

General Service
This classification refers to all service supplied to premises other than those classified as Residential or Lighting. Some General Service accounts are energy(kWh)-billed, and some are demand(kW)-billed. Further servicing details are available in the utility's Conditions of Service.

Unmetered Scattered Load
This classification refers to certain instances where connections can be provided without metering. These loads are generally small in size and consistent in magnitude of load. Hydro One reserves the right to review all cases and may require that a meter be installed at its sole discretion. Services that can be unmetered include cable TV amplifiers, telephone switching devices, phone booths, bus shelters, rail way crossing signals, traffic signals, and other small fixed loads.
Further servicing details are available in the utility's Conditions of Service (including in the "Unmetered Connections" section).

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Village of Cobden Hydro System
Effective Date: May 1, 2008

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

Street Lighting

This classification refers to accounts for the distribution and supply of electrical energy for street lighting. Street lights are devices owned by or operated for the road authority and/or the municipal corporation. These street lights in fact belong to the Street Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Sentinel Lighting

This classification refers to accounts for a separate service to a sentinel light. These sentinel lights in fact belong to the Sentinel Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Urban Density Classification

Customers who meet the Urban Density Criteria of being in an area containing 3,000 or more customers with a line density of at least 60 customers per kilometre, will be mapped to an Urban customer classification.

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Village of Cobden Hydro System
Effective Date: May 1, 2008

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

MONTHLY RATES AND CHARGES

Residential - R1 Cobden

Service Charge	$	14.49
Distribution Volumetric Rate	$ / kWh	0.0271
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0041
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0004)
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0047
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0046
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service Less Than 50 kW (Energy-Billed) - GSe Cobden

Service Charge	$	23.61
Distribution Volumetric Rate	$ / kWh	0.0321
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0030
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0006)
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0035
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0032
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service 50 kW or Greater (Demand-Billed) - GSd Cobden

Service Charge	$	27.21
Distribution Volumetric Rate	$ / kW	9.22
Regulatory Asset Recovery - Rider #2	$ / kW	0.90
Regulatory Asset Recovery - Rider #3	$ / kW	(0.22)
Retail Transmission Rate - Network Service Rate (4)	$ / kW	1.11
Retail Transmission Rate - Line and Transformation Connection Service Rate (4)	$ / kW	1.00
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Village of Cobden Hydro System
Effective Date: May 1, 2008

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Unmetered, Scattered Load

Service Charge	$	13.75
Distribution Volumetric Rate	$ / kWh	0.0200
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0030
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0006)
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0035
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0032
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

(3) For energy-only metered customers, the billing determinant is the customer's metered energy consumption adjusted by the total loss factor as approved by the Board for Acquired LDC customers.
(4) For demand billed customers, appropriate loss factors must be applied to the applicable tariffs. Also the billing determinant for the Line and Transformation Connection Services rate is the customer's peak demand in the billing period. The billing determinant for the Network Services rate is: for non-interval-metered customers, the peak demand in the billing period, and for interval-metered customers, the peak demand between 7 AM and 7 PM local time on IESO business days

Customer-Supplied Transformation Allowance

Applicable to customers providing their own transformers

Demand-billed	$ / kW	0.60
Energy-billed	$ / kWh	0.0014

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Village of Cobden Hydro System
Effective Date: May 1, 2008

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Loss Factors

Residential	1.085
General Service Less Than 50 kW (Energy-Billed)	1.092
General Service 50 kW or Greater (Demand-Billed)	1.061
Unmetered Scattered Load	1.092

Transformer Loss Allowance

Applicable to customers requiring a billing adjustment for transformer losses as the result of being metered on the primary side of a transformer. The following uniform values shall be applied to measured demand and energy to calculate transformer losses for voltages up to and including 50 kV (as metered on the primary side):

(a) 1.5% for transformer installations up to an individual bank capacity of 400 kVA,
(b) 1.0% for bank capacities over 400 kVA.

Alternatively, transformer losses may be determined from transformer test data, and measured demand and energy adjusted accordingly
For services which are not demand metered, an assumed demand of 50% of the transformer capacity will be used to calculate the loss allowance. Where several transformers are involved, the bank capacity is assumed to be the arithmetic sum of all transformer capacities

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Village of Cobden Hydro System
Effective Date: May 1, 2008

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

MISCELLANEOUS CHARGES

Specific Service Charges: Standard Amounts

Rate Code	Specific Service Charge - Standard Name	Calculation Method			
		2006 Rate Handbook	Standard Formula	Other Formula	Time and Materials
1	Temporary Service	$500			
2	Dispute Meter Test	$30 plus Measurement Canada fees			
3	Collection of account – no disconnection/load limiter	$30			
4	Collection/Disconnect/load limiter/reconnect (at meter) trip – regular hours	$65			
5	Collection/Disconnect/load limiter/reconnect (at meter) trip – after regular hours	$185			
6	Collection/Disconnect/load limiter/reconnect (at pole) trip – regular hours	$185			
7	Collection/Disconnect/load limiter/reconnect (at pole) trip – after regular hours	$415			
8	Account Set-up Charge	$30			
9	Arrears Certificate	$15			
10	NSF Cheque Charge	$15 + bank charges			
11	Easement Charge for Unregistered Rights	$15			
12	Late Payment Charge	1.5%/month			
13a	Retailer Services – Establishing Service Agreements (refer to Handbook for all charges)	$100/agreement/Retailer +$20/month/Retailer +$0.50/month/customer + other			
13b	Retailer Services – Other (includes Bill Ready for Retailers and Service Transactions Requests) as per the Handbook, Chapter 12	$0.30/month/customer + $0.25/request for request fee + $0.50/request for process fee			
14	Special Meter Reads	$30			
15	Service Layout Fee – Basic		$495		
16	Service Layout Fee – Complex		$690		
17	Crossing Application – Pipeline		$2,445		
18	Crossing Application – Water		$3,045		
19	Crossing Application – Railroad		$2,945		
20	Line Staking – per meter		$3.70		
21	Central Metering – New service < 45 kW		$115		
22	Conversion to Central Metering < 45 kW		$915		
23	Conversion to Central Metering > 45 kW		$800		
24	Tingle Voltage Test – In Excess of 4 Hours (per hour – average 2 additional hours)		$125		
25	Standby Administration Charge per month		$440		
26	Sentinel Lights Rental Rate per month			$7.10	
27	Sentinel Pole Rental Rate per month			$4.15	
28	Joint Use for Cable and Telecom companies per pole			$22.35	
29	Joint Use for LDCs per pole			$28.61	

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Village of Cobden Hydro System
Effective Date: May 1, 2007

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

APPLICATION

The application of these rates and charges shall be in accordance with The Licence of The Distributor and any Codes, Guidelines or Orders of The Board, and amendments thereto as approved by The Board, which may be applicable to the administration of this schedule.
No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code, Guideline or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.
This schedule does not contain any rates and charges relating to the electricity commodity (e.g. the Regulated Price Plan).

EFFECTIVE DATES

DISTRIBUTION RATES - May 1, 2007 for all consumption or deemed consumption services used on or after that date.

MISCELLANEOUS CHARGES - May 1, 2007 for all charges billed to customers on or after that date.
RETAIL TRANSMISSION RATES - May 1, 2007 for all consumption or deemed consumption services used on or after that date.
LOSS FACTOR ADJUSTMENT – May 1, 2007

SERVICE CLASSIFICATIONS

Residential
This classification (note 1) refers to all service supplied to single-family dwelling units for domestic or household purpose. Multi-unit residential establishments such as apartment buildings supplied through one service (bulk metered) will normally be classified as General Service, but, at Hydro One's discretion, up to four residential units may be classified as residential. Where electricity service is provided to combined residential and business (including agricultural usage) and the wiring does not provide for separate metering, the classification shall be at the discretion of Hydro One based on such considerations as the estimated predominant consumption.
Further servicing details are available in the utility's Conditions of Service.

General Service
This classification (note 1) refers to all service supplied to premises other than those classified as Residential or Lighting. Some General Service accounts are energy(kWh)-billed, and some are demand(kW)-billed. Further servicing details are available in the utility's Conditions of Service. Also, see note 2.

Unmetered Scattered Load
This classification refers to certain instances where connections can be provided without metering. These loads are generally small in size and consistent in magnitude of load. Hydro One reserves the right to review all cases and may require that a meter be installed at its sole discretion. Services that can be unmetered include cable TV amplifiers, telephone switching devices, phone booths, bus shelters, rail way crossing signals, traffic signals, and other small fixed loads.
Further servicing details are available in the utility's Conditions of Service (including in the "Unmetered Connections" section).

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Village of Cobden Hydro System
Effective Date: May 1, 2007

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

Street Lighting

This classification refers to accounts for the distribution and supply of electrical energy for street lighting. Street lights are devices owned by or operated for the road authority and/or the municipal corporation. These street lights in fact belong to the Street Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Sentinel Lighting

This classification refers to accounts for a separate service to a sentinel light. These sentinel lights in fact belong to the Sentinel Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Interim Demand-Side Management Time-of-Use

This is potentially applicable to Demand-billed General Service accounts. See Note 2 below.

Note (1): Classification descriptions are paraphrases from the document "Hydro One Networks Inc. - Distribution Customers Conditions of Service - August 2004"

Note (2):

Interim Demand-Side Management Time-of-Use Rates: demand charges will be based on demand during the on-peak periods.

Criteria: Customers' electricity consumption (kW) in the off-peak period is at least twice the electricity consumption (kW) during the on-peak period.

Definition of Time Periods: The on-peak hours will be between 0700 hours to 1900 hours Eastern Standard Time during the winter (standard time) on IESO business days and 0600 hours to 1800 hours Eastern Standard Time during the summer (daylight savings time) on IESO business days. The off-peak period constitutes all of the remaining hours.

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
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Village of Cobden Hydro System
Effective Date: May 1, 2007

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MONTHLY RATES AND CHARGES

Residential

Service Charge	$	13.07
Distribution Volumetric Rate	$ / kWh	0.0176
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0068
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0041
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0055
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0047
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service - Energy Billed (less than 50 kW)

Service Charge	$	21.93
Distribution Volumetric Rate	$ / kWh	0.0213
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0036
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0030
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0050
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0043
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service - Demand Billed (50 kW or greater)

Service Charge	$	21.93
Distribution Volumetric Rate	$ / kW	6.49
Regulatory Asset Recovery - Rider #1	$ / kW	1.16
Regulatory Asset Recovery - Rider #2	$ / kW	0.90
Retail Transmission Rate - Network Service Rate (4)	$ / kW	1.94
Retail Transmission Rate - Line and Transformation Connection Service Rate (4)	$ / kW	1.61
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Village of Cobden Hydro System
Effective Date: May 1, 2007

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Unmetered, Scattered Load

Service Charge	$	10.50
Distribution Volumetric Rate	$ / kWh	0.0213
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0036
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0030
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0050
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0043
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

(3) For energy-only metered customers, the billing determinant is the customer's metered energy consumption adjusted by the total loss factor as approved by the Board for Acquired LDC customers.
(4) For demand billed customers, appropriate loss factors must be applied to the applicable tariffs. Also the billing determinant for the Line and Transformation Connection Services rate is the customer's peak demand in the billing period. The billing determinant for the Network Services rate is: for non-interval-metered customers, the peak demand in the billing period, and for interval-metered customers, the peak demand between 7 AM and 7 PM local time on IESO business days

Interim Demand-Side Management Time-of-Use

See the "Service Classifications" section of this schedule.

Customer-Supplied Transformation Allowance

Applicable to demand-billed customers providing their own transformers
Primary Voltage under 50 kV (per kW)

Single Phase	$ / kW	0.20
Three Phase	$ / kW	0.60

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Village of Cobden Hydro System
Effective Date: May 1, 2007

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

Loss Factors

Supply Facilities Loss Factor	1.0045
Distribution Loss Factors	
Customer less than 5,000 kW	1.0500
Customer greater than or equal to 5,000 kW	1.0100
Total Loss Factors	
Customer less than 5,000 kW	1.0545
Customer greater than or equal to 5,000 kW	1.0145

Transformer Loss Allowance

Applicable to customers requiring a billing adjustment for transformer losses as the result of being metered on the primary side of a transformer. The following uniform values shall be applied to measured demand and energy to calculate transformer losses for voltages up to and including 50 kV (as metered on the primary side):

(a) 1.5% for transformer installations up to an individual bank capacity of 400 kVA,
(b) 1.0% for bank capacities over 400 kVA.

Alternatively, transformer losses may be determined from transformer test data, and measured demand and energy adjusted accordingly

For services which are not demand metered, an assumed demand of 50% of the transformer capacity will be used to calculate the loss allowance. Where several transformers are involved, the bank capacity is assumed to be the arithmetic sum of all transformer capacities

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Village of Cobden Hydro System
Effective Date: May 1, 2007

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

MISCELLANEOUS CHARGES

Specific Service Charges: Standard Amounts

Rate Code	Specific Service Charge - Standard Name	Calculation Method			
		2006 Rate Handbook	Standard Formula	Other Formula	Time and Materials
1	Temporary Service	$500			
2	Dispute Meter Test	$30 plus Measurement Canada fees			
3	Collection of account – no disconnection/load limiter	$30			
4	Collection/Disconnect/load limiter/reconnect (at meter) trip – regular hours	$65			
5	Collection/Disconnect/load limiter/reconnect (at meter) trip – after regular hours	$185			
6	Collection/Disconnect/load limiter/reconnect (at pole) trip – regular hours	$185			
7	Collection/Disconnect/load limiter/reconnect (at pole) trip – after regular hours	$415			
8	Account Set-up Charge	$30			
9	Arrears Certificate	$15			
10	NSF Cheque Charge	$15 + bank charges			
11	Easement Charge for Unregistered Rights	$15			
12	Late Payment Charge	1.5%/month			
13a	Retailer Services – Establishing Service Agreements (refer to Handbook for all charges)	$100/agreement/Retailer +$20/month/Retailer +$0.50/month/customer + other			
13b	Retailer Services – Other (includes Bill Ready for Retailers and Service Transactions Requests) as per the Handbook, Chapter 12	$0.30/month/customer + $0.25/request for request fee + $0.50/request for process fee			
14	Special Meter Reads	$30			
15	Billing Suspension and Terminations in Trailer Parks		$130		
16	Service Layout Fee – Basic		$405		
17	Service Layout Fee – Complex		$580		

Hydro One Networks Inc.

TARIFF OF RATES AND CHARGES

for the Service Area Formerly Served by

Village of Cobden Hydro System

Effective Date: May 1, 2007

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

18	Crossing Application – Pipeline		$2,065		
19	Crossing Application – Water		$2,525		
20	Crossing Application – Railroad		$2,565		
21	Line Staking – per meter		$3.10		
22	Central Metering – New service < 45 kW		$115		
23	Conversion to Central Metering < 45 kW		$795		
24	Conversion to Central Metering > 45 kW		$680		
25	Tingle Voltage Test – In Excess of 4 Hours (per hour – average 2 additional hours)		$105		
26	Standby Administration Charge per month (interim)		$375		
27	Sentinel Lights Rental Rate per month – Mercury Vapor			$7.00	
28	Guaranteed Units from Jan 01/91 to Aug 01/91			$26.50 / month	
29	Guaranteed Units from Jan 01/87 to Dec 31/90			$23.50 / month	
30	Joint Use for Cable and Telecom companies per pole			$22.35	
31	Joint Use for LDCs per pole			$28.61	

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Hydro-Electric Commission of the Town of Deep River
Effective Date: May 1, 2008

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

APPLICATION

The application of these rates and charges shall be in accordance with The Licence of The Distributor and any Codes, Guidelines or Orders of The Board, and amendments thereto as approved by The Board, which may be applicable to the administration of this schedule.
No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code, Guideline or Order of the Board, and amendments thereto as approved by the Board, or as specified herein
This schedule does not contain any rates and charges relating to the electricity commodity (e.g. the Regulated Price Plan).

EFFECTIVE DATES

DISTRIBUTION RATES - May 1, 2008 for all consumption or deemed consumption services used on or after that date.

MISCELLANEOUS CHARGES - May 1, 2008 for all charges billed to customers on or after that date.
RETAIL TRANSMISSION RATES - May 1, 2008 for all consumption or deemed consumption services used on or after that date.
LOSS FACTOR ADJUSTMENT – for all consumption or deemed consumption services billed following May 1, 2008 or later

SERVICE CLASSIFICATIONS

Residential
This classification refers to all service supplied to single-family dwelling units for domestic or household purpose. Multi-unit residential establishments such as apartment buildings supplied through one service (bulk metered) will normally be classified as General Service, but, at Hydro One's discretion, up to four residential units may be classified as residential. Where electricity service is provided to combined residential and business (including agricultural usage) and the wiring does not provide for separate metering, the classification shall be at the discretion of Hydro One based on such considerations as the estimated predominant consumption.
Further servicing details are available in the utility's Conditions of Service.

General Service
This classification refers to all service supplied to premises other than those classified as Residential or Lighting. Some General Service accounts are energy(kWh)-billed, and some are demand(kW)-billed. Further servicing details are available in the utility's Conditions of Service.

Unmetered Scattered Load
This classification refers to certain instances where connections can be provided without metering. These loads are generally small in size and consistent in magnitude of load. Hydro One reserves the right to review all cases and may require that a meter be installed at its sole discretion. Services that can be unmetered include cable TV amplifiers, telephone switching devices, phone booths, bus shelters, rail way crossing signals, traffic signals, and other small fixed loads.
Further servicing details are available in the utility's Conditions of Service (including in the "Unmetered Connections" section).

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Hydro-Electric Commission of the Town of Deep River
Effective Date: May 1, 2008

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

Street Lighting

This classification refers to accounts for the distribution and supply of electrical energy for street lighting. Street lights are devices owned by or operated for the road authority and/or the municipal corporation. These street lights in fact belong to the Street Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Sentinel Lighting

This classification refers to accounts for a separate service to a sentinel light. These sentinel lights in fact belong to the Sentinel Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Urban Density Classification

Customers who meet the Urban Density Criteria of being in an area containing 3,000 or more customers with a line density of at least 60 customers per kilometre, will be mapped to an Urban customer classification.

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Hydro-Electric Commission of the Town of Deep River
Effective Date: May 1, 2008

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

MONTHLY RATES AND CHARGES

Residential - R1 Deep River

Service Charge	$	16.61
Distribution Volumetric Rate	$ / kWh	0.0271
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0025
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0004)
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0047
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0046
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service Less Than 50 kW (Energy-Billed) - GSe Deep River

Service Charge	$	25.11
Distribution Volumetric Rate	$ / kWh	0.0321
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0014
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0006)
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0035
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0032
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service 50 kW or Greater (Demand-Billed) - GSd Deep River

Service Charge	$	28.70
Distribution Volumetric Rate	$ / kW	9.22
Regulatory Asset Recovery - Rider #2	$ / kW	0.46
Regulatory Asset Recovery - Rider #3	$ / kW	(0.22)
Retail Transmission Rate - Network Service Rate (4)	$ / kW	1.11
Retail Transmission Rate - Line and Transformation Connection Service Rate (4)	$ / kW	1.00
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Hydro-Electric Commission of the Town of Deep River
Effective Date: May 1, 2008

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

Unmetered, Scattered Load

Service Charge	$	14.50
Distribution Volumetric Rate	$ / kWh	0.0200
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0014
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0006)
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0035
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0032
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

(3) For energy-only metered customers, the billing determinant is the customer’s metered energy consumption adjusted by the total loss factor as approved by the Board for Acquired LDC customers.
(4) For demand billed customers, appropriate loss factors must be applied to the applicable tariffs. Also the billing determinant for the Line and Transformation Connection Services rate is the customer’s peak demand in the billing period. The billing determinant for the Network Services rate is: for non-interval-metered customers, the peak demand in the billing period, and for interval-metered customers, the peak demand between 7 AM and 7 PM local time on IESO business days

Customer-Supplied Transformation Allowance

Applicable to customers providing their own transformers		
Demand-billed	$ / kW	0.60
Energy-billed	$ / kWh	0.0014

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Hydro-Electric Commission of the Town of Deep River
Effective Date: May 1, 2008

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

Loss Factors

Residential	1.085
General Service Less Than 50 kW (Energy-Billed)	1.092
General Service 50 kW or Greater (Demand-Billed)	1.061
Unmetered Scattered Load	1.092

Transformer Loss Allowance

Applicable to customers requiring a billing adjustment for transformer losses as the result of being metered on the primary side of a transformer. The following uniform values shall be applied to measured demand and energy to calculate transformer losses for voltages up to and including 50 kV (as metered on the primary side):

(a) 1.5% for transformer installations up to an individual bank capacity of 400 kVA,
(b) 1.0% for bank capacities over 400 kVA.

Alternatively, transformer losses may be determined from transformer test data, and measured demand and energy adjusted accordingly

For services which are not demand metered, an assumed demand of 50% of the transformer capacity will be used to calculate the loss allowance. Where several transformers are involved, the bank capacity is assumed to be the arithmetic sum of all transformer capacities

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Hydro-Electric Commission of the Town of Deep River
Effective Date: May 1, 2008

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

MISCELLANEOUS CHARGES

Specific Service Charges: Standard Amounts

Rate Code	Specific Service Charge - Standard Name	Calculation Method			
		2006 Rate Handbook	Standard Formula	Other Formula	Time and Materials
1	Temporary Service	$500			
2	Dispute Meter Test	$30 plus Measurement Canada fees			
3	Collection of account – no disconnection/load limiter	$30			
4	Collection/Disconnect/load limiter/reconnect (at meter) trip – regular hours	$65			
5	Collection/Disconnect/load limiter/reconnect (at meter) trip – after regular hours	$185			
6	Collection/Disconnect/load limiter/reconnect (at pole) trip – regular hours	$185			
7	Collection/Disconnect/load limiter/reconnect (at pole) trip – after regular hours	$415			
8	Account Set-up Charge	$30			
9	Arrears Certificate	$15			
10	NSF Cheque Charge	$15 + bank charges			
11	Easement Charge for Unregistered Rights	$15			
12	Late Payment Charge	1.5%/month			
13a	Retailer Services – Establishing Service Agreements (refer to Handbook for all charges)	$100/agreement/Retailer +$20/month/Retailer +$0.50/month/customer + other			
13b	Retailer Services – Other (includes Bill Ready for Retailers and Service Transactions Requests) as per the Handbook, Chapter 12	$0.30/month/customer + $0.25/request for request fee + $0.50/request for process fee			
14	Special Meter Reads	$30			
15	Service Layout Fee – Basic		$495		
16	Service Layout Fee – Complex		$690		
17	Crossing Application – Pipeline		$2,445		
18	Crossing Application – Water		$3,045		
19	Crossing Application – Railroad		$2,945		
20	Line Staking – per meter		$3.70		
21	Central Metering – New service < 45 kW		$115		
22	Conversion to Central Metering < 45 kW		$915		
23	Conversion to Central Metering > 45 kW		$800		
24	Tingle Voltage Test – In Excess of 4 Hours (per hour – average 2 additional hours)		$125		
25	Standby Administration Charge per month		$440		
26	Sentinel Lights Rental Rate per month			$7.10	
27	Sentinel Pole Rental Rate per month			$4.15	
28	Joint Use for Cable and Telecom companies per pole			$22.35	
29	Joint Use for LDCs per pole			$28.61	

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Hydro-Electric Commission of the Town of Deep River
Effective Date: May 1, 2007

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APPLICATION

The application of these rates and charges shall be in accordance with The Licence of The Distributor and any Codes, Guidelines or Orders of The Board, and amendments thereto as approved by The Board, which may be applicable to the administration of this schedule.
No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code, Guideline or Order of the Board, and amendments thereto as approved by the Board, or as specified herein
This schedule does not contain any rates and charges relating to the electricity commodity (e.g. the Regulated Price Plan).

EFFECTIVE DATES

DISTRIBUTION RATES - May 1, 2007 for all consumption or deemed consumption services used on or after that date.

MISCELLANEOUS CHARGES - May 1, 2007 for all charges billed to customers on or after that date.
RETAIL TRANSMISSION RATES - May 1, 2007 for all consumption or deemed consumption services used on or after that date.
LOSS FACTOR ADJUSTMENT – May 1, 2007

SERVICE CLASSIFICATIONS

Residential
This classification (note 1) refers to all service supplied to single-family dwelling units for domestic or household purpose. Multi-unit residential establishments such as apartment buildings supplied through one service (bulk metered) will normally be classified as General Service, but, at Hydro One's discretion, up to four residential units may be classified as residential. Where electricity service is provided to combined residential and business (including agricultural usage) and the wiring does not provide for separate metering, the classification shall be at the discretion of Hydro One based on such considerations as the estimated predominant consumption.
Further servicing details are available in the utility's Conditions of Service.

General Service
This classification (note 1) refers to all service supplied to premises other than those classified as Residential or Lighting. Some General Service accounts are energy(kWh)-billed, and some are demand(kW)-billed. Further servicing details are available in the utility's Conditions of Service. Also, see note 2.

Unmetered Scattered Load
This classification refers to certain instances where connections can be provided without metering. These loads are generally small in size and consistent in magnitude of load. Hydro One reserves the right to review all cases and may require that a meter be installed at its sole discretion. Services that can be unmetered include cable TV amplifiers, telephone switching devices, phone booths, bus shelters, rail way crossing signals, traffic signals, and other small fixed loads.
Further servicing details are available in the utility's Conditions of Service (including in the "Unmetered Connections" section).

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Hydro-Electric Commission of the Town of Deep River
Effective Date: May 1, 2007

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Street Lighting

This classification refers to accounts for the distribution and supply of electrical energy for street lighting. Street lights are devices owned by or operated for the road authority and/or the municipal corporation. These street lights in fact belong to the Street Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Sentinel Lighting

This classification refers to accounts for a separate service to a sentinel light. These sentinel lights in fact belong to the Sentinel Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Interim Demand-Side Management Time-of-Use

This is potentially applicable to Demand-billed General Service accounts. See Note 2 below.

Note (1): Classification descriptions are paraphrases from the document "Hydro One Networks Inc. - Distribution Customers Conditions of Service - August 2004"

Note (2):

Interim Demand-Side Management Time-of-Use Rates: demand charges will be based on demand during the on-peak periods.

Criteria: Customers' electricity consumption (kW) in the off-peak period is at least twice the electricity consumption (kW) during the on-peak period.

Definition of Time Periods: The on-peak hours will be between 0700 hours to 1900 hours Eastern Standard Time during the winter (standard time) on IESO business days and 0600 hours to 1800 hours Eastern Standard Time during the summer (daylight savings time) on IESO business days. The off-peak period constitutes all of the remaining hours.

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
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MONTHLY RATES AND CHARGES

Residential

Service Charge	$	16.62
Distribution Volumetric Rate	$ / kWh	0.0229
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0038
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0025
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0055
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0047
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service - Energy Billed (less than 50 kW)

Service Charge	$	23.94
Distribution Volumetric Rate	$ / kWh	0.0226
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0015
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0014
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0050
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0043
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service - Demand Billed (50 kW or greater)

Service Charge	$	23.94
Distribution Volumetric Rate	$ / kW	7.18
Regulatory Asset Recovery - Rider #1	$ / kW	0.46
Regulatory Asset Recovery - Rider #2	$ / kW	0.46
Retail Transmission Rate - Network Service Rate (4)	$ / kW	1.94
Retail Transmission Rate - Line and Transformation Connection Service Rate (4)	$ / kW	1.61
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
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Unmetered, Scattered Load

Service Charge	$	11.50
Distribution Volumetric Rate	$ / kWh	0.0226
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0015
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0014
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0050
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0043
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

(3) For energy-only metered customers, the billing determinant is the customer’s metered energy consumption adjusted by the total loss factor as approved by the Board for Acquired LDC customers.
(4) For demand billed customers, appropriate loss factors must be applied to the applicable tariffs. Also the billing determinant for the Line and Transformation Connection Services rate is the customer’s peak demand in the billing period. The billing determinant for the Network Services rate is: for non-interval-metered customers, the peak demand in the billing period, and for interval-metered customers, the peak demand between 7 AM and 7 PM local time on IESO business days

Interim Demand-Side Management Time-of-Use

See the "Service Classifications" section of this schedule.

Customer-Supplied Transformation Allowance

Applicable to demand-billed customers providing their own transformers
Primary Voltage under 50 kV (per kW)

Single Phase	$ / kW	0.20
Three Phase	$ / kW	0.60

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Loss Factors

Supply Facilities Loss Factor	1.0045
Distribution Loss Factors	
Customer less than 5,000 kW	1.0500
Customer greater than or equal to 5,000 kW	1.0100
Total Loss Factors	
Customer less than 5,000 kW	1.0545
Customer greater than or equal to 5,000 kW	1.0145

Transformer Loss Allowance

Applicable to customers requiring a billing adjustment for transformer losses as the result of being metered on the primary side of a transformer. The following uniform values shall be applied to measured demand and energy to calculate transformer losses for voltages up to and including 50 kV (as metered on the primary side):

(a) 1.5% for transformer installations up to an individual bank capacity of 400 kVA,
(b) 1.0% for bank capacities over 400 kVA.

Alternatively, transformer losses may be determined from transformer test data, and measured demand and energy adjusted accordingly

For services which are not demand metered, an assumed demand of 50% of the transformer capacity will be used to calculate the loss allowance. Where several transformers are involved, the bank capacity is assumed to be the arithmetic sum of all transformer capacities

Hydro One Networks Inc.
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MISCELLANEOUS CHARGES

Specific Service Charges: Standard Amounts

Rate Code	Specific Service Charge - Standard Name	Calculation Method			
		2006 Rate Handbook	Standard Formula	Other Formula	Time and Materials
1	Temporary Service	$500			
2	Dispute Meter Test	$30 plus Measurement Canada fees			
3	Collection of account – no disconnection/load limiter	$30			
4	Collection/Disconnect/load limiter/reconnect (at meter) trip – regular hours	$65			
5	Collection/Disconnect/load limiter/reconnect (at meter) trip – after regular hours	$185			
6	Collection/Disconnect/load limiter/reconnect (at pole) trip – regular hours	$185			
7	Collection/Disconnect/load limiter/reconnect (at pole) trip – after regular hours	$415			
8	Account Set-up Charge	$30			
9	Arrears Certificate	$15			
10	NSF Cheque Charge	$15 + bank charges			
11	Easement Charge for Unregistered Rights	$15			
12	Late Payment Charge	1.5%/month			
13a	Retailer Services – Establishing Service Agreements (refer to Handbook for all charges)	$100/agreement/Retailer +$20/month/Retailer +$0.50/month/customer + other			
13b	Retailer Services – Other (includes Bill Ready for Retailers and Service Transactions Requests) as per the Handbook, Chapter 12	$0.30/month/customer + $0.25/request for request fee + $0.50/request for process fee			
14	Special Meter Reads	$30			
15	Billing Suspension and Terminations in Trailer Parks		$130		
16	Service Layout Fee – Basic		$405		
17	Service Layout Fee – Complex		$580		

Hydro One Networks Inc.
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18	Crossing Application – Pipeline		$2,065		
19	Crossing Application – Water		$2,525		
20	Crossing Application – Railroad		$2,565		
21	Line Staking – per meter		$3.10		
22	Central Metering – New service < 45 kW		$115		
23	Conversion to Central Metering < 45 kW		$795		
24	Conversion to Central Metering > 45 kW		$680		
25	Tingle Voltage Test – In Excess of 4 Hours (per hour – average 2 additional hours)		$105		
26	Standby Administration Charge per month (interim)		$375		
27	Sentinel Lights Rental Rate per month – Mercury Vapor			$7.00	
28	Guaranteed Units from Jan 01/91 to Aug 01/91			$26.50 / month	
29	Guaranteed Units from Jan 01/87 to Dec 31/90			$23.50 / month	
30	Joint Use for Cable and Telecom companies per pole			$22.35	
31	Joint Use for LDCs per pole			$28.61	

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
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Deseronto Public Utilities Commission
Effective Date: May 1, 2008

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APPLICATION

The application of these rates and charges shall be in accordance with The Licence of The Distributor and any Codes, Guidelines or Orders of The Board, and amendments thereto as approved by The Board, which may be applicable to the administration of this schedule.
No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code, Guideline or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.
This schedule does not contain any rates and charges relating to the electricity commodity (e.g. the Regulated Price Plan).

EFFECTIVE DATES

DISTRIBUTION RATES - May 1, 2008 for all consumption or deemed consumption services used on or after that date.

MISCELLANEOUS CHARGES - May 1, 2008 for all charges billed to customers on or after that date.
RETAIL TRANSMISSION RATES - May 1, 2008 for all consumption or deemed consumption services used on or after that date.
LOSS FACTOR ADJUSTMENT – for all consumption or deemed consumption services billed following May 1, 2008 or later

SERVICE CLASSIFICATIONS

Residential
This classification refers to all service supplied to single-family dwelling units for domestic or household purpose. Multi-unit residential establishments such as apartment buildings supplied through one service (bulk metered) will normally be classified as General Service, but, at Hydro One's discretion, up to four residential units may be classified as residential. Where electricity service is provided to combined residential and business (including agricultural usage) and the wiring does not provide for separate metering, the classification shall be at the discretion of Hydro One based on such considerations as the estimated predominant consumption.
Further servicing details are available in the utility's Conditions of Service.

General Service
This classification refers to all service supplied to premises other than those classified as Residential or Lighting. Some General Service accounts are energy(kWh)-billed, and some are demand(kW)-billed. Further servicing details are available in the utility's Conditions of Service.

Unmetered Scattered Load
This classification refers to certain instances where connections can be provided without metering. These loads are generally small in size and consistent in magnitude of load. Hydro One reserves the right to review all cases and may require that a meter be installed at its sole discretion. Services that can be unmetered include cable TV amplifiers, telephone switching devices, phone booths, bus shelters, rail way crossing signals, traffic signals, and other small fixed loads.
Further servicing details are available in the utility's Conditions of Service (including in the "Unmetered Connections" section).

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
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Deseronto Public Utilities Commission
Effective Date: May 1, 2008

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Street Lighting

This classification refers to accounts for the distribution and supply of electrical energy for street lighting. Street lights are devices owned by or operated for the road authority and/or the municipal corporation. These street lights in fact belong to the Street Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Sentinel Lighting

This classification refers to accounts for a separate service to a sentinel light. These sentinel lights in fact belong to the Sentinel Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Urban Density Classification

Customers who meet the Urban Density Criteria of being in an area containing 3,000 or more customers with a line density of at least 60 customers per kilometre, will be mapped to an Urban customer classification.

Hydro One Networks Inc.
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Effective Date: May 1, 2008

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MONTHLY RATES AND CHARGES

Residential - R1 Deseronto

Service Charge	$	13.54
Distribution Volumetric Rate	$ / kWh	0.0230
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0011
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0004)
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0047
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0046
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service Less Than 50 kW (Energy-Billed) - GSe Deseronto

Service Charge	$	15.56
Distribution Volumetric Rate	$ / kWh	0.0218
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0005
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0006)
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0035
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0032
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service 50 kW or Greater (Demand-Billed) - GSd Deseronto

Service Charge	$	19.15
Distribution Volumetric Rate	$ / kW	8.50
Regulatory Asset Recovery - Rider #2	$ / kW	0.14
Regulatory Asset Recovery - Rider #3	$ / kW	(0.22)
Retail Transmission Rate - Network Service Rate (4)	$ / kW	1.11
Retail Transmission Rate - Line and Transformation Connection Service Rate (4)	$ / kW	1.00
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

Hydro One Networks Inc.
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Unmetered, Scattered Load

Service Charge	$	9.23
Distribution Volumetric Rate	$ / kWh	0.0200
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0005
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0006)
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0035
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0032
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

(3) For energy-only metered customers, the billing determinant is the customer’s metered energy consumption adjusted by the total loss factor as approved by the Board for Acquired LDC customers.
(4) For demand billed customers, appropriate loss factors must be applied to the applicable tariffs. Also the billing determinant for the Line and Transformation Connection Services rate is the customer’s peak demand in the billing period. The billing determinant for the Network Services rate is: for non-interval-metered customers, the peak demand in the billing period, and for interval-metered customers, the peak demand between 7 AM and 7 PM local time on IESO business days

Customer-Supplied Transformation Allowance

Applicable to customers providing their own transformers

Demand-billed	$ / kW	0.60
Energy-billed	$ / kWh	0.0014

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Loss Factors

Residential	1.085
General Service Less Than 50 kW (Energy-Billed)	1.092
General Service 50 kW or Greater (Demand-Billed)	1.061
Unmetered Scattered Load	1.092

Transformer Loss Allowance

Applicable to customers requiring a billing adjustment for transformer losses as the result of being metered on the primary side of a transformer. The following uniform values shall be applied to measured demand and energy to calculate transformer losses for voltages up to and including 50 kV (as metered on the primary side):

(a) 1.5% for transformer installations up to an individual bank capacity of 400 kVA,
(b) 1.0% for bank capacities over 400 kVA.

Alternatively, transformer losses may be determined from transformer test data, and measured demand and energy adjusted accordingly

For services which are not demand metered, an assumed demand of 50% of the transformer capacity will be used to calculate the loss allowance. Where several transformers are involved, the bank capacity is assumed to be the arithmetic sum of all transformer capacities

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MISCELLANEOUS CHARGES

Specific Service Charges: Standard Amounts

Rate Code	Specific Service Charge - Standard Name	Calculation Method			
		2006 Rate Handbook	Standard Formula	Other Formula	Time and Materials
1	Temporary Service	$500			
2	Dispute Meter Test	$30 plus Measurement Canada fees			
3	Collection of account – no disconnection/load limiter	$30			
4	Collection/Disconnect/load limiter/reconnect (at meter) trip – regular hours	$65			
5	Collection/Disconnect/load limiter/reconnect (at meter) trip – after regular hours	$185			
6	Collection/Disconnect/load limiter/reconnect (at pole) trip – regular hours	$185			
7	Collection/Disconnect/load limiter/reconnect (at pole) trip – after regular hours	$415			
8	Account Set-up Charge	$30			
9	Arrears Certificate	$15			
10	NSF Cheque Charge	$15 + bank charges			
11	Easement Charge for Unregistered Rights	$15			
12	Late Payment Charge	1.5%/month			
13a	Retailer Services – Establishing Service Agreements (refer to Handbook for all charges)	$100/agreement/Retailer +$20/month/Retailer +$0.50/month/customer + other			
13b	Retailer Services – Other (includes Bill Ready for Retailers and Service Transactions Requests) as per the Handbook, Chapter 12	$0.30/month/customer + $0.25/request for request fee + $0.50/request for process fee			
14	Special Meter Reads	$30			
15	Service Layout Fee – Basic		$495		
16	Service Layout Fee – Complex		$690		
17	Crossing Application – Pipeline		$2,445		
18	Crossing Application – Water		$3,045		
19	Crossing Application – Railroad		$2,945		
20	Line Staking – per meter		$3.70		
21	Central Metering – New service < 45 kW		$115		
22	Conversion to Central Metering < 45 kW		$915		
23	Conversion to Central Metering > 45 kW		$800		
24	Tingle Voltage Test – In Excess of 4 Hours (per hour – average 2 additional hours)		$125		
25	Standby Administration Charge per month		$440		
26	Sentinel Lights Rental Rate per month			$7.10	
27	Sentinel Pole Rental Rate per month			$4.15	
28	Joint Use for Cable and Telecom companies per pole			$22.35	
29	Joint Use for LDCs per pole			$28.61	

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APPLICATION

The application of these rates and charges shall be in accordance with The Licence of The Distributor and any Codes, Guidelines or Orders of The Board, and amendments thereto as approved by The Board, which may be applicable to the administration of this schedule.
No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code, Guideline or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.
This schedule does not contain any rates and charges relating to the electricity commodity (e.g. the Regulated Price Plan).

EFFECTIVE DATES

DISTRIBUTION RATES - May 1, 2007 for all consumption or deemed consumption services used on or after that date.

MISCELLANEOUS CHARGES - May 1, 2007 for all charges billed to customers on or after that date.
RETAIL TRANSMISSION RATES - May 1, 2007 for all consumption or deemed consumption services used on or after that date.
LOSS FACTOR ADJUSTMENT – May 1, 2007

SERVICE CLASSIFICATIONS

Residential
This classification (note 1) refers to all service supplied to single-family dwelling units for domestic or household purpose. Multi-unit residential establishments such as apartment buildings supplied through one service (bulk metered) will normally be classified as General Service, but, at Hydro One’s discretion, up to four residential units may be classified as residential. Where electricity service is provided to combined residential and business (including agricultural usage) and the wiring does not provide for separate metering, the classification shall be at the discretion of Hydro One based on such considerations as the estimated predominant consumption.
Further servicing details are available in the utility’s Conditions of Service.

General Service
This classification (note 1) refers to all service supplied to premises other than those classified as Residential or Lighting. Some General Service accounts are energy(kWh)-billed, and some are demand(kW)-billed. Further servicing details are available in the utility’s Conditions of Service. Also, see note 2.

Unmetered Scattered Load
This classification refers to certain instances where connections can be provided without metering. These loads are generally small in size and consistent in magnitude of load. Hydro One reserves the right to review all cases and may require that a meter be installed at its sole discretion. Services that can be unmetered include cable TV amplifiers, telephone switching devices, phone booths, bus shelters, rail way crossing signals, traffic signals, and other small fixed loads.
Further servicing details are available in the utility’s Conditions of Service (including in the "Unmetered Connections" section).

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Effective Date: May 1, 2007

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Street Lighting

This classification refers to accounts for the distribution and supply of electrical energy for street lighting. Street lights are devices owned by or operated for the road authority and/or the municipal corporation. These street lights in fact belong to the Street Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Sentinel Lighting

This classification refers to accounts for a separate service to a sentinel light. These sentinel lights in fact belong to the Sentinel Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Interim Demand-Side Management Time-of-Use

This is potentially applicable to Demand-billed General Service accounts. See Note 2 below.

Note (1): Classification descriptions are paraphrases from the document "Hydro One Networks Inc. - Distribution Customers Conditions of Service - August 2004"

Note (2):

Interim Demand-Side Management Time-of-Use Rates: demand charges will be based on demand during the on-peak periods.

Criteria: Customers' electricity consumption (kW) in the off-peak period is at least twice the electricity consumption (kW) during the on-peak period.

Definition of Time Periods: The on-peak hours will be between 0700 hours to 1900 hours Eastern Standard Time during the winter (standard time) on IESO business days and 0600 hours to 1800 hours Eastern Standard Time during the summer (daylight savings time) on IESO business days. The off-peak period constitutes all of the remaining hours.

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Deseronto Public Utilities Commission
Effective Date: May 1, 2007

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

MONTHLY RATES AND CHARGES

Residential

Service Charge	$	12.89
Distribution Volumetric Rate	$ / kWh	0.0112
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0037
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0011
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0055
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0047
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service - Energy Billed (less than 50 kW)

Service Charge	$	10.14
Distribution Volumetric Rate	$ / kWh	0.0135
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0013
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0005
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0050
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0043
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service - Demand Billed (50 kW or greater)

Service Charge	$	10.14
Distribution Volumetric Rate	$ / kW	3.85
Regulatory Asset Recovery - Rider #1	$ / kW	0.41
Regulatory Asset Recovery - Rider #2	$ / kW	0.14
Retail Transmission Rate - Network Service Rate (4)	$ / kW	1.94
Retail Transmission Rate - Line and Transformation Connection Service Rate (4)	$ / kW	1.61
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Deseronto Public Utilities Commission
Effective Date: May 1, 2007

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

Unmetered, Scattered Load

Service Charge	$	4.61
Distribution Volumetric Rate	$ / kWh	0.0135
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0013
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0005
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0050
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0043
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

(3) For energy-only metered customers, the billing determinant is the customer’s metered energy consumption adjusted by the total loss factor as approved by the Board for Acquired LDC customers.
(4) For demand billed customers, appropriate loss factors must be applied to the applicable tariffs. Also the billing determinant for the Line and Transformation Connection Services rate is the customer’s peak demand in the billing period. The billing determinant for the Network Services rate is: for non-interval-metered customers, the peak demand in the billing period, and for interval-metered customers, the peak demand between 7 AM and 7 PM local time on IESO business days

Interim Demand-Side Management Time-of-Use

See the "Service Classifications" section of this schedule.

Customer-Supplied Transformation Allowance

Applicable to demand-billed customers providing their own transformers
Primary Voltage under 50 kV (per kW)

Single Phase	$ / kW	0.20
Three Phase	$ / kW	0.60

Hydro One Networks Inc.
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Loss Factors

Supply Facilities Loss Factor	1.0045
Distribution Loss Factors	
Customer less than 5,000 kW	1.0500
Customer greater than or equal to 5,000 kW	1.0100
Total Loss Factors	
Customer less than 5,000 kW	1.0545
Customer greater than or equal to 5,000 kW	1.0145

Transformer Loss Allowance

Applicable to customers requiring a billing adjustment for transformer losses as the result of being metered on the primary side of a transformer. The following uniform values shall be applied to measured demand and energy to calculate transformer losses for voltages up to and including 50 kV (as metered on the primary side):

(a) 1.5% for transformer installations up to an individual bank capacity of 400 kVA,
(b) 1.0% for bank capacities over 400 kVA.

Alternatively, transformer losses may be determined from transformer test data, and measured demand and energy adjusted accordingly

For services which are not demand metered, an assumed demand of 50% of the transformer capacity will be used to calculate the loss allowance. Where several transformers are involved, the bank capacity is assumed to be the arithmetic sum of all transformer capacities

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
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This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

MISCELLANEOUS CHARGES

Specific Service Charges: Standard Amounts

Rate Code	Specific Service Charge - Standard Name	Calculation Method			
		2006 Rate Handbook	Standard Formula	Other Formula	Time and Materials
1	Temporary Service	$500			
2	Dispute Meter Test	$30 plus Measurement Canada fees			
3	Collection of account – no disconnection/load limiter	$30			
4	Collection/Disconnect/load limiter/reconnect (at meter) trip – regular hours	$65			
5	Collection/Disconnect/load limiter/reconnect (at meter) trip – after regular hours	$185			
6	Collection/Disconnect/load limiter/reconnect (at pole) trip – regular hours	$185			
7	Collection/Disconnect/load limiter/reconnect (at pole) trip – after regular hours	$415			
8	Account Set-up Charge	$30			
9	Arrears Certificate	$15			
10	NSF Cheque Charge	$15 + bank charges			
11	Easement Charge for Unregistered Rights	$15			
12	Late Payment Charge	1.5%/month			
13a	Retailer Services – Establishing Service Agreements (refer to Handbook for all charges)	$100/agreement/Retailer +$20/month/Retailer +$0.50/month/customer + other			
13b	Retailer Services – Other (includes Bill Ready for Retailers and Service Transactions Requests) as per the Handbook, Chapter 12	$0.30/month/customer + $0.25/request for request fee + $0.50/request for process fee			
14	Special Meter Reads	$30			
15	Billing Suspension and Terminations in Trailer Parks		$130		
16	Service Layout Fee – Basic		$405		
17	Service Layout Fee – Complex		$580		

Hydro One Networks Inc.
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18	Crossing Application – Pipeline		$2,065		
19	Crossing Application – Water		$2,525		
20	Crossing Application – Railroad		$2,565		
21	Line Staking – per meter		$3.10		
22	Central Metering – New service < 45 kW		$115		
23	Conversion to Central Metering < 45 kW		$795		
24	Conversion to Central Metering > 45 kW		$680		
25	Tingle Voltage Test – In Excess of 4 Hours (per hour – average 2 additional hours)		$105		
26	Standby Administration Charge per month (interim)		$375		
27	Sentinel Lights Rental Rate per month – Mercury Vapor			$7.00	
28	Guaranteed Units from Jan 01/91 to Aug 01/91			$26.50 / month	
29	Guaranteed Units from Jan 01/87 to Dec 31/90			$23.50 / month	
30	Joint Use for Cable and Telecom companies per pole			$22.35	
31	Joint Use for LDCs per pole			$28.61	

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
City of Dryden Hydro Electric Commission
Effective Date: May 1, 2008

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

APPLICATION

The application of these rates and charges shall be in accordance with The Licence of The Distributor and any Codes, Guidelines or Orders of The Board, and amendments thereto as approved by The Board, which may be applicable to the administration of this schedule.
No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code, Guideline or Order of the Board, and amendments thereto as approved by the Board, or as specified herein
This schedule does not contain any rates and charges relating to the electricity commodity (e.g. the Regulated Price Plan).

EFFECTIVE DATES

DISTRIBUTION RATES - May 1, 2008 for all consumption or deemed consumption services used on or after that date.

MISCELLANEOUS CHARGES - May 1, 2008 for all charges billed to customers on or after that date.
RETAIL TRANSMISSION RATES - May 1, 2008 for all consumption or deemed consumption services used on or after that date.
LOSS FACTOR ADJUSTMENT – for all consumption or deemed consumption services billed following May 1, 2008 or later

SERVICE CLASSIFICATIONS

Residential
This classification refers to all service supplied to single-family dwelling units for domestic or household purpose. Multi-unit residential establishments such as apartment buildings supplied through one service (bulk metered) will normally be classified as General Service, but, at Hydro One's discretion, up to four residential units may be classified as residential. Where electricity service is provided to combined residential and business (including agricultural usage) and the wiring does not provide for separate metering, the classification shall be at the discretion of Hydro One based on such considerations as the estimated predominant consumption.
Further servicing details are available in the utility's Conditions of Service.

General Service
This classification refers to all service supplied to premises other than those classified as Residential or Lighting. Some General Service accounts are energy(kWh)-billed, and some are demand(kW)-billed. Further servicing details are available in the utility's Conditions of Service.

Unmetered Scattered Load
This classification refers to certain instances where connections can be provided without metering. These loads are generally small in size and consistent in magnitude of load. Hydro One reserves the right to review all cases and may require that a meter be installed at its sole discretion. Services that can be unmetered include cable TV amplifiers, telephone switching devices, phone booths, bus shelters, rail way crossing signals, traffic signals, and other small fixed loads.
Further servicing details are available in the utility's Conditions of Service (including in the "Unmetered Connections" section).

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
City of Dryden Hydro Electric Commission
Effective Date: May 1, 2008

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Street Lighting

This classification refers to accounts for the distribution and supply of electrical energy for street lighting. Street lights are devices owned by or operated for the road authority and/or the municipal corporation. These street lights in fact belong to the Street Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Sentinel Lighting

This classification refers to accounts for a separate service to a sentinel light. These sentinel lights in fact belong to the Sentinel Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Urban Density Classification

Customers who meet the Urban Density Criteria of being in an area containing 3,000 or more customers with a line density of at least 60 customers per kilometre, will be mapped to an Urban customer classification.

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
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MONTHLY RATES AND CHARGES

Residential - UR/R1 Dryden

Service Charge	$	14.01
Distribution Volumetric Rate	$ / kWh	0.0240
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0018
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0002)
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0047
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0045
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service Less Than 50 kW (Energy-Billed) - UGe/GSe Dryden

Service Charge	$	17.31
Distribution Volumetric Rate	$ / kWh	0.0200
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0004
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0006)
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0036
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0033
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service 50 kW or Greater (Demand-Billed) - UGd/GSd Dryden

Service Charge	$	21.52
Distribution Volumetric Rate	$ / kW	7.33
Regulatory Asset Recovery - Rider #2	$ / kW	0.13
Regulatory Asset Recovery - Rider #3	$ / kW	(0.27)
Retail Transmission Rate - Network Service Rate (4)	$ / kW	1.41
Retail Transmission Rate - Line and Transformation Connection Service Rate (4)	$ / kW	1.27
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
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City of Dryden Hydro Electric Commission
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Unmetered, Scattered Load

Service Charge	$	13.11
Distribution Volumetric Rate	$ / kWh	0.0200
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0004
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0006)
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0035
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0032
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

(3) For energy-only metered customers, the billing determinant is the customer's metered energy consumption adjusted by the total loss factor as approved by the Board for Acquired LDC customers.

(4) For demand billed customers, appropriate loss factors must be applied to the applicable tariffs. Also the billing determinant for the Line and Transformation Connection Services rate is the customer's peak demand in the billing period. The billing determinant for the Network Services rate is: for non-interval-metered customers, the peak demand in the billing period, and for interval-metered customers, the peak demand between 7 AM and 7 PM local time on IESO business days

Customer-Supplied Transformation Allowance

Applicable to customers providing their own transformers

Demand-billed	$ / kW	0.60
Energy-billed	$ / kWh	0.0014

Hydro One Networks Inc.
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Loss Factors

Residential	1.078
General Service Less Than 50 kW (Energy-Billed)	1.092
General Service 50 kW or Greater (Demand-Billed)	1.061
Unmetered Scattered Load	1.092

Transformer Loss Allowance

Applicable to customers requiring a billing adjustment for transformer losses as the result of being metered on the primary side of a transformer. The following uniform values shall be applied to measured demand and energy to calculate transformer losses for voltages up to and including 50 kV (as metered on the primary side):

(a) 1.5% for transformer installations up to an individual bank capacity of 400 kVA,
(b) 1.0% for bank capacities over 400 kVA.

Alternatively, transformer losses may be determined from transformer test data, and measured demand and energy adjusted accordingly
For services which are not demand metered, an assumed demand of 50% of the transformer capacity will be used to calculate the loss allowance. Where several transformers are involved, the bank capacity is assumed to be the arithmetic sum of all transformer capacities

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
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Effective Date: May 1, 2008

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MISCELLANEOUS CHARGES

Specific Service Charges: Standard Amounts

Rate Code	Specific Service Charge - Standard Name	Calculation Method			
		2006 Rate Handbook	Standard Formula	Other Formula	Time and Materials
1	Temporary Service	$500			
2	Dispute Meter Test	$30 plus Measurement Canada fees			
3	Collection of account – no disconnection/load limiter	$30			
4	Collection/Disconnect/load limiter/reconnect (at meter) trip – regular hours	$65			
5	Collection/Disconnect/load limiter/reconnect (at meter) trip – after regular hours	$185			
6	Collection/Disconnect/load limiter/reconnect (at pole) trip – regular hours	$185			
7	Collection/Disconnect/load limiter/reconnect (at pole) trip – after regular hours	$415			
8	Account Set-up Charge	$30			
9	Arrears Certificate	$15			
10	NSF Cheque Charge	$15 + bank charges			
11	Easement Charge for Unregistered Rights	$15			
12	Late Payment Charge	1.5%/month			
13a	Retailer Services – Establishing Service Agreements (refer to Handbook for all charges)	$100/agreement/Retailer +$20/month/Retailer +$0.50/month/customer + other			
13b	Retailer Services – Other (includes Bill Ready for Retailers and Service Transactions Requests) as per the Handbook, Chapter 12	$0.30/month/customer + $0.25/request for request fee + $0.50/request for process fee			
14	Special Meter Reads	$30			
15	Service Layout Fee – Basic		$495		
16	Service Layout Fee – Complex		$690		
17	Crossing Application – Pipeline		$2,445		
18	Crossing Application – Water		$3,045		
19	Crossing Application – Railroad		$2,945		
20	Line Staking – per meter		$3.70		
21	Central Metering – New service < 45 kW		$115		
22	Conversion to Central Metering < 45 kW		$915		
23	Conversion to Central Metering > 45 kW		$800		
24	Tingle Voltage Test – In Excess of 4 Hours (per hour – average 2 additional hours)		$125		
25	Standby Administration Charge per month		$440		
26	Sentinel Lights Rental Rate per month			$7.10	
27	Sentinel Pole Rental Rate per month			$4.15	
28	Joint Use for Cable and Telecom companies per pole			$22.35	
29	Joint Use for LDCs per pole			$28.61	

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
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City of Dryden Hydro Electric Commission
Effective Date: May 1, 2007

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

APPLICATION

The application of these rates and charges shall be in accordance with The Licence of The Distributor and any Codes, Guidelines or Orders of The Board, and amendments thereto as approved by The Board, which may be applicable to the administration of this schedule.
No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code, Guideline or Order of the Board, and amendments thereto as approved by the Board, or as specified herein
This schedule does not contain any rates and charges relating to the electricity commodity (e.g. the Regulated Price Plan).

EFFECTIVE DATES

DISTRIBUTION RATES - May 1, 2007 for all consumption or deemed consumption services used on or after that date.

MISCELLANEOUS CHARGES - May 1, 2007 for all charges billed to customers on or after that date.
RETAIL TRANSMISSION RATES - May 1, 2007 for all consumption or deemed consumption services used on or after that date.
LOSS FACTOR ADJUSTMENT – May 1, 2007

SERVICE CLASSIFICATIONS

Residential
This classification (note 1) refers to all service supplied to single-family dwelling units for domestic or household purpose. Multi-unit residential establishments such as apartment buildings supplied through one service (bulk metered) will normally be classified as General Service, but, at Hydro One's discretion, up to four residential units may be classified as residential. Where electricity service is provided to combined residential and business (including agricultural usage) and the wiring does not provide for separate metering, the classification shall be at the discretion of Hydro One based on such considerations as the estimated predominant consumption.
Further servicing details are available in the utility's Conditions of Service.

General Service
This classification (note 1) refers to all service supplied to premises other than those classified as Residential or Lighting. Some General Service accounts are energy(kWh)-billed, and some are demand(kW)-billed. Further servicing details are available in the utility's Conditions of Service. Also, see note 2.

Unmetered Scattered Load
This classification refers to certain instances where connections can be provided without metering. These loads are generally small in size and consistent in magnitude of load. Hydro One reserves the right to review all cases and may require that a meter be installed at its sole discretion. Services that can be unmetered include cable TV amplifiers, telephone switching devices, phone booths, bus shelters, rail way crossing signals, traffic signals, and other small fixed loads.
Further servicing details are available in the utility's Conditions of Service (including in the "Unmetered Connections" section).

Hydro One Networks Inc.
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Street Lighting

This classification refers to accounts for the distribution and supply of electrical energy for street lighting. Street lights are devices owned by or operated for the road authority and/or the municipal corporation. These street lights in fact belong to the Street Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Sentinel Lighting

This classification refers to accounts for a separate service to a sentinel light. These sentinel lights in fact belong to the Sentinel Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Interim Demand-Side Management Time-of-Use

This is potentially applicable to Demand-billed General Service accounts. See Note 2 below.

Note (1): Classification descriptions are paraphrases from the document "Hydro One Networks Inc. - Distribution Customers Conditions of Service - August 2004"

Note (2):

Interim Demand-Side Management Time-of-Use Rates: demand charges will be based on demand during the on-peak periods.

Criteria: Customers' electricity consumption (kW) in the off-peak period is at least twice the electricity consumption (kW) during the on-peak period.

Definition of Time Periods: The on-peak hours will be between 0700 hours to 1900 hours Eastern Standard Time during the winter (standard time) on IESO business days and 0600 hours to 1800 hours Eastern Standard Time during the summer (daylight savings time) on IESO business days. The off-peak period constitutes all of the remaining hours.

Hydro One Networks Inc.
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This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

MONTHLY RATES AND CHARGES

Residential

Service Charge	$	14.28
Distribution Volumetric Rate	$ / kWh	0.0165
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0043
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0018
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0055
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0047
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service - Energy Billed (less than 50 kW)

Service Charge	$	19.11
Distribution Volumetric Rate	$ / kWh	0.0103
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0012
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0004
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0050
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0043
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service - Demand Billed (50 kW or greater)

Service Charge	$	19.11
Distribution Volumetric Rate	$ / kW	3.29
Regulatory Asset Recovery - Rider #1	$ / kW	0.38
Regulatory Asset Recovery - Rider #2	$ / kW	0.13
Retail Transmission Rate - Network Service Rate (4)	$ / kW	1.94
Retail Transmission Rate - Line and Transformation Connection Service Rate (4)	$ / kW	1.61
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
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This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

Unmetered, Scattered Load

Service Charge	$	9.09
Distribution Volumetric Rate	$ / kWh	0.0103
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0012
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0004
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0050
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0043
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

(3) For energy-only metered customers, the billing determinant is the customer’s metered energy consumption adjusted by the total loss factor as approved by the Board for Acquired LDC customers.

(4) For demand billed customers, appropriate loss factors must be applied to the applicable tariffs. Also the billing determinant for the Line and Transformation Connection Services rate is the customer’s peak demand in the billing period. The billing determinant for the Network Services rate is: for non-interval-metered customers, the peak demand in the billing period, and for interval-metered customers, the peak demand between 7 AM and 7 PM local time on IESO business days

Interim Demand-Side Management Time-of-Use

See the "Service Classifications" section of this schedule.

Customer-Supplied Transformation Allowance

Applicable to demand-billed customers providing their own transformers
Primary Voltage under 50 kV (per kW)

Single Phase	$ / kW	0.20
Three Phase	$ / kW	0.60

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
City of Dryden Hydro Electric Commission
Effective Date: May 1, 2007

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

Loss Factors

Supply Facilities Loss Factor	1.0045
Distribution Loss Factors	
Customer less than 5,000 kW	1.0500
Customer greater than or equal to 5,000 kW	1.0100
Total Loss Factors	
Customer less than 5,000 kW	1.0545
Customer greater than or equal to 5,000 kW	1.0145

Transformer Loss Allowance

Applicable to customers requiring a billing adjustment for transformer losses as the result of being metered on the primary side of a transformer. The following uniform values shall be applied to measured demand and energy to calculate transformer losses for voltages up to and including 50 kV (as metered on the primary side):

(a) 1.5% for transformer installations up to an individual bank capacity of 400 kVA,
(b) 1.0% for bank capacities over 400 kVA.

Alternatively, transformer losses may be determined from transformer test data, and measured demand and energy adjusted accordingly

For services which are not demand metered, an assumed demand of 50% of the transformer capacity will be used to calculate the loss allowance. Where several transformers are involved, the bank capacity is assumed to be the arithmetic sum of all transformer capacities

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
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City of Dryden Hydro Electric Commission
Effective Date: May 1, 2007

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MISCELLANEOUS CHARGES

Specific Service Charges: Standard Amounts

Rate Code	Specific Service Charge - Standard Name	Calculation Method			
		2006 Rate Handbook	Standard Formula	Other Formula	Time and Materials
1	Temporary Service	$500			
2	Dispute Meter Test	$30 plus Measurement Canada fees			
3	Collection of account – no disconnection/load limiter	$30			
4	Collection/Disconnect/load limiter/reconnect (at meter) trip – regular hours	$65			
5	Collection/Disconnect/load limiter/reconnect (at meter) trip – after regular hours	$185			
6	Collection/Disconnect/load limiter/reconnect (at pole) trip – regular hours	$185			
7	Collection/Disconnect/load limiter/reconnect (at pole) trip – after regular hours	$415			
8	Account Set-up Charge	$30			
9	Arrears Certificate	$15			
10	NSF Cheque Charge	$15 + bank charges			
11	Easement Charge for Unregistered Rights	$15			
12	Late Payment Charge	1.5%/month			
13a	Retailer Services – Establishing Service Agreements (refer to Handbook for all charges)	$100/agreement/Retailer +$20/month/Retailer +$0.50/month/customer + other			
13b	Retailer Services – Other (includes Bill Ready for Retailers and Service Transactions Requests) as per the Handbook, Chapter 12	$0.30/month/customer + $0.25/request for request fee + $0.50/request for process fee			
14	Special Meter Reads	$30			
15	Billing Suspension and Terminations in Trailer Parks		$130		
16	Service Layout Fee – Basic		$405		
17	Service Layout Fee – Complex		$580		

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
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18	Crossing Application – Pipeline		$2,065		
19	Crossing Application – Water		$2,525		
20	Crossing Application – Railroad		$2,565		
21	Line Staking – per meter		$3.10		
22	Central Metering – New service < 45 kW		$115		
23	Conversion to Central Metering < 45 kW		$795		
24	Conversion to Central Metering > 45 kW		$680		
25	Tingle Voltage Test – In Excess of 4 Hours (per hour – average 2 additional hours)		$105		
26	Standby Administration Charge per month (interim)		$375		
27	Sentinel Lights Rental Rate per month – Mercury Vapor			$7.00	
28	Guaranteed Units from Jan 01/91 to Aug 01/91			$26.50 / month	
29	Guaranteed Units from Jan 01/87 to Dec 31/90			$23.50 / month	
30	Joint Use for Cable and Telecom companies per pole			$22.35	
31	Joint Use for LDCs per pole			$28.61	

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Dundalk Energy Services
Effective Date: May 1, 2008

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

APPLICATION

The application of these rates and charges shall be in accordance with The Licence of The Distributor and any Codes, Guidelines or Orders of The Board, and amendments thereto as approved by The Board, which may be applicable to the administration of this schedule.
No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code, Guideline or Order of the Board, and amendments thereto as approved by the Board, or as specified herein
This schedule does not contain any rates and charges relating to the electricity commodity (e.g. the Regulated Price Plan).

EFFECTIVE DATES

DISTRIBUTION RATES - May 1, 2008 for all consumption or deemed consumption services used on or after that date.

MISCELLANEOUS CHARGES - May 1, 2008 for all charges billed to customers on or after that date.
RETAIL TRANSMISSION RATES - May 1, 2008 for all consumption or deemed consumption services used on or after that date.
LOSS FACTOR ADJUSTMENT – for all consumption or deemed consumption services billed following May 1, 2008 or later

SERVICE CLASSIFICATIONS

Residential
This classification refers to all service supplied to single-family dwelling units for domestic or household purpose. Multi-unit residential establishments such as apartment buildings supplied through one service (bulk metered) will normally be classified as General Service, but, at Hydro One's discretion, up to four residential units may be classified as residential. Where electricity service is provided to combined residential and business (including agricultural usage) and the wiring does not provide for separate metering, the classification shall be at the discretion of Hydro One based on such considerations as the estimated predominant consumption.
Further servicing details are available in the utility's Conditions of Service.

General Service
This classification refers to all service supplied to premises other than those classified as Residential or Lighting. Some General Service accounts are energy(kWh)-billed, and some are demand(kW)-billed. Further servicing details are available in the utility's Conditions of Service.

Unmetered Scattered Load
This classification refers to certain instances where connections can be provided without metering. These loads are generally small in size and consistent in magnitude of load. Hydro One reserves the right to review all cases and may require that a meter be installed at its sole discretion. Services that can be unmetered include cable TV amplifiers, telephone switching devices, phone booths, bus shelters, rail way crossing signals, traffic signals, and other small fixed loads.
Further servicing details are available in the utility's Conditions of Service (including in the "Unmetered Connections" section).

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Dundalk Energy Services
Effective Date: May 1, 2008

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

Street Lighting
This classification refers to accounts for the distribution and supply of electrical energy for street lighting. Street lights are devices owned by or operated for the road authority and/or the municipal corporation. These street lights in fact belong to the Street Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Sentinel Lighting
This classification refers to accounts for a separate service to a sentinel light. These sentinel lights in fact belong to the Sentinel Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Urban Density Classification
Customers who meet the Urban Density Criteria of being in an area containing 3,000 or more customers with a line density of at least 60 customers per kilometre, will be mapped to an Urban customer classification.

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Dundalk Energy Services
Effective Date: May 1, 2008

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

MONTHLY RATES AND CHARGES

Residential - R1 Dundalk

Service Charge	$	15.14
Distribution Volumetric Rate	$ / kWh	0.0230
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0013
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0004)
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0047
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0046
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service Less Than 50 kW (Energy-Billed) - GSe Dundalk

Service Charge	$	25.20
Distribution Volumetric Rate	$ / kWh	0.0285
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0009
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0006)
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0035
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0032
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service 50 kW or Greater (Demand-Billed) - GSd Dundalk

Service Charge	$	28.80
Distribution Volumetric Rate	$ / kW	9.22
Regulatory Asset Recovery - Rider #2	$ / kW	0.28
Regulatory Asset Recovery - Rider #3	$ / kW	(0.22)
Retail Transmission Rate - Network Service Rate (4)	$ / kW	1.11
Retail Transmission Rate - Line and Transformation Connection Service Rate (4)	$ / kW	1.00
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
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Dundalk Energy Services
Effective Date: May 1, 2008

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Unmetered, Scattered Load

Service Charge	$	14.55
Distribution Volumetric Rate	$ / kWh	0.0200
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0009
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0006)
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0035
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0032
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

(3) For energy-only metered customers, the billing determinant is the customer's metered energy consumption adjusted by the total loss factor as approved by the Board for Acquired LDC customers.
(4) For demand billed customers, appropriate loss factors must be applied to the applicable tariffs. Also the billing determinant for the Line and Transformation Connection Services rate is the customer's peak demand in the billing period. The billing determinant for the Network Services rate is: for non-interval-metered customers, the peak demand in the billing period, and for interval-metered customers, the peak demand between 7 AM and 7 PM local time on IESO business days

Customer-Supplied Transformation Allowance

Applicable to customers providing their own transformers

Demand-billed	$ / kW	0.60
Energy-billed	$ / kWh	0.0014

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
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Dundalk Energy Services
Effective Date: May 1, 2008

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Loss Factors

Residential	1.085
General Service Less Than 50 kW (Energy-Billed)	1.092
General Service 50 kW or Greater (Demand-Billed)	1.061
Unmetered Scattered Load	1.092

Transformer Loss Allowance

Applicable to customers requiring a billing adjustment for transformer losses as the result of being metered on the primary side of a transformer. The following uniform values shall be applied to measured demand and energy to calculate transformer losses for voltages up to and including 50 kV (as metered on the primary side):

(a) 1.5% for transformer installations up to an individual bank capacity of 400 kVA,
(b) 1.0% for bank capacities over 400 kVA.

Alternatively, transformer losses may be determined from transformer test data, and measured demand and energy adjusted accordingly

For services which are not demand metered, an assumed demand of 50% of the transformer capacity will be used to calculate the loss allowance. Where several transformers are involved, the bank capacity is assumed to be the arithmetic sum of all transformer capacities

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Dundalk Energy Services
Effective Date: May 1, 2008

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

MISCELLANEOUS CHARGES

Specific Service Charges: Standard Amounts

Rate Code	Specific Service Charge - Standard Name	Calculation Method			
		2006 Rate Handbook	Standard Formula	Other Formula	Time and Materials
1	Temporary Service	$500			
2	Dispute Meter Test	$30 plus Measurement Canada fees			
3	Collection of account – no disconnection/load limiter	$30			
4	Collection/Disconnect/load limiter/reconnect (at meter) trip – regular hours	$65			
5	Collection/Disconnect/load limiter/reconnect (at meter) trip – after regular hours	$185			
6	Collection/Disconnect/load limiter/reconnect (at pole) trip – regular hours	$185			
7	Collection/Disconnect/load limiter/reconnect (at pole) trip – after regular hours	$415			
8	Account Set-up Charge	$30			
9	Arrears Certificate	$15			
10	NSF Cheque Charge	$15 + bank charges			
11	Easement Charge for Unregistered Rights	$15			
12	Late Payment Charge	1.5%/month			
13a	Retailer Services – Establishing Service Agreements (refer to Handbook for all charges)	$100/agreement/Retailer +$20/month/Retailer +$0.50/month/customer + other			
13b	Retailer Services – Other (includes Bill Ready for Retailers and Service Transactions Requests) as per the Handbook, Chapter 12	$0.30/month/customer + $0.25/request for request fee + $0.50/request for process fee			
14	Special Meter Reads	$30			
15	Service Layout Fee – Basic		$495		
16	Service Layout Fee – Complex		$690		
17	Crossing Application – Pipeline		$2,445		
18	Crossing Application – Water		$3,045		
19	Crossing Application – Railroad		$2,945		
20	Line Staking – per meter		$3.70		
21	Central Metering – New service < 45 kW		$115		
22	Conversion to Central Metering < 45 kW		$915		
23	Conversion to Central Metering > 45 kW		$800		
24	Tingle Voltage Test – In Excess of 4 Hours (per hour – average 2 additional hours)		$125		
25	Standby Administration Charge per month		$440		
26	Sentinel Lights Rental Rate per month			$7.10	
27	Sentinel Pole Rental Rate per month			$4.15	
28	Joint Use for Cable and Telecom companies per pole			$22.35	
29	Joint Use for LDCs per pole			$28.61	

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
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Dundalk Energy Services
Effective Date: May 1, 2007

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

APPLICATION

The application of these rates and charges shall be in accordance with The Licence of The Distributor and any Codes, Guidelines or Orders of The Board, and amendments thereto as approved by The Board, which may be applicable to the administration of this schedule.
No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code, Guideline or Order of the Board, and amendments thereto as approved by the Board, or as specified herein
This schedule does not contain any rates and charges relating to the electricity commodity (e.g. the Regulated Price Plan).

EFFECTIVE DATES

DISTRIBUTION RATES - May 1, 2007 for all consumption or deemed consumption services used on or after that date.

MISCELLANEOUS CHARGES - May 1, 2007 for all charges billed to customers on or after that date.
RETAIL TRANSMISSION RATES - May 1, 2007 for all consumption or deemed consumption services used on or after that date.
LOSS FACTOR ADJUSTMENT – May 1, 2007

SERVICE CLASSIFICATIONS

Residential
This classification (note 1) refers to all service supplied to single-family dwelling units for domestic or household purpose. Multi-unit residential establishments such as apartment buildings supplied through one service (bulk metered) will normally be classified as General Service, but, at Hydro One's discretion, up to four residential units may be classified as residential. Where electricity service is provided to combined residential and business (including agricultural usage) and the wiring does not provide for separate metering, the classification shall be at the discretion of Hydro One based on such considerations as the estimated predominant consumption.
Further servicing details are available in the utility's Conditions of Service.

General Service
This classification (note 1) refers to all service supplied to premises other than those classified as Residential or Lighting. Some General Service accounts are energy(kWh)-billed, and some are demand(kW)-billed. Further servicing details are available in the utility's Conditions of Service. Also, see note 2.

Unmetered Scattered Load
This classification refers to certain instances where connections can be provided without metering. These loads are generally small in size and consistent in magnitude of load. Hydro One reserves the right to review all cases and may require that a meter be installed at its sole discretion. Services that can be unmetered include cable TV amplifiers, telephone switching devices, phone booths, bus shelters, rail way crossing signals, traffic signals, and other small fixed loads.
Further servicing details are available in the utility's Conditions of Service (including in the "Unmetered Connections" section).

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Dundalk Energy Services
Effective Date: May 1, 2007

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

Street Lighting

This classification refers to accounts for the distribution and supply of electrical energy for street lighting. Street lights are devices owned by or operated for the road authority and/or the municipal corporation. These street lights in fact belong to the Street Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Sentinel Lighting

This classification refers to accounts for a separate service to a sentinel light. These sentinel lights in fact belong to the Sentinel Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Interim Demand-Side Management Time-of-Use

This is potentially applicable to Demand-billed General Service accounts. See Note 2 below.

Note (1): Classification descriptions are paraphrases from the document "Hydro One Networks Inc. - Distribution Customers Conditions of Service - August 2004"

Note (2):

Interim Demand-Side Management Time-of-Use Rates: demand charges will be based on demand during the on-peak periods.

Criteria: Customers' electricity consumption (kW) in the off-peak period is at least twice the electricity consumption (kW) during the on-peak period.

Definition of Time Periods: The on-peak hours will be between 0700 hours to 1900 hours Eastern Standard Time during the winter (standard time) on IESO business days and 0600 hours to 1800 hours Eastern Standard Time during the summer (daylight savings time) on IESO business days. The off-peak period constitutes all of the remaining hours.

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
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Dundalk Energy Services
Effective Date: May 1, 2007

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MONTHLY RATES AND CHARGES

Residential

Service Charge	$	14.47
Distribution Volumetric Rate	$ / kWh	0.0108
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0039
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0013
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0055
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0047
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service - Energy Billed (less than 50 kW)

Service Charge	$	23.56
Distribution Volumetric Rate	$ / kWh	0.0164
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0023
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0009
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0050
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0043
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service - Demand Billed (50 kW or greater)

Service Charge	$	23.56
Distribution Volumetric Rate	$ / kW	5.17
Regulatory Asset Recovery - Rider #1	$ / kW	0.74
Regulatory Asset Recovery - Rider #2	$ / kW	0.28
Retail Transmission Rate - Network Service Rate (4)	$ / kW	1.94
Retail Transmission Rate - Line and Transformation Connection Service Rate (4)	$ / kW	1.61
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
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Dundalk Energy Services
Effective Date: May 1, 2007

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

Unmetered, Scattered Load

Service Charge	$	11.32
Distribution Volumetric Rate	$ / kWh	0.0164
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0023
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0009
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0050
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0043
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

(3) For energy-only metered customers, the billing determinant is the customer's metered energy consumption adjusted by the total loss factor as approved by the Board for Acquired LDC customers.
(4) For demand billed customers, appropriate loss factors must be applied to the applicable tariffs. Also the billing determinant for the Line and Transformation Connection Services rate is the customer's peak demand in the billing period. The billing determinant for the Network Services rate is: for non-interval-metered customers, the peak demand in the billing period, and for interval-metered customers, the peak demand between 7 AM and 7 PM local time on IESO business days

Interim Demand-Side Management Time-of-Use

See the "Service Classifications" section of this schedule.

Customer-Supplied Transformation Allowance

Applicable to demand-billed customers providing their own transformers
Primary Voltage under 50 kV (per kW)

Single Phase	$ / kW	0.20
Three Phase	$ / kW	0.60

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Dundalk Energy Services
Effective Date: May 1, 2007

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

Loss Factors

Supply Facilities Loss Factor	1.0045
Distribution Loss Factors	
Customer less than 5,000 kW	1.0500
Customer greater than or equal to 5,000 kW	1.0100
Total Loss Factors	
Customer less than 5,000 kW	1.0545
Customer greater than or equal to 5,000 kW	1.0145

Transformer Loss Allowance

Applicable to customers requiring a billing adjustment for transformer losses as the result of being metered on the primary side of a transformer. The following uniform values shall be applied to measured demand and energy to calculate transformer losses for voltages up to and including 50 kV (as metered on the primary side):

(a) 1.5% for transformer installations up to an individual bank capacity of 400 kVA,
(b) 1.0% for bank capacities over 400 kVA.

Alternatively, transformer losses may be determined from transformer test data, and measured demand and energy adjusted accordingly

For services which are not demand metered, an assumed demand of 50% of the transformer capacity will be used to calculate the loss allowance. Where several transformers are involved, the bank capacity is assumed to be the arithmetic sum of all transformer capacities

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Dundalk Energy Services
Effective Date: May 1, 2007

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

MISCELLANEOUS CHARGES

Specific Service Charges: Standard Amounts

Rate Code	Specific Service Charge - Standard Name	Calculation Method			
		2006 Rate Handbook	Standard Formula	Other Formula	Time and Materials
1	Temporary Service	$500			
2	Dispute Meter Test	$30 plus Measurement Canada fees			
3	Collection of account – no disconnection/load limiter	$30			
4	Collection/Disconnect/load limiter/reconnect (at meter) trip – regular hours	$65			
5	Collection/Disconnect/load limiter/reconnect (at meter) trip – after regular hours	$185			
6	Collection/Disconnect/load limiter/reconnect (at pole) trip – regular hours	$185			
7	Collection/Disconnect/load limiter/reconnect (at pole) trip – after regular hours	$415			
8	Account Set-up Charge	$30			
9	Arrears Certificate	$15			
10	NSF Cheque Charge	$15 + bank charges			
11	Easement Charge for Unregistered Rights	$15			
12	Late Payment Charge	1.5%/month			
13a	Retailer Services – Establishing Service Agreements (refer to Handbook for all charges)	$100/agreement/Retailer +$20/month/Retailer +$0.50/month/customer + other			
13b	Retailer Services – Other (includes Bill Ready for Retailers and Service Transactions Requests) as per the Handbook, Chapter 12	$0.30/month/customer + $0.25/request for request fee + $0.50/request for process fee			
14	Special Meter Reads	$30			
15	Billing Suspension and Terminations in Trailer Parks		$130		
16	Service Layout Fee – Basic		$405		
17	Service Layout Fee – Complex		$580		

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Dundalk Energy Services
Effective Date: May 1, 2007

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

18	Crossing Application – Pipeline		$2,065		
19	Crossing Application – Water		$2,525		
20	Crossing Application – Railroad		$2,565		
21	Line Staking – per meter		$3.10		
22	Central Metering – New service < 45 kW		$115		
23	Conversion to Central Metering < 45 kW		$795		
24	Conversion to Central Metering > 45 kW		$680		
25	Tingle Voltage Test – In Excess of 4 Hours (per hour – average 2 additional hours)		$105		
26	Standby Administration Charge per month (interim)		$375		
27	Sentinel Lights Rental Rate per month – Mercury Vapor			$7.00	
28	Guaranteed Units from Jan 01/91 to Aug 01/91			$26.50 / month	
29	Guaranteed Units from Jan 01/87 to Dec 31/90			$23.50 / month	
30	Joint Use for Cable and Telecom companies per pole			$22.35	
31	Joint Use for LDCs per pole			$28.61	

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Durham Hydro-Electric Commission
Effective Date: May 1, 2008

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

APPLICATION

The application of these rates and charges shall be in accordance with The Licence of The Distributor and any Codes, Guidelines or Orders of The Board, and amendments thereto as approved by The Board, which may be applicable to the administration of this schedule.
No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code, Guideline or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.
This schedule does not contain any rates and charges relating to the electricity commodity (e.g. the Regulated Price Plan).

EFFECTIVE DATES

DISTRIBUTION RATES - May 1, 2008 for all consumption or deemed consumption services used on or after that date.

MISCELLANEOUS CHARGES - May 1, 2008 for all charges billed to customers on or after that date.
RETAIL TRANSMISSION RATES - May 1, 2008 for all consumption or deemed consumption services used on or after that date.
LOSS FACTOR ADJUSTMENT – for all consumption or deemed consumption services billed following May 1, 2008 or later

SERVICE CLASSIFICATIONS

Residential
This classification refers to all service supplied to single-family dwelling units for domestic or household purpose. Multi-unit residential establishments such as apartment buildings supplied through one service (bulk metered) will normally be classified as General Service, but, at Hydro One's discretion, up to four residential units may be classified as residential. Where electricity service is provided to combined residential and business (including agricultural usage) and the wiring does not provide for separate metering, the classification shall be at the discretion of Hydro One based on such considerations as the estimated predominant consumption.
Further servicing details are available in the utility's Conditions of Service.

General Service
This classification refers to all service supplied to premises other than those classified as Residential or Lighting. Some General Service accounts are energy(kWh)-billed, and some are demand(kW)-billed. Further servicing details are available in the utility's Conditions of Service.

Unmetered Scattered Load
This classification refers to certain instances where connections can be provided without metering. These loads are generally small in size and consistent in magnitude of load. Hydro One reserves the right to review all cases and may require that a meter be installed at its sole discretion. Services that can be unmetered include cable TV amplifiers, telephone switching devices, phone booths, bus shelters, rail way crossing signals, traffic signals, and other small fixed loads.
Further servicing details are available in the utility's Conditions of Service (including in the "Unmetered Connections" section).

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Durham Hydro-Electric Commission
Effective Date: May 1, 2008

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

Street Lighting

This classification refers to accounts for the distribution and supply of electrical energy for street lighting. Street lights are devices owned by or operated for the road authority and/or the municipal corporation. These street lights in fact belong to the Street Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Sentinel Lighting

This classification refers to accounts for a separate service to a sentinel light. These sentinel lights in fact belong to the Sentinel Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Urban Density Classification

Customers who meet the Urban Density Criteria of being in an area containing 3,000 or more customers with a line density of at least 60 customers per kilometre, will be mapped to an Urban customer classification.

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Durham Hydro-Electric Commission
Effective Date: May 1, 2008

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MONTHLY RATES AND CHARGES

Residential - R1 Durham

Service Charge	$	16.67
Distribution Volumetric Rate	$ / kWh	0.0260
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0016
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0004)
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0047
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0046
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service Less Than 50 kW (Energy-Billed) - GSe Durham

Service Charge	$	26.06
Distribution Volumetric Rate	$ / kWh	0.0248
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0006
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0006)
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0035
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0032
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service 50 kW or Greater (Demand-Billed) - GSd Durham

Service Charge	$	29.66
Distribution Volumetric Rate	$ / kW	9.22
Regulatory Asset Recovery - Rider #2	$ / kW	0.18
Regulatory Asset Recovery - Rider #3	$ / kW	(0.22)
Retail Transmission Rate - Network Service Rate (4)	$ / kW	1.11
Retail Transmission Rate - Line and Transformation Connection Service Rate (4)	$ / kW	1.00
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

Hydro One Networks Inc.
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Durham Hydro-Electric Commission
Effective Date: May 1, 2008

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Unmetered, Scattered Load

Service Charge	$	14.48
Distribution Volumetric Rate	$ / kWh	0.0200
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0006
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0006)
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0035
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0032
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

(3) For energy-only metered customers, the billing determinant is the customer's metered energy consumption adjusted by the total loss factor as approved by the Board for Acquired LDC customers.
(4) For demand billed customers, appropriate loss factors must be applied to the applicable tariffs. Also the billing determinant for the Line and Transformation Connection Services rate is the customer's peak demand in the billing period. The billing determinant for the Network Services rate is: for non-interval-metered customers, the peak demand in the billing period, and for interval-metered customers, the peak demand between 7 AM and 7 PM local time on IESO business days

Customer-Supplied Transformation Allowance

Applicable to customers providing their own transformers

Demand-billed	$ / kW	0.60
Energy-billed	$ / kWh	0.0014

Hydro One Networks Inc.
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Durham Hydro-Electric Commission
Effective Date: May 1, 2008

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Loss Factors

Residential	1.085
General Service Less Than 50 kW (Energy-Billed)	1.092
General Service 50 kW or Greater (Demand-Billed)	1.061
Unmetered Scattered Load	1.092

Transformer Loss Allowance

Applicable to customers requiring a billing adjustment for transformer losses as the result of being metered on the primary side of a transformer. The following uniform values shall be applied to measured demand and energy to calculate transformer losses for voltages up to and including 50 kV (as metered on the primary side):

(a) 1.5% for transformer installations up to an individual bank capacity of 400 kVA,
(b) 1.0% for bank capacities over 400 kVA.

Alternatively, transformer losses may be determined from transformer test data, and measured demand and energy adjusted accordingly

For services which are not demand metered, an assumed demand of 50% of the transformer capacity will be used to calculate the loss allowance. Where several transformers are involved, the bank capacity is assumed to be the arithmetic sum of all transformer capacities

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
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Durham Hydro-Electric Commission
Effective Date: May 1, 2008

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

MISCELLANEOUS CHARGES

Specific Service Charges: Standard Amounts

Rate Code	Specific Service Charge - Standard Name	Calculation Method			
		2006 Rate Handbook	Standard Formula	Other Formula	Time and Materials
1	Temporary Service	$500			
2	Dispute Meter Test	$30 plus Measurement Canada fees			
3	Collection of account – no disconnection/load limiter	$30			
4	Collection/Disconnect/load limiter/reconnect (at meter) trip – regular hours	$65			
5	Collection/Disconnect/load limiter/reconnect (at meter) trip – after regular hours	$185			
6	Collection/Disconnect/load limiter/reconnect (at pole) trip – regular hours	$185			
7	Collection/Disconnect/load limiter/reconnect (at pole) trip – after regular hours	$415			
8	Account Set-up Charge	$30			
9	Arrears Certificate	$15			
10	NSF Cheque Charge	$15 + bank charges			
11	Easement Charge for Unregistered Rights	$15			
12	Late Payment Charge	1.5%/month			
13a	Retailer Services – Establishing Service Agreements (refer to Handbook for all charges)	$100/agreement/Retailer +$20/month/Retailer +$0.50/month/customer + other			
13b	Retailer Services – Other (includes Bill Ready for Retailers and Service Transactions Requests) as per the Handbook, Chapter 12	$0.30/month/customer + $0.25/request for request fee + $0.50/request for process fee			
14	Special Meter Reads	$30			
15	Service Layout Fee – Basic		$495		
16	Service Layout Fee – Complex		$690		
17	Crossing Application – Pipeline		$2,445		
18	Crossing Application – Water		$3,045		
19	Crossing Application – Railroad		$2,945		
20	Line Staking – per meter		$3.70		
21	Central Metering – New service < 45 kW		$115		
22	Conversion to Central Metering < 45 kW		$915		
23	Conversion to Central Metering > 45 kW		$800		
24	Tingle Voltage Test – In Excess of 4 Hours (per hour – average 2 additional hours)		$125		
25	Standby Administration Charge per month		$440		
26	Sentinel Lights Rental Rate per month			$7.10	
27	Sentinel Pole Rental Rate per month			$4.15	
28	Joint Use for Cable and Telecom companies per pole			$22.35	
29	Joint Use for LDCs per pole			$28.61	

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Durham Hydro-Electric Commission
Effective Date: May 1, 2007

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

APPLICATION

The application of these rates and charges shall be in accordance with The Licence of The Distributor and any Codes, Guidelines or Orders of The Board, and amendments thereto as approved by The Board, which may be applicable to the administration of this schedule.
No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code, Guideline or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.
This schedule does not contain any rates and charges relating to the electricity commodity (e.g. the Regulated Price Plan).

EFFECTIVE DATES

DISTRIBUTION RATES - May 1, 2007 for all consumption or deemed consumption services used on or after that date.

MISCELLANEOUS CHARGES - May 1, 2007 for all charges billed to customers on or after that date.
RETAIL TRANSMISSION RATES - May 1, 2007 for all consumption or deemed consumption services used on or after that date.
LOSS FACTOR ADJUSTMENT – May 1, 2007

SERVICE CLASSIFICATIONS

Residential
This classification (note 1) refers to all service supplied to single-family dwelling units for domestic or household purpose. Multi-unit residential establishments such as apartment buildings supplied through one service (bulk metered) will normally be classified as General Service, but, at Hydro One's discretion, up to four residential units may be classified as residential. Where electricity service is provided to combined residential and business (including agricultural usage) and the wiring does not provide for separate metering, the classification shall be at the discretion of Hydro One based on such considerations as the estimated predominant consumption.
Further servicing details are available in the utility's Conditions of Service.

General Service
This classification (note 1) refers to all service supplied to premises other than those classified as Residential or Lighting. Some General Service accounts are energy(kWh)-billed, and some are demand(kW)-billed. Further servicing details are available in the utility's Conditions of Service. Also, see note 2.

Unmetered Scattered Load
This classification refers to certain instances where connections can be provided without metering. These loads are generally small in size and consistent in magnitude of load. Hydro One reserves the right to review all cases and may require that a meter be installed at its sole discretion. Services that can be unmetered include cable TV amplifiers, telephone switching devices, phone booths, bus shelters, rail way crossing signals, traffic signals, and other small fixed loads.
Further servicing details are available in the utility's Conditions of Service (including in the "Unmetered Connections" section).

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
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Durham Hydro-Electric Commission
Effective Date: May 1, 2007

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Street Lighting

This classification refers to accounts for the distribution and supply of electrical energy for street lighting. Street lights are devices owned by or operated for the road authority and/or the municipal corporation. These street lights in fact belong to the Street Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Sentinel Lighting

This classification refers to accounts for a separate service to a sentinel light. These sentinel lights in fact belong to the Sentinel Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Interim Demand-Side Management Time-of-Use

This is potentially applicable to Demand-billed General Service accounts. See Note 2 below.

Note (1): Classification descriptions are paraphrases from the document "Hydro One Networks Inc. - Distribution Customers Conditions of Service - August 2004"
Note (2):

Interim Demand-Side Management Time-of-Use Rates: demand charges will be based on demand during the on-peak periods.
Criteria: Customers' electricity consumption (kW) in the off-peak period is at least twice the electricity consumption (kW) during the on-peak period.
Definition of Time Periods: The on-peak hours will be between 0700 hours to 1900 hours Eastern Standard Time during the winter (standard time) on IESO business days and 0600 hours to 1800 hours Eastern Standard Time during the summer (daylight savings time) on IESO business days. The off-peak period constitutes all of the remaining hours.

Hydro One Networks Inc.
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MONTHLY RATES AND CHARGES

Residential

Service Charge	$	16.35
Distribution Volumetric Rate	$ / kWh	0.0124
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0046
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0016
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0055
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0047
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service - Energy Billed (less than 50 kW)

Service Charge	$	24.12
Distribution Volumetric Rate	$ / kWh	0.0137
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0015
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0006
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0050
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0043
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service - Demand Billed (50 kW or greater)

Service Charge	$	24.12
Distribution Volumetric Rate	$ / kW	4.31
Regulatory Asset Recovery - Rider #1	$ / kW	0.48
Regulatory Asset Recovery - Rider #2	$ / kW	0.18
Retail Transmission Rate - Network Service Rate (4)	$ / kW	1.94
Retail Transmission Rate - Line and Transformation Connection Service Rate (4)	$ / kW	1.61
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

Hydro One Networks Inc.
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Unmetered, Scattered Load

Service Charge	$	11.59
Distribution Volumetric Rate	$ / kWh	0.0137
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0015
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0006
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0050
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0043
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

(3) For energy-only metered customers, the billing determinant is the customer's metered energy consumption adjusted by the total loss factor as approved by the Board for Acquired LDC customers.
(4) For demand billed customers, appropriate loss factors must be applied to the applicable tariffs. Also the billing determinant for the Line and Transformation Connection Services rate is the customer's peak demand in the billing period. The billing determinant for the Network Services rate is: for non-interval-metered customers, the peak demand in the billing period, and for interval-metered customers, the peak demand between 7 AM and 7 PM local time on IESO business days

Interim Demand-Side Management Time-of-Use

See the "Service Classifications" section of this schedule.

Customer-Supplied Transformation Allowance

Applicable to demand-billed customers providing their own transformers
Primary Voltage under 50 kV (per kW)

Single Phase	$ / kW	0.20
Three Phase	$ / kW	0.60

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Loss Factors

Supply Facilities Loss Factor	1.0045
Distribution Loss Factors	
Customer less than 5,000 kW	1.0500
Customer greater than or equal to 5,000 kW	1.0100
Total Loss Factors	
Customer less than 5,000 kW	1.0545
Customer greater than or equal to 5,000 kW	1.0145

Transformer Loss Allowance

Applicable to customers requiring a billing adjustment for transformer losses as the result of being metered on the primary side of a transformer. The following uniform values shall be applied to measured demand and energy to calculate transformer losses for voltages up to and including 50 kV (as metered on the primary side):

(a) 1.5% for transformer installations up to an individual bank capacity of 400 kVA,
(b) 1.0% for bank capacities over 400 kVA.

Alternatively, transformer losses may be determined from transformer test data, and measured demand and energy adjusted accordingly

For services which are not demand metered, an assumed demand of 50% of the transformer capacity will be used to calculate the loss allowance. Where several transformers are involved, the bank capacity is assumed to be the arithmetic sum of all transformer capacities

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
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Effective Date: May 1, 2007

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MISCELLANEOUS CHARGES

Specific Service Charges: Standard Amounts

Rate Code	Specific Service Charge - Standard Name	Calculation Method			
		2006 Rate Handbook	Standard Formula	Other Formula	Time and Materials
1	Temporary Service	$500			
2	Dispute Meter Test	$30 plus Measurement Canada fees			
3	Collection of account – no disconnection/load limiter	$30			
4	Collection/Disconnect/load limiter/reconnect (at meter) trip – regular hours	$65			
5	Collection/Disconnect/load limiter/reconnect (at meter) trip – after regular hours	$185			
6	Collection/Disconnect/load limiter/reconnect (at pole) trip – regular hours	$185			
7	Collection/Disconnect/load limiter/reconnect (at pole) trip – after regular hours	$415			
8	Account Set-up Charge	$30			
9	Arrears Certificate	$15			
10	NSF Cheque Charge	$15 + bank charges			
11	Easement Charge for Unregistered Rights	$15			
12	Late Payment Charge	1.5%/month			
13a	Retailer Services – Establishing Service Agreements (refer to Handbook for all charges)	$100/agreement/Retailer +$20/month/Retailer +$0.50/month/customer + other			
13b	Retailer Services – Other (includes Bill Ready for Retailers and Service Transactions Requests) as per the Handbook, Chapter 12	$0.30/month/customer + $0.25/request for request fee + $0.50/request for process fee			
14	Special Meter Reads	$30			
15	Billing Suspension and Terminations in Trailer Parks		$130		
16	Service Layout Fee – Basic		$405		
17	Service Layout Fee – Complex		$580		

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
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Effective Date: May 1, 2007

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18	Crossing Application – Pipeline		$2,065		
19	Crossing Application – Water		$2,525		
20	Crossing Application – Railroad		$2,565		
21	Line Staking – per meter		$3.10		
22	Central Metering – New service < 45 kW		$115		
23	Conversion to Central Metering < 45 kW		$795		
24	Conversion to Central Metering > 45 kW		$680		
25	Tingle Voltage Test – In Excess of 4 Hours (per hour – average 2 additional hours)		$105		
26	Standby Administration Charge per month (interim)		$375		
27	Sentinel Lights Rental Rate per month – Mercury Vapor			$7.00	
28	Guaranteed Units from Jan 01/91 to Aug 01/91			$26.50 / month	
29	Guaranteed Units from Jan 01/87 to Dec 31/90			$23.50 / month	
30	Joint Use for Cable and Telecom companies per pole			$22.35	
31	Joint Use for LDCs per pole			$28.61	

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Public Utilities Commission of the Village of Eganville
Effective Date: May 1, 2008

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

APPLICATION

The application of these rates and charges shall be in accordance with The Licence of The Distributor and any Codes, Guidelines or Orders of The Board, and amendments thereto as approved by The Board, which may be applicable to the administration of this schedule.
No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code, Guideline or Order of the Board, and amendments thereto as approved by the Board, or as specified herein
This schedule does not contain any rates and charges relating to the electricity commodity (e.g. the Regulated Price Plan).

EFFECTIVE DATES

DISTRIBUTION RATES - May 1, 2008 for all consumption or deemed consumption services used on or after that date.

MISCELLANEOUS CHARGES - May 1, 2008 for all charges billed to customers on or after that date.
RETAIL TRANSMISSION RATES - May 1, 2008 for all consumption or deemed consumption services used on or after that date.
LOSS FACTOR ADJUSTMENT – for all consumption or deemed consumption services billed following May 1, 2008 or later

SERVICE CLASSIFICATIONS

Residential
This classification refers to all service supplied to single-family dwelling units for domestic or household purpose. Multi-unit residential establishments such as apartment buildings supplied through one service (bulk metered) will normally be classified as General Service, but, at Hydro One's discretion, up to four residential units may be classified as residential. Where electricity service is provided to combined residential and business (including agricultural usage) and the wiring does not provide for separate metering, the classification shall be at the discretion of Hydro One based on such considerations as the estimated predominant consumption.
Further servicing details are available in the utility's Conditions of Service.

General Service
This classification refers to all service supplied to premises other than those classified as Residential or Lighting. Some General Service accounts are energy(kWh)-billed, and some are demand(kW)-billed. Further servicing details are available in the utility's Conditions of Service.

Unmetered Scattered Load
This classification refers to certain instances where connections can be provided without metering. These loads are generally small in size and consistent in magnitude of load. Hydro One reserves the right to review all cases and may require that a meter be installed at its sole discretion. Services that can be unmetered include cable TV amplifiers, telephone switching devices, phone booths, bus shelters, rail way crossing signals, traffic signals, and other small fixed loads.
Further servicing details are available in the utility's Conditions of Service (including in the "Unmetered Connections" section).

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Public Utilities Commission of the Village of Eganville
Effective Date: May 1, 2008

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

Street Lighting

This classification refers to accounts for the distribution and supply of electrical energy for street lighting. Street lights are devices owned by or operated for the road authority and/or the municipal corporation. These street lights in fact belong to the Street Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Sentinel Lighting

This classification refers to accounts for a separate service to a sentinel light. These sentinel lights in fact belong to the Sentinel Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Urban Density Classification

Customers who meet the Urban Density Criteria of being in an area containing 3,000 or more customers with a line density of at least 60 customers per kilometre, will be mapped to an Urban customer classification.

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Public Utilities Commission of the Village of Eganville
Effective Date: May 1, 2008

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

MONTHLY RATES AND CHARGES

Residential - R1 Eganville

Service Charge	$	14.30
Distribution Volumetric Rate	$ / kWh	0.0271
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0012
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0004)
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0047
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0046
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service Less Than 50 kW (Energy-Billed) - GSe Eganville

Service Charge	$	23.75
Distribution Volumetric Rate	$ / kWh	0.0321
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0012
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0006)
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0035
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0032
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service 50 kW or Greater (Demand-Billed) - GSd Eganville

Service Charge	$	27.35
Distribution Volumetric Rate	$ / kW	9.22
Regulatory Asset Recovery - Rider #2	$ / kW	0.37
Regulatory Asset Recovery - Rider #3	$ / kW	(0.22)
Retail Transmission Rate - Network Service Rate (4)	$ / kW	1.11
Retail Transmission Rate - Line and Transformation Connection Service Rate (4)	$ / kW	1.00
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Public Utilities Commission of the Village of Eganville
Effective Date: May 1, 2008

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

Unmetered, Scattered Load

Service Charge	$	13.82
Distribution Volumetric Rate	$ / kWh	0.0200
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0012
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0006)
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0035
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0032
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

(3) For energy-only metered customers, the billing determinant is the customer's metered energy consumption adjusted by the total loss factor as approved by the Board for Acquired LDC customers.
(4) For demand billed customers, appropriate loss factors must be applied to the applicable tariffs. Also the billing determinant for the Line and Transformation Connection Services rate is the customer's peak demand in the billing period. The billing determinant for the Network Services rate is: for non-interval-metered customers, the peak demand in the billing period, and for interval-metered customers, the peak demand between 7 AM and 7 PM local time on IESO business days

Customer-Supplied Transformation Allowance

Applicable to customers providing their own transformers		
Demand-billed	$ / kW	0.60
Energy-billed	$ / kWh	0.0014

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
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Public Utilities Commission of the Village of Eganville
Effective Date: May 1, 2008

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Loss Factors

Residential	1.085
General Service Less Than 50 kW (Energy-Billed)	1.092
General Service 50 kW or Greater (Demand-Billed)	1.061
Unmetered Scattered Load	1.092

Transformer Loss Allowance

Applicable to customers requiring a billing adjustment for transformer losses as the result of being metered on the primary side of a transformer. The following uniform values shall be applied to measured demand and energy to calculate transformer losses for voltages up to and including 50 kV (as metered on the primary side):

(a) 1.5% for transformer installations up to an individual bank capacity of 400 kVA,
(b) 1.0% for bank capacities over 400 kVA.

Alternatively, transformer losses may be determined from transformer test data, and measured demand and energy adjusted accordingly

For services which are not demand metered, an assumed demand of 50% of the transformer capacity will be used to calculate the loss allowance. Where several transformers are involved, the bank capacity is assumed to be the arithmetic sum of all transformer capacities

Hydro One Networks Inc.
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MISCELLANEOUS CHARGES

Specific Service Charges: Standard Amounts

Rate Code	Specific Service Charge - Standard Name	Calculation Method			
		2006 Rate Handbook	Standard Formula	Other Formula	Time and Materials
1	Temporary Service	$500			
2	Dispute Meter Test	$30 plus Measurement Canada fees			
3	Collection of account – no disconnection/load limiter	$30			
4	Collection/Disconnect/load limiter/reconnect (at meter) trip – regular hours	$65			
5	Collection/Disconnect/load limiter/reconnect (at meter) trip – after regular hours	$185			
6	Collection/Disconnect/load limiter/reconnect (at pole) trip – regular hours	$185			
7	Collection/Disconnect/load limiter/reconnect (at pole) trip – after regular hours	$415			
8	Account Set-up Charge	$30			
9	Arrears Certificate	$15			
10	NSF Cheque Charge	$15 + bank charges			
11	Easement Charge for Unregistered Rights	$15			
12	Late Payment Charge	1.5%/month			
13a	Retailer Services – Establishing Service Agreements (refer to Handbook for all charges)	$100/agreement/Retailer +$20/month/Retailer +$0.50/month/customer + other			
13b	Retailer Services – Other (includes Bill Ready for Retailers and Service Transactions Requests) as per the Handbook, Chapter 12	$0.30/month/customer + $0.25/request for request fee + $0.50/request for process fee			
14	Special Meter Reads	$30			
15	Service Layout Fee – Basic		$495		
16	Service Layout Fee – Complex		$690		
17	Crossing Application – Pipeline		$2,445		
18	Crossing Application – Water		$3,045		
19	Crossing Application – Railroad		$2,945		
20	Line Staking – per meter		$3.70		
21	Central Metering – New service < 45 kW		$115		
22	Conversion to Central Metering < 45 kW		$915		
23	Conversion to Central Metering > 45 kW		$800		
24	Tingle Voltage Test – In Excess of 4 Hours (per hour – average 2 additional hours)		$125		
25	Standby Administration Charge per month		$440		
26	Sentinel Lights Rental Rate per month			$7.10	
27	Sentinel Pole Rental Rate per month			$4.15	
28	Joint Use for Cable and Telecom companies per pole			$22.35	
29	Joint Use for LDCs per pole			$28.61	

Hydro One Networks Inc.
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Public Utilities Commission of the Village of Eganville
Effective Date: May 1, 2007

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

APPLICATION

The application of these rates and charges shall be in accordance with The Licence of The Distributor and any Codes, Guidelines or Orders of The Board, and amendments thereto as approved by The Board, which may be applicable to the administration of this schedule.
No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code, Guideline or Order of the Board, and amendments thereto as approved by the Board, or as specified herein
This schedule does not contain any rates and charges relating to the electricity commodity (e.g. the Regulated Price Plan).

EFFECTIVE DATES

DISTRIBUTION RATES - May 1, 2007 for all consumption or deemed consumption services used on or after that date.

MISCELLANEOUS CHARGES - May 1, 2007 for all charges billed to customers on or after that date.
RETAIL TRANSMISSION RATES - May 1, 2007 for all consumption or deemed consumption services used on or after that date.
LOSS FACTOR ADJUSTMENT – May 1, 2007

SERVICE CLASSIFICATIONS

Residential
This classification (note 1) refers to all service supplied to single-family dwelling units for domestic or household purpose. Multi-unit residential establishments such as apartment buildings supplied through one service (bulk metered) will normally be classified as General Service, but, at Hydro One's discretion, up to four residential units may be classified as residential. Where electricity service is provided to combined residential and business (including agricultural usage) and the wiring does not provide for separate metering, the classification shall be at the discretion of Hydro One based on such considerations as the estimated predominant consumption.
Further servicing details are available in the utility's Conditions of Service.

General Service
This classification (note 1) refers to all service supplied to premises other than those classified as Residential or Lighting. Some General Service accounts are energy(kWh)-billed, and some are demand(kW)-billed. Further servicing details are available in the utility's Conditions of Service. Also, see note 2.

Unmetered Scattered Load
This classification refers to certain instances where connections can be provided without metering. These loads are generally small in size and consistent in magnitude of load. Hydro One reserves the right to review all cases and may require that a meter be installed at its sole discretion. Services that can be unmetered include cable TV amplifiers, telephone switching devices, phone booths, bus shelters, rail way crossing signals, traffic signals, and other small fixed loads.
Further servicing details are available in the utility's Conditions of Service (including in the "Unmetered Connections" section).

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Street Lighting

This classification refers to accounts for the distribution and supply of electrical energy for street lighting. Street lights are devices owned by or operated for the road authority and/or the municipal corporation. These street lights in fact belong to the Street Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Sentinel Lighting

This classification refers to accounts for a separate service to a sentinel light. These sentinel lights in fact belong to the Sentinel Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Interim Demand-Side Management Time-of-Use

This is potentially applicable to Demand-billed General Service accounts. See Note 2 below.

Note (1): Classification descriptions are paraphrases from the document "Hydro One Networks Inc. - Distribution Customers Conditions of Service - August 2004"

Note (2):

Interim Demand-Side Management Time-of-Use Rates: demand charges will be based on demand during the on-peak periods.

Criteria: Customers' electricity consumption (kW) in the off-peak period is at least twice the electricity consumption (kW) during the on-peak period.

Definition of Time Periods: The on-peak hours will be between 0700 hours to 1900 hours Eastern Standard Time during the winter (standard time) on IESO business days and 0600 hours to 1800 hours Eastern Standard Time during the summer (daylight savings time) on IESO business days. The off-peak period constitutes all of the remaining hours.

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MONTHLY RATES AND CHARGES

Residential

Service Charge	$	13.86
Distribution Volumetric Rate	$ / kWh	0.0153
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0029
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0012
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0055
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0047
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service - Energy Billed (less than 50 kW)

Service Charge	$	21.35
Distribution Volumetric Rate	$ / kWh	0.0232
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0017
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0012
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0050
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0043
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service - Demand Billed (50 kW or greater)

Service Charge	$	21.35
Distribution Volumetric Rate	$ / kW	7.35
Regulatory Asset Recovery - Rider #1	$ / kW	0.55
Regulatory Asset Recovery - Rider #2	$ / kW	0.37
Retail Transmission Rate - Network Service Rate (4)	$ / kW	1.94
Retail Transmission Rate - Line and Transformation Connection Service Rate (4)	$ / kW	1.61
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

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Unmetered, Scattered Load

Service Charge	$	10.22
Distribution Volumetric Rate	$ / kWh	0.0232
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0017
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0012
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0050
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0043
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

(3) For energy-only metered customers, the billing determinant is the customer’s metered energy consumption adjusted by the total loss factor as approved by the Board for Acquired LDC customers.
(4) For demand billed customers, appropriate loss factors must be applied to the applicable tariffs. Also the billing determinant for the Line and Transformation Connection Services rate is the customer’s peak demand in the billing period. The billing determinant for the Network Services rate is: for non-interval-metered customers, the peak demand in the billing period, and for interval-metered customers, the peak demand between 7 AM and 7 PM local time on IESO business days

Interim Demand-Side Management Time-of-Use

See the "Service Classifications" section of this schedule.

Customer-Supplied Transformation Allowance

Applicable to demand-billed customers providing their own transformers
Primary Voltage under 50 kV (per kW)

Single Phase	$ / kW	0.20
Three Phase	$ / kW	0.60

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Loss Factors

Supply Facilities Loss Factor	1.0045
Distribution Loss Factors	
Customer less than 5,000 kW	1.0500
Customer greater than or equal to 5,000 kW	1.0100
Total Loss Factors	
Customer less than 5,000 kW	1.0545
Customer greater than or equal to 5,000 kW	1.0145

Transformer Loss Allowance

Applicable to customers requiring a billing adjustment for transformer losses as the result of being metered on the primary side of a transformer. The following uniform values shall be applied to measured demand and energy to calculate transformer losses for voltages up to and including 50 kV (as metered on the primary side):

(a) 1.5% for transformer installations up to an individual bank capacity of 400 kVA,
(b) 1.0% for bank capacities over 400 kVA.

Alternatively, transformer losses may be determined from transformer test data, and measured demand and energy adjusted accordingly

For services which are not demand metered, an assumed demand of 50% of the transformer capacity will be used to calculate the loss allowance. Where several transformers are involved, the bank capacity is assumed to be the arithmetic sum of all transformer capacities

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MISCELLANEOUS CHARGES

Specific Service Charges: Standard Amounts

Rate Code	Specific Service Charge - Standard Name	Calculation Method			
		2006 Rate Handbook	Standard Formula	Other Formula	Time and Materials
1	Temporary Service	$500			
2	Dispute Meter Test	$30 plus Measurement Canada fees			
3	Collection of account – no disconnection/load limiter	$30			
4	Collection/Disconnect/load limiter/reconnect (at meter) trip – regular hours	$65			
5	Collection/Disconnect/load limiter/reconnect (at meter) trip – after regular hours	$185			
6	Collection/Disconnect/load limiter/reconnect (at pole) trip – regular hours	$185			
7	Collection/Disconnect/load limiter/reconnect (at pole) trip – after regular hours	$415			
8	Account Set-up Charge	$30			
9	Arrears Certificate	$15			
10	NSF Cheque Charge	$15 + bank charges			
11	Easement Charge for Unregistered Rights	$15			
12	Late Payment Charge	1.5%/month			
13a	Retailer Services – Establishing Service Agreements (refer to Handbook for all charges)	$100/agreement/Retailer +$20/month/Retailer +$0.50/month/customer + other			
13b	Retailer Services – Other (includes Bill Ready for Retailers and Service Transactions Requests) as per the Handbook, Chapter 12	$0.30/month/customer + $0.25/request for request fee + $0.50/request for process fee			
14	Special Meter Reads	$30			
15	Billing Suspension and Terminations in Trailer Parks		$130		
16	Service Layout Fee – Basic		$405		
17	Service Layout Fee – Complex		$580		

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18	Crossing Application – Pipeline		$2,065		
19	Crossing Application – Water		$2,525		
20	Crossing Application – Railroad		$2,565		
21	Line Staking – per meter		$3.10		
22	Central Metering – New service < 45 kW		$115		
23	Conversion to Central Metering < 45 kW		$795		
24	Conversion to Central Metering > 45 kW		$680		
25	Tingle Voltage Test – In Excess of 4 Hours (per hour – average 2 additional hours)		$105		
26	Standby Administration Charge per month (interim)		$375		
27	Sentinel Lights Rental Rate per month – Mercury Vapor			$7.00	
28	Guaranteed Units from Jan 01/91 to Aug 01/91			$26.50 / month	
29	Guaranteed Units from Jan 01/87 to Dec 31/90			$23.50 / month	
30	Joint Use for Cable and Telecom companies per pole			$22.35	
31	Joint Use for LDCs per pole			$28.61	

Hydro One Networks Inc.
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Hydro-Electric Commission of the Town of Erin
Effective Date: May 1, 2008

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APPLICATION

The application of these rates and charges shall be in accordance with The Licence of The Distributor and any Codes, Guidelines or Orders of The Board, and amendments thereto as approved by The Board, which may be applicable to the administration of this schedule.
No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code, Guideline or Order of the Board, and amendments thereto as approved by the Board, or as specified herein
This schedule does not contain any rates and charges relating to the electricity commodity (e.g. the Regulated Price Plan).

EFFECTIVE DATES

DISTRIBUTION RATES - May 1, 2008 for all consumption or deemed consumption services used on or after that date.

MISCELLANEOUS CHARGES - May 1, 2008 for all charges billed to customers on or after that date.
RETAIL TRANSMISSION RATES - May 1, 2008 for all consumption or deemed consumption services used on or after that date.
LOSS FACTOR ADJUSTMENT – for all consumption or deemed consumption services billed following May 1, 2008 or later

SERVICE CLASSIFICATIONS

Residential
This classification refers to all service supplied to single-family dwelling units for domestic or household purpose. Multi-unit residential establishments such as apartment buildings supplied through one service (bulk metered) will normally be classified as General Service, but, at Hydro One's discretion, up to four residential units may be classified as residential. Where electricity service is provided to combined residential and business (including agricultural usage) and the wiring does not provide for separate metering, the classification shall be at the discretion of Hydro One based on such considerations as the estimated predominant consumption.
Further servicing details are available in the utility's Conditions of Service.

General Service
This classification refers to all service supplied to premises other than those classified as Residential or Lighting. Some General Service accounts are energy(kWh)-billed, and some are demand(kW)-billed. Further servicing details are available in the utility's Conditions of Service.

Unmetered Scattered Load
This classification refers to certain instances where connections can be provided without metering. These loads are generally small in size and consistent in magnitude of load. Hydro One reserves the right to review all cases and may require that a meter be installed at its sole discretion. Services that can be unmetered include cable TV amplifiers, telephone switching devices, phone booths, bus shelters, rail way crossing signals, traffic signals, and other small fixed loads.
Further servicing details are available in the utility's Conditions of Service (including in the "Unmetered Connections" section).

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Effective Date: May 1, 2008

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Street Lighting

This classification refers to accounts for the distribution and supply of electrical energy for street lighting. Street lights are devices owned by or operated for the road authority and/or the municipal corporation. These street lights in fact belong to the Street Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Sentinel Lighting

This classification refers to accounts for a separate service to a sentinel light. These sentinel lights in fact belong to the Sentinel Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Urban Density Classification

Customers who meet the Urban Density Criteria of being in an area containing 3,000 or more customers with a line density of at least 60 customers per kilometre, will be mapped to an Urban customer classification.

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MONTHLY RATES AND CHARGES

Residential - R1 Erin

Service Charge	$	14.48
Distribution Volumetric Rate	$ / kWh	0.0271
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0040
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0004)
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0047
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0046
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service Less Than 50 kW (Energy-Billed) - GSe Erin

Service Charge	$	38.00
Distribution Volumetric Rate	$ / kWh	0.0210
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0008
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0006)
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0035
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0032
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service 50 kW or Greater (Demand-Billed) - GSd Erin

Service Charge	$	41.59
Distribution Volumetric Rate	$ / kW	7.20
Regulatory Asset Recovery - Rider #2	$ / kW	0.25
Regulatory Asset Recovery - Rider #3	$ / kW	(0.22)
Retail Transmission Rate - Network Service Rate (4)	$ / kW	1.11
Retail Transmission Rate - Line and Transformation Connection Service Rate (4)	$ / kW	1.00
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

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Unmetered, Scattered Load

Service Charge	$	20.45
Distribution Volumetric Rate	$ / kWh	0.0200
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0008
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0006)
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0035
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0032
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

(3) For energy-only metered customers, the billing determinant is the customer's metered energy consumption adjusted by the total loss factor as approved by the Board for Acquired LDC customers.
(4) For demand billed customers, appropriate loss factors must be applied to the applicable tariffs. Also the billing determinant for the Line and Transformation Connection Services rate is the customer's peak demand in the billing period. The billing determinant for the Network Services rate is: for non-interval-metered customers, the peak demand in the billing period, and for interval-metered customers, the peak demand between 7 AM and 7 PM local time on IESO business days

Customer-Supplied Transformation Allowance

Applicable to customers providing their own transformers

Demand-billed	$ / kW	0.60
Energy-billed	$ / kWh	0.0014

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Loss Factors

Residential	1.085
General Service Less Than 50 kW (Energy-Billed)	1.092
General Service 50 kW or Greater (Demand-Billed)	1.061
Unmetered Scattered Load	1.092

Transformer Loss Allowance

Applicable to customers requiring a billing adjustment for transformer losses as the result of being metered on the primary side of a transformer. The following uniform values shall be applied to measured demand and energy to calculate transformer losses for voltages up to and including 50 kV (as metered on the primary side):

(a) 1.5% for transformer installations up to an individual bank capacity of 400 kVA,
(b) 1.0% for bank capacities over 400 kVA.

Alternatively, transformer losses may be determined from transformer test data, and measured demand and energy adjusted accordingly

For services which are not demand metered, an assumed demand of 50% of the transformer capacity will be used to calculate the loss allowance. Where several transformers are involved, the bank capacity is assumed to be the arithmetic sum of all transformer capacities

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MISCELLANEOUS CHARGES

Specific Service Charges: Standard Amounts

Rate Code	Specific Service Charge - Standard Name	Calculation Method			
		2006 Rate Handbook	Standard Formula	Other Formula	Time and Materials
1	Temporary Service	$500			
2	Dispute Meter Test	$30 plus Measurement Canada fees			
3	Collection of account – no disconnection/load limiter	$30			
4	Collection/Disconnect/load limiter/reconnect (at meter) trip – regular hours	$65			
5	Collection/Disconnect/load limiter/reconnect (at meter) trip – after regular hours	$185			
6	Collection/Disconnect/load limiter/reconnect (at pole) trip – regular hours	$185			
7	Collection/Disconnect/load limiter/reconnect (at pole) trip – after regular hours	$415			
8	Account Set-up Charge	$30			
9	Arrears Certificate	$15			
10	NSF Cheque Charge	$15 + bank charges			
11	Easement Charge for Unregistered Rights	$15			
12	Late Payment Charge	1.5%/month			
13a	Retailer Services – Establishing Service Agreements (refer to Handbook for all charges)	$100/agreement/Retailer +$20/month/Retailer +$0.50/month/customer + other			
13b	Retailer Services – Other (includes Bill Ready for Retailers and Service Transactions Requests) as per the Handbook, Chapter 12	$0.30/month/customer + $0.25/request for request fee + $0.50/request for process fee			
14	Special Meter Reads	$30			
15	Service Layout Fee – Basic		$495		
16	Service Layout Fee – Complex		$690		
17	Crossing Application – Pipeline		$2,445		
18	Crossing Application – Water		$3,045		
19	Crossing Application – Railroad		$2,945		
20	Line Staking – per meter		$3.70		
21	Central Metering – New service < 45 kW		$115		
22	Conversion to Central Metering < 45 kW		$915		
23	Conversion to Central Metering > 45 kW		$800		
24	Tingle Voltage Test – In Excess of 4 Hours (per hour – average 2 additional hours)		$125		
25	Standby Administration Charge per month		$440		
26	Sentinel Lights Rental Rate per month			$7.10	
27	Sentinel Pole Rental Rate per month			$4.15	
28	Joint Use for Cable and Telecom companies per pole			$22.35	
29	Joint Use for LDCs per pole			$28.61	

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Hydro-Electric Commission of the Town of Erin
Effective Date: May 1, 2007

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

APPLICATION

The application of these rates and charges shall be in accordance with The Licence of The Distributor and any Codes, Guidelines or Orders of The Board, and amendments thereto as approved by The Board, which may be applicable to the administration of this schedule.
No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code, Guideline or Order of the Board, and amendments thereto as approved by the Board, or as specified herein
This schedule does not contain any rates and charges relating to the electricity commodity (e.g. the Regulated Price Plan).

EFFECTIVE DATES

DISTRIBUTION RATES - May 1, 2007 for all consumption or deemed consumption services used on or after that date.

MISCELLANEOUS CHARGES - May 1, 2007 for all charges billed to customers on or after that date.
RETAIL TRANSMISSION RATES - May 1, 2007 for all consumption or deemed consumption services used on or after that date.
LOSS FACTOR ADJUSTMENT – May 1, 2007

SERVICE CLASSIFICATIONS

Residential
This classification (note 1) refers to all service supplied to single-family dwelling units for domestic or household purpose. Multi-unit residential establishments such as apartment buildings supplied through one service (bulk metered) will normally be classified as General Service, but, at Hydro One’s discretion, up to four residential units may be classified as residential. Where electricity service is provided to combined residential and business (including agricultural usage) and the wiring does not provide for separate metering, the classification shall be at the discretion of Hydro One based on such considerations as the estimated predominant consumption.
Further servicing details are available in the utility’s Conditions of Service.

General Service
This classification (note 1) refers to all service supplied to premises other than those classified as Residential or Lighting. Some General Service accounts are energy(kWh)-billed, and some are demand(kW)-billed. Further servicing details are available in the utility’s Conditions of Service. Also, see note 2.

Unmetered Scattered Load
This classification refers to certain instances where connections can be provided without metering. These loads are generally small in size and consistent in magnitude of load. Hydro One reserves the right to review all cases and may require that a meter be installed at its sole discretion. Services that can be unmetered include cable TV amplifiers, telephone switching devices, phone booths, bus shelters, rail way crossing signals, traffic signals, and other small fixed loads.
Further servicing details are available in the utility’s Conditions of Service (including in the "Unmetered Connections" section).

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Hydro-Electric Commission of the Town of Erin
Effective Date: May 1, 2007

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

Street Lighting

This classification refers to accounts for the distribution and supply of electrical energy for street lighting. Street lights are devices owned by or operated for the road authority and/or the municipal corporation. These street lights in fact belong to the Street Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Sentinel Lighting

This classification refers to accounts for a separate service to a sentinel light. These sentinel lights in fact belong to the Sentinel Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Interim Demand-Side Management Time-of-Use

This is potentially applicable to Demand-billed General Service accounts. See Note 2 below.

Note (1): Classification descriptions are paraphrases from the document "Hydro One Networks Inc. - Distribution Customers Conditions of Service - August 2004"

Note (2):

Interim Demand-Side Management Time-of-Use Rates: demand charges will be based on demand during the on-peak periods.

Criteria: Customers' electricity consumption (kW) in the off-peak period is at least twice the electricity consumption (kW) during the on-peak period.

Definition of Time Periods: The on-peak hours will be between 0700 hours to 1900 hours Eastern Standard Time during the winter (standard time) on IESO business days and 0600 hours to 1800 hours Eastern Standard Time during the summer (daylight savings time) on IESO business days. The off-peak period constitutes all of the remaining hours.

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Hydro-Electric Commission of the Town of Erin
Effective Date: May 1, 2007

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MONTHLY RATES AND CHARGES

Residential

Service Charge	$	13.13
Distribution Volumetric Rate	$ / kWh	0.0190
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0083
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0040
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0055
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0047
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service - Energy Billed (less than 50 kW)

Service Charge	$	40.38
Distribution Volumetric Rate	$ / kWh	0.0073
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0019
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0008
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0050
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0043
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service - Demand Billed (50 kW or greater)

Service Charge	$	40.38
Distribution Volumetric Rate	$ / kW	2.36
Regulatory Asset Recovery - Rider #1	$ / kW	0.59
Regulatory Asset Recovery - Rider #2	$ / kW	0.25
Retail Transmission Rate - Network Service Rate (4)	$ / kW	1.94
Retail Transmission Rate - Line and Transformation Connection Service Rate (4)	$ / kW	1.61
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Hydro-Electric Commission of the Town of Erin
Effective Date: May 1, 2007

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

Unmetered, Scattered Load

Service Charge	$	19.72
Distribution Volumetric Rate	$ / kWh	0.0073
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0019
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0008
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0050
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0043
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

(3) For energy-only metered customers, the billing determinant is the customer's metered energy consumption adjusted by the total loss factor as approved by the Board for Acquired LDC customers.

(4) For demand billed customers, appropriate loss factors must be applied to the applicable tariffs. Also the billing determinant for the Line and Transformation Connection Services rate is the customer's peak demand in the billing period. The billing determinant for the Network Services rate is: for non-interval-metered customers, the peak demand in the billing period, and for interval-metered customers, the peak demand between 7 AM and 7 PM local time on IESO business days

Interim Demand-Side Management Time-of-Use

See the "Service Classifications" section of this schedule.

Customer-Supplied Transformation Allowance

Applicable to demand-billed customers providing their own transformers

Primary Voltage under 50 kV (per kW)		
Single Phase	$ / kW	0.20
Three Phase	$ / kW	0.60

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
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Effective Date: May 1, 2007

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Loss Factors

Supply Facilities Loss Factor	1.0045
Distribution Loss Factors	
Customer less than 5,000 kW	1.0500
Customer greater than or equal to 5,000 kW	1.0100
Total Loss Factors	
Customer less than 5,000 kW	1.0545
Customer greater than or equal to 5,000 kW	1.0145

Transformer Loss Allowance

Applicable to customers requiring a billing adjustment for transformer losses as the result of being metered on the primary side of a transformer. The following uniform values shall be applied to measured demand and energy to calculate transformer losses for voltages up to and including 50 kV (as metered on the primary side):

(a) 1.5% for transformer installations up to an individual bank capacity of 400 kVA,
(b) 1.0% for bank capacities over 400 kVA.

Alternatively, transformer losses may be determined from transformer test data, and measured demand and energy adjusted accordingly

For services which are not demand metered, an assumed demand of 50% of the transformer capacity will be used to calculate the loss allowance. Where several transformers are involved, the bank capacity is assumed to be the arithmetic sum of all transformer capacities

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Hydro-Electric Commission of the Town of Erin
Effective Date: May 1, 2007

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MISCELLANEOUS CHARGES

Specific Service Charges: Standard Amounts

Rate Code	Specific Service Charge - Standard Name	Calculation Method			
		2006 Rate Handbook	Standard Formula	Other Formula	Time and Materials
1	Temporary Service	$500			
2	Dispute Meter Test	$30 plus Measurement Canada fees			
3	Collection of account – no disconnection/load limiter	$30			
4	Collection/Disconnect/load limiter/reconnect (at meter) trip – regular hours	$65			
5	Collection/Disconnect/load limiter/reconnect (at meter) trip – after regular hours	$185			
6	Collection/Disconnect/load limiter/reconnect (at pole) trip – regular hours	$185			
7	Collection/Disconnect/load limiter/reconnect (at pole) trip – after regular hours	$415			
8	Account Set-up Charge	$30			
9	Arrears Certificate	$15			
10	NSF Cheque Charge	$15 + bank charges			
11	Easement Charge for Unregistered Rights	$15			
12	Late Payment Charge	1.5%/month			
13a	Retailer Services – Establishing Service Agreements (refer to Handbook for all charges)	$100/agreement/Retailer +$20/month/Retailer +$0.50/month/customer + other			
13b	Retailer Services – Other (includes Bill Ready for Retailers and Service Transactions Requests) as per the Handbook, Chapter 12	$0.30/month/customer + $0.25/request for request fee + $0.50/request for process fee			
14	Special Meter Reads	$30			
15	Billing Suspension and Terminations in Trailer Parks		$130		
16	Service Layout Fee – Basic		$405		
17	Service Layout Fee – Complex		$580		

Hydro One Networks Inc.
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18	Crossing Application – Pipeline		$2,065		
19	Crossing Application – Water		$2,525		
20	Crossing Application – Railroad		$2,565		
21	Line Staking – per meter		$3.10		
22	Central Metering – New service < 45 kW		$115		
23	Conversion to Central Metering < 45 kW		$795		
24	Conversion to Central Metering > 45 kW		$680		
25	Tingle Voltage Test – In Excess of 4 Hours (per hour – average 2 additional hours)		$105		
26	Standby Administration Charge per month (interim)		$375		
27	Sentinel Lights Rental Rate per month – Mercury Vapor			$7.00	
28	Guaranteed Units from Jan 01/91 to Aug 01/91			$26.50 / month	
29	Guaranteed Units from Jan 01/87 to Dec 31/90			$23.50 / month	
30	Joint Use for Cable and Telecom companies per pole			$22.35	
31	Joint Use for LDCs per pole			$28.61	

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
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Hydro-Electric Commission of the Town of Exeter
Effective Date: May 1, 2008

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

APPLICATION

The application of these rates and charges shall be in accordance with The Licence of The Distributor and any Codes, Guidelines or Orders of The Board, and amendments thereto as approved by The Board, which may be applicable to the administration of this schedule.
No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code, Guideline or Order of the Board, and amendments thereto as approved by the Board, or as specified herein
This schedule does not contain any rates and charges relating to the electricity commodity (e.g. the Regulated Price Plan).

EFFECTIVE DATES

DISTRIBUTION RATES - May 1, 2008 for all consumption or deemed consumption services used on or after that date.

MISCELLANEOUS CHARGES - May 1, 2008 for all charges billed to customers on or after that date.
RETAIL TRANSMISSION RATES - May 1, 2008 for all consumption or deemed consumption services used on or after that date.
LOSS FACTOR ADJUSTMENT – for all consumption or deemed consumption services billed following May 1, 2008 or later

SERVICE CLASSIFICATIONS

Residential
This classification refers to all service supplied to single-family dwelling units for domestic or household purpose. Multi-unit residential establishments such as apartment buildings supplied through one service (bulk metered) will normally be classified as General Service, but, at Hydro One's discretion, up to four residential units may be classified as residential. Where electricity service is provided to combined residential and business (including agricultural usage) and the wiring does not provide for separate metering, the classification shall be at the discretion of Hydro One based on such considerations as the estimated predominant consumption.
Further servicing details are available in the utility's Conditions of Service.

General Service
This classification refers to all service supplied to premises other than those classified as Residential or Lighting. Some General Service accounts are energy(kWh)-billed, and some are demand(kW)-billed. Further servicing details are available in the utility's Conditions of Service.

Unmetered Scattered Load
This classification refers to certain instances where connections can be provided without metering. These loads are generally small in size and consistent in magnitude of load. Hydro One reserves the right to review all cases and may require that a meter be installed at its sole discretion. Services that can be unmetered include cable TV amplifiers, telephone switching devices, phone booths, bus shelters, rail way crossing signals, traffic signals, and other small fixed loads.
Further servicing details are available in the utility's Conditions of Service (including in the "Unmetered Connections" section).

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
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Hydro-Electric Commission of the Town of Exeter
Effective Date: May 1, 2008

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

Street Lighting

This classification refers to accounts for the distribution and supply of electrical energy for street lighting. Street lights are devices owned by or operated for the road authority and/or the municipal corporation. These street lights in fact belong to the Street Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Sentinel Lighting

This classification refers to accounts for a separate service to a sentinel light. These sentinel lights in fact belong to the Sentinel Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Urban Density Classification

Customers who meet the Urban Density Criteria of being in an area containing 3,000 or more customers with a line density of at least 60 customers per kilometre, will be mapped to an Urban customer classification.

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Hydro-Electric Commission of the Town of Exeter
Effective Date: May 1, 2008

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MONTHLY RATES AND CHARGES

Residential - R1 Exeter

Service Charge	$	15.99
Distribution Volumetric Rate	$ / kWh	0.0225
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0015
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0004)
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0047
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0046
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service Less Than 50 kW (Energy-Billed) - GSe Exeter

Service Charge	$	16.25
Distribution Volumetric Rate	$ / kWh	0.0218
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0006
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0006)
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0035
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0032
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service 50 kW or Greater (Demand-Billed) - GSd Exeter

Service Charge	$	19.85
Distribution Volumetric Rate	$ / kW	8.95
Regulatory Asset Recovery - Rider #2	$ / kW	0.18
Regulatory Asset Recovery - Rider #3	$ / kW	(0.22)
Retail Transmission Rate - Network Service Rate (4)	$ / kW	1.11
Retail Transmission Rate - Line and Transformation Connection Service Rate (4)	$ / kW	1.00
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Hydro-Electric Commission of the Town of Exeter
Effective Date: May 1, 2008

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Unmetered, Scattered Load

Service Charge	$	10.08
Distribution Volumetric Rate	$ / kWh	0.0200
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0006
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0006)
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0035
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0032
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

(3) For energy-only metered customers, the billing determinant is the customer's metered energy consumption adjusted by the total loss factor as approved by the Board for Acquired LDC customers.
(4) For demand billed customers, appropriate loss factors must be applied to the applicable tariffs. Also the billing determinant for the Line and Transformation Connection Services rate is the customer's peak demand in the billing period. The billing determinant for the Network Services rate is: for non-interval-metered customers, the peak demand in the billing period, and for interval-metered customers, the peak demand between 7 AM and 7 PM local time on IESO business days

Customer-Supplied Transformation Allowance

Applicable to customers providing their own transformers

Demand-billed	$ / kW	0.60
Energy-billed	$ / kWh	0.0014

Hydro One Networks Inc.
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Loss Factors

Residential	1.085
General Service Less Than 50 kW (Energy-Billed)	1.092
General Service 50 kW or Greater (Demand-Billed)	1.061
Unmetered Scattered Load	1.092

Transformer Loss Allowance

Applicable to customers requiring a billing adjustment for transformer losses as the result of being metered on the primary side of a transformer. The following uniform values shall be applied to measured demand and energy to calculate transformer losses for voltages up to and including 50 kV (as metered on the primary side):

(a) 1.5% for transformer installations up to an individual bank capacity of 400 kVA,
(b) 1.0% for bank capacities over 400 kVA.

Alternatively, transformer losses may be determined from transformer test data, and measured demand and energy adjusted accordingly

For services which are not demand metered, an assumed demand of 50% of the transformer capacity will be used to calculate the loss allowance. Where several transformers are involved, the bank capacity is assumed to be the arithmetic sum of all transformer capacities

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
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Effective Date: May 1, 2008

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MISCELLANEOUS CHARGES

Specific Service Charges: Standard Amounts

Rate Code	Specific Service Charge - Standard Name	Calculation Method			
		2006 Rate Handbook	Standard Formula	Other Formula	Time and Materials
1	Temporary Service	$500			
2	Dispute Meter Test	$30 plus Measurement Canada fees			
3	Collection of account – no disconnection/load limiter	$30			
4	Collection/Disconnect/load limiter/reconnect (at meter) trip – regular hours	$65			
5	Collection/Disconnect/load limiter/reconnect (at meter) trip – after regular hours	$185			
6	Collection/Disconnect/load limiter/reconnect (at pole) trip – regular hours	$185			
7	Collection/Disconnect/load limiter/reconnect (at pole) trip – after regular hours	$415			
8	Account Set-up Charge	$30			
9	Arrears Certificate	$15			
10	NSF Cheque Charge	$15 + bank charges			
11	Easement Charge for Unregistered Rights	$15			
12	Late Payment Charge	1.5%/month			
13a	Retailer Services – Establishing Service Agreements (refer to Handbook for all charges)	$100/agreement/Retailer +$20/month/Retailer +$0.50/month/customer + other			
13b	Retailer Services – Other (includes Bill Ready for Retailers and Service Transactions Requests) as per the Handbook, Chapter 12	$0.30/month/customer + $0.25/request for request fee + $0.50/request for process fee			
14	Special Meter Reads	$30			
15	Service Layout Fee – Basic		$495		
16	Service Layout Fee – Complex		$690		
17	Crossing Application – Pipeline		$2,445		
18	Crossing Application – Water		$3,045		
19	Crossing Application – Railroad		$2,945		
20	Line Staking – per meter		$3.70		
21	Central Metering – New service < 45 kW		$115		
22	Conversion to Central Metering < 45 kW		$915		
23	Conversion to Central Metering > 45 kW		$800		
24	Tingle Voltage Test – In Excess of 4 Hours (per hour – average 2 additional hours)		$125		
25	Standby Administration Charge per month		$440		
26	Sentinel Lights Rental Rate per month			$7.10	
27	Sentinel Pole Rental Rate per month			$4.15	
28	Joint Use for Cable and Telecom companies per pole			$22.35	
29	Joint Use for LDCs per pole			$28.61	

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APPLICATION

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No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code, Guideline or Order of the Board, and amendments thereto as approved by the Board, or as specified herein
This schedule does not contain any rates and charges relating to the electricity commodity (e.g. the Regulated Price Plan).

EFFECTIVE DATES

DISTRIBUTION RATES - May 1, 2007 for all consumption or deemed consumption services used on or after that date.

MISCELLANEOUS CHARGES - May 1, 2007 for all charges billed to customers on or after that date.
RETAIL TRANSMISSION RATES - May 1, 2007 for all consumption or deemed consumption services used on or after that date.
LOSS FACTOR ADJUSTMENT – May 1, 2007

SERVICE CLASSIFICATIONS

Residential
This classification (note 1) refers to all service supplied to single-family dwelling units for domestic or household purpose. Multi-unit residential establishments such as apartment buildings supplied through one service (bulk metered) will normally be classified as General Service, but, at Hydro One's discretion, up to four residential units may be classified as residential. Where electricity service is provided to combined residential and business (including agricultural usage) and the wiring does not provide for separate metering, the classification shall be at the discretion of Hydro One based on such considerations as the estimated predominant consumption.
Further servicing details are available in the utility's Conditions of Service.

General Service
This classification (note 1) refers to all service supplied to premises other than those classified as Residential or Lighting. Some General Service accounts are energy(kWh)-billed, and some are demand(kW)-billed. Further servicing details are available in the utility's Conditions of Service. Also, see note 2.

Unmetered Scattered Load
This classification refers to certain instances where connections can be provided without metering. These loads are generally small in size and consistent in magnitude of load. Hydro One reserves the right to review all cases and may require that a meter be installed at its sole discretion. Services that can be unmetered include cable TV amplifiers, telephone switching devices, phone booths, bus shelters, rail way crossing signals, traffic signals, and other small fixed loads.
Further servicing details are available in the utility's Conditions of Service (including in the "Unmetered Connections" section).

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
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Effective Date: May 1, 2007

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Street Lighting

This classification refers to accounts for the distribution and supply of electrical energy for street lighting. Street lights are devices owned by or operated for the road authority and/or the municipal corporation. These street lights in fact belong to the Street Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Sentinel Lighting

This classification refers to accounts for a separate service to a sentinel light. These sentinel lights in fact belong to the Sentinel Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Interim Demand-Side Management Time-of-Use

This is potentially applicable to Demand-billed General Service accounts. See Note 2 below.

Note (1): Classification descriptions are paraphrases from the document "Hydro One Networks Inc. - Distribution Customers Conditions of Service - August 2004"

Note (2):

Interim Demand-Side Management Time-of-Use Rates: demand charges will be based on demand during the on-peak periods.

Criteria: Customers' electricity consumption (kW) in the off-peak period is at least twice the electricity consumption (kW) during the on-peak period.

Definition of Time Periods: The on-peak hours will be between 0700 hours to 1900 hours Eastern Standard Time during the winter (standard time) on IESO business days and 0600 hours to 1800 hours Eastern Standard Time during the summer (daylight savings time) on IESO business days. The off-peak period constitutes all of the remaining hours.

Hydro One Networks Inc.
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Effective Date: May 1, 2007

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MONTHLY RATES AND CHARGES

Residential

Service Charge	$	15.10
Distribution Volumetric Rate	$ / kWh	0.0096
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0045
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0015
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0055
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0047
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service - Energy Billed (less than 50 kW)

Service Charge	$	11.36
Distribution Volumetric Rate	$ / kWh	0.0130
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0015
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0006
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0050
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0043
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service - Demand Billed (50 kW or greater)

Service Charge	$	11.36
Distribution Volumetric Rate	$ / kW	4.11
Regulatory Asset Recovery - Rider #1	$ / kW	0.49
Regulatory Asset Recovery - Rider #2	$ / kW	0.18
Retail Transmission Rate - Network Service Rate (4)	$ / kW	1.94
Retail Transmission Rate - Line and Transformation Connection Service Rate (4)	$ / kW	1.61
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Hydro-Electric Commission of the Town of Exeter
Effective Date: May 1, 2007

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

Unmetered, Scattered Load

Service Charge	$	5.21
Distribution Volumetric Rate	$ / kWh	0.0130
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0015
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0006
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0050
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0043
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

(3) For energy-only metered customers, the billing determinant is the customer's metered energy consumption adjusted by the total loss factor as approved by the Board for Acquired LDC customers.

(4) For demand billed customers, appropriate loss factors must be applied to the applicable tariffs. Also the billing determinant for the Line and Transformation Connection Services rate is the customer's peak demand in the billing period. The billing determinant for the Network Services rate is: for non-interval-metered customers, the peak demand in the billing period, and for interval-metered customers, the peak demand between 7 AM and 7 PM local time on IESO business days

Interim Demand-Side Management Time-of-Use

See the "Service Classifications" section of this schedule.

Customer-Supplied Transformation Allowance

Applicable to demand-billed customers providing their own transformers
Primary Voltage under 50 kV (per kW)

Single Phase	$ / kW	0.20
Three Phase	$ / kW	0.60

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Hydro-Electric Commission of the Town of Exeter
Effective Date: May 1, 2007

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

Loss Factors

Supply Facilities Loss Factor	1.0045
Distribution Loss Factors	
Customer less than 5,000 kW	1.0500
Customer greater than or equal to 5,000 kW	1.0100
Total Loss Factors	
Customer less than 5,000 kW	1.0545
Customer greater than or equal to 5,000 kW	1.0145

Transformer Loss Allowance

Applicable to customers requiring a billing adjustment for transformer losses as the result of being metered on the primary side of a transformer. The following uniform values shall be applied to measured demand and energy to calculate transformer losses for voltages up to and including 50 kV (as metered on the primary side):

(a) 1.5% for transformer installations up to an individual bank capacity of 400 kVA,
(b) 1.0% for bank capacities over 400 kVA.

Alternatively, transformer losses may be determined from transformer test data, and measured demand and energy adjusted accordingly

For services which are not demand metered, an assumed demand of 50% of the transformer capacity will be used to calculate the loss allowance. Where several transformers are involved, the bank capacity is assumed to be the arithmetic sum of all transformer capacities

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Hydro-Electric Commission of the Town of Exeter
Effective Date: May 1, 2007

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

MISCELLANEOUS CHARGES

Specific Service Charges: Standard Amounts

Rate Code	Specific Service Charge - Standard Name	Calculation Method			
		2006 Rate Handbook	Standard Formula	Other Formula	Time and Materials
1	Temporary Service	$500			
2	Dispute Meter Test	$30 plus Measurement Canada fees			
3	Collection of account – no disconnection/load limiter	$30			
4	Collection/Disconnect/load limiter/reconnect (at meter) trip – regular hours	$65			
5	Collection/Disconnect/load limiter/reconnect (at meter) trip – after regular hours	$185			
6	Collection/Disconnect/load limiter/reconnect (at pole) trip – regular hours	$185			
7	Collection/Disconnect/load limiter/reconnect (at pole) trip – after regular hours	$415			
8	Account Set-up Charge	$30			
9	Arrears Certificate	$15			
10	NSF Cheque Charge	$15 + bank charges			
11	Easement Charge for Unregistered Rights	$15			
12	Late Payment Charge	1.5%/month			
13a	Retailer Services – Establishing Service Agreements (refer to Handbook for all charges)	$100/agreement/Retailer +$20/month/Retailer +$0.50/month/customer + other			
13b	Retailer Services – Other (includes Bill Ready for Retailers and Service Transactions Requests) as per the Handbook, Chapter 12	$0.30/month/customer + $0.25/request for request fee + $0.50/request for process fee			
14	Special Meter Reads	$30			
15	Billing Suspension and Terminations in Trailer Parks		$130		
16	Service Layout Fee – Basic		$405		
17	Service Layout Fee – Complex		$580		

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
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18	Crossing Application – Pipeline		$2,065		
19	Crossing Application – Water		$2,525		
20	Crossing Application – Railroad		$2,565		
21	Line Staking – per meter		$3.10		
22	Central Metering – New service < 45 kW		$115		
23	Conversion to Central Metering < 45 kW		$795		
24	Conversion to Central Metering > 45 kW		$680		
25	Tingle Voltage Test – In Excess of 4 Hours (per hour – average 2 additional hours)		$105		
26	Standby Administration Charge per month (interim)		$375		
27	Sentinel Lights Rental Rate per month – Mercury Vapor			$7.00	
28	Guaranteed Units from Jan 01/91 to Aug 01/91			$26.50 / month	
29	Guaranteed Units from Jan 01/87 to Dec 31/90			$23.50 / month	
30	Joint Use for Cable and Telecom companies per pole			$22.35	
31	Joint Use for LDCs per pole			$28.61	

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Fenelon Falls Board of Water, Light and Power Commission
Effective Date: May 1, 2008

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

APPLICATION

The application of these rates and charges shall be in accordance with The Licence of The Distributor and any Codes, Guidelines or Orders of The Board, and amendments thereto as approved by The Board, which may be applicable to the administration of this schedule.
No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code, Guideline or Order of the Board, and amendments thereto as approved by the Board, or as specified herein
This schedule does not contain any rates and charges relating to the electricity commodity (e.g. the Regulated Price Plan).

EFFECTIVE DATES

DISTRIBUTION RATES - May 1, 2008 for all consumption or deemed consumption services used on or after that date.

MISCELLANEOUS CHARGES - May 1, 2008 for all charges billed to customers on or after that date.
RETAIL TRANSMISSION RATES - May 1, 2008 for all consumption or deemed consumption services used on or after that date.
LOSS FACTOR ADJUSTMENT – for all consumption or deemed consumption services billed following May 1, 2008 or later

SERVICE CLASSIFICATIONS

Residential
This classification refers to all service supplied to single-family dwelling units for domestic or household purpose. Multi-unit residential establishments such as apartment buildings supplied through one service (bulk metered) will normally be classified as General Service, but, at Hydro One's discretion, up to four residential units may be classified as residential. Where electricity service is provided to combined residential and business (including agricultural usage) and the wiring does not provide for separate metering, the classification shall be at the discretion of Hydro One based on such considerations as the estimated predominant consumption.
Further servicing details are available in the utility's Conditions of Service.

General Service
This classification refers to all service supplied to premises other than those classified as Residential or Lighting. Some General Service accounts are energy(kWh)-billed, and some are demand(kW)-billed. Further servicing details are available in the utility's Conditions of Service.

Unmetered Scattered Load
This classification refers to certain instances where connections can be provided without metering. These loads are generally small in size and consistent in magnitude of load. Hydro One reserves the right to review all cases and may require that a meter be installed at its sole discretion. Services that can be unmetered include cable TV amplifiers, telephone switching devices, phone booths, bus shelters, rail way crossing signals, traffic signals, and other small fixed loads.
Further servicing details are available in the utility's Conditions of Service (including in the "Unmetered Connections" section).

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Fenelon Falls Board of Water, Light and Power Commission
Effective Date: May 1, 2008

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

Street Lighting

This classification refers to accounts for the distribution and supply of electrical energy for street lighting. Street lights are devices owned by or operated for the road authority and/or the municipal corporation. These street lights in fact belong to the Street Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Sentinel Lighting

This classification refers to accounts for a separate service to a sentinel light. These sentinel lights in fact belong to the Sentinel Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Urban Density Classification

Customers who meet the Urban Density Criteria of being in an area containing 3,000 or more customers with a line density of at least 60 customers per kilometre, will be mapped to an Urban customer classification.

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
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Effective Date: May 1, 2008

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MONTHLY RATES AND CHARGES

Residential - R1 Fenelon Falls

Service Charge	$	9.24
Distribution Volumetric Rate	$ / kWh	0.0170
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0008
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0004)
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0047
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0046
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service Less Than 50 kW (Energy-Billed) - GSe Fenelon Falls

Service Charge	$	22.14
Distribution Volumetric Rate	$ / kWh	0.0198
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0008
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0006)
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0035
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0032
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service 50 kW or Greater (Demand-Billed) - GSd Fenelon Falls

Service Charge	$	25.74
Distribution Volumetric Rate	$ / kW	7.75
Regulatory Asset Recovery - Rider #2	$ / kW	0.24
Regulatory Asset Recovery - Rider #3	$ / kW	(0.22)
Retail Transmission Rate - Network Service Rate (4)	$ / kW	1.11
Retail Transmission Rate - Line and Transformation Connection Service Rate (4)	$ / kW	1.00
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
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Effective Date: May 1, 2008

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

Unmetered, Scattered Load

Service Charge	$	13.02
Distribution Volumetric Rate	$ / kWh	0.0200
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0008
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0006)
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0035
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0032
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

(3) For energy-only metered customers, the billing determinant is the customer’s metered energy consumption adjusted by the total loss factor as approved by the Board for Acquired LDC customers.
(4) For demand billed customers, appropriate loss factors must be applied to the applicable tariffs. Also the billing determinant for the Line and Transformation Connection Services rate is the customer’s peak demand in the billing period. The billing determinant for the Network Services rate is: for non-interval-metered customers, the peak demand in the billing period, and for interval-metered customers, the peak demand between 7 AM and 7 PM local time on IESO business days

Customer-Supplied Transformation Allowance

Applicable to customers providing their own transformers		
Demand-billed	$ / kW	0.60
Energy-billed	$ / kWh	0.0014

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
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Loss Factors

Residential	1.085
General Service Less Than 50 kW (Energy-Billed)	1.092
General Service 50 kW or Greater (Demand-Billed)	1.061
Unmetered Scattered Load	1.092

Transformer Loss Allowance

Applicable to customers requiring a billing adjustment for transformer losses as the result of being metered on the primary side of a transformer. The following uniform values shall be applied to measured demand and energy to calculate transformer losses for voltages up to and including 50 kV (as metered on the primary side):

(a) 1.5% for transformer installations up to an individual bank capacity of 400 kVA,
(b) 1.0% for bank capacities over 400 kVA.

Alternatively, transformer losses may be determined from transformer test data, and measured demand and energy adjusted accordingly

For services which are not demand metered, an assumed demand of 50% of the transformer capacity will be used to calculate the loss allowance. Where several transformers are involved, the bank capacity is assumed to be the arithmetic sum of all transformer capacities

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
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Fenelon Falls Board of Water, Light and Power Commission
Effective Date: May 1, 2008

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

MISCELLANEOUS CHARGES

Specific Service Charges: Standard Amounts

Rate Code	Specific Service Charge - Standard Name	Calculation Method			
		2006 Rate Handbook	Standard Formula	Other Formula	Time and Materials
1	Temporary Service	$500			
2	Dispute Meter Test	$30 plus Measurement Canada fees			
3	Collection of account – no disconnection/load limiter	$30			
4	Collection/Disconnect/load limiter/reconnect (at meter) trip – regular hours	$65			
5	Collection/Disconnect/load limiter/reconnect (at meter) trip – after regular hours	$185			
6	Collection/Disconnect/load limiter/reconnect (at pole) trip – regular hours	$185			
7	Collection/Disconnect/load limiter/reconnect (at pole) trip – after regular hours	$415			
8	Account Set-up Charge	$30			
9	Arrears Certificate	$15			
10	NSF Cheque Charge	$15 + bank charges			
11	Easement Charge for Unregistered Rights	$15			
12	Late Payment Charge	1.5%/month			
13a	Retailer Services – Establishing Service Agreements (refer to Handbook for all charges)	$100/agreement/Retailer +$20/month/Retailer +$0.50/month/customer + other			
13b	Retailer Services – Other (includes Bill Ready for Retailers and Service Transactions Requests) as per the Handbook, Chapter 12	$0.30/month/customer + $0.25/request for request fee + $0.50/request for process fee			
14	Special Meter Reads	$30			
15	Service Layout Fee – Basic		$495		
16	Service Layout Fee – Complex		$690		
17	Crossing Application – Pipeline		$2,445		
18	Crossing Application – Water		$3,045		
19	Crossing Application – Railroad		$2,945		
20	Line Staking – per meter		$3.70		
21	Central Metering – New service < 45 kW		$115		
22	Conversion to Central Metering < 45 kW		$915		
23	Conversion to Central Metering > 45 kW		$800		
24	Tingle Voltage Test – In Excess of 4 Hours (per hour – average 2 additional hours)		$125		
25	Standby Administration Charge per month		$440		
26	Sentinel Lights Rental Rate per month			$7.10	
27	Sentinel Pole Rental Rate per month			$4.15	
28	Joint Use for Cable and Telecom companies per pole			$22.35	
29	Joint Use for LDCs per pole			$28.61	

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
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Effective Date: May 1, 2007

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

APPLICATION

The application of these rates and charges shall be in accordance with The Licence of The Distributor and any Codes, Guidelines or Orders of The Board, and amendments thereto as approved by The Board, which may be applicable to the administration of this schedule.
No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code, Guideline or Order of the Board, and amendments thereto as approved by the Board, or as specified herein
This schedule does not contain any rates and charges relating to the electricity commodity (e.g. the Regulated Price Plan).

EFFECTIVE DATES

DISTRIBUTION RATES - May 1, 2007 for all consumption or deemed consumption services used on or after that date.

MISCELLANEOUS CHARGES - May 1, 2007 for all charges billed to customers on or after that date.
RETAIL TRANSMISSION RATES - May 1, 2007 for all consumption or deemed consumption services used on or after that date.
LOSS FACTOR ADJUSTMENT – May 1, 2007

SERVICE CLASSIFICATIONS

Residential
This classification (note 1) refers to all service supplied to single-family dwelling units for domestic or household purpose. Multi-unit residential establishments such as apartment buildings supplied through one service (bulk metered) will normally be classified as General Service, but, at Hydro One's discretion, up to four residential units may be classified as residential. Where electricity service is provided to combined residential and business (including agricultural usage) and the wiring does not provide for separate metering, the classification shall be at the discretion of Hydro One based on such considerations as the estimated predominant consumption.
Further servicing details are available in the utility's Conditions of Service.

General Service
This classification (note 1) refers to all service supplied to premises other than those classified as Residential or Lighting. Some General Service accounts are energy(kWh)-billed, and some are demand(kW)-billed. Further servicing details are available in the utility's Conditions of Service. Also, see note 2.

Unmetered Scattered Load
This classification refers to certain instances where connections can be provided without metering. These loads are generally small in size and consistent in magnitude of load. Hydro One reserves the right to review all cases and may require that a meter be installed at its sole discretion. Services that can be unmetered include cable TV amplifiers, telephone switching devices, phone booths, bus shelters, rail way crossing signals, traffic signals, and other small fixed loads.
Further servicing details are available in the utility's Conditions of Service (including in the "Unmetered Connections" section).

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
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Street Lighting

This classification refers to accounts for the distribution and supply of electrical energy for street lighting. Street lights are devices owned by or operated for the road authority and/or the municipal corporation. These street lights in fact belong to the Street Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility’s Conditions of Service.

Sentinel Lighting

This classification refers to accounts for a separate service to a sentinel light. These sentinel lights in fact belong to the Sentinel Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility’s Conditions of Service.

Interim Demand-Side Management Time-of-Use

This is potentially applicable to Demand-billed General Service accounts. See Note 2 below.

Note (1): Classification descriptions are paraphrases from the document "Hydro One Networks Inc. - Distribution Customers Conditions of Service - August 2004"

Note (2):

Interim Demand-Side Management Time-of-Use Rates: demand charges will be based on demand during the on-peak periods.

Criteria: Customers' electricity consumption (kW) in the off-peak period is at least twice the electricity consumption (kW) during the on-peak period.

Definition of Time Periods: The on-peak hours will be between 0700 hours to 1900 hours Eastern Standard Time during the winter (standard time) on IESO business days and 0600 hours to 1800 hours Eastern Standard Time during the summer (daylight savings time) on IESO business days. The off-peak period constitutes all of the remaining hours.

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
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MONTHLY RATES AND CHARGES

Residential

Service Charge	$	6.09
Distribution Volumetric Rate	$ / kWh	0.0096
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0025
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0008
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0055
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0047
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service - Energy Billed (less than 50 kW)

Service Charge	$	19.81
Distribution Volumetric Rate	$ / kWh	0.0095
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0015
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0008
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0050
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0043
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service - Demand Billed (50 kW or greater)

Service Charge	$	19.81
Distribution Volumetric Rate	$ / kW	3.02
Regulatory Asset Recovery - Rider #1	$ / kW	0.47
Regulatory Asset Recovery - Rider #2	$ / kW	0.24
Retail Transmission Rate - Network Service Rate (4)	$ / kW	1.94
Retail Transmission Rate - Line and Transformation Connection Service Rate (4)	$ / kW	1.61
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
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Effective Date: May 1, 2007

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Unmetered, Scattered Load

Service Charge	$	9.43
Distribution Volumetric Rate	$ / kWh	0.0095
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0015
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0008
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0050
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0043
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

(3) For energy-only metered customers, the billing determinant is the customer’s metered energy consumption adjusted by the total loss factor as approved by the Board for Acquired LDC customers.
(4) For demand billed customers, appropriate loss factors must be applied to the applicable tariffs. Also the billing determinant for the Line and Transformation Connection Services rate is the customer’s peak demand in the billing period. The billing determinant for the Network Services rate is: for non-interval-metered customers, the peak demand in the billing period, and for interval-metered customers, the peak demand between 7 AM and 7 PM local time on IESO business days

Interim Demand-Side Management Time-of-Use

See the "Service Classifications" section of this schedule.

Customer-Supplied Transformation Allowance

Applicable to demand-billed customers providing their own transformers
Primary Voltage under 50 kV (per kW)

Single Phase	$ / kW	0.20
Three Phase	$ / kW	0.60

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
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Loss Factors

Supply Facilities Loss Factor	1.0045
Distribution Loss Factors	
Customer less than 5,000 kW	1.0500
Customer greater than or equal to 5,000 kW	1.0100
Total Loss Factors	
Customer less than 5,000 kW	1.0545
Customer greater than or equal to 5,000 kW	1.0145

Transformer Loss Allowance

Applicable to customers requiring a billing adjustment for transformer losses as the result of being metered on the primary side of a transformer. The following uniform values shall be applied to measured demand and energy to calculate transformer losses for voltages up to and including 50 kV (as metered on the primary side):

(a) 1.5% for transformer installations up to an individual bank capacity of 400 kVA,
(b) 1.0% for bank capacities over 400 kVA.

Alternatively, transformer losses may be determined from transformer test data, and measured demand and energy adjusted accordingly

For services which are not demand metered, an assumed demand of 50% of the transformer capacity will be used to calculate the loss allowance. Where several transformers are involved, the bank capacity is assumed to be the arithmetic sum of all transformer capacities

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
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Fenelon Falls Board of Water, Light and Power Commission
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MISCELLANEOUS CHARGES

Specific Service Charges: Standard Amounts

Rate Code	Specific Service Charge - Standard Name	Calculation Method			
		2006 Rate Handbook	Standard Formula	Other Formula	Time and Materials
1	Temporary Service	$500			
2	Dispute Meter Test	$30 plus Measurement Canada fees			
3	Collection of account – no disconnection/load limiter	$30			
4	Collection/Disconnect/load limiter/reconnect (at meter) trip – regular hours	$65			
5	Collection/Disconnect/load limiter/reconnect (at meter) trip – after regular hours	$185			
6	Collection/Disconnect/load limiter/reconnect (at pole) trip – regular hours	$185			
7	Collection/Disconnect/load limiter/reconnect (at pole) trip – after regular hours	$415			
8	Account Set-up Charge	$30			
9	Arrears Certificate	$15			
10	NSF Cheque Charge	$15 + bank charges			
11	Easement Charge for Unregistered Rights	$15			
12	Late Payment Charge	1.5%/month			
13a	Retailer Services – Establishing Service Agreements (refer to Handbook for all charges)	$100/agreement/Retailer +$20/month/Retailer +$0.50/month/customer + other			
13b	Retailer Services – Other (includes Bill Ready for Retailers and Service Transactions Requests) as per the Handbook, Chapter 12	$0.30/month/customer + $0.25/request for request fee + $0.50/request for process fee			
14	Special Meter Reads	$30			
15	Billing Suspension and Terminations in Trailer Parks		$130		
16	Service Layout Fee – Basic		$405		
17	Service Layout Fee – Complex		$580		

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Fenelon Falls Board of Water, Light and Power Commission
Effective Date: May 1, 2007

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

18	Crossing Application – Pipeline		$2,065		
19	Crossing Application – Water		$2,525		
20	Crossing Application – Railroad		$2,565		
21	Line Staking – per meter		$3.10		
22	Central Metering – New service < 45 kW		$115		
23	Conversion to Central Metering < 45 kW		$795		
24	Conversion to Central Metering > 45 kW		$680		
25	Tingle Voltage Test – In Excess of 4 Hours (per hour – average 2 additional hours)		$105		
26	Standby Administration Charge per month (interim)		$375		
27	Sentinel Lights Rental Rate per month – Mercury Vapor			$7.00	
28	Guaranteed Units from Jan 01/91 to Aug 01/91			$26.50 / month	
29	Guaranteed Units from Jan 01/87 to Dec 31/90			$23.50 / month	
30	Joint Use for Cable and Telecom companies per pole			$22.35	
31	Joint Use for LDCs per pole			$28.61	

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Town of Forest Public Utilities Commission
Effective Date: May 1, 2008

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

APPLICATION

The application of these rates and charges shall be in accordance with The Licence of The Distributor and any Codes, Guidelines or Orders of The Board, and amendments thereto as approved by The Board, which may be applicable to the administration of this schedule.
No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code, Guideline or Order of the Board, and amendments thereto as approved by the Board, or as specified herein
This schedule does not contain any rates and charges relating to the electricity commodity (e.g. the Regulated Price Plan).

EFFECTIVE DATES

DISTRIBUTION RATES - May 1, 2008 for all consumption or deemed consumption services used on or after that date.

MISCELLANEOUS CHARGES - May 1, 2008 for all charges billed to customers on or after that date.
RETAIL TRANSMISSION RATES - May 1, 2008 for all consumption or deemed consumption services used on or after that date.
LOSS FACTOR ADJUSTMENT – for all consumption or deemed consumption services billed following May 1, 2008 or later

SERVICE CLASSIFICATIONS

Residential
This classification refers to all service supplied to single-family dwelling units for domestic or household purpose. Multi-unit residential establishments such as apartment buildings supplied through one service (bulk metered) will normally be classified as General Service, but, at Hydro One's discretion, up to four residential units may be classified as residential. Where electricity service is provided to combined residential and business (including agricultural usage) and the wiring does not provide for separate metering, the classification shall be at the discretion of Hydro One based on such considerations as the estimated predominant consumption.
Further servicing details are available in the utility's Conditions of Service.

General Service
This classification refers to all service supplied to premises other than those classified as Residential or Lighting. Some General Service accounts are energy(kWh)-billed, and some are demand(kW)-billed. Further servicing details are available in the utility's Conditions of Service.

Unmetered Scattered Load
This classification refers to certain instances where connections can be provided without metering. These loads are generally small in size and consistent in magnitude of load. Hydro One reserves the right to review all cases and may require that a meter be installed at its sole discretion. Services that can be unmetered include cable TV amplifiers, telephone switching devices, phone booths, bus shelters, rail way crossing signals, traffic signals, and other small fixed loads.
Further servicing details are available in the utility's Conditions of Service (including in the "Unmetered Connections" section).

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Town of Forest Public Utilities Commission
Effective Date: May 1, 2008

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

Street Lighting

This classification refers to accounts for the distribution and supply of electrical energy for street lighting. Street lights are devices owned by or operated for the road authority and/or the municipal corporation. These street lights in fact belong to the Street Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Sentinel Lighting

This classification refers to accounts for a separate service to a sentinel light. These sentinel lights in fact belong to the Sentinel Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Urban Density Classification

Customers who meet the Urban Density Criteria of being in an area containing 3,000 or more customers with a line density of at least 60 customers per kilometre, will be mapped to an Urban customer classification.

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Town of Forest Public Utilities Commission
Effective Date: May 1, 2008

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

MONTHLY RATES AND CHARGES

Residential - R1 Forest

Service Charge	$	15.95
Distribution Volumetric Rate	$ / kWh	0.0220
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0015
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0004)
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0047
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0046
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service Less Than 50 kW (Energy-Billed) - GSe Forest

Service Charge	$	25.86
Distribution Volumetric Rate	$ / kWh	0.0232
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0006
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0006)
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0035
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0032
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service 50 kW or Greater (Demand-Billed) - GSd Forest

Service Charge	$	29.46
Distribution Volumetric Rate	$ / kW	8.50
Regulatory Asset Recovery - Rider #2	$ / kW	0.20
Regulatory Asset Recovery - Rider #3	$ / kW	(0.22)
Retail Transmission Rate - Network Service Rate (4)	$ / kW	1.11
Retail Transmission Rate - Line and Transformation Connection Service Rate (4)	$ / kW	1.00
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Town of Forest Public Utilities Commission
Effective Date: May 1, 2008

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

Unmetered, Scattered Load

Service Charge	$	14.38
Distribution Volumetric Rate	$ / kWh	0.0200
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0006
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0006)
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0035
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0032
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

(3) For energy-only metered customers, the billing determinant is the customer’s metered energy consumption adjusted by the total loss factor as approved by the Board for Acquired LDC customers.
(4) For demand billed customers, appropriate loss factors must be applied to the applicable tariffs. Also the billing determinant for the Line and Transformation Connection Services rate is the customer’s peak demand in the billing period. The billing determinant for the Network Services rate is: for non-interval-metered customers, the peak demand in the billing period, and for interval-metered customers, the peak demand between 7 AM and 7 PM local time on IESO business days

Customer-Supplied Transformation Allowance

Applicable to customers providing their own transformers

Demand-billed	$ / kW	0.60
Energy-billed	$ / kWh	0.0014

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Town of Forest Public Utilities Commission
Effective Date: May 1, 2008

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

Loss Factors

Residential	1.085
General Service Less Than 50 kW (Energy-Billed)	1.092
General Service 50 kW or Greater (Demand-Billed)	1.061
Unmetered Scattered Load	1.092

Transformer Loss Allowance

Applicable to customers requiring a billing adjustment for transformer losses as the result of being metered on the primary side of a transformer. The following uniform values shall be applied to measured demand and energy to calculate transformer losses for voltages up to and including 50 kV (as metered on the primary side):

(a) 1.5% for transformer installations up to an individual bank capacity of 400 kVA,
(b) 1.0% for bank capacities over 400 kVA.

Alternatively, transformer losses may be determined from transformer test data, and measured demand and energy adjusted accordingly

For services which are not demand metered, an assumed demand of 50% of the transformer capacity will be used to calculate the loss allowance. Where several transformers are involved, the bank capacity is assumed to be the arithmetic sum of all transformer capacities

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Town of Forest Public Utilities Commission
Effective Date: May 1, 2008

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

MISCELLANEOUS CHARGES

Specific Service Charges: Standard Amounts

Rate Code	Specific Service Charge - Standard Name	Calculation Method			
		2006 Rate Handbook	Standard Formula	Other Formula	Time and Materials
1	Temporary Service	$500			
2	Dispute Meter Test	$30 plus Measurement Canada fees			
3	Collection of account – no disconnection/load limiter	$30			
4	Collection/Disconnect/load limiter/reconnect (at meter) trip – regular hours	$65			
5	Collection/Disconnect/load limiter/reconnect (at meter) trip – after regular hours	$185			
6	Collection/Disconnect/load limiter/reconnect (at pole) trip – regular hours	$185			
7	Collection/Disconnect/load limiter/reconnect (at pole) trip – after regular hours	$415			
8	Account Set-up Charge	$30			
9	Arrears Certificate	$15			
10	NSF Cheque Charge	$15 + bank charges			
11	Easement Charge for Unregistered Rights	$15			
12	Late Payment Charge	1.5%/month			
13a	Retailer Services – Establishing Service Agreements (refer to Handbook for all charges)	$100/agreement/Retailer +$20/month/Retailer +$0.50/month/customer + other			
13b	Retailer Services – Other (includes Bill Ready for Retailers and Service Transactions Requests) as per the Handbook, Chapter 12	$0.30/month/customer + $0.25/request for request fee + $0.50/request for process fee			
14	Special Meter Reads	$30			
15	Service Layout Fee – Basic		$495		
16	Service Layout Fee – Complex		$690		
17	Crossing Application – Pipeline		$2,445		
18	Crossing Application – Water		$3,045		
19	Crossing Application – Railroad		$2,945		
20	Line Staking – per meter		$3.70		
21	Central Metering – New service < 45 kW		$115		
22	Conversion to Central Metering < 45 kW		$915		
23	Conversion to Central Metering > 45 kW		$800		
24	Tingle Voltage Test – In Excess of 4 Hours (per hour – average 2 additional hours)		$125		
25	Standby Administration Charge per month		$440		
26	Sentinel Lights Rental Rate per month			$7.10	
27	Sentinel Pole Rental Rate per month			$4.15	
28	Joint Use for Cable and Telecom companies per pole			$22.35	
29	Joint Use for LDCs per pole			$28.61	

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Town of Forest Public Utilities Commission
Effective Date: May 1, 2007

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

APPLICATION

The application of these rates and charges shall be in accordance with The Licence of The Distributor and any Codes, Guidelines or Orders of The Board, and amendments thereto as approved by The Board, which may be applicable to the administration of this schedule.
No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code, Guideline or Order of the Board, and amendments thereto as approved by the Board, or as specified herein
This schedule does not contain any rates and charges relating to the electricity commodity (e.g. the Regulated Price Plan).

EFFECTIVE DATES

DISTRIBUTION RATES - May 1, 2007 for all consumption or deemed consumption services used on or after that date.

MISCELLANEOUS CHARGES - May 1, 2007 for all charges billed to customers on or after that date.
RETAIL TRANSMISSION RATES - May 1, 2007 for all consumption or deemed consumption services used on or after that date.
LOSS FACTOR ADJUSTMENT – May 1, 2007

SERVICE CLASSIFICATIONS

Residential
This classification (note 1) refers to all service supplied to single-family dwelling units for domestic or household purpose. Multi-unit residential establishments such as apartment buildings supplied through one service (bulk metered) will normally be classified as General Service, but, at Hydro One's discretion, up to four residential units may be classified as residential. Where electricity service is provided to combined residential and business (including agricultural usage) and the wiring does not provide for separate metering, the classification shall be at the discretion of Hydro One based on such considerations as the estimated predominant consumption.
Further servicing details are available in the utility's Conditions of Service.

General Service
This classification (note 1) refers to all service supplied to premises other than those classified as Residential or Lighting. Some General Service accounts are energy(kWh)-billed, and some are demand(kW)-billed. Further servicing details are available in the utility's Conditions of Service. Also, see note 2.

Unmetered Scattered Load
This classification refers to certain instances where connections can be provided without metering. These loads are generally small in size and consistent in magnitude of load. Hydro One reserves the right to review all cases and may require that a meter be installed at its sole discretion. Services that can be unmetered include cable TV amplifiers, telephone switching devices, phone booths, bus shelters, rail way crossing signals, traffic signals, and other small fixed loads.
Further servicing details are available in the utility's Conditions of Service (including in the "Unmetered Connections" section).

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Town of Forest Public Utilities Commission
Effective Date: May 1, 2007

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

Street Lighting

This classification refers to accounts for the distribution and supply of electrical energy for street lighting. Street lights are devices owned by or operated for the road authority and/or the municipal corporation. These street lights in fact belong to the Street Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Sentinel Lighting

This classification refers to accounts for a separate service to a sentinel light. These sentinel lights in fact belong to the Sentinel Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Interim Demand-Side Management Time-of-Use

This is potentially applicable to Demand-billed General Service accounts. See Note 2 below.

Note (1): Classification descriptions are paraphrases from the document "Hydro One Networks Inc. - Distribution Customers Conditions of Service - August 2004"

Note (2):

Interim Demand-Side Management Time-of-Use Rates: demand charges will be based on demand during the on-peak periods.

Criteria: Customers' electricity consumption (kW) in the off-peak period is at least twice the electricity consumption (kW) during the on-peak period.

Definition of Time Periods: The on-peak hours will be between 0700 hours to 1900 hours Eastern Standard Time during the winter (standard time) on IESO business days and 0600 hours to 1800 hours Eastern Standard Time during the summer (daylight savings time) on IESO business days. The off-peak period constitutes all of the remaining hours.

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Town of Forest Public Utilities Commission
Effective Date: May 1, 2007

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

MONTHLY RATES AND CHARGES

Residential

Service Charge	$	15.26
Distribution Volumetric Rate	$ / kWh	0.0095
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0041
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0015
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0055
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0047
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service - Energy Billed (less than 50 kW)

Service Charge	$	24.91
Distribution Volumetric Rate	$ / kWh	0.0118
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0016
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0006
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0050
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0043
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service - Demand Billed (50 kW or greater)

Service Charge	$	24.91
Distribution Volumetric Rate	$ / kW	3.74
Regulatory Asset Recovery - Rider #1	$ / kW	0.50
Regulatory Asset Recovery - Rider #2	$ / kW	0.20
Retail Transmission Rate - Network Service Rate (4)	$ / kW	1.94
Retail Transmission Rate - Line and Transformation Connection Service Rate (4)	$ / kW	1.61
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Town of Forest Public Utilities Commission
Effective Date: May 1, 2007

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

Unmetered, Scattered Load

Service Charge	$	11.98
Distribution Volumetric Rate	$ / kWh	0.0118
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0016
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0006
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0050
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0043
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

(3) For energy-only metered customers, the billing determinant is the customer’s metered energy consumption adjusted by the total loss factor as approved by the Board for Acquired LDC customers.
(4) For demand billed customers, appropriate loss factors must be applied to the applicable tariffs. Also the billing determinant for the Line and Transformation Connection Services rate is the customer’s peak demand in the billing period. The billing determinant for the Network Services rate is: for non-interval-metered customers, the peak demand in the billing period, and for interval-metered customers, the peak demand between 7 AM and 7 PM local time on IESO business days

Interim Demand-Side Management Time-of-Use

See the "Service Classifications" section of this schedule.

Customer-Supplied Transformation Allowance

Applicable to demand-billed customers providing their own transformers
Primary Voltage under 50 kV (per kW)

Single Phase	$ / kW	0.20
Three Phase	$ / kW	0.60

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Town of Forest Public Utilities Commission
Effective Date: May 1, 2007

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

Loss Factors

Supply Facilities Loss Factor	1.0045
Distribution Loss Factors	
Customer less than 5,000 kW	1.0500
Customer greater than or equal to 5,000 kW	1.0100
Total Loss Factors	
Customer less than 5,000 kW	1.0545
Customer greater than or equal to 5,000 kW	1.0145

Transformer Loss Allowance

Applicable to customers requiring a billing adjustment for transformer losses as the result of being metered on the primary side of a transformer. The following uniform values shall be applied to measured demand and energy to calculate transformer losses for voltages up to and including 50 kV (as metered on the primary side):

(a) 1.5% for transformer installations up to an individual bank capacity of 400 kVA,
(b) 1.0% for bank capacities over 400 kVA.

Alternatively, transformer losses may be determined from transformer test data, and measured demand and energy adjusted accordingly

For services which are not demand metered, an assumed demand of 50% of the transformer capacity will be used to calculate the loss allowance. Where several transformers are involved, the bank capacity is assumed to be the arithmetic sum of all transformer capacities

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Town of Forest Public Utilities Commission
Effective Date: May 1, 2007

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

MISCELLANEOUS CHARGES

Specific Service Charges: Standard Amounts

Rate Code	Specific Service Charge - Standard Name	Calculation Method			
		2006 Rate Handbook	Standard Formula	Other Formula	Time and Materials
1	Temporary Service	$500			
2	Dispute Meter Test	$30 plus Measurement Canada fees			
3	Collection of account – no disconnection/load limiter	$30			
4	Collection/Disconnect/load limiter/reconnect (at meter) trip – regular hours	$65			
5	Collection/Disconnect/load limiter/reconnect (at meter) trip – after regular hours	$185			
6	Collection/Disconnect/load limiter/reconnect (at pole) trip – regular hours	$185			
7	Collection/Disconnect/load limiter/reconnect (at pole) trip – after regular hours	$415			
8	Account Set-up Charge	$30			
9	Arrears Certificate	$15			
10	NSF Cheque Charge	$15 + bank charges			
11	Easement Charge for Unregistered Rights	$15			
12	Late Payment Charge	1.5%/month			
13a	Retailer Services – Establishing Service Agreements (refer to Handbook for all charges)	$100/agreement/Retailer +$20/month/Retailer +$0.50/month/customer + other			
13b	Retailer Services – Other (includes Bill Ready for Retailers and Service Transactions Requests) as per the Handbook, Chapter 12	$0.30/month/customer + $0.25/request for request fee + $0.50/request for process fee			
14	Special Meter Reads	$30			
15	Billing Suspension and Terminations in Trailer Parks		$130		
16	Service Layout Fee – Basic		$405		
17	Service Layout Fee – Complex		$580		

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Town of Forest Public Utilities Commission
Effective Date: May 1, 2007

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

18	Crossing Application – Pipeline		$2,065		
19	Crossing Application – Water		$2,525		
20	Crossing Application – Railroad		$2,565		
21	Line Staking – per meter		$3.10		
22	Central Metering – New service < 45 kW		$115		
23	Conversion to Central Metering < 45 kW		$795		
24	Conversion to Central Metering > 45 kW		$680		
25	Tingle Voltage Test – In Excess of 4 Hours (per hour – average 2 additional hours)		$105		
26	Standby Administration Charge per month (interim)		$375		
27	Sentinel Lights Rental Rate per month – Mercury Vapor			$7.00	
28	Guaranteed Units from Jan 01/91 to Aug 01/91			$26.50 / month	
29	Guaranteed Units from Jan 01/87 to Dec 31/90			$23.50 / month	
30	Joint Use for Cable and Telecom companies per pole			$22.35	
31	Joint Use for LDCs per pole			$28.61	

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Georgian Bay Energy Inc.
Effective Date: May 1, 2008

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

APPLICATION

The application of these rates and charges shall be in accordance with The Licence of The Distributor and any Codes, Guidelines or Orders of The Board, and amendments thereto as approved by The Board, which may be applicable to the administration of this schedule.
No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code, Guideline or Order of the Board, and amendments thereto as approved by the Board, or as specified herein
This schedule does not contain any rates and charges relating to the electricity commodity (e.g. the Regulated Price Plan).

EFFECTIVE DATES

DISTRIBUTION RATES - May 1, 2008 for all consumption or deemed consumption services used on or after that date.

MISCELLANEOUS CHARGES - May 1, 2008 for all charges billed to customers on or after that date.
RETAIL TRANSMISSION RATES - May 1, 2008 for all consumption or deemed consumption services used on or after that date.
LOSS FACTOR ADJUSTMENT – for all consumption or deemed consumption services billed following May 1, 2008 or later

SERVICE CLASSIFICATIONS

Residential
This classification refers to all service supplied to single-family dwelling units for domestic or household purpose. Multi-unit residential establishments such as apartment buildings supplied through one service (bulk metered) will normally be classified as General Service, but, at Hydro One's discretion, up to four residential units may be classified as residential. Where electricity service is provided to combined residential and business (including agricultural usage) and the wiring does not provide for separate metering, the classification shall be at the discretion of Hydro One based on such considerations as the estimated predominant consumption.
Further servicing details are available in the utility's Conditions of Service.

General Service
This classification refers to all service supplied to premises other than those classified as Residential or Lighting. Some General Service accounts are energy(kWh)-billed, and some are demand(kW)-billed. Further servicing details are available in the utility's Conditions of Service.

Unmetered Scattered Load
This classification refers to certain instances where connections can be provided without metering. These loads are generally small in size and consistent in magnitude of load. Hydro One reserves the right to review all cases and may require that a meter be installed at its sole discretion. Services that can be unmetered include cable TV amplifiers, telephone switching devices, phone booths, bus shelters, rail way crossing signals, traffic signals, and other small fixed loads.
Further servicing details are available in the utility's Conditions of Service (including in the "Unmetered Connections" section).

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Georgian Bay Energy Inc.
Effective Date: May 1, 2008

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

Large Use - see Note 1

Street Lighting

This classification refers to accounts for the distribution and supply of electrical energy for street lighting. Street lights are devices owned by or operated for the road authority and/or the municipal corporation. These street lights in fact belong to the Street Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Sentinel Lighting

This classification refers to accounts for a separate service to a sentinel light. These sentinel lights in fact belong to the Sentinel Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Urban Density Classification

Customers who meet the Urban Density Criteria of being in an area containing 3,000 or more customers with a line density of at least 60 customers per kilometre, will be mapped to an Urban customer classification.

Note (1) The former Large Use class is now part of the ST class, which is separate from the classes for customers of acquired distribution companies.
This former class refered to individual Customers whose monthly measured maximum demand (kW) averaged over the most recent 12 consecutive months is equal to or greater than 5,000 kW.

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Georgian Bay Energy Inc.
Effective Date: May 1, 2008

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

MONTHLY RATES AND CHARGES

Residential - UR/R1 GBE

Service Charge	$	10.16
Distribution Volumetric Rate	$ / kWh	0.0235
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0013
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0002)
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0047
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0045
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service Less Than 50 kW (Energy-Billed) - UGe/GSe GBE

Service Charge	$	10.39
Distribution Volumetric Rate	$ / kWh	0.0200
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0006
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0006)
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0036
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0033
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service 50 kW or Greater (Demand-Billed) - UGd/GSd GBE

Service Charge	$	14.61
Distribution Volumetric Rate	$ / kW	7.33
Regulatory Asset Recovery - Rider #2	$ / kW	0.19
Regulatory Asset Recovery - Rider #3	$ / kW	(0.27)
Retail Transmission Rate - Network Service Rate (4)	$ / kW	1.41
Retail Transmission Rate - Line and Transformation Connection Service Rate (4)	$ / kW	1.27
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
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Georgian Bay Energy Inc.
Effective Date: May 1, 2008

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

Unmetered, Scattered Load

Service Charge	$	9.15
Distribution Volumetric Rate	$ / kWh	0.0200
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0006
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0006)
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0035
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0032
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

(3) For energy-only metered customers, the billing determinant is the customer’s metered energy consumption adjusted by the total loss factor as approved by the Board for Acquired LDC customers.
(4) For demand billed customers, appropriate loss factors must be applied to the applicable tariffs. Also the billing determinant for the Line and Transformation Connection Services rate is the customer’s peak demand in the billing period. The billing determinant for the Network Services rate is: for non-interval-metered customers, the peak demand in the billing period, and for interval-metered customers, the peak demand between 7 AM and 7 PM local time on IESO business days

Customer-Supplied Transformation Allowance

Applicable to customers providing their own transformers		
Demand-billed	$ / kW	0.60
Energy-billed	$ / kWh	0.0014

Hydro One Networks Inc.
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Loss Factors

Residential	1.078
General Service Less Than 50 kW (Energy-Billed)	1.092
General Service 50 kW or Greater (Demand-Billed)	1.061
Unmetered Scattered Load	1.092

Transformer Loss Allowance

Applicable to customers requiring a billing adjustment for transformer losses as the result of being metered on the primary side of a transformer. The following uniform values shall be applied to measured demand and energy to calculate transformer losses for voltages up to and including 50 kV (as metered on the primary side):

(a) 1.5% for transformer installations up to an individual bank capacity of 400 kVA,
(b) 1.0% for bank capacities over 400 kVA.

Alternatively, transformer losses may be determined from transformer test data, and measured demand and energy adjusted accordingly

For services which are not demand metered, an assumed demand of 50% of the transformer capacity will be used to calculate the loss allowance. Where several transformers are involved, the bank capacity is assumed to be the arithmetic sum of all transformer capacities

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
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Effective Date: May 1, 2008

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

MISCELLANEOUS CHARGES

Specific Service Charges: Standard Amounts

Rate Code	Specific Service Charge - Standard Name	Calculation Method			
		2006 Rate Handbook	Standard Formula	Other Formula	Time and Materials
1	Temporary Service	$500			
2	Dispute Meter Test	$30 plus Measurement Canada fees			
3	Collection of account – no disconnection/load limiter	$30			
4	Collection/Disconnect/load limiter/reconnect (at meter) trip – regular hours	$65			
5	Collection/Disconnect/load limiter/reconnect (at meter) trip – after regular hours	$185			
6	Collection/Disconnect/load limiter/reconnect (at pole) trip – regular hours	$185			
7	Collection/Disconnect/load limiter/reconnect (at pole) trip – after regular hours	$415			
8	Account Set-up Charge	$30			
9	Arrears Certificate	$15			
10	NSF Cheque Charge	$15 + bank charges			
11	Easement Charge for Unregistered Rights	$15			
12	Late Payment Charge	1.5%/month			
13a	Retailer Services – Establishing Service Agreements (refer to Handbook for all charges)	$100/agreement/Retailer +$20/month/Retailer +$0.50/month/customer + other			
13b	Retailer Services – Other (includes Bill Ready for Retailers and Service Transactions Requests) as per the Handbook, Chapter 12	$0.30/month/customer + $0.25/request for request fee + $0.50/request for process fee			
14	Special Meter Reads	$30			
15	Service Layout Fee – Basic		$495		
16	Service Layout Fee – Complex		$690		
17	Crossing Application – Pipeline		$2,445		
18	Crossing Application – Water		$3,045		
19	Crossing Application – Railroad		$2,945		
20	Line Staking – per meter		$3.70		
21	Central Metering – New service < 45 kW		$115		
22	Conversion to Central Metering < 45 kW		$915		
23	Conversion to Central Metering > 45 kW		$800		
24	Tingle Voltage Test – In Excess of 4 Hours (per hour – average 2 additional hours)		$125		
25	Standby Administration Charge per month		$440		
26	Sentinel Lights Rental Rate per month			$7.10	
27	Sentinel Pole Rental Rate per month			$4.15	
28	Joint Use for Cable and Telecom companies per pole			$22.35	
29	Joint Use for LDCs per pole			$28.61	

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Georgian Bay Energy Inc.
Effective Date: May 1, 2007

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

APPLICATION

The application of these rates and charges shall be in accordance with The Licence of The Distributor and any Codes, Guidelines or Orders of The Board, and amendments thereto as approved by The Board, which may be applicable to the administration of this schedule.
No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code, Guideline or Order of the Board, and amendments thereto as approved by the Board, or as specified herein
This schedule does not contain any rates and charges relating to the electricity commodity (e.g. the Regulated Price Plan).

EFFECTIVE DATES

DISTRIBUTION RATES - May 1, 2007 for all consumption or deemed consumption services used on or after that date.

MISCELLANEOUS CHARGES - May 1, 2007 for all charges billed to customers on or after that date.
RETAIL TRANSMISSION RATES - May 1, 2007 for all consumption or deemed consumption services used on or after that date.
LOSS FACTOR ADJUSTMENT – May 1, 2007

SERVICE CLASSIFICATIONS

Residential
This classification (note 1) refers to all service supplied to single-family dwelling units for domestic or household purpose. Multi-unit residential establishments such as apartment buildings supplied through one service (bulk metered) will normally be classified as General Service, but, at Hydro One’s discretion, up to four residential units may be classified as residential. Where electricity service is provided to combined residential and business (including agricultural usage) and the wiring does not provide for separate metering, the classification shall be at the discretion of Hydro One based on such considerations as the estimated predominant consumption.
Further servicing details are available in the utility’s Conditions of Service.

General Service
This classification (note 1) refers to all service supplied to premises other than those classified as Residential, Lighting or Large Use. Some General Service accounts are energy(kWh)-billed, and some are demand(kW)-billed. Further servicing details are available in the utility’s Conditions of Service. Also, see note 2.

Unmetered Scattered Load
This classification refers to certain instances where connections can be provided without metering. These loads are generally small in size and consistent in magnitude of load. Hydro One reserves the right to review all cases and may require that a meter be installed at its sole discretion. Services that can be unmetered include cable TV amplifiers, telephone switching devices, phone booths, bus shelters, rail way crossing signals, traffic signals, and other small fixed loads.
Further servicing details are available in the utility’s Conditions of Service (including in the "Unmetered Connections" section).

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
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Georgian Bay Energy Inc.
Effective Date: May 1, 2007

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

Large Use

This classification refers to individual Customers whose monthly measured maximum demand (kW) averaged over the
Further servicing details are available in the utility's Conditions of Service. Also, see note 2.

Street Lighting

This classification refers to accounts for the distribution and supply of electrical energy for street lighting. Street lights are devices owned by or operated for the road authority and/or the municipal corporation. These street lights in fact belong to the Street Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Sentinel Lighting

This classification refers to accounts for a separate service to a sentinel light. These sentinel lights in fact belong to the Sentinel Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Interim Demand-Side Management Time-of-Use

This is potentially applicable to Demand-billed General Service and Large Use accounts. See Note 2 below.

Note (1): Classification descriptions are paraphrases from the document "Hydro One Networks Inc. - Distribution Customers Conditions of Service - August 2004"
Note (2):

Interim Demand-Side Management Time-of-Use Rates: demand charges will be based on demand during the on-peak periods.
Criteria: Customers' electricity consumption (kW) in the off-peak period is at least twice the electricity consumption (kW) during the on-peak period.
Definition of Time Periods: The on-peak hours will be between 0700 hours to 1900 hours Eastern Standard Time during the winter (standard time) on IESO business days and 0600 hours to 1800 hours Eastern Standard Time during the summer (daylight savings time) on IESO business days. The off-peak period constitutes all of the remaining hours.

Hydro One Networks Inc.
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MONTHLY RATES AND CHARGES

Residential

Service Charge	$	9.68
Distribution Volumetric Rate	$ / kWh	0.0095
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0046
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0013
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0055
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0047
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service - Energy Billed (less than 50 kW)

Service Charge	$	10.77
Distribution Volumetric Rate	$ / kWh	0.0114
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0016
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0006
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0050
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0043
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service - Demand Billed (50 kW or greater)

Service Charge	$	10.77
Distribution Volumetric Rate	$ / kW	3.64
Regulatory Asset Recovery - Rider #1	$ / kW	0.49
Regulatory Asset Recovery - Rider #2	$ / kW	0.19
Retail Transmission Rate - Network Service Rate (4)	$ / kW	1.94
Retail Transmission Rate - Line and Transformation Connection Service Rate (4)	$ / kW	1.61
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

Hydro One Networks Inc.
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Unmetered, Scattered Load

Service Charge	$	4.92
Distribution Volumetric Rate	$ / kWh	0.0114
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0016
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0006
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0050
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0043
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

Large User

Service Charge	$	3,242
Distribution Volumetric Rate	$ / kW	4.37
Regulatory Asset Recovery - Rider #1	$ / kW	0.36
Regulatory Asset Recovery - Rider #2	$ / kW	0.17
Retail Transmission Rate - Network Service Rate (4)	$ / kW	2.37
Retail Transmission Rate - Line and Transformation Connection Service Rate (4)	$ / kW	2.09
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

(3) For energy-only metered customers, the billing determinant is the customer’s metered energy consumption adjusted by the total loss factor as approved by the Board for Acquired LDC customers.
(4) For demand billed customers, appropriate loss factors must be applied to the applicable tariffs. Also the billing determinant for the Line and Transformation Connection Services rate is the customer’s peak demand in the billing period. The billing determinant for the Network Services rate is: for non-interval-metered customers, the peak demand in the billing period, and for interval-metered customers, the peak demand between 7 AM and 7 PM local time on IESO business days

Interim Demand-Side Management Time-of-Use

See the "Service Classifications" section of this schedule.

Customer-Supplied Transformation Allowance

Applicable to demand-billed customers (excluding Large Users) providing their own transformers
Primary Voltage under 50 kV (per kW)

Single Phase	$ / kW	0.20
Three Phase	$ / kW	0.60

Hydro One Networks Inc.
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Loss Factors

Supply Facilities Loss Factor	1.0045
Distribution Loss Factors	
Customer less than 5,000 kW	1.0500
Customer greater than or equal to 5,000 kW	1.0100
Total Loss Factors	
Customer less than 5,000 kW	1.0545
Customer greater than or equal to 5,000 kW	1.0145

Transformer Loss Allowance

Applicable to customers requiring a billing adjustment for transformer losses as the result of being metered on the primary side of a transformer. The following uniform values shall be applied to measured demand and energy to calculate transformer losses for voltages up to and including 50 kV (as metered on the primary side):

(a) 1.5% for transformer installations up to an individual bank capacity of 400 kVA,
(b) 1.0% for bank capacities over 400 kVA.

Alternatively, transformer losses may be determined from transformer test data, and measured demand and energy adjusted accordingly

For services which are not demand metered, an assumed demand of 50% of the transformer capacity will be used to calculate the loss allowance. Where several transformers are involved, the bank capacity is assumed to be the arithmetic sum of all transformer capacities

Hydro One Networks Inc.
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Georgian Bay Energy Inc.
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MISCELLANEOUS CHARGES

Specific Service Charges: Standard Amounts

Rate Code	Specific Service Charge - Standard Name	Calculation Method			
		2006 Rate Handbook	Standard Formula	Other Formula	Time and Materials
1	Temporary Service	$500			
2	Dispute Meter Test	$30 plus Measurement Canada fees			
3	Collection of account – no disconnection/load limiter	$30			
4	Collection/Disconnect/load limiter/reconnect (at meter) trip – regular hours	$65			
5	Collection/Disconnect/load limiter/reconnect (at meter) trip – after regular hours	$185			
6	Collection/Disconnect/load limiter/reconnect (at pole) trip – regular hours	$185			
7	Collection/Disconnect/load limiter/reconnect (at pole) trip – after regular hours	$415			
8	Account Set-up Charge	$30			
9	Arrears Certificate	$15			
10	NSF Cheque Charge	$15 + bank charges			
11	Easement Charge for Unregistered Rights	$15			
12	Late Payment Charge	1.5%/month			
13a	Retailer Services – Establishing Service Agreements (refer to Handbook for all charges)	$100/agreement/Retailer +$20/month/Retailer +$0.50/month/customer + other			
13b	Retailer Services – Other (includes Bill Ready for Retailers and Service Transactions Requests) as per the Handbook, Chapter 12	$0.30/month/customer + $0.25/request for request fee + $0.50/request for process fee			
14	Special Meter Reads	$30			
15	Billing Suspension and Terminations in Trailer Parks		$130		
16	Service Layout Fee – Basic		$405		
17	Service Layout Fee – Complex		$580		

Hydro One Networks Inc.
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18	Crossing Application – Pipeline		$2,065		
19	Crossing Application – Water		$2,525		
20	Crossing Application – Railroad		$2,565		
21	Line Staking – per meter		$3.10		
22	Central Metering – New service < 45 kW		$115		
23	Conversion to Central Metering < 45 kW		$795		
24	Conversion to Central Metering > 45 kW		$680		
25	Tingle Voltage Test – In Excess of 4 Hours (per hour – average 2 additional hours)		$105		
26	Standby Administration Charge per month (interim)		$375		
27	Sentinel Lights Rental Rate per month – Mercury Vapor			$7.00	
28	Guaranteed Units from Jan 01/91 to Aug 01/91			$26.50 / month	
29	Guaranteed Units from Jan 01/87 to Dec 31/90			$23.50 / month	
30	Joint Use for Cable and Telecom companies per pole			$22.35	
31	Joint Use for LDCs per pole			$28.61	

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
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Georgina Hydro Electric Commission
Effective Date: May 1, 2008

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

APPLICATION

The application of these rates and charges shall be in accordance with The Licence of The Distributor and any Codes, Guidelines or Orders of The Board, and amendments thereto as approved by The Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code, Guideline or Order of the Board, and amendments thereto as approved by the Board, or as specified herein

This schedule does not contain any rates and charges relating to the electricity commodity (e.g. the Regulated Price Plan).

EFFECTIVE DATES

DISTRIBUTION RATES - May 1, 2008 for all consumption or deemed consumption services used on or after that date.

MISCELLANEOUS CHARGES - May 1, 2008 for all charges billed to customers on or after that date.

RETAIL TRANSMISSION RATES - May 1, 2008 for all consumption or deemed consumption services used on or after that date.

LOSS FACTOR ADJUSTMENT – for all consumption or deemed consumption services billed following May 1, 2008 or later

SERVICE CLASSIFICATIONS

Residential

This classification refers to all service supplied to single-family dwelling units for domestic or household purpose. Multi-unit residential establishments such as apartment buildings supplied through one service (bulk metered) will normally be classified as General Service, but, at Hydro One's discretion, up to four residential units may be classified as residential. Where electricity service is provided to combined residential and business (including agricultural usage) and the wiring does not provide for separate metering, the classification shall be at the discretion of Hydro One based on such considerations as the estimated predominant consumption.

Further servicing details are available in the utility's Conditions of Service.

General Service

This classification refers to all service supplied to premises other than those classified as Residential or Lighting. Some General Service accounts are energy(kWh)-billed, and some are demand(kW)-billed. Further servicing details are available in the utility's Conditions of Service.

Unmetered Scattered Load

This classification refers to certain instances where connections can be provided without metering. These loads are generally small in size and consistent in magnitude of load. Hydro One reserves the right to review all cases and may require that a meter be installed at its sole discretion. Services that can be unmetered include cable TV amplifiers, telephone switching devices, phone booths, bus shelters, rail way crossing signals, traffic signals, and other small fixed loads.

Further servicing details are available in the utility's Conditions of Service (including in the "Unmetered Connections" section).

Hydro One Networks Inc.
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Georgina Hydro Electric Commission
Effective Date: May 1, 2008

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

Street Lighting

This classification refers to accounts for the distribution and supply of electrical energy for street lighting. Street lights are devices owned by or operated for the road authority and/or the municipal corporation. These street lights in fact belong to the Street Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Sentinel Lighting

This classification refers to accounts for a separate service to a sentinel light. These sentinel lights in fact belong to the Sentinel Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Urban Density Classification

Customers who meet the Urban Density Criteria of being in an area containing 3,000 or more customers with a line density of at least 60 customers per kilometre, will be mapped to an Urban customer classification.

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
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Georgina Hydro Electric Commission
Effective Date: May 1, 2008

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

MONTHLY RATES AND CHARGES

Residential - R1 Georgina

Service Charge	$	12.83
Distribution Volumetric Rate	$ / kWh	0.0205
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0009
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0004)
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0047
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0046
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service Less Than 50 kW (Energy-Billed) - GSe Georgina

Service Charge	$	20.74
Distribution Volumetric Rate	$ / kWh	0.0265
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0008
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0006)
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0035
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0032
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service 50 kW or Greater (Demand-Billed) - GSd Georgina

Service Charge	$	24.34
Distribution Volumetric Rate	$ / kW	9.22
Regulatory Asset Recovery - Rider #2	$ / kW	0.25
Regulatory Asset Recovery - Rider #3	$ / kW	(0.22)
Retail Transmission Rate - Network Service Rate (4)	$ / kW	1.11
Retail Transmission Rate - Line and Transformation Connection Service Rate (4)	$ / kW	1.00
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
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Georgina Hydro Electric Commission
Effective Date: May 1, 2008

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

Unmetered, Scattered Load

Service Charge	$	12.32
Distribution Volumetric Rate	$ / kWh	0.0200
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0008
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0006)
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0035
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0032
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

(3) For energy-only metered customers, the billing determinant is the customer's metered energy consumption adjusted by the total loss factor as approved by the Board for Acquired LDC customers.

(4) For demand billed customers, appropriate loss factors must be applied to the applicable tariffs. Also the billing determinant for the Line and Transformation Connection Services rate is the customer's peak demand in the billing period. The billing determinant for the Network Services rate is: for non-interval-metered customers, the peak demand in the billing period, and for interval-metered customers, the peak demand between 7 AM and 7 PM local time on IESO business days

Customer-Supplied Transformation Allowance

Applicable to customers providing their own transformers

Demand-billed	$ / kW	0.60
Energy-billed	$ / kWh	0.0014

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
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Georgina Hydro Electric Commission
Effective Date: May 1, 2008

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Loss Factors

Residential	1.085
General Service Less Than 50 kW (Energy-Billed)	1.092
General Service 50 kW or Greater (Demand-Billed)	1.061
Unmetered Scattered Load	1.092

Transformer Loss Allowance

Applicable to customers requiring a billing adjustment for transformer losses as the result of being metered on the primary side of a transformer. The following uniform values shall be applied to measured demand and energy to calculate transformer losses for voltages up to and including 50 kV (as metered on the primary side):

(a) 1.5% for transformer installations up to an individual bank capacity of 400 kVA,
(b) 1.0% for bank capacities over 400 kVA.

Alternatively, transformer losses may be determined from transformer test data, and measured demand and energy adjusted accordingly

For services which are not demand metered, an assumed demand of 50% of the transformer capacity will be used to calculate the loss allowance. Where several transformers are involved, the bank capacity is assumed to be the arithmetic sum of all transformer capacities

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MISCELLANEOUS CHARGES

Specific Service Charges: Standard Amounts

Rate Code	Specific Service Charge - Standard Name	Calculation Method			
		2006 Rate Handbook	Standard Formula	Other Formula	Time and Materials
1	Temporary Service	$500			
2	Dispute Meter Test	$30 plus Measurement Canada fees			
3	Collection of account – no disconnection/load limiter	$30			
4	Collection/Disconnect/load limiter/reconnect (at meter) trip – regular hours	$65			
5	Collection/Disconnect/load limiter/reconnect (at meter) trip – after regular hours	$185			
6	Collection/Disconnect/load limiter/reconnect (at pole) trip – regular hours	$185			
7	Collection/Disconnect/load limiter/reconnect (at pole) trip – after regular hours	$415			
8	Account Set-up Charge	$30			
9	Arrears Certificate	$15			
10	NSF Cheque Charge	$15 + bank charges			
11	Easement Charge for Unregistered Rights	$15			
12	Late Payment Charge	1.5%/month			
13a	Retailer Services – Establishing Service Agreements (refer to Handbook for all charges)	$100/agreement/Retailer +$20/month/Retailer +$0.50/month/customer + other			
13b	Retailer Services – Other (includes Bill Ready for Retailers and Service Transactions Requests) as per the Handbook, Chapter 12	$0.30/month/customer + $0.25/request for request fee + $0.50/request for process fee			
14	Special Meter Reads	$30			
15	Service Layout Fee – Basic		$495		
16	Service Layout Fee – Complex		$690		
17	Crossing Application – Pipeline		$2,445		
18	Crossing Application – Water		$3,045		
19	Crossing Application – Railroad		$2,945		
20	Line Staking – per meter		$3.70		
21	Central Metering – New service < 45 kW		$115		
22	Conversion to Central Metering < 45 kW		$915		
23	Conversion to Central Metering > 45 kW		$800		
24	Tingle Voltage Test – In Excess of 4 Hours (per hour – average 2 additional hours)		$125		
25	Standby Administration Charge per month		$440		
26	Sentinel Lights Rental Rate per month			$7.10	
27	Sentinel Pole Rental Rate per month			$4.15	
28	Joint Use for Cable and Telecom companies per pole			$22.35	
29	Joint Use for LDCs per pole			$28.61	

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
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Georgina Hydro Electric Commission
Effective Date: May 1, 2007

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APPLICATION

The application of these rates and charges shall be in accordance with The Licence of The Distributor and any Codes, Guidelines or Orders of The Board, and amendments thereto as approved by The Board, which may be applicable to the administration of this schedule.
No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code, Guideline or Order of the Board, and amendments thereto as approved by the Board, or as specified herein
This schedule does not contain any rates and charges relating to the electricity commodity (e.g. the Regulated Price Plan).

EFFECTIVE DATES

DISTRIBUTION RATES - May 1, 2007 for all consumption or deemed consumption services used on or after that date.

MISCELLANEOUS CHARGES - May 1, 2007 for all charges billed to customers on or after that date.
RETAIL TRANSMISSION RATES - May 1, 2007 for all consumption or deemed consumption services used on or after that date.
LOSS FACTOR ADJUSTMENT – May 1, 2007

SERVICE CLASSIFICATIONS

Residential
This classification (note 1) refers to all service supplied to single-family dwelling units for domestic or household purpose. Multi-unit residential establishments such as apartment buildings supplied through one service (bulk metered) will normally be classified as General Service, but, at Hydro One's discretion, up to four residential units may be classified as residential. Where electricity service is provided to combined residential and business (including agricultural usage) and the wiring does not provide for separate metering, the classification shall be at the discretion of Hydro One based on such considerations as the estimated predominant consumption.
Further servicing details are available in the utility's Conditions of Service.

General Service
This classification (note 1) refers to all service supplied to premises other than those classified as Residential or Lighting. Some General Service accounts are energy(kWh)-billed, and some are demand(kW)-billed. Further servicing details are available in the utility's Conditions of Service. Also, see note 2.

Unmetered Scattered Load
This classification refers to certain instances where connections can be provided without metering. These loads are generally small in size and consistent in magnitude of load. Hydro One reserves the right to review all cases and may require that a meter be installed at its sole discretion. Services that can be unmetered include cable TV amplifiers, telephone switching devices, phone booths, bus shelters, rail way crossing signals, traffic signals, and other small fixed loads.
Further servicing details are available in the utility's Conditions of Service (including in the "Unmetered Connections" section).

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
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Georgina Hydro Electric Commission
Effective Date: May 1, 2007

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

Street Lighting

This classification refers to accounts for the distribution and supply of electrical energy for street lighting. Street lights are devices owned by or operated for the road authority and/or the municipal corporation. These street lights in fact belong to the Street Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility’s Conditions of Service.

Sentinel Lighting

This classification refers to accounts for a separate service to a sentinel light. These sentinel lights in fact belong to the Sentinel Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility’s Conditions of Service.

Interim Demand-Side Management Time-of-Use

This is potentially applicable to Demand-billed General Service accounts. See Note 2 below.

Note (1): Classification descriptions are paraphrases from the document "Hydro One Networks Inc. - Distribution Customers Conditions of Service - August 2004"

Note (2):

Interim Demand-Side Management Time-of-Use Rates: demand charges will be based on demand during the on-peak periods.

Criteria: Customers' electricity consumption (kW) in the off-peak period is at least twice the electricity consumption (kW) during the on-peak period.

Definition of Time Periods: The on-peak hours will be between 0700 hours to 1900 hours Eastern Standard Time during the winter (standard time) on IESO business days and 0600 hours to 1800 hours Eastern Standard Time during the summer (daylight savings time) on IESO business days. The off-peak period constitutes all of the remaining hours.

Hydro One Networks Inc.
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MONTHLY RATES AND CHARGES

Residential

Service Charge	$	11.72
Distribution Volumetric Rate	$ / kWh	0.0098
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0031
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0009
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0055
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0047
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service - Energy Billed (less than 50 kW)

Service Charge	$	17.40
Distribution Volumetric Rate	$ / kWh	0.0162
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0016
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0008
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0050
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0043
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service - Demand Billed (50 kW or greater)

Service Charge	$	17.40
Distribution Volumetric Rate	$ / kW	5.10
Regulatory Asset Recovery - Rider #1	$ / kW	0.51
Regulatory Asset Recovery - Rider #2	$ / kW	0.25
Retail Transmission Rate - Network Service Rate (4)	$ / kW	1.94
Retail Transmission Rate - Line and Transformation Connection Service Rate (4)	$ / kW	1.61
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

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Unmetered, Scattered Load

Service Charge	$	8.24
Distribution Volumetric Rate	$ / kWh	0.0162
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0016
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0008
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0050
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0043
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

(3) For energy-only metered customers, the billing determinant is the customer's metered energy consumption adjusted by the total loss factor as approved by the Board for Acquired LDC customers.
(4) For demand billed customers, appropriate loss factors must be applied to the applicable tariffs. Also the billing determinant for the Line and Transformation Connection Services rate is the customer's peak demand in the billing period. The billing determinant for the Network Services rate is: for non-interval-metered customers, the peak demand in the billing period, and for interval-metered customers, the peak demand between 7 AM and 7 PM local time on IESO business days

Interim Demand-Side Management Time-of-Use

See the "Service Classifications" section of this schedule.

Customer-Supplied Transformation Allowance

Applicable to demand-billed customers providing their own transformers
Primary Voltage under 50 kV (per kW)

Single Phase	$ / kW	0.20
Three Phase	$ / kW	0.60

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Loss Factors

Supply Facilities Loss Factor	1.0045
Distribution Loss Factors	
Customer less than 5,000 kW	1.0500
Customer greater than or equal to 5,000 kW	1.0100
Total Loss Factors	
Customer less than 5,000 kW	1.0545
Customer greater than or equal to 5,000 kW	1.0145

Transformer Loss Allowance

Applicable to customers requiring a billing adjustment for transformer losses as the result of being metered on the primary side of a transformer. The following uniform values shall be applied to measured demand and energy to calculate transformer losses for voltages up to and including 50 kV (as metered on the primary side):

(a) 1.5% for transformer installations up to an individual bank capacity of 400 kVA,
(b) 1.0% for bank capacities over 400 kVA.

Alternatively, transformer losses may be determined from transformer test data, and measured demand and energy adjusted accordingly

For services which are not demand metered, an assumed demand of 50% of the transformer capacity will be used to calculate the loss allowance. Where several transformers are involved, the bank capacity is assumed to be the arithmetic sum of all transformer capacities

Hydro One Networks Inc.
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MISCELLANEOUS CHARGES

Specific Service Charges: Standard Amounts

Rate Code	Specific Service Charge - Standard Name	Calculation Method			
		2006 Rate Handbook	Standard Formula	Other Formula	Time and Materials
1	Temporary Service	$500			
2	Dispute Meter Test	$30 plus Measurement Canada fees			
3	Collection of account – no disconnection/load limiter	$30			
4	Collection/Disconnect/load limiter/reconnect (at meter) trip – regular hours	$65			
5	Collection/Disconnect/load limiter/reconnect (at meter) trip – after regular hours	$185			
6	Collection/Disconnect/load limiter/reconnect (at pole) trip – regular hours	$185			
7	Collection/Disconnect/load limiter/reconnect (at pole) trip – after regular hours	$415			
8	Account Set-up Charge	$30			
9	Arrears Certificate	$15			
10	NSF Cheque Charge	$15 + bank charges			
11	Easement Charge for Unregistered Rights	$15			
12	Late Payment Charge	1.5%/month			
13a	Retailer Services – Establishing Service Agreements (refer to Handbook for all charges)	$100/agreement/Retailer +$20/month/Retailer +$0.50/month/customer + other			
13b	Retailer Services – Other (includes Bill Ready for Retailers and Service Transactions Requests) as per the Handbook, Chapter 12	$0.30/month/customer + $0.25/request for request fee + $0.50/request for process fee			
14	Special Meter Reads	$30			
15	Billing Suspension and Terminations in Trailer Parks		$130		
16	Service Layout Fee – Basic		$405		
17	Service Layout Fee – Complex		$580		

Hydro One Networks Inc.
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18	Crossing Application – Pipeline		$2,065		
19	Crossing Application – Water		$2,525		
20	Crossing Application – Railroad		$2,565		
21	Line Staking – per meter		$3.10		
22	Central Metering – New service < 45 kW		$115		
23	Conversion to Central Metering < 45 kW		$795		
24	Conversion to Central Metering > 45 kW		$680		
25	Tingle Voltage Test – In Excess of 4 Hours (per hour – average 2 additional hours)		$105		
26	Standby Administration Charge per month (interim)		$375		
27	Sentinel Lights Rental Rate per month – Mercury Vapor			$7.00	
28	Guaranteed Units from Jan 01/91 to Aug 01/91			$26.50 / month	
29	Guaranteed Units from Jan 01/87 to Dec 31/90			$23.50 / month	
30	Joint Use for Cable and Telecom companies per pole			$22.35	
31	Joint Use for LDCs per pole			$28.61	

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Public Utilities Commission of the Village of Glencoe
Effective Date: May 1, 2008

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

APPLICATION

The application of these rates and charges shall be in accordance with The Licence of The Distributor and any Codes, Guidelines or Orders of The Board, and amendments thereto as approved by The Board, which may be applicable to the administration of this schedule.
No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code, Guideline or Order of the Board, and amendments thereto as approved by the Board, or as specified herein
This schedule does not contain any rates and charges relating to the electricity commodity (e.g. the Regulated Price Plan).

EFFECTIVE DATES

DISTRIBUTION RATES - May 1, 2008 for all consumption or deemed consumption services used on or after that date.

MISCELLANEOUS CHARGES - May 1, 2008 for all charges billed to customers on or after that date.
RETAIL TRANSMISSION RATES - May 1, 2008 for all consumption or deemed consumption services used on or after that date.
LOSS FACTOR ADJUSTMENT – for all consumption or deemed consumption services billed following May 1, 2008 or later

SERVICE CLASSIFICATIONS

Residential
This classification refers to all service supplied to single-family dwelling units for domestic or household purpose. Multi-unit residential establishments such as apartment buildings supplied through one service (bulk metered) will normally be classified as General Service, but, at Hydro One's discretion, up to four residential units may be classified as residential. Where electricity service is provided to combined residential and business (including agricultural usage) and the wiring does not provide for separate metering, the classification shall be at the discretion of Hydro One based on such considerations as the estimated predominant consumption.
Further servicing details are available in the utility's Conditions of Service.

General Service
This classification refers to all service supplied to premises other than those classified as Residential or Lighting. Some General Service accounts are energy(kWh)-billed, and some are demand(kW)-billed. Further servicing details are available in the utility's Conditions of Service.

Unmetered Scattered Load
This classification refers to certain instances where connections can be provided without metering. These loads are generally small in size and consistent in magnitude of load. Hydro One reserves the right to review all cases and may require that a meter be installed at its sole discretion. Services that can be unmetered include cable TV amplifiers, telephone switching devices, phone booths, bus shelters, rail way crossing signals, traffic signals, and other small fixed loads.
Further servicing details are available in the utility's Conditions of Service (including in the "Unmetered Connections" section).

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Public Utilities Commission of the Village of Glencoe
Effective Date: May 1, 2008

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Street Lighting

This classification refers to accounts for the distribution and supply of electrical energy for street lighting. Street lights are devices owned by or operated for the road authority and/or the municipal corporation. These street lights in fact belong to the Street Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Sentinel Lighting

This classification refers to accounts for a separate service to a sentinel light. These sentinel lights in fact belong to the Sentinel Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Urban Density Classification

Customers who meet the Urban Density Criteria of being in an area containing 3,000 or more customers with a line density of at least 60 customers per kilometre, will be mapped to an Urban customer classification.

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
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Effective Date: May 1, 2008

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MONTHLY RATES AND CHARGES

Residential - R1 Glencoe

Service Charge	$	13.54
Distribution Volumetric Rate	$ / kWh	0.0255
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0043
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0004)
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0047
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0046
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service Less Than 50 kW (Energy-Billed) - GSe Glencoe

Service Charge	$	16.25
Distribution Volumetric Rate	$ / kWh	0.0174
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0014
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0006)
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0035
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0032
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service 50 kW or Greater (Demand-Billed) - GSd Glencoe

Service Charge	$	19.85
Distribution Volumetric Rate	$ / kW	7.40
Regulatory Asset Recovery - Rider #2	$ / kW	0.44
Regulatory Asset Recovery - Rider #3	$ / kW	(0.22)
Retail Transmission Rate - Network Service Rate (4)	$ / kW	1.11
Retail Transmission Rate - Line and Transformation Connection Service Rate (4)	$ / kW	1.00
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

Hydro One Networks Inc.
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Unmetered, Scattered Load

Service Charge	$	10.08
Distribution Volumetric Rate	$ / kWh	0.0200
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0014
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0006)
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0035
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0032
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

(3) For energy-only metered customers, the billing determinant is the customer's metered energy consumption adjusted by the total loss factor as approved by the Board for Acquired LDC customers.
(4) For demand billed customers, appropriate loss factors must be applied to the applicable tariffs. Also the billing determinant for the Line and Transformation Connection Services rate is the customer's peak demand in the billing period. The billing determinant for the Network Services rate is: for non-interval-metered customers, the peak demand in the billing period, and for interval-metered customers, the peak demand between 7 AM and 7 PM local time on IESO business days

Customer-Supplied Transformation Allowance

Applicable to customers providing their own transformers		
Demand-billed	$ / kW	0.60
Energy-billed	$ / kWh	0.0014

Hydro One Networks Inc.
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Loss Factors

Residential	1.085
General Service Less Than 50 kW (Energy-Billed)	1.092
General Service 50 kW or Greater (Demand-Billed)	1.061
Unmetered Scattered Load	1.092

Transformer Loss Allowance

Applicable to customers requiring a billing adjustment for transformer losses as the result of being metered on the primary side of a transformer. The following uniform values shall be applied to measured demand and energy to calculate transformer losses for voltages up to and including 50 kV (as metered on the primary side):

(a) 1.5% for transformer installations up to an individual bank capacity of 400 kVA,
(b) 1.0% for bank capacities over 400 kVA.

Alternatively, transformer losses may be determined from transformer test data, and measured demand and energy adjusted accordingly

For services which are not demand metered, an assumed demand of 50% of the transformer capacity will be used to calculate the loss allowance. Where several transformers are involved, the bank capacity is assumed to be the arithmetic sum of all transformer capacities

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MISCELLANEOUS CHARGES

Specific Service Charges: Standard Amounts

Rate Code	Specific Service Charge - Standard Name	Calculation Method			
		2006 Rate Handbook	Standard Formula	Other Formula	Time and Materials
1	Temporary Service	$500			
2	Dispute Meter Test	$30 plus Measurement Canada fees			
3	Collection of account – no disconnection/load limiter	$30			
4	Collection/Disconnect/load limiter/reconnect (at meter) trip – regular hours	$65			
5	Collection/Disconnect/load limiter/reconnect (at meter) trip – after regular hours	$185			
6	Collection/Disconnect/load limiter/reconnect (at pole) trip – regular hours	$185			
7	Collection/Disconnect/load limiter/reconnect (at pole) trip – after regular hours	$415			
8	Account Set-up Charge	$30			
9	Arrears Certificate	$15			
10	NSF Cheque Charge	$15 + bank charges			
11	Easement Charge for Unregistered Rights	$15			
12	Late Payment Charge	1.5%/month			
13a	Retailer Services – Establishing Service Agreements (refer to Handbook for all charges)	$100/agreement/Retailer +$20/month/Retailer +$0.50/month/customer + other			
13b	Retailer Services – Other (includes Bill Ready for Retailers and Service Transactions Requests) as per the Handbook, Chapter 12	$0.30/month/customer + $0.25/request for request fee + $0.50/request for process fee			
14	Special Meter Reads	$30			
15	Service Layout Fee – Basic		$495		
16	Service Layout Fee – Complex		$690		
17	Crossing Application – Pipeline		$2,445		
18	Crossing Application – Water		$3,045		
19	Crossing Application – Railroad		$2,945		
20	Line Staking – per meter		$3.70		
21	Central Metering – New service < 45 kW		$115		
22	Conversion to Central Metering < 45 kW		$915		
23	Conversion to Central Metering > 45 kW		$800		
24	Tingle Voltage Test – In Excess of 4 Hours (per hour – average 2 additional hours)		$125		
25	Standby Administration Charge per month		$440		
26	Sentinel Lights Rental Rate per month			$7.10	
27	Sentinel Pole Rental Rate per month			$4.15	
28	Joint Use for Cable and Telecom companies per pole			$22.35	
29	Joint Use for LDCs per pole			$28.61	

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APPLICATION

The application of these rates and charges shall be in accordance with The Licence of The Distributor and any Codes, Guidelines or Orders of The Board, and amendments thereto as approved by The Board, which may be applicable to the administration of this schedule.
No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code, Guideline or Order of the Board, and amendments thereto as approved by the Board, or as specified herein
This schedule does not contain any rates and charges relating to the electricity commodity (e.g. the Regulated Price Plan).

EFFECTIVE DATES

DISTRIBUTION RATES - May 1, 2007 for all consumption or deemed consumption services used on or after that date.

MISCELLANEOUS CHARGES - May 1, 2007 for all charges billed to customers on or after that date.
RETAIL TRANSMISSION RATES - May 1, 2007 for all consumption or deemed consumption services used on or after that date.
LOSS FACTOR ADJUSTMENT – May 1, 2007

SERVICE CLASSIFICATIONS

Residential
This classification (note 1) refers to all service supplied to single-family dwelling units for domestic or household purpose. Multi-unit residential establishments such as apartment buildings supplied through one service (bulk metered) will normally be classified as General Service, but, at Hydro One’s discretion, up to four residential units may be classified as residential. Where electricity service is provided to combined residential and business (including agricultural usage) and the wiring does not provide for separate metering, the classification shall be at the discretion of Hydro One based on such considerations as the estimated predominant consumption.
Further servicing details are available in the utility’s Conditions of Service.

General Service
This classification (note 1) refers to all service supplied to premises other than those classified as Residential or Lighting. Some General Service accounts are energy(kWh)-billed, and some are demand(kW)-billed. Further servicing details are available in the utility’s Conditions of Service. Also, see note 2.

Unmetered Scattered Load
This classification refers to certain instances where connections can be provided without metering. These loads are generally small in size and consistent in magnitude of load. Hydro One reserves the right to review all cases and may require that a meter be installed at its sole discretion. Services that can be unmetered include cable TV amplifiers, telephone switching devices, phone booths, bus shelters, rail way crossing signals, traffic signals, and other small fixed loads.
Further servicing details are available in the utility’s Conditions of Service (including in the "Unmetered Connections" section).

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Public Utilities Commission of the Village of Glencoe
Effective Date: May 1, 2007

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

Street Lighting

This classification refers to accounts for the distribution and supply of electrical energy for street lighting. Street lights are devices owned by or operated for the road authority and/or the municipal corporation. These street lights in fact belong to the Street Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Sentinel Lighting

This classification refers to accounts for a separate service to a sentinel light. These sentinel lights in fact belong to the Sentinel Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Interim Demand-Side Management Time-of-Use

This is potentially applicable to Demand-billed General Service accounts. See Note 2 below.

Note (1): Classification descriptions are paraphrases from the document "Hydro One Networks Inc. - Distribution Customers Conditions of Service - August 2004"

Note (2):

Interim Demand-Side Management Time-of-Use Rates: demand charges will be based on demand during the on-peak periods.

Criteria: Customers' electricity consumption (kW) in the off-peak period is at least twice the electricity consumption (kW) during the on-peak period.

Definition of Time Periods: The on-peak hours will be between 0700 hours to 1900 hours Eastern Standard Time during the winter (standard time) on IESO business days and 0600 hours to 1800 hours Eastern Standard Time during the summer (daylight savings time) on IESO business days. The off-peak period constitutes all of the remaining hours.

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
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Effective Date: May 1, 2007

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MONTHLY RATES AND CHARGES

Residential

Service Charge	$	12.90
Distribution Volumetric Rate	$ / kWh	0.0077
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0089
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0043
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0055
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0047
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service - Energy Billed (less than 50 kW)

Service Charge	$	11.37
Distribution Volumetric Rate	$ / kWh	0.0081
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0022
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0014
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0050
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0043
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service - Demand Billed (50 kW or greater)

Service Charge	$	11.37
Distribution Volumetric Rate	$ / kW	2.55
Regulatory Asset Recovery - Rider #1	$ / kW	0.69
Regulatory Asset Recovery - Rider #2	$ / kW	0.44
Retail Transmission Rate - Network Service Rate (4)	$ / kW	1.94
Retail Transmission Rate - Line and Transformation Connection Service Rate (4)	$ / kW	1.61
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
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Unmetered, Scattered Load

Service Charge	$	5.21
Distribution Volumetric Rate	$ / kWh	0.0081
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0022
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0014
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0050
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0043
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

(3) For energy-only metered customers, the billing determinant is the customer's metered energy consumption adjusted by the total loss factor as approved by the Board for Acquired LDC customers.
(4) For demand billed customers, appropriate loss factors must be applied to the applicable tariffs. Also the billing determinant for the Line and Transformation Connection Services rate is the customer's peak demand in the billing period. The billing determinant for the Network Services rate is: for non-interval-metered customers, the peak demand in the billing period, and for interval-metered customers, the peak demand between 7 AM and 7 PM local time on IESO business days

Interim Demand-Side Management Time-of-Use

See the "Service Classifications" section of this schedule.

Customer-Supplied Transformation Allowance

Applicable to demand-billed customers providing their own transformers
Primary Voltage under 50 kV (per kW)

Single Phase	$ / kW	0.20
Three Phase	$ / kW	0.60

Hydro One Networks Inc.
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Loss Factors

Supply Facilities Loss Factor	1.0045
Distribution Loss Factors	
Customer less than 5,000 kW	1.0500
Customer greater than or equal to 5,000 kW	1.0100
Total Loss Factors	
Customer less than 5,000 kW	1.0545
Customer greater than or equal to 5,000 kW	1.0145

Transformer Loss Allowance

Applicable to customers requiring a billing adjustment for transformer losses as the result of being metered on the primary side of a transformer. The following uniform values shall be applied to measured demand and energy to calculate transformer losses for voltages up to and including 50 kV (as metered on the primary side):

(a) 1.5% for transformer installations up to an individual bank capacity of 400 kVA,
(b) 1.0% for bank capacities over 400 kVA.

Alternatively, transformer losses may be determined from transformer test data, and measured demand and energy adjusted accordingly

For services which are not demand metered, an assumed demand of 50% of the transformer capacity will be used to calculate the loss allowance. Where several transformers are involved, the bank capacity is assumed to be the arithmetic sum of all transformer capacities

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
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MISCELLANEOUS CHARGES

Specific Service Charges: Standard Amounts

Rate Code	Specific Service Charge - Standard Name	Calculation Method			
		2006 Rate Handbook	Standard Formula	Other Formula	Time and Materials
1	Temporary Service	$500			
2	Dispute Meter Test	$30 plus Measurement Canada fees			
3	Collection of account – no disconnection/load limiter	$30			
4	Collection/Disconnect/load limiter/reconnect (at meter) trip – regular hours	$65			
5	Collection/Disconnect/load limiter/reconnect (at meter) trip – after regular hours	$185			
6	Collection/Disconnect/load limiter/reconnect (at pole) trip – regular hours	$185			
7	Collection/Disconnect/load limiter/reconnect (at pole) trip – after regular hours	$415			
8	Account Set-up Charge	$30			
9	Arrears Certificate	$15			
10	NSF Cheque Charge	$15 + bank charges			
11	Easement Charge for Unregistered Rights	$15			
12	Late Payment Charge	1.5%/month			
13a	Retailer Services – Establishing Service Agreements (refer to Handbook for all charges)	$100/agreement/Retailer +$20/month/Retailer +$0.50/month/customer + other			
13b	Retailer Services – Other (includes Bill Ready for Retailers and Service Transactions Requests) as per the Handbook, Chapter 12	$0.30/month/customer + $0.25/request for request fee + $0.50/request for process fee			
14	Special Meter Reads	$30			
15	Billing Suspension and Terminations in Trailer Parks		$130		
16	Service Layout Fee – Basic		$405		
17	Service Layout Fee – Complex		$580		

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18	Crossing Application – Pipeline		$2,065		
19	Crossing Application – Water		$2,525		
20	Crossing Application – Railroad		$2,565		
21	Line Staking – per meter		$3.10		
22	Central Metering – New service < 45 kW		$115		
23	Conversion to Central Metering < 45 kW		$795		
24	Conversion to Central Metering > 45 kW		$680		
25	Tingle Voltage Test – In Excess of 4 Hours (per hour – average 2 additional hours)		$105		
26	Standby Administration Charge per month (interim)		$375		
27	Sentinel Lights Rental Rate per month – Mercury Vapor			$7.00	
28	Guaranteed Units from Jan 01/91 to Aug 01/91			$26.50 / month	
29	Guaranteed Units from Jan 01/87 to Dec 31/90			$23.50 / month	
30	Joint Use for Cable and Telecom companies per pole			$22.35	
31	Joint Use for LDCs per pole			$28.61	

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
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Public Utility Commission of Village of Grand Bend
Effective Date: May 1, 2008

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APPLICATION

The application of these rates and charges shall be in accordance with The Licence of The Distributor and any Codes, Guidelines or Orders of The Board, and amendments thereto as approved by The Board, which may be applicable to the administration of this schedule.
No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code, Guideline or Order of the Board, and amendments thereto as approved by the Board, or as specified herein
This schedule does not contain any rates and charges relating to the electricity commodity (e.g. the Regulated Price Plan).

EFFECTIVE DATES

DISTRIBUTION RATES - May 1, 2008 for all consumption or deemed consumption services used on or after that date.

MISCELLANEOUS CHARGES - May 1, 2008 for all charges billed to customers on or after that date.
RETAIL TRANSMISSION RATES - May 1, 2008 for all consumption or deemed consumption services used on or after that date.
LOSS FACTOR ADJUSTMENT – for all consumption or deemed consumption services billed following May 1, 2008 or later

SERVICE CLASSIFICATIONS

Residential
This classification refers to all service supplied to single-family dwelling units for domestic or household purpose. Multi-unit residential establishments such as apartment buildings supplied through one service (bulk metered) will normally be classified as General Service, but, at Hydro One's discretion, up to four residential units may be classified as residential. Where electricity service is provided to combined residential and business (including agricultural usage) and the wiring does not provide for separate metering, the classification shall be at the discretion of Hydro One based on such considerations as the estimated predominant consumption.
Further servicing details are available in the utility's Conditions of Service.

General Service
This classification refers to all service supplied to premises other than those classified as Residential or Lighting. Some General Service accounts are energy(kWh)-billed, and some are demand(kW)-billed. Further servicing details are available in the utility's Conditions of Service.

Unmetered Scattered Load
This classification refers to certain instances where connections can be provided without metering. These loads are generally small in size and consistent in magnitude of load. Hydro One reserves the right to review all cases and may require that a meter be installed at its sole discretion. Services that can be unmetered include cable TV amplifiers, telephone switching devices, phone booths, bus shelters, rail way crossing signals, traffic signals, and other small fixed loads.
Further servicing details are available in the utility's Conditions of Service (including in the "Unmetered Connections" section).

Hydro One Networks Inc.
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Effective Date: May 1, 2008

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Street Lighting

This classification refers to accounts for the distribution and supply of electrical energy for street lighting. Street lights are devices owned by or operated for the road authority and/or the municipal corporation. These street lights in fact belong to the Street Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Sentinel Lighting

This classification refers to accounts for a separate service to a sentinel light. These sentinel lights in fact belong to the Sentinel Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Urban Density Classification

Customers who meet the Urban Density Criteria of being in an area containing 3,000 or more customers with a line density of at least 60 customers per kilometre, will be mapped to an Urban customer classification.

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
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Effective Date: May 1, 2008

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MONTHLY RATES AND CHARGES

Residential - R1 Grand Bend

Service Charge	$	14.37
Distribution Volumetric Rate	$ / kWh	0.0210
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0013
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0004)
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0047
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0046
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service Less Than 50 kW (Energy-Billed) - GSe Grand Bend

Service Charge	$	24.54
Distribution Volumetric Rate	$ / kWh	0.0234
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0007
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0006)
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0035
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0032
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service 50 kW or Greater (Demand-Billed) - GSd Grand Bend

Service Charge	$	28.14
Distribution Volumetric Rate	$ / kW	8.75
Regulatory Asset Recovery - Rider #2	$ / kW	0.23
Regulatory Asset Recovery - Rider #3	$ / kW	(0.22)
Retail Transmission Rate - Network Service Rate (4)	$ / kW	1.11
Retail Transmission Rate - Line and Transformation Connection Service Rate (4)	$ / kW	1.00
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

Hydro One Networks Inc.
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Effective Date: May 1, 2008

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Unmetered, Scattered Load

Service Charge	$	13.72
Distribution Volumetric Rate	$ / kWh	0.0200
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0007
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0006)
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0035
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0032
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

(3) For energy-only metered customers, the billing determinant is the customer's metered energy consumption adjusted by the total loss factor as approved by the Board for Acquired LDC customers.
(4) For demand billed customers, appropriate loss factors must be applied to the applicable tariffs. Also the billing determinant for the Line and Transformation Connection Services rate is the customer's peak demand in the billing period. The billing determinant for the Network Services rate is: for non-interval-metered customers, the peak demand in the billing period, and for interval-metered customers, the peak demand between 7 AM and 7 PM local time on IESO business days

Customer-Supplied Transformation Allowance

Applicable to customers providing their own transformers

Demand-billed	$ / kW	0.60
Energy-billed	$ / kWh	0.0014

Hydro One Networks Inc.
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Loss Factors

Residential	1.085
General Service Less Than 50 kW (Energy-Billed)	1.092
General Service 50 kW or Greater (Demand-Billed)	1.061
Unmetered Scattered Load	1.092

Transformer Loss Allowance

Applicable to customers requiring a billing adjustment for transformer losses as the result of being metered on the primary side of a transformer. The following uniform values shall be applied to measured demand and energy to calculate transformer losses for voltages up to and including 50 kV (as metered on the primary side):

(a) 1.5% for transformer installations up to an individual bank capacity of 400 kVA,
(b) 1.0% for bank capacities over 400 kVA.

Alternatively, transformer losses may be determined from transformer test data, and measured demand and energy adjusted accordingly

For services which are not demand metered, an assumed demand of 50% of the transformer capacity will be used to calculate the loss allowance. Where several transformers are involved, the bank capacity is assumed to be the arithmetic sum of all transformer capacities

Hydro One Networks Inc.
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MISCELLANEOUS CHARGES

Specific Service Charges: Standard Amounts

Rate Code	Specific Service Charge - Standard Name	Calculation Method			
		2006 Rate Handbook	Standard Formula	Other Formula	Time and Materials
1	Temporary Service	$500			
2	Dispute Meter Test	$30 plus Measurement Canada fees			
3	Collection of account – no disconnection/load limiter	$30			
4	Collection/Disconnect/load limiter/reconnect (at meter) trip – regular hours	$65			
5	Collection/Disconnect/load limiter/reconnect (at meter) trip – after regular hours	$185			
6	Collection/Disconnect/load limiter/reconnect (at pole) trip – regular hours	$185			
7	Collection/Disconnect/load limiter/reconnect (at pole) trip – after regular hours	$415			
8	Account Set-up Charge	$30			
9	Arrears Certificate	$15			
10	NSF Cheque Charge	$15 + bank charges			
11	Easement Charge for Unregistered Rights	$15			
12	Late Payment Charge	1.5%/month			
13a	Retailer Services – Establishing Service Agreements (refer to Handbook for all charges)	$100/agreement/Retailer +$20/month/Retailer +$0.50/month/customer + other			
13b	Retailer Services – Other (includes Bill Ready for Retailers and Service Transactions Requests) as per the Handbook, Chapter 12	$0.30/month/customer + $0.25/request for request fee + $0.50/request for process fee			
14	Special Meter Reads	$30			
15	Service Layout Fee – Basic		$495		
16	Service Layout Fee – Complex		$690		
17	Crossing Application – Pipeline		$2,445		
18	Crossing Application – Water		$3,045		
19	Crossing Application – Railroad		$2,945		
20	Line Staking – per meter		$3.70		
21	Central Metering – New service < 45 kW		$115		
22	Conversion to Central Metering < 45 kW		$915		
23	Conversion to Central Metering > 45 kW		$800		
24	Tingle Voltage Test – In Excess of 4 Hours (per hour – average 2 additional hours)		$125		
25	Standby Administration Charge per month		$440		
26	Sentinel Lights Rental Rate per month			$7.10	
27	Sentinel Pole Rental Rate per month			$4.15	
28	Joint Use for Cable and Telecom companies per pole			$22.35	
29	Joint Use for LDCs per pole			$28.61	

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APPLICATION

The application of these rates and charges shall be in accordance with The Licence of The Distributor and any Codes, Guidelines or Orders of The Board, and amendments thereto as approved by The Board, which may be applicable to the administration of this schedule.
No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code, Guideline or Order of the Board, and amendments thereto as approved by the Board, or as specified herein
This schedule does not contain any rates and charges relating to the electricity commodity (e.g. the Regulated Price Plan).

EFFECTIVE DATES

DISTRIBUTION RATES - May 1, 2007 for all consumption or deemed consumption services used on or after that date.

MISCELLANEOUS CHARGES - May 1, 2007 for all charges billed to customers on or after that date.
RETAIL TRANSMISSION RATES - May 1, 2007 for all consumption or deemed consumption services used on or after that date.
LOSS FACTOR ADJUSTMENT – May 1, 2007

SERVICE CLASSIFICATIONS

Residential
This classification (note 1) refers to all service supplied to single-family dwelling units for domestic or household purpose. Multi-unit residential establishments such as apartment buildings supplied through one service (bulk metered) will normally be classified as General Service, but, at Hydro One's discretion, up to four residential units may be classified as residential. Where electricity service is provided to combined residential and business (including agricultural usage) and the wiring does not provide for separate metering, the classification shall be at the discretion of Hydro One based on such considerations as the estimated predominant consumption.
Further servicing details are available in the utility's Conditions of Service.

General Service
This classification (note 1) refers to all service supplied to premises other than those classified as Residential or Lighting. Some General Service accounts are energy(kWh)-billed, and some are demand(kW)-billed. Further servicing details are available in the utility's Conditions of Service. Also, see note 2.

Unmetered Scattered Load
This classification refers to certain instances where connections can be provided without metering. These loads are generally small in size and consistent in magnitude of load. Hydro One reserves the right to review all cases and may require that a meter be installed at its sole discretion. Services that can be unmetered include cable TV amplifiers, telephone switching devices, phone booths, bus shelters, rail way crossing signals, traffic signals, and other small fixed loads.
Further servicing details are available in the utility's Conditions of Service (including in the "Unmetered Connections" section).

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Street Lighting

This classification refers to accounts for the distribution and supply of electrical energy for street lighting. Street lights are devices owned by or operated for the road authority and/or the municipal corporation. These street lights in fact belong to the Street Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Sentinel Lighting

This classification refers to accounts for a separate service to a sentinel light. These sentinel lights in fact belong to the Sentinel Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Interim Demand-Side Management Time-of-Use

This is potentially applicable to Demand-billed General Service accounts. See Note 2 below.

Note (1): Classification descriptions are paraphrases from the document "Hydro One Networks Inc. - Distribution Customers Conditions of Service - August 2004"

Note (2):

Interim Demand-Side Management Time-of-Use Rates: demand charges will be based on demand during the on-peak periods.

Criteria: Customers' electricity consumption (kW) in the off-peak period is at least twice the electricity consumption (kW) during the on-peak period.

Definition of Time Periods: The on-peak hours will be between 0700 hours to 1900 hours Eastern Standard Time during the winter (standard time) on IESO business days and 0600 hours to 1800 hours Eastern Standard Time during the summer (daylight savings time) on IESO business days. The off-peak period constitutes all of the remaining hours.

Hydro One Networks Inc.
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MONTHLY RATES AND CHARGES

Residential

Service Charge	$	13.58
Distribution Volumetric Rate	$ / kWh	0.0087
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0042
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0013
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0055
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0047
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service - Energy Billed (less than 50 kW)

Service Charge	$	22.20
Distribution Volumetric Rate	$ / kWh	0.0123
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0019
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0007
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0050
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0043
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service - Demand Billed (50 kW or greater)

Service Charge	$	22.20
Distribution Volumetric Rate	$ / kW	3.90
Regulatory Asset Recovery - Rider #1	$ / kW	0.59
Regulatory Asset Recovery - Rider #2	$ / kW	0.23
Retail Transmission Rate - Network Service Rate (4)	$ / kW	1.94
Retail Transmission Rate - Line and Transformation Connection Service Rate (4)	$ / kW	1.61
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Public Utility Commission of Village of Grand Bend
Effective Date: May 1, 2007

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

Unmetered, Scattered Load

Service Charge	$	10.63
Distribution Volumetric Rate	$ / kWh	0.0123
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0019
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0007
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0050
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0043
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

(3) For energy-only metered customers, the billing determinant is the customer's metered energy consumption adjusted by the total loss factor as approved by the Board for Acquired LDC customers.

(4) For demand billed customers, appropriate loss factors must be applied to the applicable tariffs. Also the billing determinant for the Line and Transformation Connection Services rate is the customer's peak demand in the billing period. The billing determinant for the Network Services rate is: for non-interval-metered customers, the peak demand in the billing period, and for interval-metered customers, the peak demand between 7 AM and 7 PM local time on IESO business days

Interim Demand-Side Management Time-of-Use

See the "Service Classifications" section of this schedule.

Customer-Supplied Transformation Allowance

Applicable to demand-billed customers providing their own transformers
Primary Voltage under 50 kV (per kW)

Single Phase	$ / kW	0.20
Three Phase	$ / kW	0.60

Hydro One Networks Inc.
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Effective Date: May 1, 2007

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Loss Factors

Supply Facilities Loss Factor	1.0045
Distribution Loss Factors	
Customer less than 5,000 kW	1.0500
Customer greater than or equal to 5,000 kW	1.0100
Total Loss Factors	
Customer less than 5,000 kW	1.0545
Customer greater than or equal to 5,000 kW	1.0145

Transformer Loss Allowance

Applicable to customers requiring a billing adjustment for transformer losses as the result of being metered on the primary side of a transformer. The following uniform values shall be applied to measured demand and energy to calculate transformer losses for voltages up to and including 50 kV (as metered on the primary side):

(a) 1.5% for transformer installations up to an individual bank capacity of 400 kVA,
(b) 1.0% for bank capacities over 400 kVA.

Alternatively, transformer losses may be determined from transformer test data, and measured demand and energy adjusted accordingly

For services which are not demand metered, an assumed demand of 50% of the transformer capacity will be used to calculate the loss allowance. Where several transformers are involved, the bank capacity is assumed to be the arithmetic sum of all transformer capacities

Hydro One Networks Inc.
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Effective Date: May 1, 2007

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MISCELLANEOUS CHARGES

Specific Service Charges: Standard Amounts

Rate Code	Specific Service Charge - Standard Name	Calculation Method			
		2006 Rate Handbook	Standard Formula	Other Formula	Time and Materials
1	Temporary Service	$500			
2	Dispute Meter Test	$30 plus Measurement Canada fees			
3	Collection of account – no disconnection/load limiter	$30			
4	Collection/Disconnect/load limiter/reconnect (at meter) trip – regular hours	$65			
5	Collection/Disconnect/load limiter/reconnect (at meter) trip – after regular hours	$185			
6	Collection/Disconnect/load limiter/reconnect (at pole) trip – regular hours	$185			
7	Collection/Disconnect/load limiter/reconnect (at pole) trip – after regular hours	$415			
8	Account Set-up Charge	$30			
9	Arrears Certificate	$15			
10	NSF Cheque Charge	$15 + bank charges			
11	Easement Charge for Unregistered Rights	$15			
12	Late Payment Charge	1.5%/month			
13a	Retailer Services – Establishing Service Agreements (refer to Handbook for all charges)	$100/agreement/Retailer +$20/month/Retailer +$0.50/month/customer + other			
13b	Retailer Services – Other (includes Bill Ready for Retailers and Service Transactions Requests) as per the Handbook, Chapter 12	$0.30/month/customer + $0.25/request for request fee + $0.50/request for process fee			
14	Special Meter Reads	$30			
15	Billing Suspension and Terminations in Trailer Parks		$130		
16	Service Layout Fee – Basic		$405		
17	Service Layout Fee – Complex		$580		

Hydro One Networks Inc.
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18	Crossing Application – Pipeline		$2,065		
19	Crossing Application – Water		$2,525		
20	Crossing Application – Railroad		$2,565		
21	Line Staking – per meter		$3.10		
22	Central Metering – New service < 45 kW		$115		
23	Conversion to Central Metering < 45 kW		$795		
24	Conversion to Central Metering > 45 kW		$680		
25	Tingle Voltage Test – In Excess of 4 Hours (per hour – average 2 additional hours)		$105		
26	Standby Administration Charge per month (interim)		$375		
27	Sentinel Lights Rental Rate per month – Mercury Vapor			$7.00	
28	Guaranteed Units from Jan 01/91 to Aug 01/91			$26.50 / month	
29	Guaranteed Units from Jan 01/87 to Dec 31/90			$23.50 / month	
30	Joint Use for Cable and Telecom companies per pole			$22.35	
31	Joint Use for LDCs per pole			$28.61	

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Public Utilities Commission of the Village of Hastings
Effective Date: May 1, 2008

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

APPLICATION

The application of these rates and charges shall be in accordance with The Licence of The Distributor and any Codes, Guidelines or Orders of The Board, and amendments thereto as approved by The Board, which may be applicable to the administration of this schedule.
No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code, Guideline or Order of the Board, and amendments thereto as approved by the Board, or as specified herein
This schedule does not contain any rates and charges relating to the electricity commodity (e.g. the Regulated Price Plan).

EFFECTIVE DATES

DISTRIBUTION RATES - May 1, 2008 for all consumption or deemed consumption services used on or after that date.

MISCELLANEOUS CHARGES - May 1, 2008 for all charges billed to customers on or after that date.
RETAIL TRANSMISSION RATES - May 1, 2008 for all consumption or deemed consumption services used on or after that date.
LOSS FACTOR ADJUSTMENT – for all consumption or deemed consumption services billed following May 1, 2008 or later

SERVICE CLASSIFICATIONS

Residential
This classification refers to all service supplied to single-family dwelling units for domestic or household purpose. Multi-unit residential establishments such as apartment buildings supplied through one service (bulk metered) will normally be classified as General Service, but, at Hydro One's discretion, up to four residential units may be classified as residential. Where electricity service is provided to combined residential and business (including agricultural usage) and the wiring does not provide for separate metering, the classification shall be at the discretion of Hydro One based on such considerations as the estimated predominant consumption.
Further servicing details are available in the utility's Conditions of Service.

General Service
This classification refers to all service supplied to premises other than those classified as Residential or Lighting. Some General Service accounts are energy(kWh)-billed, and some are demand(kW)-billed. Further servicing details are available in the utility's Conditions of Service.

Unmetered Scattered Load
This classification refers to certain instances where connections can be provided without metering. These loads are generally small in size and consistent in magnitude of load. Hydro One reserves the right to review all cases and may require that a meter be installed at its sole discretion. Services that can be unmetered include cable TV amplifiers, telephone switching devices, phone booths, bus shelters, rail way crossing signals, traffic signals, and other small fixed loads.
Further servicing details are available in the utility's Conditions of Service (including in the "Unmetered Connections" section).

Hydro One Networks Inc.
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Public Utilities Commission of the Village of Hastings
Effective Date: May 1, 2008

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Street Lighting

This classification refers to accounts for the distribution and supply of electrical energy for street lighting. Street lights are devices owned by or operated for the road authority and/or the municipal corporation. These street lights in fact belong to the Street Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Sentinel Lighting

This classification refers to accounts for a separate service to a sentinel light. These sentinel lights in fact belong to the Sentinel Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Urban Density Classification

Customers who meet the Urban Density Criteria of being in an area containing 3,000 or more customers with a line density of at least 60 customers per kilometre, will be mapped to an Urban customer classification.

Hydro One Networks Inc.
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MONTHLY RATES AND CHARGES

Residential - R1 Hastings

Service Charge	$	16.65
Distribution Volumetric Rate	$ / kWh	0.0265
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0012
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0004)
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0047
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0046
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service Less Than 50 kW (Energy-Billed) - GSe Hastings

Service Charge	$	24.37
Distribution Volumetric Rate	$ / kWh	0.0293
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0009
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0006)
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0035
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0032
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service 50 kW or Greater (Demand-Billed) - GSd Hastings

Service Charge	$	27.97
Distribution Volumetric Rate	$ / kW	9.22
Regulatory Asset Recovery - Rider #2	$ / kW	0.29
Regulatory Asset Recovery - Rider #3	$ / kW	(0.22)
Retail Transmission Rate - Network Service Rate (4)	$ / kW	1.11
Retail Transmission Rate - Line and Transformation Connection Service Rate (4)	$ / kW	1.00
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

Hydro One Networks Inc.
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Unmetered, Scattered Load

Service Charge	$	13.63
Distribution Volumetric Rate	$ / kWh	0.0200
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0009
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0006)
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0035
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0032
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

(3) For energy-only metered customers, the billing determinant is the customer’s metered energy consumption adjusted by the total loss factor as approved by the Board for Acquired LDC customers.

(4) For demand billed customers, appropriate loss factors must be applied to the applicable tariffs. Also the billing determinant for the Line and Transformation Connection Services rate is the customer’s peak demand in the billing period. The billing determinant for the Network Services rate is: for non-interval-metered customers, the peak demand in the billing period, and for interval-metered customers, the peak demand between 7 AM and 7 PM local time on IESO business days

Customer-Supplied Transformation Allowance

Applicable to customers providing their own transformers		
Demand-billed	$ / kW	0.60
Energy-billed	$ / kWh	0.0014

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Loss Factors

Residential	1.085
General Service Less Than 50 kW (Energy-Billed)	1.092
General Service 50 kW or Greater (Demand-Billed)	1.061
Unmetered Scattered Load	1.092

Transformer Loss Allowance

Applicable to customers requiring a billing adjustment for transformer losses as the result of being metered on the primary side of a transformer. The following uniform values shall be applied to measured demand and energy to calculate transformer losses for voltages up to and including 50 kV (as metered on the primary side):

(a) 1.5% for transformer installations up to an individual bank capacity of 400 kVA,
(b) 1.0% for bank capacities over 400 kVA.

Alternatively, transformer losses may be determined from transformer test data, and measured demand and energy adjusted accordingly

For services which are not demand metered, an assumed demand of 50% of the transformer capacity will be used to calculate the loss allowance. Where several transformers are involved, the bank capacity is assumed to be the arithmetic sum of all transformer capacities

Hydro One Networks Inc.
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Effective Date: May 1, 2008

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MISCELLANEOUS CHARGES

Specific Service Charges: Standard Amounts

Rate Code	Specific Service Charge - Standard Name	Calculation Method			
		2006 Rate Handbook	Standard Formula	Other Formula	Time and Materials
1	Temporary Service	$500			
2	Dispute Meter Test	$30 plus Measurement Canada fees			
3	Collection of account – no disconnection/load limiter	$30			
4	Collection/Disconnect/load limiter/reconnect (at meter) trip – regular hours	$65			
5	Collection/Disconnect/load limiter/reconnect (at meter) trip – after regular hours	$185			
6	Collection/Disconnect/load limiter/reconnect (at pole) trip – regular hours	$185			
7	Collection/Disconnect/load limiter/reconnect (at pole) trip – after regular hours	$415			
8	Account Set-up Charge	$30			
9	Arrears Certificate	$15			
10	NSF Cheque Charge	$15 + bank charges			
11	Easement Charge for Unregistered Rights	$15			
12	Late Payment Charge	1.5%/month			
13a	Retailer Services – Establishing Service Agreements (refer to Handbook for all charges)	$100/agreement/Retailer +$20/month/Retailer +$0.50/month/customer + other			
13b	Retailer Services – Other (includes Bill Ready for Retailers and Service Transactions Requests) as per the Handbook, Chapter 12	$0.30/month/customer + $0.25/request for request fee + $0.50/request for process fee			
14	Special Meter Reads	$30			
15	Service Layout Fee – Basic		$495		
16	Service Layout Fee – Complex		$690		
17	Crossing Application – Pipeline		$2,445		
18	Crossing Application – Water		$3,045		
19	Crossing Application – Railroad		$2,945		
20	Line Staking – per meter		$3.70		
21	Central Metering – New service < 45 kW		$115		
22	Conversion to Central Metering < 45 kW		$915		
23	Conversion to Central Metering > 45 kW		$800		
24	Tingle Voltage Test – In Excess of 4 Hours (per hour – average 2 additional hours)		$125		
25	Standby Administration Charge per month		$440		
26	Sentinel Lights Rental Rate per month			$7.10	
27	Sentinel Pole Rental Rate per month			$4.15	
28	Joint Use for Cable and Telecom companies per pole			$22.35	
29	Joint Use for LDCs per pole			$28.61	

Hydro One Networks Inc.
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Effective Date: May 1, 2007

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APPLICATION

The application of these rates and charges shall be in accordance with The Licence of The Distributor and any Codes, Guidelines or Orders of The Board, and amendments thereto as approved by The Board, which may be applicable to the administration of this schedule.
No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code, Guideline or Order of the Board, and amendments thereto as approved by the Board, or as specified herein
This schedule does not contain any rates and charges relating to the electricity commodity (e.g. the Regulated Price Plan).

EFFECTIVE DATES

DISTRIBUTION RATES - May 1, 2007 for all consumption or deemed consumption services used on or after that date.

MISCELLANEOUS CHARGES - May 1, 2007 for all charges billed to customers on or after that date.
RETAIL TRANSMISSION RATES - May 1, 2007 for all consumption or deemed consumption services used on or after that date.
LOSS FACTOR ADJUSTMENT – May 1, 2007

SERVICE CLASSIFICATIONS

Residential
This classification (note 1) refers to all service supplied to single-family dwelling units for domestic or household purpose. Multi-unit residential establishments such as apartment buildings supplied through one service (bulk metered) will normally be classified as General Service, but, at Hydro One's discretion, up to four residential units may be classified as residential. Where electricity service is provided to combined residential and business (including agricultural usage) and the wiring does not provide for separate metering, the classification shall be at the discretion of Hydro One based on such considerations as the estimated predominant consumption.
Further servicing details are available in the utility's Conditions of Service.

General Service
This classification (note 1) refers to all service supplied to premises other than those classified as Residential or Lighting. Some General Service accounts are energy(kWh)-billed, and some are demand(kW)-billed. Further servicing details are available in the utility's Conditions of Service. Also, see note 2.

Unmetered Scattered Load
This classification refers to certain instances where connections can be provided without metering. These loads are generally small in size and consistent in magnitude of load. Hydro One reserves the right to review all cases and may require that a meter be installed at its sole discretion. Services that can be unmetered include cable TV amplifiers, telephone switching devices, phone booths, bus shelters, rail way crossing signals, traffic signals, and other small fixed loads.
Further servicing details are available in the utility's Conditions of Service (including in the "Unmetered Connections" section).

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Street Lighting

This classification refers to accounts for the distribution and supply of electrical energy for street lighting. Street lights are devices owned by or operated for the road authority and/or the municipal corporation. These street lights in fact belong to the Street Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Sentinel Lighting

This classification refers to accounts for a separate service to a sentinel light. These sentinel lights in fact belong to the Sentinel Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Interim Demand-Side Management Time-of-Use

This is potentially applicable to Demand-billed General Service accounts. See Note 2 below.

Note (1): Classification descriptions are paraphrases from the document "Hydro One Networks Inc. - Distribution Customers Conditions of Service - August 2004"

Note (2):

Interim Demand-Side Management Time-of-Use Rates: demand charges will be based on demand during the on-peak periods.

Criteria: Customers' electricity consumption (kW) in the off-peak period is at least twice the electricity consumption (kW) during the on-peak period.

Definition of Time Periods: The on-peak hours will be between 0700 hours to 1900 hours Eastern Standard Time during the winter (standard time) on IESO business days and 0600 hours to 1800 hours Eastern Standard Time during the summer (daylight savings time) on IESO business days. The off-peak period constitutes all of the remaining hours.

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MONTHLY RATES AND CHARGES

Residential

Service Charge	$	16.44
Distribution Volumetric Rate	$ / kWh	0.0135
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0037
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0012
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0055
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0047
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service - Energy Billed (less than 50 kW)

Service Charge	$	22.89
Distribution Volumetric Rate	$ / kWh	0.0169
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0023
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0009
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0050
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0043
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service - Demand Billed (50 kW or greater)

Service Charge	$	22.89
Distribution Volumetric Rate	$ / kW	5.32
Regulatory Asset Recovery - Rider #1	$ / kW	0.74
Regulatory Asset Recovery - Rider #2	$ / kW	0.29
Retail Transmission Rate - Network Service Rate (4)	$ / kW	1.94
Retail Transmission Rate - Line and Transformation Connection Service Rate (4)	$ / kW	1.61
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

Hydro One Networks Inc.
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Unmetered, Scattered Load

Service Charge	$	10.98
Distribution Volumetric Rate	$ / kWh	0.0169
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0023
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0009
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0050
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0043
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

(3) For energy-only metered customers, the billing determinant is the customer’s metered energy consumption adjusted by the total loss factor as approved by the Board for Acquired LDC customers.
(4) For demand billed customers, appropriate loss factors must be applied to the applicable tariffs. Also the billing determinant for the Line and Transformation Connection Services rate is the customer’s peak demand in the billing period. The billing determinant for the Network Services rate is: for non-interval-metered customers, the peak demand in the billing period, and for interval-metered customers, the peak demand between 7 AM and 7 PM local time on IESO business days

Interim Demand-Side Management Time-of-Use

See the "Service Classifications" section of this schedule.

Customer-Supplied Transformation Allowance

Applicable to demand-billed customers providing their own transformers
Primary Voltage under 50 kV (per kW)

Single Phase	$ / kW	0.20
Three Phase	$ / kW	0.60

Hydro One Networks Inc.
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Loss Factors

Supply Facilities Loss Factor	1.0045
Distribution Loss Factors	
Customer less than 5,000 kW	1.0500
Customer greater than or equal to 5,000 kW	1.0100
Total Loss Factors	
Customer less than 5,000 kW	1.0545
Customer greater than or equal to 5,000 kW	1.0145

Transformer Loss Allowance

Applicable to customers requiring a billing adjustment for transformer losses as the result of being metered on the primary side of a transformer. The following uniform values shall be applied to measured demand and energy to calculate transformer losses for voltages up to and including 50 kV (as metered on the primary side):

(a) 1.5% for transformer installations up to an individual bank capacity of 400 kVA,
(b) 1.0% for bank capacities over 400 kVA.

Alternatively, transformer losses may be determined from transformer test data, and measured demand and energy adjusted accordingly

For services which are not demand metered, an assumed demand of 50% of the transformer capacity will be used to calculate the loss allowance. Where several transformers are involved, the bank capacity is assumed to be the arithmetic sum of all transformer capacities

Hydro One Networks Inc.
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MISCELLANEOUS CHARGES

Specific Service Charges: Standard Amounts

Rate Code	Specific Service Charge - Standard Name	Calculation Method			
		2006 Rate Handbook	Standard Formula	Other Formula	Time and Materials
1	Temporary Service	$500			
2	Dispute Meter Test	$30 plus Measurement Canada fees			
3	Collection of account – no disconnection/load limiter	$30			
4	Collection/Disconnect/load limiter/reconnect (at meter) trip – regular hours	$65			
5	Collection/Disconnect/load limiter/reconnect (at meter) trip – after regular hours	$185			
6	Collection/Disconnect/load limiter/reconnect (at pole) trip – regular hours	$185			
7	Collection/Disconnect/load limiter/reconnect (at pole) trip – after regular hours	$415			
8	Account Set-up Charge	$30			
9	Arrears Certificate	$15			
10	NSF Cheque Charge	$15 + bank charges			
11	Easement Charge for Unregistered Rights	$15			
12	Late Payment Charge	1.5%/month			
13a	Retailer Services – Establishing Service Agreements (refer to Handbook for all charges)	$100/agreement/Retailer +$20/month/Retailer +$0.50/month/customer + other			
13b	Retailer Services – Other (includes Bill Ready for Retailers and Service Transactions Requests) as per the Handbook, Chapter 12	$0.30/month/customer + $0.25/request for request fee + $0.50/request for process fee			
14	Special Meter Reads	$30			
15	Billing Suspension and Terminations in Trailer Parks		$130		
16	Service Layout Fee – Basic		$405		
17	Service Layout Fee – Complex		$580		

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TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Public Utilities Commission of the Village of Hastings
Effective Date: May 1, 2007

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

18	Crossing Application – Pipeline		$2,065		
19	Crossing Application – Water		$2,525		
20	Crossing Application – Railroad		$2,565		
21	Line Staking – per meter		$3.10		
22	Central Metering – New service < 45 kW		$115		
23	Conversion to Central Metering < 45 kW		$795		
24	Conversion to Central Metering > 45 kW		$680		
25	Tingle Voltage Test – In Excess of 4 Hours (per hour – average 2 additional hours)		$105		
26	Standby Administration Charge per month (interim)		$375		
27	Sentinel Lights Rental Rate per month – Mercury Vapor			$7.00	
28	Guaranteed Units from Jan 01/91 to Aug 01/91			$26.50 / month	
29	Guaranteed Units from Jan 01/87 to Dec 31/90			$23.50 / month	
30	Joint Use for Cable and Telecom companies per pole			$22.35	
31	Joint Use for LDCs per pole			$28.61	

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Hydro Electric Commission of the Township of Havelock-Belmonth-Methuen
Effective Date: May 1, 2008

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

APPLICATION

The application of these rates and charges shall be in accordance with The Licence of The Distributor and any Codes, Guidelines or Orders of The Board, and amendments thereto as approved by The Board, which may be applicable to the administration of this schedule.
No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code, Guideline or Order of the Board, and amendments thereto as approved by the Board, or as specified herein
This schedule does not contain any rates and charges relating to the electricity commodity (e.g. the Regulated Price Plan).

EFFECTIVE DATES

DISTRIBUTION RATES - May 1, 2008 for all consumption or deemed consumption services used on or after that date.

MISCELLANEOUS CHARGES - May 1, 2008 for all charges billed to customers on or after that date.
RETAIL TRANSMISSION RATES - May 1, 2008 for all consumption or deemed consumption services used on or after that date.
LOSS FACTOR ADJUSTMENT – for all consumption or deemed consumption services billed following May 1, 2008 or later

SERVICE CLASSIFICATIONS

Residential
This classification refers to all service supplied to single-family dwelling units for domestic or household purpose. Multi-unit residential establishments such as apartment buildings supplied through one service (bulk metered) will normally be classified as General Service, but, at Hydro One's discretion, up to four residential units may be classified as residential. Where electricity service is provided to combined residential and business (including agricultural usage) and the wiring does not provide for separate metering, the classification shall be at the discretion of Hydro One based on such considerations as the estimated predominant consumption.
Further servicing details are available in the utility's Conditions of Service.

General Service
This classification refers to all service supplied to premises other than those classified as Residential or Lighting. Some General Service accounts are energy(kWh)-billed, and some are demand(kW)-billed. Further servicing details are available in the utility's Conditions of Service.

Unmetered Scattered Load
This classification refers to certain instances where connections can be provided without metering. These loads are generally small in size and consistent in magnitude of load. Hydro One reserves the right to review all cases and may require that a meter be installed at its sole discretion. Services that can be unmetered include cable TV amplifiers, telephone switching devices, phone booths, bus shelters, rail way crossing signals, traffic signals, and other small fixed loads.
Further servicing details are available in the utility's Conditions of Service (including in the "Unmetered Connections" section).

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Hydro Electric Commission of the Township of Havelock-Belmonth-Methuen
Effective Date: May 1, 2008

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

Street Lighting

This classification refers to accounts for the distribution and supply of electrical energy for street lighting. Street lights are devices owned by or operated for the road authority and/or the municipal corporation. These street lights in fact belong to the Street Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Sentinel Lighting

This classification refers to accounts for a separate service to a sentinel light. These sentinel lights in fact belong to the Sentinel Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Urban Density Classification

Customers who meet the Urban Density Criteria of being in an area containing 3,000 or more customers with a line density of at least 60 customers per kilometre, will be mapped to an Urban customer classification.

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Hydro Electric Commission of the Township of Havelock-Belmonth-Methuen
Effective Date: May 1, 2008

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

MONTHLY RATES AND CHARGES

Residential - R1 Havelock

Service Charge	$	15.97
Distribution Volumetric Rate	$ / kWh	0.0230
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0013
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0004)
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0047
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0046
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service Less Than 50 kW (Energy-Billed) - GSe Havelock

Service Charge	$	24.55
Distribution Volumetric Rate	$ / kWh	0.0260
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0009
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0006)
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0035
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0032
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service 50 kW or Greater (Demand-Billed) - GSd Havelock

Service Charge	$	28.14
Distribution Volumetric Rate	$ / kW	9.22
Regulatory Asset Recovery - Rider #2	$ / kW	0.28
Regulatory Asset Recovery - Rider #3	$ / kW	(0.22)
Retail Transmission Rate - Network Service Rate (4)	$ / kW	1.11
Retail Transmission Rate - Line and Transformation Connection Service Rate (4)	$ / kW	1.00
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Hydro Electric Commission of the Township of Havelock-Belmonth-Methuen
Effective Date: May 1, 2008

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

Unmetered, Scattered Load

Service Charge	$	13.72
Distribution Volumetric Rate	$ / kWh	0.0200
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0009
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0006)
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0035
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0032
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

(3) For energy-only metered customers, the billing determinant is the customer's metered energy consumption adjusted by the total loss factor as approved by the Board for Acquired LDC customers.
(4) For demand billed customers, appropriate loss factors must be applied to the applicable tariffs. Also the billing determinant for the Line and Transformation Connection Services rate is the customer's peak demand in the billing period. The billing determinant for the Network Services rate is: for non-interval-metered customers, the peak demand in the billing period, and for interval-metered customers, the peak demand between 7 AM and 7 PM local time on IESO business days

Customer-Supplied Transformation Allowance

Applicable to customers providing their own transformers

Demand-billed	$ / kW	0.60
Energy-billed	$ / kWh	0.0014

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Hydro Electric Commission of the Township of Havelock-Belmonth-Methuen
Effective Date: May 1, 2008

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

Loss Factors

Residential	1.085
General Service Less Than 50 kW (Energy-Billed)	1.092
General Service 50 kW or Greater (Demand-Billed)	1.061
Unmetered Scattered Load	1.092

Transformer Loss Allowance

Applicable to customers requiring a billing adjustment for transformer losses as the result of being metered on the primary side of a transformer. The following uniform values shall be applied to measured demand and energy to calculate transformer losses for voltages up to and including 50 kV (as metered on the primary side):

(a) 1.5% for transformer installations up to an individual bank capacity of 400 kVA,
(b) 1.0% for bank capacities over 400 kVA.

Alternatively, transformer losses may be determined from transformer test data, and measured demand and energy adjusted accordingly

For services which are not demand metered, an assumed demand of 50% of the transformer capacity will be used to calculate the loss allowance. Where several transformers are involved, the bank capacity is assumed to be the arithmetic sum of all transformer capacities

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Hydro Electric Commission of the Township of Havelock-Belmonth-Methuen
Effective Date: May 1, 2008

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

MISCELLANEOUS CHARGES

Specific Service Charges: Standard Amounts

Rate Code	Specific Service Charge - Standard Name	Calculation Method			
		2006 Rate Handbook	Standard Formula	Other Formula	Time and Materials
1	Temporary Service	$500			
2	Dispute Meter Test	$30 plus Measurement Canada fees			
3	Collection of account – no disconnection/load limiter	$30			
4	Collection/Disconnect/load limiter/reconnect (at meter) trip – regular hours	$65			
5	Collection/Disconnect/load limiter/reconnect (at meter) trip – after regular hours	$185			
6	Collection/Disconnect/load limiter/reconnect (at pole) trip – regular hours	$185			
7	Collection/Disconnect/load limiter/reconnect (at pole) trip – after regular hours	$415			
8	Account Set-up Charge	$30			
9	Arrears Certificate	$15			
10	NSF Cheque Charge	$15 + bank charges			
11	Easement Charge for Unregistered Rights	$15			
12	Late Payment Charge	1.5%/month			
13a	Retailer Services – Establishing Service Agreements (refer to Handbook for all charges)	$100/agreement/Retailer +$20/month/Retailer +$0.50/month/customer + other			
13b	Retailer Services – Other (includes Bill Ready for Retailers and Service Transactions Requests) as per the Handbook, Chapter 12	$0.30/month/customer + $0.25/request for request fee + $0.50/request for process fee			
14	Special Meter Reads	$30			
15	Service Layout Fee – Basic		$495		
16	Service Layout Fee – Complex		$690		
17	Crossing Application – Pipeline		$2,445		
18	Crossing Application – Water		$3,045		
19	Crossing Application – Railroad		$2,945		
20	Line Staking – per meter		$3.70		
21	Central Metering – New service < 45 kW		$115		
22	Conversion to Central Metering < 45 kW		$915		
23	Conversion to Central Metering > 45 kW		$800		
24	Tingle Voltage Test – In Excess of 4 Hours (per hour – average 2 additional hours)		$125		
25	Standby Administration Charge per month		$440		
26	Sentinel Lights Rental Rate per month			$7.10	
27	Sentinel Pole Rental Rate per month			$4.15	
28	Joint Use for Cable and Telecom companies per pole			$22.35	
29	Joint Use for LDCs per pole			$28.61	

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Hydro Electric Commission of the Township of Havelock-Belmonth-Methuen
Effective Date: May 1, 2007

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

APPLICATION

The application of these rates and charges shall be in accordance with The Licence of The Distributor and any Codes, Guidelines or Orders of The Board, and amendments thereto as approved by The Board, which may be applicable to the administration of this schedule.
No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code, Guideline or Order of the Board, and amendments thereto as approved by the Board, or as specified herein
This schedule does not contain any rates and charges relating to the electricity commodity (e.g. the Regulated Price Plan).

EFFECTIVE DATES

DISTRIBUTION RATES - May 1, 2007 for all consumption or deemed consumption services used on or after that date.

MISCELLANEOUS CHARGES - May 1, 2007 for all charges billed to customers on or after that date.
RETAIL TRANSMISSION RATES - May 1, 2007 for all consumption or deemed consumption services used on or after that date.
LOSS FACTOR ADJUSTMENT – May 1, 2007

SERVICE CLASSIFICATIONS

Residential
This classification (note 1) refers to all service supplied to single-family dwelling units for domestic or household purpose. Multi-unit residential establishments such as apartment buildings supplied through one service (bulk metered) will normally be classified as General Service, but, at Hydro One’s discretion, up to four residential units may be classified as residential. Where electricity service is provided to combined residential and business (including agricultural usage) and the wiring does not provide for separate metering, the classification shall be at the discretion of Hydro One based on such considerations as the estimated predominant consumption.
Further servicing details are available in the utility’s Conditions of Service.

General Service
This classification (note 1) refers to all service supplied to premises other than those classified as Residential or Lighting. Some General Service accounts are energy(kWh)-billed, and some are demand(kW)-billed. Further servicing details are available in the utility’s Conditions of Service. Also, see note 2.

Unmetered Scattered Load
This classification refers to certain instances where connections can be provided without metering. These loads are generally small in size and consistent in magnitude of load. Hydro One reserves the right to review all cases and may require that a meter be installed at its sole discretion. Services that can be unmetered include cable TV amplifiers, telephone switching devices, phone booths, bus shelters, rail way crossing signals, traffic signals, and other small fixed loads.
Further servicing details are available in the utility’s Conditions of Service (including in the "Unmetered Connections" section).

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Hydro Electric Commission of the Township of Havelock-Belmonth-Methuen
Effective Date: May 1, 2007

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

Street Lighting

This classification refers to accounts for the distribution and supply of electrical energy for street lighting. Street lights are devices owned by or operated for the road authority and/or the municipal corporation. These street lights in fact belong to the Street Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility’s Conditions of Service.

Sentinel Lighting

This classification refers to accounts for a separate service to a sentinel light. These sentinel lights in fact belong to the Sentinel Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility’s Conditions of Service.

Interim Demand-Side Management Time-of-Use

This is potentially applicable to Demand-billed General Service accounts. See Note 2 below.

Note (1): Classification descriptions are paraphrases from the document "Hydro One Networks Inc. - Distribution Customers Conditions of Service - August 2004"

Note (2):

Interim Demand-Side Management Time-of-Use Rates: demand charges will be based on demand during the on-peak periods.

Criteria: Customers' electricity consumption (kW) in the off-peak period is at least twice the electricity consumption (kW) during the on-peak period.

Definition of Time Periods: The on-peak hours will be between 0700 hours to 1900 hours Eastern Standard Time during the winter (standard time) on IESO business days and 0600 hours to 1800 hours Eastern Standard Time during the summer (daylight savings time) on IESO business days. The off-peak period constitutes all of the remaining hours.

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Hydro Electric Commission of the Township of Havelock-Belmonth-Methuen
Effective Date: May 1, 2007

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

MONTHLY RATES AND CHARGES

Residential

Service Charge	$	15.17
Distribution Volumetric Rate	$ / kWh	0.0114
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0032
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0013
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0055
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0047
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service - Energy Billed (less than 50 kW)

Service Charge	$	22.18
Distribution Volumetric Rate	$ / kWh	0.0152
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0016
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0009
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0050
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0043
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service - Demand Billed (50 kW or greater)

Service Charge	$	22.18
Distribution Volumetric Rate	$ / kW	4.82
Regulatory Asset Recovery - Rider #1	$ / kW	0.50
Regulatory Asset Recovery - Rider #2	$ / kW	0.28
Retail Transmission Rate - Network Service Rate (4)	$ / kW	1.94
Retail Transmission Rate - Line and Transformation Connection Service Rate (4)	$ / kW	1.61
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Hydro Electric Commission of the Township of Havelock-Belmonth-Methuen
Effective Date: May 1, 2007

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

Unmetered, Scattered Load

Service Charge	$	10.63
Distribution Volumetric Rate	$ / kWh	0.0152
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0016
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0009
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0050
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0043
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

(3) For energy-only metered customers, the billing determinant is the customer's metered energy consumption adjusted by the total loss factor as approved by the Board for Acquired LDC customers.

(4) For demand billed customers, appropriate loss factors must be applied to the applicable tariffs. Also the billing determinant for the Line and Transformation Connection Services rate is the customer's peak demand in the billing period. The billing determinant for the Network Services rate is: for non-interval-metered customers, the peak demand in the billing period, and for interval-metered customers, the peak demand between 7 AM and 7 PM local time on IESO business days

Interim Demand-Side Management Time-of-Use

See the "Service Classifications" section of this schedule.

Customer-Supplied Transformation Allowance

Applicable to demand-billed customers providing their own transformers

Primary Voltage under 50 kV (per kW)		
Single Phase	$ / kW	0.20
Three Phase	$ / kW	0.60

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Hydro Electric Commission of the Township of Havelock-Belmonth-Methuen
Effective Date: May 1, 2007

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

Loss Factors

Supply Facilities Loss Factor	1.0045
Distribution Loss Factors	
Customer less than 5,000 kW	1.0500
Customer greater than or equal to 5,000 kW	1.0100
Total Loss Factors	
Customer less than 5,000 kW	1.0545
Customer greater than or equal to 5,000 kW	1.0145

Transformer Loss Allowance

Applicable to customers requiring a billing adjustment for transformer losses as the result of being metered on the primary side of a transformer. The following uniform values shall be applied to measured demand and energy to calculate transformer losses for voltages up to and including 50 kV (as metered on the primary side):

(a) 1.5% for transformer installations up to an individual bank capacity of 400 kVA,
(b) 1.0% for bank capacities over 400 kVA.

Alternatively, transformer losses may be determined from transformer test data, and measured demand and energy adjusted accordingly

For services which are not demand metered, an assumed demand of 50% of the transformer capacity will be used to calculate the loss allowance. Where several transformers are involved, the bank capacity is assumed to be the arithmetic sum of all transformer capacities

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Hydro Electric Commission of the Township of Havelock-Belmonth-Methuen
Effective Date: May 1, 2007

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

MISCELLANEOUS CHARGES

Specific Service Charges: Standard Amounts

Rate Code	Specific Service Charge - Standard Name	Calculation Method			
		2006 Rate Handbook	Standard Formula	Other Formula	Time and Materials
1	Temporary Service	$500			
2	Dispute Meter Test	$30 plus Measurement Canada fees			
3	Collection of account – no disconnection/load limiter	$30			
4	Collection/Disconnect/load limiter/reconnect (at meter) trip – regular hours	$65			
5	Collection/Disconnect/load limiter/reconnect (at meter) trip – after regular hours	$185			
6	Collection/Disconnect/load limiter/reconnect (at pole) trip – regular hours	$185			
7	Collection/Disconnect/load limiter/reconnect (at pole) trip – after regular hours	$415			
8	Account Set-up Charge	$30			
9	Arrears Certificate	$15			
10	NSF Cheque Charge	$15 + bank charges			
11	Easement Charge for Unregistered Rights	$15			
12	Late Payment Charge	1.5%/month			
13a	Retailer Services – Establishing Service Agreements (refer to Handbook for all charges)	$100/agreement/Retailer +$20/month/Retailer +$0.50/month/customer + other			
13b	Retailer Services – Other (includes Bill Ready for Retailers and Service Transactions Requests) as per the Handbook, Chapter 12	$0.30/month/customer + $0.25/request for request fee + $0.50/request for process fee			
14	Special Meter Reads	$30			
15	Billing Suspension and Terminations in Trailer Parks		$130		
16	Service Layout Fee – Basic		$405		
17	Service Layout Fee – Complex		$580		

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Hydro Electric Commission of the Township of Havelock-Belmonth-Methuen
Effective Date: May 1, 2007

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

18	Crossing Application – Pipeline		$2,065		
19	Crossing Application – Water		$2,525		
20	Crossing Application – Railroad		$2,565		
21	Line Staking – per meter		$3.10		
22	Central Metering – New service < 45 kW		$115		
23	Conversion to Central Metering < 45 kW		$795		
24	Conversion to Central Metering > 45 kW		$680		
25	Tingle Voltage Test – In Excess of 4 Hours (per hour – average 2 additional hours)		$105		
26	Standby Administration Charge per month (interim)		$375		
27	Sentinel Lights Rental Rate per month – Mercury Vapor			$7.00	
28	Guaranteed Units from Jan 01/91 to Aug 01/91			$26.50 / month	
29	Guaranteed Units from Jan 01/87 to Dec 31/90			$23.50 / month	
30	Joint Use for Cable and Telecom companies per pole			$22.35	
31	Joint Use for LDCs per pole			$28.61	

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Kirkfield Hydro Electric System
Effective Date: May 1, 2008

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

APPLICATION

The application of these rates and charges shall be in accordance with The Licence of The Distributor and any Codes, Guidelines or Orders of The Board, and amendments thereto as approved by The Board, which may be applicable to the administration of this schedule.
No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code, Guideline or Order of the Board, and amendments thereto as approved by the Board, or as specified herein
This schedule does not contain any rates and charges relating to the electricity commodity (e.g. the Regulated Price Plan).

EFFECTIVE DATES

DISTRIBUTION RATES - May 1, 2008 for all consumption or deemed consumption services used on or after that date.

MISCELLANEOUS CHARGES - May 1, 2008 for all charges billed to customers on or after that date.
RETAIL TRANSMISSION RATES - May 1, 2008 for all consumption or deemed consumption services used on or after that date.
LOSS FACTOR ADJUSTMENT – for all consumption or deemed consumption services billed following May 1, 2008 or later

SERVICE CLASSIFICATIONS

Residential
This classification refers to all service supplied to single-family dwelling units for domestic or household purpose. Multi-unit residential establishments such as apartment buildings supplied through one service (bulk metered) will normally be classified as General Service, but, at Hydro One's discretion, up to four residential units may be classified as residential. Where electricity service is provided to combined residential and business (including agricultural usage) and the wiring does not provide for separate metering, the classification shall be at the discretion of Hydro One based on such considerations as the estimated predominant consumption.
Further servicing details are available in the utility's Conditions of Service.

General Service
This classification refers to all service supplied to premises other than those classified as Residential or Lighting. Some General Service accounts are energy(kWh)-billed, and some are demand(kW)-billed. Further servicing details are available in the utility's Conditions of Service.

Unmetered Scattered Load
This classification refers to certain instances where connections can be provided without metering. These loads are generally small in size and consistent in magnitude of load. Hydro One reserves the right to review all cases and may require that a meter be installed at its sole discretion. Services that can be unmetered include cable TV amplifiers, telephone switching devices, phone booths, bus shelters, rail way crossing signals, traffic signals, and other small fixed loads.
Further servicing details are available in the utility's Conditions of Service (including in the "Unmetered Connections" section).

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Kirkfield Hydro Electric System
Effective Date: May 1, 2008

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

Street Lighting

This classification refers to accounts for the distribution and supply of electrical energy for street lighting. Street lights are devices owned by or operated for the road authority and/or the municipal corporation. These street lights in fact belong to the Street Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Sentinel Lighting

This classification refers to accounts for a separate service to a sentinel light. These sentinel lights in fact belong to the Sentinel Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Urban Density Classification

Customers who meet the Urban Density Criteria of being in an area containing 3,000 or more customers with a line density of at least 60 customers per kilometre, will be mapped to an Urban customer classification.

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Kirkfield Hydro Electric System
Effective Date: May 1, 2008

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

MONTHLY RATES AND CHARGES

Residential - R1 Kirkfield

Service Charge	$	8.43
Distribution Volumetric Rate	$ / kWh	0.0200
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0026
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0004)
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0047
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0046
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service Less Than 50 kW (Energy-Billed) - GSe Kirkfield

Service Charge	$	18.42
Distribution Volumetric Rate	$ / kWh	0.0321
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0044
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0006)
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0035
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0032
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service 50 kW or Greater (Demand-Billed) - GSd Kirkfield

Service Charge	$	22.02
Distribution Volumetric Rate	$ / kW	9.22
Regulatory Asset Recovery - Rider #2	$ / kW	1.34
Regulatory Asset Recovery - Rider #3	$ / kW	(0.22)
Retail Transmission Rate - Network Service Rate (4)	$ / kW	1.11
Retail Transmission Rate - Line and Transformation Connection Service Rate (4)	$ / kW	1.00
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
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Unmetered, Scattered Load

Service Charge	$	10.66
Distribution Volumetric Rate	$ / kWh	0.0200
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0044
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0006)
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0035
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0032
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

(3) For energy-only metered customers, the billing determinant is the customer's metered energy consumption adjusted by the total loss factor as approved by the Board for Acquired LDC customers.
(4) For demand billed customers, appropriate loss factors must be applied to the applicable tariffs. Also the billing determinant for the Line and Transformation Connection Services rate is the customer's peak demand in the billing period. The billing determinant for the Network Services rate is: for non-interval-metered customers, the peak demand in the billing period, and for interval-metered customers, the peak demand between 7 AM and 7 PM local time on IESO business days

Customer-Supplied Transformation Allowance

Applicable to customers providing their own transformers

Demand-billed	$ / kW	0.60
Energy-billed	$ / kWh	0.0014

Hydro One Networks Inc.
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Loss Factors

Residential	1.085
General Service Less Than 50 kW (Energy-Billed)	1.092
General Service 50 kW or Greater (Demand-Billed)	1.061
Unmetered Scattered Load	1.092

Transformer Loss Allowance

Applicable to customers requiring a billing adjustment for transformer losses as the result of being metered on the primary side of a transformer. The following uniform values shall be applied to measured demand and energy to calculate transformer losses for voltages up to and including 50 kV (as metered on the primary side):

(a) 1.5% for transformer installations up to an individual bank capacity of 400 kVA,
(b) 1.0% for bank capacities over 400 kVA.

Alternatively, transformer losses may be determined from transformer test data, and measured demand and energy adjusted accordingly

For services which are not demand metered, an assumed demand of 50% of the transformer capacity will be used to calculate the loss allowance. Where several transformers are involved, the bank capacity is assumed to be the arithmetic sum of all transformer capacities

Hydro One Networks Inc.
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MISCELLANEOUS CHARGES

Specific Service Charges: Standard Amounts

Rate Code	Specific Service Charge - Standard Name	Calculation Method			
		2006 Rate Handbook	Standard Formula	Other Formula	Time and Materials
1	Temporary Service	$500			
2	Dispute Meter Test	$30 plus Measurement Canada fees			
3	Collection of account – no disconnection/load limiter	$30			
4	Collection/Disconnect/load limiter/reconnect (at meter) trip – regular hours	$65			
5	Collection/Disconnect/load limiter/reconnect (at meter) trip – after regular hours	$185			
6	Collection/Disconnect/load limiter/reconnect (at pole) trip – regular hours	$185			
7	Collection/Disconnect/load limiter/reconnect (at pole) trip – after regular hours	$415			
8	Account Set-up Charge	$30			
9	Arrears Certificate	$15			
10	NSF Cheque Charge	$15 + bank charges			
11	Easement Charge for Unregistered Rights	$15			
12	Late Payment Charge	1.5%/month			
13a	Retailer Services – Establishing Service Agreements (refer to Handbook for all charges)	$100/agreement/Retailer +$20/month/Retailer +$0.50/month/customer + other			
13b	Retailer Services – Other (includes Bill Ready for Retailers and Service Transactions Requests) as per the Handbook, Chapter 12	$0.30/month/customer + $0.25/request for request fee + $0.50/request for process fee			
14	Special Meter Reads	$30			
15	Service Layout Fee – Basic		$495		
16	Service Layout Fee – Complex		$690		
17	Crossing Application – Pipeline		$2,445		
18	Crossing Application – Water		$3,045		
19	Crossing Application – Railroad		$2,945		
20	Line Staking – per meter		$3.70		
21	Central Metering – New service < 45 kW		$115		
22	Conversion to Central Metering < 45 kW		$915		
23	Conversion to Central Metering > 45 kW		$800		
24	Tingle Voltage Test – In Excess of 4 Hours (per hour – average 2 additional hours)		$125		
25	Standby Administration Charge per month		$440		
26	Sentinel Lights Rental Rate per month			$7.10	
27	Sentinel Pole Rental Rate per month			$4.15	
28	Joint Use for Cable and Telecom companies per pole			$22.35	
29	Joint Use for LDCs per pole			$28.61	

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
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Kirkfield Hydro Electric System
Effective Date: May 1, 2007

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

APPLICATION

The application of these rates and charges shall be in accordance with The Licence of The Distributor and any Codes, Guidelines or Orders of The Board, and amendments thereto as approved by The Board, which may be applicable to the administration of this schedule.
No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code, Guideline or Order of the Board, and amendments thereto as approved by the Board, or as specified herein
This schedule does not contain any rates and charges relating to the electricity commodity (e.g. the Regulated Price Plan).

EFFECTIVE DATES

DISTRIBUTION RATES - May 1, 2007 for all consumption or deemed consumption services used on or after that date.

MISCELLANEOUS CHARGES - May 1, 2007 for all charges billed to customers on or after that date.
RETAIL TRANSMISSION RATES - May 1, 2007 for all consumption or deemed consumption services used on or after that date.
LOSS FACTOR ADJUSTMENT – May 1, 2007

SERVICE CLASSIFICATIONS

Residential
This classification (note 1) refers to all service supplied to single-family dwelling units for domestic or household purpose. Multi-unit residential establishments such as apartment buildings supplied through one service (bulk metered) will normally be classified as General Service, but, at Hydro One's discretion, up to four residential units may be classified as residential. Where electricity service is provided to combined residential and business (including agricultural usage) and the wiring does not provide for separate metering, the classification shall be at the discretion of Hydro One based on such considerations as the estimated predominant consumption.
Further servicing details are available in the utility's Conditions of Service.

General Service
This classification (note 1) refers to all service supplied to premises other than those classified as Residential or Lighting. Some General Service accounts are energy(kWh)-billed, and some are demand(kW)-billed. Further servicing details are available in the utility's Conditions of Service. Also, see note 2.

Unmetered Scattered Load
This classification refers to certain instances where connections can be provided without metering. These loads are generally small in size and consistent in magnitude of load. Hydro One reserves the right to review all cases and may require that a meter be installed at its sole discretion. Services that can be unmetered include cable TV amplifiers, telephone switching devices, phone booths, bus shelters, rail way crossing signals, traffic signals, and other small fixed loads.
Further servicing details are available in the utility's Conditions of Service (including in the "Unmetered Connections" section).

Hydro One Networks Inc.
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Kirkfield Hydro Electric System
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Street Lighting

This classification refers to accounts for the distribution and supply of electrical energy for street lighting. Street lights are devices owned by or operated for the road authority and/or the municipal corporation. These street lights in fact belong to the Street Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Sentinel Lighting

This classification refers to accounts for a separate service to a sentinel light. These sentinel lights in fact belong to the Sentinel Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Interim Demand-Side Management Time-of-Use

This is potentially applicable to Demand-billed General Service accounts. See Note 2 below.

Note (1): Classification descriptions are paraphrases from the document "Hydro One Networks Inc. - Distribution Customers Conditions of Service - August 2004"

Note (2):

Interim Demand-Side Management Time-of-Use Rates: demand charges will be based on demand during the on-peak periods.

Criteria: Customers' electricity consumption (kW) in the off-peak period is at least twice the electricity consumption (kW) during the on-peak period.

Definition of Time Periods: The on-peak hours will be between 0700 hours to 1900 hours Eastern Standard Time during the winter (standard time) on IESO business days and 0600 hours to 1800 hours Eastern Standard Time during the summer (daylight savings time) on IESO business days. The off-peak period constitutes all of the remaining hours.

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MONTHLY RATES AND CHARGES

Residential

Service Charge	$	5.34
Distribution Volumetric Rate	$ / kWh	0.0100
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0048
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0026
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0055
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0047
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service - Energy Billed (less than 50 kW)

Service Charge	$	14.69
Distribution Volumetric Rate	$ / kWh	0.0195
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0061
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0044
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0050
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0043
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service - Demand Billed (50 kW or greater)

Service Charge	$	14.69
Distribution Volumetric Rate	$ / kW	5.92
Regulatory Asset Recovery - Rider #1	$ / kW	1.95
Regulatory Asset Recovery - Rider #2	$ / kW	1.34
Retail Transmission Rate - Network Service Rate (4)	$ / kW	1.94
Retail Transmission Rate - Line and Transformation Connection Service Rate (4)	$ / kW	1.61
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

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Unmetered, Scattered Load

Service Charge	$	6.88
Distribution Volumetric Rate	$ / kWh	0.0195
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0061
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0044
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0050
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0043
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

(3) For energy-only metered customers, the billing determinant is the customer’s metered energy consumption adjusted by the total loss factor as approved by the Board for Acquired LDC customers.
(4) For demand billed customers, appropriate loss factors must be applied to the applicable tariffs. Also the billing determinant for the Line and Transformation Connection Services rate is the customer’s peak demand in the billing period. The billing determinant for the Network Services rate is: for non-interval-metered customers, the peak demand in the billing period, and for interval-metered customers, the peak demand between 7 AM and 7 PM local time on IESO business days

Interim Demand-Side Management Time-of-Use

See the "Service Classifications" section of this schedule.

Customer-Supplied Transformation Allowance

Applicable to demand-billed customers providing their own transformers
Primary Voltage under 50 kV (per kW)

Single Phase	$ / kW	0.20
Three Phase	$ / kW	0.60

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Loss Factors

Supply Facilities Loss Factor	1.0045
Distribution Loss Factors	
Customer less than 5,000 kW	1.0500
Customer greater than or equal to 5,000 kW	1.0100
Total Loss Factors	
Customer less than 5,000 kW	1.0545
Customer greater than or equal to 5,000 kW	1.0145

Transformer Loss Allowance

Applicable to customers requiring a billing adjustment for transformer losses as the result of being metered on the primary side of a transformer. The following uniform values shall be applied to measured demand and energy to calculate transformer losses for voltages up to and including 50 kV (as metered on the primary side):

(a) 1.5% for transformer installations up to an individual bank capacity of 400 kVA,
(b) 1.0% for bank capacities over 400 kVA.

Alternatively, transformer losses may be determined from transformer test data, and measured demand and energy adjusted accordingly

For services which are not demand metered, an assumed demand of 50% of the transformer capacity will be used to calculate the loss allowance. Where several transformers are involved, the bank capacity is assumed to be the arithmetic sum of all transformer capacities

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MISCELLANEOUS CHARGES

Specific Service Charges: Standard Amounts

Rate Code	Specific Service Charge - Standard Name	Calculation Method			
		2006 Rate Handbook	Standard Formula	Other Formula	Time and Materials
1	Temporary Service	$500			
2	Dispute Meter Test	$30 plus Measurement Canada fees			
3	Collection of account – no disconnection/load limiter	$30			
4	Collection/Disconnect/load limiter/reconnect (at meter) trip – regular hours	$65			
5	Collection/Disconnect/load limiter/reconnect (at meter) trip – after regular hours	$185			
6	Collection/Disconnect/load limiter/reconnect (at pole) trip – regular hours	$185			
7	Collection/Disconnect/load limiter/reconnect (at pole) trip – after regular hours	$415			
8	Account Set-up Charge	$30			
9	Arrears Certificate	$15			
10	NSF Cheque Charge	$15 + bank charges			
11	Easement Charge for Unregistered Rights	$15			
12	Late Payment Charge	1.5%/month			
13a	Retailer Services – Establishing Service Agreements (refer to Handbook for all charges)	$100/agreement/Retailer +$20/month/Retailer +$0.50/month/customer + other			
13b	Retailer Services – Other (includes Bill Ready for Retailers and Service Transactions Requests) as per the Handbook, Chapter 12	$0.30/month/customer + $0.25/request for request fee + $0.50/request for process fee			
14	Special Meter Reads	$30			
15	Billing Suspension and Terminations in Trailer Parks		$130		
16	Service Layout Fee – Basic		$405		
17	Service Layout Fee – Complex		$580		

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18	Crossing Application – Pipeline		$2,065		
19	Crossing Application – Water		$2,525		
20	Crossing Application – Railroad		$2,565		
21	Line Staking – per meter		$3.10		
22	Central Metering – New service < 45 kW		$115		
23	Conversion to Central Metering < 45 kW		$795		
24	Conversion to Central Metering > 45 kW		$680		
25	Tingle Voltage Test – In Excess of 4 Hours (per hour – average 2 additional hours)		$105		
26	Standby Administration Charge per month (interim)		$375		
27	Sentinel Lights Rental Rate per month – Mercury Vapor			$7.00	
28	Guaranteed Units from Jan 01/91 to Aug 01/91			$26.50 / month	
29	Guaranteed Units from Jan 01/87 to Dec 31/90			$23.50 / month	
30	Joint Use for Cable and Telecom companies per pole			$22.35	
31	Joint Use for LDCs per pole			$28.61	

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Public Utilities Commission of the Township of Lanark Highlands
Effective Date: May 1, 2008

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

APPLICATION

The application of these rates and charges shall be in accordance with The Licence of The Distributor and any Codes, Guidelines or Orders of The Board, and amendments thereto as approved by The Board, which may be applicable to the administration of this schedule.
No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code, Guideline or Order of the Board, and amendments thereto as approved by the Board, or as specified herein
This schedule does not contain any rates and charges relating to the electricity commodity (e.g. the Regulated Price Plan).

EFFECTIVE DATES

DISTRIBUTION RATES - May 1, 2008 for all consumption or deemed consumption services used on or after that date.

MISCELLANEOUS CHARGES - May 1, 2008 for all charges billed to customers on or after that date.
RETAIL TRANSMISSION RATES - May 1, 2008 for all consumption or deemed consumption services used on or after that date.
LOSS FACTOR ADJUSTMENT – for all consumption or deemed consumption services billed following May 1, 2008 or later

SERVICE CLASSIFICATIONS

Residential
This classification refers to all service supplied to single-family dwelling units for domestic or household purpose. Multi-unit residential establishments such as apartment buildings supplied through one service (bulk metered) will normally be classified as General Service, but, at Hydro One's discretion, up to four residential units may be classified as residential. Where electricity service is provided to combined residential and business (including agricultural usage) and the wiring does not provide for separate metering, the classification shall be at the discretion of Hydro One based on such considerations as the estimated predominant consumption.
Further servicing details are available in the utility's Conditions of Service.

General Service
This classification refers to all service supplied to premises other than those classified as Residential or Lighting. Some General Service accounts are energy(kWh)-billed, and some are demand(kW)-billed. Further servicing details are available in the utility's Conditions of Service.

Unmetered Scattered Load
This classification refers to certain instances where connections can be provided without metering. These loads are generally small in size and consistent in magnitude of load. Hydro One reserves the right to review all cases and may require that a meter be installed at its sole discretion. Services that can be unmetered include cable TV amplifiers, telephone switching devices, phone booths, bus shelters, rail way crossing signals, traffic signals, and other small fixed loads.
Further servicing details are available in the utility's Conditions of Service (including in the "Unmetered Connections" section).

Hydro One Networks Inc.
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Effective Date: May 1, 2008

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Street Lighting

This classification refers to accounts for the distribution and supply of electrical energy for street lighting. Street lights are devices owned by or operated for the road authority and/or the municipal corporation. These street lights in fact belong to the Street Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Sentinel Lighting

This classification refers to accounts for a separate service to a sentinel light. These sentinel lights in fact belong to the Sentinel Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Urban Density Classification

Customers who meet the Urban Density Criteria of being in an area containing 3,000 or more customers with a line density of at least 60 customers per kilometre, will be mapped to an Urban customer classification.

Hydro One Networks Inc.
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MONTHLY RATES AND CHARGES

Residential - R1 Lanark Highlands

Service Charge	$	12.93
Distribution Volumetric Rate	$ / kWh	0.0235
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0040
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0004)
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0047
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0046
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service Less Than 50 kW (Energy-Billed) - GSe Lanark Highlands

Service Charge	$	21.48
Distribution Volumetric Rate	$ / kWh	0.0321
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0050
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0006)
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0035
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0032
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service 50 kW or Greater (Demand-Billed) - GSd Lanark Highlands

Service Charge	$	25.08
Distribution Volumetric Rate	$ / kW	9.22
Regulatory Asset Recovery - Rider #2	$ / kW	1.32
Regulatory Asset Recovery - Rider #3	$ / kW	(0.22)
Retail Transmission Rate - Network Service Rate (4)	$ / kW	1.11
Retail Transmission Rate - Line and Transformation Connection Service Rate (4)	$ / kW	1.00
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

Hydro One Networks Inc.
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Unmetered, Scattered Load

Service Charge	$	12.19
Distribution Volumetric Rate	$ / kWh	0.0200
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0050
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0006)
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0035
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0032
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

(3) For energy-only metered customers, the billing determinant is the customer’s metered energy consumption adjusted by the total loss factor as approved by the Board for Acquired LDC customers.
(4) For demand billed customers, appropriate loss factors must be applied to the applicable tariffs. Also the billing determinant for the Line and Transformation Connection Services rate is the customer’s peak demand in the billing period. The billing determinant for the Network Services rate is: for non-interval-metered customers, the peak demand in the billing period, and for interval-metered customers, the peak demand between 7 AM and 7 PM local time on IESO business days

Customer-Supplied Transformation Allowance

Applicable to customers providing their own transformers		
Demand-billed	$ / kW	0.60
Energy-billed	$ / kWh	0.0014

Hydro One Networks Inc.
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Loss Factors

Residential	1.085
General Service Less Than 50 kW (Energy-Billed)	1.092
General Service 50 kW or Greater (Demand-Billed)	1.061
Unmetered Scattered Load	1.092

Transformer Loss Allowance

Applicable to customers requiring a billing adjustment for transformer losses as the result of being metered on the primary side of a transformer. The following uniform values shall be applied to measured demand and energy to calculate transformer losses for voltages up to and including 50 kV (as metered on the primary side):

(a) 1.5% for transformer installations up to an individual bank capacity of 400 kVA,
(b) 1.0% for bank capacities over 400 kVA.

Alternatively, transformer losses may be determined from transformer test data, and measured demand and energy adjusted accordingly

For services which are not demand metered, an assumed demand of 50% of the transformer capacity will be used to calculate the loss allowance. Where several transformers are involved, the bank capacity is assumed to be the arithmetic sum of all transformer capacities

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MISCELLANEOUS CHARGES

Specific Service Charges: Standard Amounts

Rate Code	Specific Service Charge - Standard Name	Calculation Method			
		2006 Rate Handbook	Standard Formula	Other Formula	Time and Materials
1	Temporary Service	$500			
2	Dispute Meter Test	$30 plus Measurement Canada fees			
3	Collection of account – no disconnection/load limiter	$30			
4	Collection/Disconnect/load limiter/reconnect (at meter) trip – regular hours	$65			
5	Collection/Disconnect/load limiter/reconnect (at meter) trip – after regular hours	$185			
6	Collection/Disconnect/load limiter/reconnect (at pole) trip – regular hours	$185			
7	Collection/Disconnect/load limiter/reconnect (at pole) trip – after regular hours	$415			
8	Account Set-up Charge	$30			
9	Arrears Certificate	$15			
10	NSF Cheque Charge	$15 + bank charges			
11	Easement Charge for Unregistered Rights	$15			
12	Late Payment Charge	1.5%/month			
13a	Retailer Services – Establishing Service Agreements (refer to Handbook for all charges)	$100/agreement/Retailer +$20/month/Retailer +$0.50/month/customer + other			
13b	Retailer Services – Other (includes Bill Ready for Retailers and Service Transactions Requests) as per the Handbook, Chapter 12	$0.30/month/customer + $0.25/request for request fee + $0.50/request for process fee			
14	Special Meter Reads	$30			
15	Service Layout Fee – Basic		$495		
16	Service Layout Fee – Complex		$690		
17	Crossing Application – Pipeline		$2,445		
18	Crossing Application – Water		$3,045		
19	Crossing Application – Railroad		$2,945		
20	Line Staking – per meter		$3.70		
21	Central Metering – New service < 45 kW		$115		
22	Conversion to Central Metering < 45 kW		$915		
23	Conversion to Central Metering > 45 kW		$800		
24	Tingle Voltage Test – In Excess of 4 Hours (per hour – average 2 additional hours)		$125		
25	Standby Administration Charge per month		$440		
26	Sentinel Lights Rental Rate per month			$7.10	
27	Sentinel Pole Rental Rate per month			$4.15	
28	Joint Use for Cable and Telecom companies per pole			$22.35	
29	Joint Use for LDCs per pole			$28.61	

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Public Utilities Commission of the Township of Lanark Highlands
Effective Date: May 1, 2007

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

APPLICATION

The application of these rates and charges shall be in accordance with The Licence of The Distributor and any Codes, Guidelines or Orders of The Board, and amendments thereto as approved by The Board, which may be applicable to the administration of this schedule.
No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code, Guideline or Order of the Board, and amendments thereto as approved by the Board, or as specified herein
This schedule does not contain any rates and charges relating to the electricity commodity (e.g. the Regulated Price Plan).

EFFECTIVE DATES

DISTRIBUTION RATES - May 1, 2007 for all consumption or deemed consumption services used on or after that date.

MISCELLANEOUS CHARGES - May 1, 2007 for all charges billed to customers on or after that date.
RETAIL TRANSMISSION RATES - May 1, 2007 for all consumption or deemed consumption services used on or after that date.
LOSS FACTOR ADJUSTMENT – May 1, 2007

SERVICE CLASSIFICATIONS

Residential
This classification (note 1) refers to all service supplied to single-family dwelling units for domestic or household purpose. Multi-unit residential establishments such as apartment buildings supplied through one service (bulk metered) will normally be classified as General Service, but, at Hydro One's discretion, up to four residential units may be classified as residential. Where electricity service is provided to combined residential and business (including agricultural usage) and the wiring does not provide for separate metering, the classification shall be at the discretion of Hydro One based on such considerations as the estimated predominant consumption.
Further servicing details are available in the utility's Conditions of Service.

General Service
This classification (note 1) refers to all service supplied to premises other than those classified as Residential or Lighting. Some General Service accounts are energy(kWh)-billed, and some are demand(kW)-billed. Further servicing details are available in the utility's Conditions of Service. Also, see note 2.

Unmetered Scattered Load
This classification refers to certain instances where connections can be provided without metering. These loads are generally small in size and consistent in magnitude of load. Hydro One reserves the right to review all cases and may require that a meter be installed at its sole discretion. Services that can be unmetered include cable TV amplifiers, telephone switching devices, phone booths, bus shelters, rail way crossing signals, traffic signals, and other small fixed loads.
Further servicing details are available in the utility's Conditions of Service (including in the "Unmetered Connections" section).

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Public Utilities Commission of the Township of Lanark Highlands
Effective Date: May 1, 2007

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

Street Lighting

This classification refers to accounts for the distribution and supply of electrical energy for street lighting. Street lights are devices owned by or operated for the road authority and/or the municipal corporation. These street lights in fact belong to the Street Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Sentinel Lighting

This classification refers to accounts for a separate service to a sentinel light. These sentinel lights in fact belong to the Sentinel Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Interim Demand-Side Management Time-of-Use

This is potentially applicable to Demand-billed General Service accounts. See Note 2 below.

Note (1): Classification descriptions are paraphrases from the document "Hydro One Networks Inc. - Distribution Customers Conditions of Service - August 2004"

Note (2):

Interim Demand-Side Management Time-of-Use Rates: demand charges will be based on demand during the on-peak periods.

Criteria: Customers' electricity consumption (kW) in the off-peak period is at least twice the electricity consumption (kW) during the on-peak period.

Definition of Time Periods: The on-peak hours will be between 0700 hours to 1900 hours Eastern Standard Time during the winter (standard time) on IESO business days and 0600 hours to 1800 hours Eastern Standard Time during the summer (daylight savings time) on IESO business days. The off-peak period constitutes all of the remaining hours.

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
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MONTHLY RATES AND CHARGES

Residential

Service Charge	$	11.31
Distribution Volumetric Rate	$ / kWh	0.0102
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0056
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0040
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0055
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0047
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service - Energy Billed (less than 50 kW)

Service Charge	$	18.43
Distribution Volumetric Rate	$ / kWh	0.0199
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0063
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0050
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0050
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0043
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service - Demand Billed (50 kW or greater)

Service Charge	$	18.43
Distribution Volumetric Rate	$ / kW	5.26
Regulatory Asset Recovery - Rider #1	$ / kW	1.99
Regulatory Asset Recovery - Rider #2	$ / kW	1.32
Retail Transmission Rate - Network Service Rate (4)	$ / kW	1.94
Retail Transmission Rate - Line and Transformation Connection Service Rate (4)	$ / kW	1.61
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
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Unmetered, Scattered Load

Service Charge	$	8.75
Distribution Volumetric Rate	$ / kWh	0.0199
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0063
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0050
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0050
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0043
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

(3) For energy-only metered customers, the billing determinant is the customer's metered energy consumption adjusted by the total loss factor as approved by the Board for Acquired LDC customers.

(4) For demand billed customers, appropriate loss factors must be applied to the applicable tariffs. Also the billing determinant for the Line and Transformation Connection Services rate is the customer's peak demand in the billing period. The billing determinant for the Network Services rate is: for non-interval-metered customers, the peak demand in the billing period, and for interval-metered customers, the peak demand between 7 AM and 7 PM local time on IESO business days

Interim Demand-Side Management Time-of-Use

See the "Service Classifications" section of this schedule.

Customer-Supplied Transformation Allowance

Applicable to demand-billed customers providing their own transformers

Primary Voltage under 50 kV (per kW)		
Single Phase	$ / kW	0.20
Three Phase	$ / kW	0.60

Hydro One Networks Inc.
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Loss Factors

Supply Facilities Loss Factor	1.0045
Distribution Loss Factors	
Customer less than 5,000 kW	1.0500
Customer greater than or equal to 5,000 kW	1.0100
Total Loss Factors	
Customer less than 5,000 kW	1.0545
Customer greater than or equal to 5,000 kW	1.0145

Transformer Loss Allowance

Applicable to customers requiring a billing adjustment for transformer losses as the result of being metered on the primary side of a transformer. The following uniform values shall be applied to measured demand and energy to calculate transformer losses for voltages up to and including 50 kV (as metered on the primary side):

(a) 1.5% for transformer installations up to an individual bank capacity of 400 kVA,
(b) 1.0% for bank capacities over 400 kVA.

Alternatively, transformer losses may be determined from transformer test data, and measured demand and energy adjusted accordingly

For services which are not demand metered, an assumed demand of 50% of the transformer capacity will be used to calculate the loss allowance. Where several transformers are involved, the bank capacity is assumed to be the arithmetic sum of all transformer capacities

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Public Utilities Commission of the Township of Lanark Highlands
Effective Date: May 1, 2007

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

MISCELLANEOUS CHARGES

Specific Service Charges: Standard Amounts

Rate Code	Specific Service Charge - Standard Name	Calculation Method			
		2006 Rate Handbook	Standard Formula	Other Formula	Time and Materials
1	Temporary Service	$500			
2	Dispute Meter Test	$30 plus Measurement Canada fees			
3	Collection of account – no disconnection/load limiter	$30			
4	Collection/Disconnect/load limiter/reconnect (at meter) trip – regular hours	$65			
5	Collection/Disconnect/load limiter/reconnect (at meter) trip – after regular hours	$185			
6	Collection/Disconnect/load limiter/reconnect (at pole) trip – regular hours	$185			
7	Collection/Disconnect/load limiter/reconnect (at pole) trip – after regular hours	$415			
8	Account Set-up Charge	$30			
9	Arrears Certificate	$15			
10	NSF Cheque Charge	$15 + bank charges			
11	Easement Charge for Unregistered Rights	$15			
12	Late Payment Charge	1.5%/month			
13a	Retailer Services – Establishing Service Agreements (refer to Handbook for all charges)	$100/agreement/Retailer +$20/month/Retailer +$0.50/month/customer + other			
13b	Retailer Services – Other (includes Bill Ready for Retailers and Service Transactions Requests) as per the Handbook, Chapter 12	$0.30/month/customer + $0.25/request for request fee + $0.50/request for process fee			
14	Special Meter Reads	$30			
15	Billing Suspension and Terminations in Trailer Parks		$130		
16	Service Layout Fee – Basic		$405		
17	Service Layout Fee – Complex		$580		

Hydro One Networks Inc.
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This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

18	Crossing Application – Pipeline		$2,065		
19	Crossing Application – Water		$2,525		
20	Crossing Application – Railroad		$2,565		
21	Line Staking – per meter		$3.10		
22	Central Metering – New service < 45 kW		$115		
23	Conversion to Central Metering < 45 kW		$795		
24	Conversion to Central Metering > 45 kW		$680		
25	Tingle Voltage Test – In Excess of 4 Hours (per hour – average 2 additional hours)		$105		
26	Standby Administration Charge per month (interim)		$375		
27	Sentinel Lights Rental Rate per month – Mercury Vapor			$7.00	
28	Guaranteed Units from Jan 01/91 to Aug 01/91			$26.50 / month	
29	Guaranteed Units from Jan 01/87 to Dec 31/90			$23.50 / month	
30	Joint Use for Cable and Telecom companies per pole			$22.35	
31	Joint Use for LDCs per pole			$28.61	

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Larder Lake Hydro-Electric System
Effective Date: May 1, 2008

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

APPLICATION

The application of these rates and charges shall be in accordance with The Licence of The Distributor and any Codes, Guidelines or Orders of The Board, and amendments thereto as approved by The Board, which may be applicable to the administration of this schedule.
No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code, Guideline or Order of the Board, and amendments thereto as approved by the Board, or as specified herein
This schedule does not contain any rates and charges relating to the electricity commodity (e.g. the Regulated Price Plan).

EFFECTIVE DATES

DISTRIBUTION RATES - May 1, 2008 for all consumption or deemed consumption services used on or after that date.

MISCELLANEOUS CHARGES - May 1, 2008 for all charges billed to customers on or after that date.
RETAIL TRANSMISSION RATES - May 1, 2008 for all consumption or deemed consumption services used on or after that date.
LOSS FACTOR ADJUSTMENT – for all consumption or deemed consumption services billed following May 1, 2008 or later

SERVICE CLASSIFICATIONS

Residential
This classification refers to all service supplied to single-family dwelling units for domestic or household purpose. Multi-unit residential establishments such as apartment buildings supplied through one service (bulk metered) will normally be classified as General Service, but, at Hydro One's discretion, up to four residential units may be classified as residential. Where electricity service is provided to combined residential and business (including agricultural usage) and the wiring does not provide for separate metering, the classification shall be at the discretion of Hydro One based on such considerations as the estimated predominant consumption.
Further servicing details are available in the utility's Conditions of Service.

General Service
This classification refers to all service supplied to premises other than those classified as Residential or Lighting. Some General Service accounts are energy(kWh)-billed, and some are demand(kW)-billed. Further servicing details are available in the utility's Conditions of Service.

Unmetered Scattered Load
This classification refers to certain instances where connections can be provided without metering. These loads are generally small in size and consistent in magnitude of load. Hydro One reserves the right to review all cases and may require that a meter be installed at its sole discretion. Services that can be unmetered include cable TV amplifiers, telephone switching devices, phone booths, bus shelters, rail way crossing signals, traffic signals, and other small fixed loads.
Further servicing details are available in the utility's Conditions of Service (including in the "Unmetered Connections" section).

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Larder Lake Hydro-Electric System
Effective Date: May 1, 2008

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

Street Lighting

This classification refers to accounts for the distribution and supply of electrical energy for street lighting. Street lights are devices owned by or operated for the road authority and/or the municipal corporation. These street lights in fact belong to the Street Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Sentinel Lighting

This classification refers to accounts for a separate service to a sentinel light. These sentinel lights in fact belong to the Sentinel Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Urban Density Classification

Customers who meet the Urban Density Criteria of being in an area containing 3,000 or more customers with a line density of at least 60 customers per kilometre, will be mapped to an Urban customer classification.

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Larder Lake Hydro-Electric System
Effective Date: May 1, 2008

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

MONTHLY RATES AND CHARGES

Residential - R1 Larder Lake

Service Charge	$	15.80
Distribution Volumetric Rate	$ / kWh	0.0270
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0043
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0004)
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0047
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0046
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service Less Than 50 kW (Energy-Billed) - GSe Larder Lake

Service Charge	$	23.05
Distribution Volumetric Rate	$ / kWh	0.0305
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0036
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0006)
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0035
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0032
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service 50 kW or Greater (Demand-Billed) - GSd Larder Lake

Service Charge	$	26.64
Distribution Volumetric Rate	$ / kW	9.22
Regulatory Asset Recovery - Rider #2	$ / kW	0.99
Regulatory Asset Recovery - Rider #3	$ / kW	(0.22)
Retail Transmission Rate - Network Service Rate (4)	$ / kW	1.11
Retail Transmission Rate - Line and Transformation Connection Service Rate (4)	$ / kW	1.00
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
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Larder Lake Hydro-Electric System
Effective Date: May 1, 2008

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Unmetered, Scattered Load

Service Charge	$	12.97
Distribution Volumetric Rate	$ / kWh	0.0200
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0036
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0006)
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0035
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0032
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

(3) For energy-only metered customers, the billing determinant is the customer's metered energy consumption adjusted by the total loss factor as approved by the Board for Acquired LDC customers.
(4) For demand billed customers, appropriate loss factors must be applied to the applicable tariffs. Also the billing determinant for the Line and Transformation Connection Services rate is the customer's peak demand in the billing period. The billing determinant for the Network Services rate is: for non-interval-metered customers, the peak demand in the billing period, and for interval-metered customers, the peak demand between 7 AM and 7 PM local time on IESO business days

Customer-Supplied Transformation Allowance

Applicable to customers providing their own transformers		
Demand-billed	$ / kW	0.60
Energy-billed	$ / kWh	0.0014

Hydro One Networks Inc.
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Loss Factors

Residential	1.085
General Service Less Than 50 kW (Energy-Billed)	1.092
General Service 50 kW or Greater (Demand-Billed)	1.061
Unmetered Scattered Load	1.092

Transformer Loss Allowance

Applicable to customers requiring a billing adjustment for transformer losses as the result of being metered on the primary side of a transformer. The following uniform values shall be applied to measured demand and energy to calculate transformer losses for voltages up to and including 50 kV (as metered on the primary side):

(a) 1.5% for transformer installations up to an individual bank capacity of 400 kVA,
(b) 1.0% for bank capacities over 400 kVA.

Alternatively, transformer losses may be determined from transformer test data, and measured demand and energy adjusted accordingly

For services which are not demand metered, an assumed demand of 50% of the transformer capacity will be used to calculate the loss allowance. Where several transformers are involved, the bank capacity is assumed to be the arithmetic sum of all transformer capacities

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
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MISCELLANEOUS CHARGES

Specific Service Charges: Standard Amounts

Rate Code	Specific Service Charge - Standard Name	Calculation Method			
		2006 Rate Handbook	Standard Formula	Other Formula	Time and Materials
1	Temporary Service	$500			
2	Dispute Meter Test	$30 plus Measurement Canada fees			
3	Collection of account – no disconnection/load limiter	$30			
4	Collection/Disconnect/load limiter/reconnect (at meter) trip – regular hours	$65			
5	Collection/Disconnect/load limiter/reconnect (at meter) trip – after regular hours	$185			
6	Collection/Disconnect/load limiter/reconnect (at pole) trip – regular hours	$185			
7	Collection/Disconnect/load limiter/reconnect (at pole) trip – after regular hours	$415			
8	Account Set-up Charge	$30			
9	Arrears Certificate	$15			
10	NSF Cheque Charge	$15 + bank charges			
11	Easement Charge for Unregistered Rights	$15			
12	Late Payment Charge	1.5%/month			
13a	Retailer Services – Establishing Service Agreements (refer to Handbook for all charges)	$100/agreement/Retailer +$20/month/Retailer +$0.50/month/customer + other			
13b	Retailer Services – Other (includes Bill Ready for Retailers and Service Transactions Requests) as per the Handbook, Chapter 12	$0.30/month/customer + $0.25/request for request fee + $0.50/request for process fee			
14	Special Meter Reads	$30			
15	Service Layout Fee – Basic		$495		
16	Service Layout Fee – Complex		$690		
17	Crossing Application – Pipeline		$2,445		
18	Crossing Application – Water		$3,045		
19	Crossing Application – Railroad		$2,945		
20	Line Staking – per meter		$3.70		
21	Central Metering – New service < 45 kW		$115		
22	Conversion to Central Metering < 45 kW		$915		
23	Conversion to Central Metering > 45 kW		$800		
24	Tingle Voltage Test – In Excess of 4 Hours (per hour – average 2 additional hours)		$125		
25	Standby Administration Charge per month		$440		
26	Sentinel Lights Rental Rate per month			$7.10	
27	Sentinel Pole Rental Rate per month			$4.15	
28	Joint Use for Cable and Telecom companies per pole			$22.35	
29	Joint Use for LDCs per pole			$28.61	

Hydro One Networks Inc.
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Larder Lake Hydro-Electric System
Effective Date: May 1, 2007

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APPLICATION

The application of these rates and charges shall be in accordance with The Licence of The Distributor and any Codes, Guidelines or Orders of The Board, and amendments thereto as approved by The Board, which may be applicable to the administration of this schedule.
No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code, Guideline or Order of the Board, and amendments thereto as approved by the Board, or as specified herein
This schedule does not contain any rates and charges relating to the electricity commodity (e.g. the Regulated Price Plan).

EFFECTIVE DATES

DISTRIBUTION RATES - May 1, 2007 for all consumption or deemed consumption services used on or after that date.

MISCELLANEOUS CHARGES - May 1, 2007 for all charges billed to customers on or after that date.
RETAIL TRANSMISSION RATES - May 1, 2007 for all consumption or deemed consumption services used on or after that date.
LOSS FACTOR ADJUSTMENT – May 1, 2007

SERVICE CLASSIFICATIONS

Residential
This classification (note 1) refers to all service supplied to single-family dwelling units for domestic or household purpose. Multi-unit residential establishments such as apartment buildings supplied through one service (bulk metered) will normally be classified as General Service, but, at Hydro One's discretion, up to four residential units may be classified as residential. Where electricity service is provided to combined residential and business (including agricultural usage) and the wiring does not provide for separate metering, the classification shall be at the discretion of Hydro One based on such considerations as the estimated predominant consumption.
Further servicing details are available in the utility's Conditions of Service.

General Service
This classification (note 1) refers to all service supplied to premises other than those classified as Residential or Lighting. Some General Service accounts are energy(kWh)-billed, and some are demand(kW)-billed. Further servicing details are available in the utility's Conditions of Service. Also, see note 2.

Unmetered Scattered Load
This classification refers to certain instances where connections can be provided without metering. These loads are generally small in size and consistent in magnitude of load. Hydro One reserves the right to review all cases and may require that a meter be installed at its sole discretion. Services that can be unmetered include cable TV amplifiers, telephone switching devices, phone booths, bus shelters, rail way crossing signals, traffic signals, and other small fixed loads.
Further servicing details are available in the utility's Conditions of Service (including in the "Unmetered Connections" section).

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This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

Street Lighting

This classification refers to accounts for the distribution and supply of electrical energy for street lighting. Street lights are devices owned by or operated for the road authority and/or the municipal corporation. These street lights in fact belong to the Street Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Sentinel Lighting

This classification refers to accounts for a separate service to a sentinel light. These sentinel lights in fact belong to the Sentinel Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Interim Demand-Side Management Time-of-Use

This is potentially applicable to Demand-billed General Service accounts. See Note 2 below.

Note (1): Classification descriptions are paraphrases from the document "Hydro One Networks Inc. - Distribution Customers Conditions of Service - August 2004"

Note (2):

Interim Demand-Side Management Time-of-Use Rates: demand charges will be based on demand during the on-peak periods.

Criteria: Customers' electricity consumption (kW) in the off-peak period is at least twice the electricity consumption (kW) during the on-peak period.

Definition of Time Periods: The on-peak hours will be between 0700 hours to 1900 hours Eastern Standard Time during the winter (standard time) on IESO business days and 0600 hours to 1800 hours Eastern Standard Time during the summer (daylight savings time) on IESO business days. The off-peak period constitutes all of the remaining hours.

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Larder Lake Hydro-Electric System
Effective Date: May 1, 2007

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

MONTHLY RATES AND CHARGES

Residential

Service Charge	$	15.84
Distribution Volumetric Rate	$ / kWh	0.0101
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0068
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0043
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0055
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0047
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service - Energy Billed (less than 50 kW)

Service Charge	$	20.18
Distribution Volumetric Rate	$ / kWh	0.0158
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0051
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0036
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0050
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0043
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service - Demand Billed (50 kW or greater)

Service Charge	$	20.18
Distribution Volumetric Rate	$ / kW	4.30
Regulatory Asset Recovery - Rider #1	$ / kW	1.61
Regulatory Asset Recovery - Rider #2	$ / kW	0.99
Retail Transmission Rate - Network Service Rate (4)	$ / kW	1.94
Retail Transmission Rate - Line and Transformation Connection Service Rate (4)	$ / kW	1.61
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Larder Lake Hydro-Electric System
Effective Date: May 1, 2007

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

Unmetered, Scattered Load

Service Charge	$	9.62
Distribution Volumetric Rate	$ / kWh	0.0158
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0051
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0036
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0050
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0043
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

(3) For energy-only metered customers, the billing determinant is the customer's metered energy consumption adjusted by the total loss factor as approved by the Board for Acquired LDC customers.
(4) For demand billed customers, appropriate loss factors must be applied to the applicable tariffs. Also the billing determinant for the Line and Transformation Connection Services rate is the customer's peak demand in the billing period. The billing determinant for the Network Services rate is: for non-interval-metered customers, the peak demand in the billing period, and for interval-metered customers, the peak demand between 7 AM and 7 PM local time on IESO business days

Interim Demand-Side Management Time-of-Use

See the "Service Classifications" section of this schedule.

Customer-Supplied Transformation Allowance

Applicable to demand-billed customers providing their own transformers
Primary Voltage under 50 kV (per kW)

Single Phase	$ / kW	0.20
Three Phase	$ / kW	0.60

Hydro One Networks Inc.
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Larder Lake Hydro-Electric System
Effective Date: May 1, 2007

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Loss Factors

Supply Facilities Loss Factor	1.0045
Distribution Loss Factors	
Customer less than 5,000 kW	1.0500
Customer greater than or equal to 5,000 kW	1.0100
Total Loss Factors	
Customer less than 5,000 kW	1.0545
Customer greater than or equal to 5,000 kW	1.0145

Transformer Loss Allowance

Applicable to customers requiring a billing adjustment for transformer losses as the result of being metered on the primary side of a transformer. The following uniform values shall be applied to measured demand and energy to calculate transformer losses for voltages up to and including 50 kV (as metered on the primary side):

(a) 1.5% for transformer installations up to an individual bank capacity of 400 kVA,
(b) 1.0% for bank capacities over 400 kVA.

Alternatively, transformer losses may be determined from transformer test data, and measured demand and energy adjusted accordingly

For services which are not demand metered, an assumed demand of 50% of the transformer capacity will be used to calculate the loss allowance. Where several transformers are involved, the bank capacity is assumed to be the arithmetic sum of all transformer capacities

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
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Effective Date: May 1, 2007

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MISCELLANEOUS CHARGES

Specific Service Charges: Standard Amounts

Rate Code	Specific Service Charge - Standard Name	Calculation Method			
		2006 Rate Handbook	Standard Formula	Other Formula	Time and Materials
1	Temporary Service	$500			
2	Dispute Meter Test	$30 plus Measurement Canada fees			
3	Collection of account – no disconnection/load limiter	$30			
4	Collection/Disconnect/load limiter/reconnect (at meter) trip – regular hours	$65			
5	Collection/Disconnect/load limiter/reconnect (at meter) trip – after regular hours	$185			
6	Collection/Disconnect/load limiter/reconnect (at pole) trip – regular hours	$185			
7	Collection/Disconnect/load limiter/reconnect (at pole) trip – after regular hours	$415			
8	Account Set-up Charge	$30			
9	Arrears Certificate	$15			
10	NSF Cheque Charge	$15 + bank charges			
11	Easement Charge for Unregistered Rights	$15			
12	Late Payment Charge	1.5%/month			
13a	Retailer Services – Establishing Service Agreements (refer to Handbook for all charges)	$100/agreement/Retailer +$20/month/Retailer +$0.50/month/customer + other			
13b	Retailer Services – Other (includes Bill Ready for Retailers and Service Transactions Requests) as per the Handbook, Chapter 12	$0.30/month/customer + $0.25/request for request fee + $0.50/request for process fee			
14	Special Meter Reads	$30			
15	Billing Suspension and Terminations in Trailer Parks		$130		
16	Service Layout Fee – Basic		$405		
17	Service Layout Fee – Complex		$580		

Hydro One Networks Inc.
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Larder Lake Hydro-Electric System
Effective Date: May 1, 2007

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

18	Crossing Application – Pipeline		$2,065		
19	Crossing Application – Water		$2,525		
20	Crossing Application – Railroad		$2,565		
21	Line Staking – per meter		$3.10		
22	Central Metering – New service < 45 kW		$115		
23	Conversion to Central Metering < 45 kW		$795		
24	Conversion to Central Metering > 45 kW		$680		
25	Tingle Voltage Test – In Excess of 4 Hours (per hour – average 2 additional hours)		$105		
26	Standby Administration Charge per month (interim)		$375		
27	Sentinel Lights Rental Rate per month – Mercury Vapor			$7.00	
28	Guaranteed Units from Jan 01/91 to Aug 01/91			$26.50 / month	
29	Guaranteed Units from Jan 01/87 to Dec 31/90			$23.50 / month	
30	Joint Use for Cable and Telecom companies per pole			$22.35	
31	Joint Use for LDCs per pole			$28.61	

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Latchford Hydro Electric
Effective Date: May 1, 2008

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

APPLICATION

The application of these rates and charges shall be in accordance with The Licence of The Distributor and any Codes, Guidelines or Orders of The Board, and amendments thereto as approved by The Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code, Guideline or Order of the Board, and amendments thereto as approved by the Board, or as specified herein

This schedule does not contain any rates and charges relating to the electricity commodity (e.g. the Regulated Price Plan).

EFFECTIVE DATES

DISTRIBUTION RATES - May 1, 2008 for all consumption or deemed consumption services used on or after that date.

MISCELLANEOUS CHARGES - May 1, 2008 for all charges billed to customers on or after that date.

RETAIL TRANSMISSION RATES - May 1, 2008 for all consumption or deemed consumption services used on or after that date.

LOSS FACTOR ADJUSTMENT – for all consumption or deemed consumption services billed following May 1, 2008 or later

SERVICE CLASSIFICATIONS

Residential

This classification refers to all service supplied to single-family dwelling units for domestic or household purpose. Multi-unit residential establishments such as apartment buildings supplied through one service (bulk metered) will normally be classified as General Service, but, at Hydro One's discretion, up to four residential units may be classified as residential. Where electricity service is provided to combined residential and business (including agricultural usage) and the wiring does not provide for separate metering, the classification shall be at the discretion of Hydro One based on such considerations as the estimated predominant consumption.

Further servicing details are available in the utility's Conditions of Service.

General Service

This classification refers to all service supplied to premises other than those classified as Residential or Lighting. Some General Service accounts are energy(kWh)-billed, and some are demand(kW)-billed. Further servicing details are available in the utility's Conditions of Service.

Unmetered Scattered Load

This classification refers to certain instances where connections can be provided without metering. These loads are generally small in size and consistent in magnitude of load. Hydro One reserves the right to review all cases and may require that a meter be installed at its sole discretion. Services that can be unmetered include cable TV amplifiers, telephone switching devices, phone booths, bus shelters, rail way crossing signals, traffic signals, and other small fixed loads.

Further servicing details are available in the utility's Conditions of Service (including in the "Unmetered Connections" section).

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Latchford Hydro Electric
Effective Date: May 1, 2008

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

Street Lighting

This classification refers to accounts for the distribution and supply of electrical energy for street lighting. Street lights are devices owned by or operated for the road authority and/or the municipal corporation. These street lights in fact belong to the Street Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Sentinel Lighting

This classification refers to accounts for a separate service to a sentinel light. These sentinel lights in fact belong to the Sentinel Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Urban Density Classification

Customers who meet the Urban Density Criteria of being in an area containing 3,000 or more customers with a line density of at least 60 customers per kilometre, will be mapped to an Urban customer classification.

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
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Effective Date: May 1, 2008

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MONTHLY RATES AND CHARGES

Residential - R1 Latchford

Service Charge	$	14.43
Distribution Volumetric Rate	$ / kWh	0.0271
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0045
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0004)
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0047
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0046
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service Less Than 50 kW (Energy-Billed) - GSe Latchford

Service Charge	$	9.37
Distribution Volumetric Rate	$ / kWh	0.0232
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0020
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0006)
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0035
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0032
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service 50 kW or Greater (Demand-Billed) - GSd Latchford

Service Charge	$	12.97
Distribution Volumetric Rate	$ / kW	8.80
Regulatory Asset Recovery - Rider #2	$ / kW	0.48
Regulatory Asset Recovery - Rider #3	$ / kW	(0.22)
Retail Transmission Rate - Network Service Rate (4)	$ / kW	1.11
Retail Transmission Rate - Line and Transformation Connection Service Rate (4)	$ / kW	1.00
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
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Effective Date: May 1, 2008

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

Unmetered, Scattered Load

Service Charge	$	6.14
Distribution Volumetric Rate	$ / kWh	0.0200
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0020
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0006)
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0035
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0032
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

(3) For energy-only metered customers, the billing determinant is the customer's metered energy consumption adjusted by the total loss factor as approved by the Board for Acquired LDC customers.
(4) For demand billed customers, appropriate loss factors must be applied to the applicable tariffs. Also the billing determinant for the Line and Transformation Connection Services rate is the customer's peak demand in the billing period. The billing determinant for the Network Services rate is: for non-interval-metered customers, the peak demand in the billing period, and for interval-metered customers, the peak demand between 7 AM and 7 PM local time on IESO business days

Customer-Supplied Transformation Allowance

Applicable to customers providing their own transformers

Demand-billed	$ / kW	0.60
Energy-billed	$ / kWh	0.0014

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
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Loss Factors

Residential	1.085
General Service Less Than 50 kW (Energy-Billed)	1.092
General Service 50 kW or Greater (Demand-Billed)	1.061
Unmetered Scattered Load	1.092

Transformer Loss Allowance

Applicable to customers requiring a billing adjustment for transformer losses as the result of being metered on the primary side of a transformer. The following uniform values shall be applied to measured demand and energy to calculate transformer losses for voltages up to and including 50 kV (as metered on the primary side):

(a) 1.5% for transformer installations up to an individual bank capacity of 400 kVA,
(b) 1.0% for bank capacities over 400 kVA.

Alternatively, transformer losses may be determined from transformer test data, and measured demand and energy adjusted accordingly
For services which are not demand metered, an assumed demand of 50% of the transformer capacity will be used to calculate the loss allowance. Where several transformers are involved, the bank capacity is assumed to be the arithmetic sum of all transformer capacities

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
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Latchford Hydro Electric
Effective Date: May 1, 2008

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

MISCELLANEOUS CHARGES

Specific Service Charges: Standard Amounts

Rate Code	Specific Service Charge - Standard Name	Calculation Method			
		2006 Rate Handbook	Standard Formula	Other Formula	Time and Materials
1	Temporary Service	$500			
2	Dispute Meter Test	$30 plus Measurement Canada fees			
3	Collection of account – no disconnection/load limiter	$30			
4	Collection/Disconnect/load limiter/reconnect (at meter) trip – regular hours	$65			
5	Collection/Disconnect/load limiter/reconnect (at meter) trip – after regular hours	$185			
6	Collection/Disconnect/load limiter/reconnect (at pole) trip – regular hours	$185			
7	Collection/Disconnect/load limiter/reconnect (at pole) trip – after regular hours	$415			
8	Account Set-up Charge	$30			
9	Arrears Certificate	$15			
10	NSF Cheque Charge	$15 + bank charges			
11	Easement Charge for Unregistered Rights	$15			
12	Late Payment Charge	1.5%/month			
13a	Retailer Services – Establishing Service Agreements (refer to Handbook for all charges)	$100/agreement/Retailer +$20/month/Retailer +$0.50/month/customer + other			
13b	Retailer Services – Other (includes Bill Ready for Retailers and Service Transactions Requests) as per the Handbook, Chapter 12	$0.30/month/customer + $0.25/request for request fee + $0.50/request for process fee			
14	Special Meter Reads	$30			
15	Service Layout Fee – Basic		$495		
16	Service Layout Fee – Complex		$690		
17	Crossing Application – Pipeline		$2,445		
18	Crossing Application – Water		$3,045		
19	Crossing Application – Railroad		$2,945		
20	Line Staking – per meter		$3.70		
21	Central Metering – New service < 45 kW		$115		
22	Conversion to Central Metering < 45 kW		$915		
23	Conversion to Central Metering > 45 kW		$800		
24	Tingle Voltage Test – In Excess of 4 Hours (per hour – average 2 additional hours)		$125		
25	Standby Administration Charge per month		$440		
26	Sentinel Lights Rental Rate per month			$7.10	
27	Sentinel Pole Rental Rate per month			$4.15	
28	Joint Use for Cable and Telecom companies per pole			$22.35	
29	Joint Use for LDCs per pole			$28.61	

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Latchford Hydro Electric
Effective Date: May 1, 2007

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

APPLICATION

The application of these rates and charges shall be in accordance with The Licence of The Distributor and any Codes, Guidelines or Orders of The Board, and amendments thereto as approved by The Board, which may be applicable to the administration of this schedule.
No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code, Guideline or Order of the Board, and amendments thereto as approved by the Board, or as specified herein
This schedule does not contain any rates and charges relating to the electricity commodity (e.g. the Regulated Price Plan).

EFFECTIVE DATES

DISTRIBUTION RATES - May 1, 2007 for all consumption or deemed consumption services used on or after that date.

MISCELLANEOUS CHARGES - May 1, 2007 for all charges billed to customers on or after that date.
RETAIL TRANSMISSION RATES - May 1, 2007 for all consumption or deemed consumption services used on or after that date.
LOSS FACTOR ADJUSTMENT – May 1, 2007

SERVICE CLASSIFICATIONS

Residential
This classification (note 1) refers to all service supplied to single-family dwelling units for domestic or household purpose. Multi-unit residential establishments such as apartment buildings supplied through one service (bulk metered) will normally be classified as General Service, but, at Hydro One's discretion, up to four residential units may be classified as residential. Where electricity service is provided to combined residential and business (including agricultural usage) and the wiring does not provide for separate metering, the classification shall be at the discretion of Hydro One based on such considerations as the estimated predominant consumption.
Further servicing details are available in the utility's Conditions of Service.

General Service
This classification (note 1) refers to all service supplied to premises other than those classified as Residential or Lighting. Some General Service accounts are energy(kWh)-billed, and some are demand(kW)-billed. Further servicing details are available in the utility's Conditions of Service. Also, see note 2.

Unmetered Scattered Load
This classification refers to certain instances where connections can be provided without metering. These loads are generally small in size and consistent in magnitude of load. Hydro One reserves the right to review all cases and may require that a meter be installed at its sole discretion. Services that can be unmetered include cable TV amplifiers, telephone switching devices, phone booths, bus shelters, rail way crossing signals, traffic signals, and other small fixed loads.
Further servicing details are available in the utility's Conditions of Service (including in the "Unmetered Connections" section).

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Street Lighting

This classification refers to accounts for the distribution and supply of electrical energy for street lighting. Street lights are devices owned by or operated for the road authority and/or the municipal corporation. These street lights in fact belong to the Street Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Sentinel Lighting

This classification refers to accounts for a separate service to a sentinel light. These sentinel lights in fact belong to the Sentinel Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Interim Demand-Side Management Time-of-Use

This is potentially applicable to Demand-billed General Service accounts. See Note 2 below.

Note (1): Classification descriptions are paraphrases from the document "Hydro One Networks Inc. - Distribution Customers Conditions of Service - August 2004"

Note (2):

Interim Demand-Side Management Time-of-Use Rates: demand charges will be based on demand during the on-peak periods.

Criteria: Customers' electricity consumption (kW) in the off-peak period is at least twice the electricity consumption (kW) during the on-peak period.

Definition of Time Periods: The on-peak hours will be between 0700 hours to 1900 hours Eastern Standard Time during the winter (standard time) on IESO business days and 0600 hours to 1800 hours Eastern Standard Time during the summer (daylight savings time) on IESO business days. The off-peak period constitutes all of the remaining hours.

Hydro One Networks Inc.
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This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

MONTHLY RATES AND CHARGES

Residential

Service Charge	$	13.31
Distribution Volumetric Rate	$ / kWh	0.0088
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0104
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0045
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0055
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0047
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service - Energy Billed (less than 50 kW)

Service Charge	$	2.88
Distribution Volumetric Rate	$ / kWh	0.0102
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0065
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0020
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0050
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0043
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service - Demand Billed (50 kW or greater)

Service Charge	$	2.88
Distribution Volumetric Rate	$ / kW	2.44
Regulatory Asset Recovery - Rider #1	$ / kW	2.06
Regulatory Asset Recovery - Rider #2	$ / kW	0.48
Retail Transmission Rate - Network Service Rate (4)	$ / kW	1.94
Retail Transmission Rate - Line and Transformation Connection Service Rate (4)	$ / kW	1.61
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

Hydro One Networks Inc.
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This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

Unmetered, Scattered Load

Service Charge	$	0.97
Distribution Volumetric Rate	$ / kWh	0.0102
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0065
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0020
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0050
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0043
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

(3) For energy-only metered customers, the billing determinant is the customer's metered energy consumption adjusted by the total loss factor as approved by the Board for Acquired LDC customers.
(4) For demand billed customers, appropriate loss factors must be applied to the applicable tariffs. Also the billing determinant for the Line and Transformation Connection Services rate is the customer's peak demand in the billing period. The billing determinant for the Network Services rate is: for non-interval-metered customers, the peak demand in the billing period, and for interval-metered customers, the peak demand between 7 AM and 7 PM local time on IESO business days

Interim Demand-Side Management Time-of-Use

See the "Service Classifications" section of this schedule.

Customer-Supplied Transformation Allowance

Applicable to demand-billed customers providing their own transformers
Primary Voltage under 50 kV (per kW)

Single Phase	$ / kW	0.20
Three Phase	$ / kW	0.60

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Latchford Hydro Electric
Effective Date: May 1, 2007

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

Loss Factors

Supply Facilities Loss Factor	1.0045
Distribution Loss Factors	
Customer less than 5,000 kW	1.0500
Customer greater than or equal to 5,000 kW	1.0100
Total Loss Factors	
Customer less than 5,000 kW	1.0545
Customer greater than or equal to 5,000 kW	1.0145

Transformer Loss Allowance

Applicable to customers requiring a billing adjustment for transformer losses as the result of being metered on the primary side of a transformer. The following uniform values shall be applied to measured demand and energy to calculate transformer losses for voltages up to and including 50 kV (as metered on the primary side):

(a) 1.5% for transformer installations up to an individual bank capacity of 400 kVA,
(b) 1.0% for bank capacities over 400 kVA.

Alternatively, transformer losses may be determined from transformer test data, and measured demand and energy adjusted accordingly

For services which are not demand metered, an assumed demand of 50% of the transformer capacity will be used to calculate the loss allowance. Where several transformers are involved, the bank capacity is assumed to be the arithmetic sum of all transformer capacities

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Latchford Hydro Electric
Effective Date: May 1, 2007

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

MISCELLANEOUS CHARGES

Specific Service Charges: Standard Amounts

Rate Code	Specific Service Charge - Standard Name	Calculation Method			
		2006 Rate Handbook	Standard Formula	Other Formula	Time and Materials
1	Temporary Service	$500			
2	Dispute Meter Test	$30 plus Measurement Canada fees			
3	Collection of account – no disconnection/load limiter	$30			
4	Collection/Disconnect/load limiter/reconnect (at meter) trip – regular hours	$65			
5	Collection/Disconnect/load limiter/reconnect (at meter) trip – after regular hours	$185			
6	Collection/Disconnect/load limiter/reconnect (at pole) trip – regular hours	$185			
7	Collection/Disconnect/load limiter/reconnect (at pole) trip – after regular hours	$415			
8	Account Set-up Charge	$30			
9	Arrears Certificate	$15			
10	NSF Cheque Charge	$15 + bank charges			
11	Easement Charge for Unregistered Rights	$15			
12	Late Payment Charge	1.5%/month			
13a	Retailer Services – Establishing Service Agreements (refer to Handbook for all charges)	$100/agreement/Retailer +$20/month/Retailer +$0.50/month/customer + other			
13b	Retailer Services – Other (includes Bill Ready for Retailers and Service Transactions Requests) as per the Handbook, Chapter 12	$0.30/month/customer + $0.25/request for request fee + $0.50/request for process fee			
14	Special Meter Reads	$30			
15	Billing Suspension and Terminations in Trailer Parks		$130		
16	Service Layout Fee – Basic		$405		
17	Service Layout Fee – Complex		$580		

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
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Latchford Hydro Electric
Effective Date: May 1, 2007

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

18	Crossing Application – Pipeline		$2,065		
19	Crossing Application – Water		$2,525		
20	Crossing Application – Railroad		$2,565		
21	Line Staking – per meter		$3.10		
22	Central Metering – New service < 45 kW		$115		
23	Conversion to Central Metering < 45 kW		$795		
24	Conversion to Central Metering > 45 kW		$680		
25	Tingle Voltage Test – In Excess of 4 Hours (per hour – average 2 additional hours)		$105		
26	Standby Administration Charge per month (interim)		$375		
27	Sentinel Lights Rental Rate per month – Mercury Vapor			$7.00	
28	Guaranteed Units from Jan 01/91 to Aug 01/91			$26.50 / month	
29	Guaranteed Units from Jan 01/87 to Dec 31/90			$23.50 / month	
30	Joint Use for Cable and Telecom companies per pole			$22.35	
31	Joint Use for LDCs per pole			$28.61	

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Lindsay Hydro Electric System
Effective Date: May 1, 2008

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

APPLICATION

The application of these rates and charges shall be in accordance with The Licence of The Distributor and any Codes, Guidelines or Orders of The Board, and amendments thereto as approved by The Board, which may be applicable to the administration of this schedule.
No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code, Guideline or Order of the Board, and amendments thereto as approved by the Board, or as specified herein
This schedule does not contain any rates and charges relating to the electricity commodity (e.g. the Regulated Price Plan).

EFFECTIVE DATES

DISTRIBUTION RATES - May 1, 2008 for all consumption or deemed consumption services used on or after that date.

MISCELLANEOUS CHARGES - May 1, 2008 for all charges billed to customers on or after that date.
RETAIL TRANSMISSION RATES - May 1, 2008 for all consumption or deemed consumption services used on or after that date.
LOSS FACTOR ADJUSTMENT – for all consumption or deemed consumption services billed following May 1, 2008 or later

SERVICE CLASSIFICATIONS

Residential
This classification refers to all service supplied to single-family dwelling units for domestic or household purpose. Multi-unit residential establishments such as apartment buildings supplied through one service (bulk metered) will normally be classified as General Service, but, at Hydro One's discretion, up to four residential units may be classified as residential. Where electricity service is provided to combined residential and business (including agricultural usage) and the wiring does not provide for separate metering, the classification shall be at the discretion of Hydro One based on such considerations as the estimated predominant consumption.
Further servicing details are available in the utility's Conditions of Service.

General Service
This classification refers to all service supplied to premises other than those classified as Residential or Lighting. Some General Service accounts are energy(kWh)-billed, and some are demand(kW)-billed. Further servicing details are available in the utility's Conditions of Service.

Unmetered Scattered Load
This classification refers to certain instances where connections can be provided without metering. These loads are generally small in size and consistent in magnitude of load. Hydro One reserves the right to review all cases and may require that a meter be installed at its sole discretion. Services that can be unmetered include cable TV amplifiers, telephone switching devices, phone booths, bus shelters, rail way crossing signals, traffic signals, and other small fixed loads.
Further servicing details are available in the utility's Conditions of Service (including in the "Unmetered Connections" section).

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Lindsay Hydro Electric System
Effective Date: May 1, 2008

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

Street Lighting

This classification refers to accounts for the distribution and supply of electrical energy for street lighting. Street lights are devices owned by or operated for the road authority and/or the municipal corporation. These street lights in fact belong to the Street Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Sentinel Lighting

This classification refers to accounts for a separate service to a sentinel light. These sentinel lights in fact belong to the Sentinel Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Urban Density Classification

Customers who meet the Urban Density Criteria of being in an area containing 3,000 or more customers with a line density of at least 60 customers per kilometre, will be mapped to an Urban customer classification.

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Lindsay Hydro Electric System
Effective Date: May 1, 2008

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

MONTHLY RATES AND CHARGES

Residential - UR/R1 Lindsay

Service Charge	$	14.63
Distribution Volumetric Rate	$ / kWh	0.0240
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0014
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0002)
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0047
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0045
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service Less Than 50 kW (Energy-Billed) - UGe/GSe Lindsay

Service Charge	$	20.10
Distribution Volumetric Rate	$ / kWh	0.0200
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0006
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0006)
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0036
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0033
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service 50 kW or Greater (Demand-Billed) - UGd/GSd Lindsay

Service Charge	$	24.31
Distribution Volumetric Rate	$ / kW	7.33
Regulatory Asset Recovery - Rider #2	$ / kW	0.19
Regulatory Asset Recovery - Rider #3	$ / kW	(0.27)
Retail Transmission Rate - Network Service Rate (4)	$ / kW	1.41
Retail Transmission Rate - Line and Transformation Connection Service Rate (4)	$ / kW	1.27
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Lindsay Hydro Electric System
Effective Date: May 1, 2008

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

Unmetered, Scattered Load

Service Charge	$	14.50
Distribution Volumetric Rate	$ / kWh	0.0200
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0006
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0006)
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0035
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0032
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

(3) For energy-only metered customers, the billing determinant is the customer's metered energy consumption adjusted by the total loss factor as approved by the Board for Acquired LDC customers.
(4) For demand billed customers, appropriate loss factors must be applied to the applicable tariffs. Also the billing determinant for the Line and Transformation Connection Services rate is the customer's peak demand in the billing period. The billing determinant for the Network Services rate is: for non-interval-metered customers, the peak demand in the billing period, and for interval-metered customers, the peak demand between 7 AM and 7 PM local time on IESO business days

Customer-Supplied Transformation Allowance

Applicable to customers providing their own transformers		
Demand-billed	$ / kW	0.60
Energy-billed	$ / kWh	0.0014

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
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Lindsay Hydro Electric System
Effective Date: May 1, 2008

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

Loss Factors

Residential	1.078
General Service Less Than 50 kW (Energy-Billed)	1.092
General Service 50 kW or Greater (Demand-Billed)	1.061
Unmetered Scattered Load	1.092

Transformer Loss Allowance

Applicable to customers requiring a billing adjustment for transformer losses as the result of being metered on the primary side of a transformer. The following uniform values shall be applied to measured demand and energy to calculate transformer losses for voltages up to and including 50 kV (as metered on the primary side):

(a) 1.5% for transformer installations up to an individual bank capacity of 400 kVA,
(b) 1.0% for bank capacities over 400 kVA.

Alternatively, transformer losses may be determined from transformer test data, and measured demand and energy adjusted accordingly

For services which are not demand metered, an assumed demand of 50% of the transformer capacity will be used to calculate the loss allowance. Where several transformers are involved, the bank capacity is assumed to be the arithmetic sum of all transformer capacities

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Lindsay Hydro Electric System
Effective Date: May 1, 2008

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

MISCELLANEOUS CHARGES

Specific Service Charges: Standard Amounts

Rate Code	Specific Service Charge - Standard Name	Calculation Method			
		2006 Rate Handbook	Standard Formula	Other Formula	Time and Materials
1	Temporary Service	$500			
2	Dispute Meter Test	$30 plus Measurement Canada fees			
3	Collection of account – no disconnection/load limiter	$30			
4	Collection/Disconnect/load limiter/reconnect (at meter) trip – regular hours	$65			
5	Collection/Disconnect/load limiter/reconnect (at meter) trip – after regular hours	$185			
6	Collection/Disconnect/load limiter/reconnect (at pole) trip – regular hours	$185			
7	Collection/Disconnect/load limiter/reconnect (at pole) trip – after regular hours	$415			
8	Account Set-up Charge	$30			
9	Arrears Certificate	$15			
10	NSF Cheque Charge	$15 + bank charges			
11	Easement Charge for Unregistered Rights	$15			
12	Late Payment Charge	1.5%/month			
13a	Retailer Services – Establishing Service Agreements (refer to Handbook for all charges)	$100/agreement/Retailer +$20/month/Retailer +$0.50/month/customer + other			
13b	Retailer Services – Other (includes Bill Ready for Retailers and Service Transactions Requests) as per the Handbook, Chapter 12	$0.30/month/customer + $0.25/request for request fee + $0.50/request for process fee			
14	Special Meter Reads	$30			
15	Service Layout Fee – Basic		$495		
16	Service Layout Fee – Complex		$690		
17	Crossing Application – Pipeline		$2,445		
18	Crossing Application – Water		$3,045		
19	Crossing Application – Railroad		$2,945		
20	Line Staking – per meter		$3.70		
21	Central Metering – New service < 45 kW		$115		
22	Conversion to Central Metering < 45 kW		$915		
23	Conversion to Central Metering > 45 kW		$800		
24	Tingle Voltage Test – In Excess of 4 Hours (per hour – average 2 additional hours)		$125		
25	Standby Administration Charge per month		$440		
26	Sentinel Lights Rental Rate per month			$7.10	
27	Sentinel Pole Rental Rate per month			$4.15	
28	Joint Use for Cable and Telecom companies per pole			$22.35	
29	Joint Use for LDCs per pole			$28.61	

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Lindsay Hydro Electric System
Effective Date: May 1, 2007

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

APPLICATION

The application of these rates and charges shall be in accordance with The Licence of The Distributor and any Codes, Guidelines or Orders of The Board, and amendments thereto as approved by The Board, which may be applicable to the administration of this schedule.
No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code, Guideline or Order of the Board, and amendments thereto as approved by the Board, or as specified herein
This schedule does not contain any rates and charges relating to the electricity commodity (e.g. the Regulated Price Plan).

EFFECTIVE DATES

DISTRIBUTION RATES - May 1, 2007 for all consumption or deemed consumption services used on or after that date.

MISCELLANEOUS CHARGES - May 1, 2007 for all charges billed to customers on or after that date.
RETAIL TRANSMISSION RATES - May 1, 2007 for all consumption or deemed consumption services used on or after that date.
LOSS FACTOR ADJUSTMENT – May 1, 2007

SERVICE CLASSIFICATIONS

Residential
This classification (note 1) refers to all service supplied to single-family dwelling units for domestic or household purpose. Multi-unit residential establishments such as apartment buildings supplied through one service (bulk metered) will normally be classified as General Service, but, at Hydro One’s discretion, up to four residential units may be classified as residential. Where electricity service is provided to combined residential and business (including agricultural usage) and the wiring does not provide for separate metering, the classification shall be at the discretion of Hydro One based on such considerations as the estimated predominant consumption.
Further servicing details are available in the utility’s Conditions of Service.

General Service
This classification (note 1) refers to all service supplied to premises other than those classified as Residential or Lighting. Some General Service accounts are energy(kWh)-billed, and some are demand(kW)-billed. Further servicing details are available in the utility’s Conditions of Service. Also, see note 2.

Unmetered Scattered Load
This classification refers to certain instances where connections can be provided without metering. These loads are generally small in size and consistent in magnitude of load. Hydro One reserves the right to review all cases and may require that a meter be installed at its sole discretion. Services that can be unmetered include cable TV amplifiers, telephone switching devices, phone booths, bus shelters, rail way crossing signals, traffic signals, and other small fixed loads.
Further servicing details are available in the utility’s Conditions of Service (including in the "Unmetered Connections" section).

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Lindsay Hydro Electric System
Effective Date: May 1, 2007

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

Street Lighting

This classification refers to accounts for the distribution and supply of electrical energy for street lighting. Street lights are devices owned by or operated for the road authority and/or the municipal corporation. These street lights in fact belong to the Street Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Sentinel Lighting

This classification refers to accounts for a separate service to a sentinel light. These sentinel lights in fact belong to the Sentinel Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Interim Demand-Side Management Time-of-Use

This is potentially applicable to Demand-billed General Service accounts. See Note 2 below.

Note (1): Classification descriptions are paraphrases from the document "Hydro One Networks Inc. - Distribution Customers Conditions of Service - August 2004"

Note (2):

Interim Demand-Side Management Time-of-Use Rates: demand charges will be based on demand during the on-peak periods.

Criteria: Customers' electricity consumption (kW) in the off-peak period is at least twice the electricity consumption (kW) during the on-peak period.

Definition of Time Periods: The on-peak hours will be between 0700 hours to 1900 hours Eastern Standard Time during the winter (standard time) on IESO business days and 0600 hours to 1800 hours Eastern Standard Time during the summer (daylight savings time) on IESO business days. The off-peak period constitutes all of the remaining hours.

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
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Lindsay Hydro Electric System
Effective Date: May 1, 2007

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

MONTHLY RATES AND CHARGES

Residential

Service Charge	$	15.81
Distribution Volumetric Rate	$ / kWh	0.0101
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0041
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0014
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0055
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0047
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service - Energy Billed (less than 50 kW)

Service Charge	$	23.94
Distribution Volumetric Rate	$ / kWh	0.0138
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0015
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0006
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0050
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0043
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service - Demand Billed (50 kW or greater)

Service Charge	$	23.94
Distribution Volumetric Rate	$ / kW	4.36
Regulatory Asset Recovery - Rider #1	$ / kW	0.49
Regulatory Asset Recovery - Rider #2	$ / kW	0.19
Retail Transmission Rate - Network Service Rate (4)	$ / kW	1.94
Retail Transmission Rate - Line and Transformation Connection Service Rate (4)	$ / kW	1.61
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Lindsay Hydro Electric System
Effective Date: May 1, 2007

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

Unmetered, Scattered Load

Service Charge	$	11.50
Distribution Volumetric Rate	$ / kWh	0.0138
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0015
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0006
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0050
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0043
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

(3) For energy-only metered customers, the billing determinant is the customer’s metered energy consumption adjusted by the total loss factor as approved by the Board for Acquired LDC customers.
(4) For demand billed customers, appropriate loss factors must be applied to the applicable tariffs. Also the billing determinant for the Line and Transformation Connection Services rate is the customer’s peak demand in the billing period. The billing determinant for the Network Services rate is: for non-interval-metered customers, the peak demand in the billing period, and for interval-metered customers, the peak demand between 7 AM and 7 PM local time on IESO business days

Interim Demand-Side Management Time-of-Use

See the "Service Classifications" section of this schedule.

Customer-Supplied Transformation Allowance

Applicable to demand-billed customers providing their own transformers
Primary Voltage under 50 kV (per kW)

Single Phase	$ / kW	0.20
Three Phase	$ / kW	0.60

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
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Lindsay Hydro Electric System
Effective Date: May 1, 2007

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

Loss Factors

Supply Facilities Loss Factor	1.0045
Distribution Loss Factors	
Customer less than 5,000 kW	1.0500
Customer greater than or equal to 5,000 kW	1.0100
Total Loss Factors	
Customer less than 5,000 kW	1.0545
Customer greater than or equal to 5,000 kW	1.0145

Transformer Loss Allowance

Applicable to customers requiring a billing adjustment for transformer losses as the result of being metered on the primary side of a transformer. The following uniform values shall be applied to measured demand and energy to calculate transformer losses for voltages up to and including 50 kV (as metered on the primary side):

(a) 1.5% for transformer installations up to an individual bank capacity of 400 kVA,
(b) 1.0% for bank capacities over 400 kVA.

Alternatively, transformer losses may be determined from transformer test data, and measured demand and energy adjusted accordingly

For services which are not demand metered, an assumed demand of 50% of the transformer capacity will be used to calculate the loss allowance. Where several transformers are involved, the bank capacity is assumed to be the arithmetic sum of all transformer capacities

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Lindsay Hydro Electric System
Effective Date: May 1, 2007

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

MISCELLANEOUS CHARGES

Specific Service Charges: Standard Amounts

Rate Code	Specific Service Charge - Standard Name	Calculation Method			
		2006 Rate Handbook	Standard Formula	Other Formula	Time and Materials
1	Temporary Service	$500			
2	Dispute Meter Test	$30 plus Measurement Canada fees			
3	Collection of account – no disconnection/load limiter	$30			
4	Collection/Disconnect/load limiter/reconnect (at meter) trip – regular hours	$65			
5	Collection/Disconnect/load limiter/reconnect (at meter) trip – after regular hours	$185			
6	Collection/Disconnect/load limiter/reconnect (at pole) trip – regular hours	$185			
7	Collection/Disconnect/load limiter/reconnect (at pole) trip – after regular hours	$415			
8	Account Set-up Charge	$30			
9	Arrears Certificate	$15			
10	NSF Cheque Charge	$15 + bank charges			
11	Easement Charge for Unregistered Rights	$15			
12	Late Payment Charge	1.5%/month			
13a	Retailer Services – Establishing Service Agreements (refer to Handbook for all charges)	$100/agreement/Retailer +$20/month/Retailer +$0.50/month/customer + other			
13b	Retailer Services – Other (includes Bill Ready for Retailers and Service Transactions Requests) as per the Handbook, Chapter 12	$0.30/month/customer + $0.25/request for request fee + $0.50/request for process fee			
14	Special Meter Reads	$30			
15	Billing Suspension and Terminations in Trailer Parks		$130		
16	Service Layout Fee – Basic		$405		
17	Service Layout Fee – Complex		$580		

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Lindsay Hydro Electric System
Effective Date: May 1, 2007

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

18	Crossing Application – Pipeline		$2,065		
19	Crossing Application – Water		$2,525		
20	Crossing Application – Railroad		$2,565		
21	Line Staking – per meter		$3.10		
22	Central Metering – New service < 45 kW		$115		
23	Conversion to Central Metering < 45 kW		$795		
24	Conversion to Central Metering > 45 kW		$680		
25	Tingle Voltage Test – In Excess of 4 Hours (per hour – average 2 additional hours)		$105		
26	Standby Administration Charge per month (interim)		$375		
27	Sentinel Lights Rental Rate per month – Mercury Vapor			$7.00	
28	Guaranteed Units from Jan 01/91 to Aug 01/91			$26.50 / month	
29	Guaranteed Units from Jan 01/87 to Dec 31/90			$23.50 / month	
30	Joint Use for Cable and Telecom companies per pole			$22.35	
31	Joint Use for LDCs per pole			$28.61	

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Lucan Granton Hydro Electric Commission
Effective Date: May 1, 2008

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

APPLICATION

The application of these rates and charges shall be in accordance with The Licence of The Distributor and any Codes, Guidelines or Orders of The Board, and amendments thereto as approved by The Board, which may be applicable to the administration of this schedule.
No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code, Guideline or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.
This schedule does not contain any rates and charges relating to the electricity commodity (e.g. the Regulated Price Plan).

EFFECTIVE DATES

DISTRIBUTION RATES - May 1, 2008 for all consumption or deemed consumption services used on or after that date.

MISCELLANEOUS CHARGES - May 1, 2008 for all charges billed to customers on or after that date.
RETAIL TRANSMISSION RATES - May 1, 2008 for all consumption or deemed consumption services used on or after that date.
LOSS FACTOR ADJUSTMENT – for all consumption or deemed consumption services billed following May 1, 2008 or later

SERVICE CLASSIFICATIONS

Residential
This classification refers to all service supplied to single-family dwelling units for domestic or household purpose. Multi-unit residential establishments such as apartment buildings supplied through one service (bulk metered) will normally be classified as General Service, but, at Hydro One's discretion, up to four residential units may be classified as residential. Where electricity service is provided to combined residential and business (including agricultural usage) and the wiring does not provide for separate metering, the classification shall be at the discretion of Hydro One based on such considerations as the estimated predominant consumption.
Further servicing details are available in the utility's Conditions of Service.

General Service
This classification refers to all service supplied to premises other than those classified as Residential or Lighting. Some General Service accounts are energy(kWh)-billed, and some are demand(kW)-billed. Further servicing details are available in the utility's Conditions of Service.

Unmetered Scattered Load
This classification refers to certain instances where connections can be provided without metering. These loads are generally small in size and consistent in magnitude of load. Hydro One reserves the right to review all cases and may require that a meter be installed at its sole discretion. Services that can be unmetered include cable TV amplifiers, telephone switching devices, phone booths, bus shelters, rail way crossing signals, traffic signals, and other small fixed loads.
Further servicing details are available in the utility's Conditions of Service (including in the "Unmetered Connections" section).

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Lucan Granton Hydro Electric Commission
Effective Date: May 1, 2008

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

Street Lighting

This classification refers to accounts for the distribution and supply of electrical energy for street lighting. Street lights are devices owned by or operated for the road authority and/or the municipal corporation. These street lights in fact belong to the Street Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Sentinel Lighting

This classification refers to accounts for a separate service to a sentinel light. These sentinel lights in fact belong to the Sentinel Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Urban Density Classification

Customers who meet the Urban Density Criteria of being in an area containing 3,000 or more customers with a line density of at least 60 customers per kilometre, will be mapped to an Urban customer classification.

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
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Lucan Granton Hydro Electric Commission
Effective Date: May 1, 2008

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MONTHLY RATES AND CHARGES

Residential - R1 Lucan Granton

Service Charge	$	12.83
Distribution Volumetric Rate	$ / kWh	0.0260
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0017
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0004)
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0047
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0046
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service Less Than 50 kW (Energy-Billed) - GSe Lucan Granton

Service Charge	$	19.84
Distribution Volumetric Rate	$ / kWh	0.0253
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0010
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0006)
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0035
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0032
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service 50 kW or Greater (Demand-Billed) - GSd Lucan Granton

Service Charge	$	23.44
Distribution Volumetric Rate	$ / kW	9.22
Regulatory Asset Recovery - Rider #2	$ / kW	0.30
Regulatory Asset Recovery - Rider #3	$ / kW	(0.22)
Retail Transmission Rate - Network Service Rate (4)	$ / kW	1.11
Retail Transmission Rate - Line and Transformation Connection Service Rate (4)	$ / kW	1.00
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

Hydro One Networks Inc.
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Unmetered, Scattered Load

Service Charge	$	12.37
Distribution Volumetric Rate	$ / kWh	0.0200
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0010
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0006)
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0035
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0032
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

(3) For energy-only metered customers, the billing determinant is the customer’s metered energy consumption adjusted by the total loss factor as approved by the Board for Acquired LDC customers.
(4) For demand billed customers, appropriate loss factors must be applied to the applicable tariffs. Also the billing determinant for the Line and Transformation Connection Services rate is the customer’s peak demand in the billing period. The billing determinant for the Network Services rate is: for non-interval-metered customers, the peak demand in the billing period, and for interval-metered customers, the peak demand between 7 AM and 7 PM local time on IESO business days

Customer-Supplied Transformation Allowance

Applicable to customers providing their own transformers		
Demand-billed	$ / kW	0.60
Energy-billed	$ / kWh	0.0014

Hydro One Networks Inc.
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Loss Factors

Residential	1.085
General Service Less Than 50 kW (Energy-Billed)	1.092
General Service 50 kW or Greater (Demand-Billed)	1.061
Unmetered Scattered Load	1.092

Transformer Loss Allowance

Applicable to customers requiring a billing adjustment for transformer losses as the result of being metered on the primary side of a transformer. The following uniform values shall be applied to measured demand and energy to calculate transformer losses for voltages up to and including 50 kV (as metered on the primary side):

(a) 1.5% for transformer installations up to an individual bank capacity of 400 kVA,
(b) 1.0% for bank capacities over 400 kVA.

Alternatively, transformer losses may be determined from transformer test data, and measured demand and energy adjusted accordingly

For services which are not demand metered, an assumed demand of 50% of the transformer capacity will be used to calculate the loss allowance. Where several transformers are involved, the bank capacity is assumed to be the arithmetic sum of all transformer capacities

Hydro One Networks Inc.
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Effective Date: May 1, 2008

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

MISCELLANEOUS CHARGES

Specific Service Charges: Standard Amounts

Rate Code	Specific Service Charge - Standard Name	Calculation Method			
		2006 Rate Handbook	Standard Formula	Other Formula	Time and Materials
1	Temporary Service	$500			
2	Dispute Meter Test	$30 plus Measurement Canada fees			
3	Collection of account – no disconnection/load limiter	$30			
4	Collection/Disconnect/load limiter/reconnect (at meter) trip – regular hours	$65			
5	Collection/Disconnect/load limiter/reconnect (at meter) trip – after regular hours	$185			
6	Collection/Disconnect/load limiter/reconnect (at pole) trip – regular hours	$185			
7	Collection/Disconnect/load limiter/reconnect (at pole) trip – after regular hours	$415			
8	Account Set-up Charge	$30			
9	Arrears Certificate	$15			
10	NSF Cheque Charge	$15 + bank charges			
11	Easement Charge for Unregistered Rights	$15			
12	Late Payment Charge	1.5%/month			
13a	Retailer Services – Establishing Service Agreements (refer to Handbook for all charges)	$100/agreement/Retailer +$20/month/Retailer +$0.50/month/customer + other			
13b	Retailer Services – Other (includes Bill Ready for Retailers and Service Transactions Requests) as per the Handbook, Chapter 12	$0.30/month/customer + $0.25/request for request fee + $0.50/request for process fee			
14	Special Meter Reads	$30			
15	Service Layout Fee – Basic		$495		
16	Service Layout Fee – Complex		$690		
17	Crossing Application – Pipeline		$2,445		
18	Crossing Application – Water		$3,045		
19	Crossing Application – Railroad		$2,945		
20	Line Staking – per meter		$3.70		
21	Central Metering – New service < 45 kW		$115		
22	Conversion to Central Metering < 45 kW		$915		
23	Conversion to Central Metering > 45 kW		$800		
24	Tingle Voltage Test – In Excess of 4 Hours (per hour – average 2 additional hours)		$125		
25	Standby Administration Charge per month		$440		
26	Sentinel Lights Rental Rate per month			$7.10	
27	Sentinel Pole Rental Rate per month			$4.15	
28	Joint Use for Cable and Telecom companies per pole			$22.35	
29	Joint Use for LDCs per pole			$28.61	

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Lucan Granton Hydro Electric Commission
Effective Date: May 1, 2007

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APPLICATION

The application of these rates and charges shall be in accordance with The Licence of The Distributor and any Codes, Guidelines or Orders of The Board, and amendments thereto as approved by The Board, which may be applicable to the administration of this schedule.
No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code, Guideline or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.
This schedule does not contain any rates and charges relating to the electricity commodity (e.g. the Regulated Price Plan).

EFFECTIVE DATES

DISTRIBUTION RATES - May 1, 2007 for all consumption or deemed consumption services used on or after that date.

MISCELLANEOUS CHARGES - May 1, 2007 for all charges billed to customers on or after that date.
RETAIL TRANSMISSION RATES - May 1, 2007 for all consumption or deemed consumption services used on or after that date.
LOSS FACTOR ADJUSTMENT – May 1, 2007

SERVICE CLASSIFICATIONS

Residential
This classification (note 1) refers to all service supplied to single-family dwelling units for domestic or household purpose. Multi-unit residential establishments such as apartment buildings supplied through one service (bulk metered) will normally be classified as General Service, but, at Hydro One's discretion, up to four residential units may be classified as residential. Where electricity service is provided to combined residential and business (including agricultural usage) and the wiring does not provide for separate metering, the classification shall be at the discretion of Hydro One based on such considerations as the estimated predominant consumption.
Further servicing details are available in the utility's Conditions of Service.

General Service
This classification (note 1) refers to all service supplied to premises other than those classified as Residential or Lighting. Some General Service accounts are energy(kWh)-billed, and some are demand(kW)-billed. Further servicing details are available in the utility's Conditions of Service. Also, see note 2.

Unmetered Scattered Load
This classification refers to certain instances where connections can be provided without metering. These loads are generally small in size and consistent in magnitude of load. Hydro One reserves the right to review all cases and may require that a meter be installed at its sole discretion. Services that can be unmetered include cable TV amplifiers, telephone switching devices, phone booths, bus shelters, rail way crossing signals, traffic signals, and other small fixed loads.
Further servicing details are available in the utility's Conditions of Service (including in the "Unmetered Connections" section).

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
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Lucan Granton Hydro Electric Commission
Effective Date: May 1, 2007

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Street Lighting

This classification refers to accounts for the distribution and supply of electrical energy for street lighting. Street lights are devices owned by or operated for the road authority and/or the municipal corporation. These street lights in fact belong to the Street Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility’s Conditions of Service.

Sentinel Lighting

This classification refers to accounts for a separate service to a sentinel light. These sentinel lights in fact belong to the Sentinel Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility’s Conditions of Service.

Interim Demand-Side Management Time-of-Use

This is potentially applicable to Demand-billed General Service accounts. See Note 2 below.

Note (1): Classification descriptions are paraphrases from the document "Hydro One Networks Inc. - Distribution Customers Conditions of Service - August 2004"

Note (2):

Interim Demand-Side Management Time-of-Use Rates: demand charges will be based on demand during the on-peak periods.

Criteria: Customers' electricity consumption (kW) in the off-peak period is at least twice the electricity consumption (kW) during the on-peak period.

Definition of Time Periods: The on-peak hours will be between 0700 hours to 1900 hours Eastern Standard Time during the winter (standard time) on IESO business days and 0600 hours to 1800 hours Eastern Standard Time during the summer (daylight savings time) on IESO business days. The off-peak period constitutes all of the remaining hours.

Hydro One Networks Inc.
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MONTHLY RATES AND CHARGES

Residential

Service Charge	$	11.72
Distribution Volumetric Rate	$ / kWh	0.0142
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0037
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0017
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0055
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0047
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service - Energy Billed (less than 50 kW)

Service Charge	$	16.99
Distribution Volumetric Rate	$ / kWh	0.0147
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0017
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0010
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0050
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0043
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service - Demand Billed (50 kW or greater)

Service Charge	$	16.99
Distribution Volumetric Rate	$ / kW	4.61
Regulatory Asset Recovery - Rider #1	$ / kW	0.53
Regulatory Asset Recovery - Rider #2	$ / kW	0.30
Retail Transmission Rate - Network Service Rate (4)	$ / kW	1.94
Retail Transmission Rate - Line and Transformation Connection Service Rate (4)	$ / kW	1.61
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
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Unmetered, Scattered Load

Service Charge	$	8.03
Distribution Volumetric Rate	$ / kWh	0.0147
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0017
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0010
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0050
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0043
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

(3) For energy-only metered customers, the billing determinant is the customer’s metered energy consumption adjusted by the total loss factor as approved by the Board for Acquired LDC customers.

(4) For demand billed customers, appropriate loss factors must be applied to the applicable tariffs. Also the billing determinant for the Line and Transformation Connection Services rate is the customer’s peak demand in the billing period. The billing determinant for the Network Services rate is: for non-interval-metered customers, the peak demand in the billing period, and for interval-metered customers, the peak demand between 7 AM and 7 PM local time on IESO business days

Interim Demand-Side Management Time-of-Use

See the "Service Classifications" section of this schedule.

Customer-Supplied Transformation Allowance

Applicable to demand-billed customers providing their own transformers
Primary Voltage under 50 kV (per kW)

Single Phase	$ / kW	0.20
Three Phase	$ / kW	0.60

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Loss Factors

Supply Facilities Loss Factor	1.0045
Distribution Loss Factors	
Customer less than 5,000 kW	1.0500
Customer greater than or equal to 5,000 kW	1.0100
Total Loss Factors	
Customer less than 5,000 kW	1.0545
Customer greater than or equal to 5,000 kW	1.0145

Transformer Loss Allowance

Applicable to customers requiring a billing adjustment for transformer losses as the result of being metered on the primary side of a transformer. The following uniform values shall be applied to measured demand and energy to calculate transformer losses for voltages up to and including 50 kV (as metered on the primary side):

(a) 1.5% for transformer installations up to an individual bank capacity of 400 kVA,
(b) 1.0% for bank capacities over 400 kVA.

Alternatively, transformer losses may be determined from transformer test data, and measured demand and energy adjusted accordingly

For services which are not demand metered, an assumed demand of 50% of the transformer capacity will be used to calculate the loss allowance. Where several transformers are involved, the bank capacity is assumed to be the arithmetic sum of all transformer capacities

Hydro One Networks Inc.
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Effective Date: May 1, 2007

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MISCELLANEOUS CHARGES

Specific Service Charges: Standard Amounts

Rate Code	Specific Service Charge - Standard Name	Calculation Method			
		2006 Rate Handbook	Standard Formula	Other Formula	Time and Materials
1	Temporary Service	$500			
2	Dispute Meter Test	$30 plus Measurement Canada fees			
3	Collection of account – no disconnection/load limiter	$30			
4	Collection/Disconnect/load limiter/reconnect (at meter) trip – regular hours	$65			
5	Collection/Disconnect/load limiter/reconnect (at meter) trip – after regular hours	$185			
6	Collection/Disconnect/load limiter/reconnect (at pole) trip – regular hours	$185			
7	Collection/Disconnect/load limiter/reconnect (at pole) trip – after regular hours	$415			
8	Account Set-up Charge	$30			
9	Arrears Certificate	$15			
10	NSF Cheque Charge	$15 + bank charges			
11	Easement Charge for Unregistered Rights	$15			
12	Late Payment Charge	1.5%/month			
13a	Retailer Services – Establishing Service Agreements (refer to Handbook for all charges)	$100/agreement/Retailer +$20/month/Retailer +$0.50/month/customer + other			
13b	Retailer Services – Other (includes Bill Ready for Retailers and Service Transactions Requests) as per the Handbook, Chapter 12	$0.30/month/customer + $0.25/request for request fee + $0.50/request for process fee			
14	Special Meter Reads	$30			
15	Billing Suspension and Terminations in Trailer Parks		$130		
16	Service Layout Fee – Basic		$405		
17	Service Layout Fee – Complex		$580		

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
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18	Crossing Application – Pipeline		$2,065		
19	Crossing Application – Water		$2,525		
20	Crossing Application – Railroad		$2,565		
21	Line Staking – per meter		$3.10		
22	Central Metering – New service < 45 kW		$115		
23	Conversion to Central Metering < 45 kW		$795		
24	Conversion to Central Metering > 45 kW		$680		
25	Tingle Voltage Test – In Excess of 4 Hours (per hour – average 2 additional hours)		$105		
26	Standby Administration Charge per month (interim)		$375		
27	Sentinel Lights Rental Rate per month – Mercury Vapor			$7.00	
28	Guaranteed Units from Jan 01/91 to Aug 01/91			$26.50 / month	
29	Guaranteed Units from Jan 01/87 to Dec 31/90			$23.50 / month	
30	Joint Use for Cable and Telecom companies per pole			$22.35	
31	Joint Use for LDCs per pole			$28.61	

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Hydro-Electric Power Commission of the Township of Malahide
Effective Date: May 1, 2008

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

APPLICATION

The application of these rates and charges shall be in accordance with The Licence of The Distributor and any Codes, Guidelines or Orders of The Board, and amendments thereto as approved by The Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code, Guideline or Order of the Board, and amendments thereto as approved by the Board, or as specified herein

This schedule does not contain any rates and charges relating to the electricity commodity (e.g. the Regulated Price Plan).

EFFECTIVE DATES

DISTRIBUTION RATES - May 1, 2008 for all consumption or deemed consumption services used on or after that date.

MISCELLANEOUS CHARGES - May 1, 2008 for all charges billed to customers on or after that date.

RETAIL TRANSMISSION RATES - May 1, 2008 for all consumption or deemed consumption services used on or after that date.

LOSS FACTOR ADJUSTMENT – for all consumption or deemed consumption services billed following May 1, 2008 or later

SERVICE CLASSIFICATIONS

Residential

This classification refers to all service supplied to single-family dwelling units for domestic or household purpose. Multi-unit residential establishments such as apartment buildings supplied through one service (bulk metered) will normally be classified as General Service, but, at Hydro One's discretion, up to four residential units may be classified as residential. Where electricity service is provided to combined residential and business (including agricultural usage) and the wiring does not provide for separate metering, the classification shall be at the discretion of Hydro One based on such considerations as the estimated predominant consumption.

Further servicing details are available in the utility's Conditions of Service.

General Service

This classification refers to all service supplied to premises other than those classified as Residential or Lighting. Some General Service accounts are energy(kWh)-billed, and some are demand(kW)-billed. Further servicing details are available in the utility's Conditions of Service.

Unmetered Scattered Load

This classification refers to certain instances where connections can be provided without metering. These loads are generally small in size and consistent in magnitude of load. Hydro One reserves the right to review all cases and may require that a meter be installed at its sole discretion. Services that can be unmetered include cable TV amplifiers, telephone switching devices, phone booths, bus shelters, rail way crossing signals, traffic signals, and other small fixed loads.

Further servicing details are available in the utility's Conditions of Service (including in the "Unmetered Connections" section).

Hydro One Networks Inc.
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Effective Date: May 1, 2008

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Street Lighting

This classification refers to accounts for the distribution and supply of electrical energy for street lighting. Street lights are devices owned by or operated for the road authority and/or the municipal corporation. These street lights in fact belong to the Street Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Sentinel Lighting

This classification refers to accounts for a separate service to a sentinel light. These sentinel lights in fact belong to the Sentinel Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Urban Density Classification

Customers who meet the Urban Density Criteria of being in an area containing 3,000 or more customers with a line density of at least 60 customers per kilometre, will be mapped to an Urban customer classification.

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
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Effective Date: May 1, 2008

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

MONTHLY RATES AND CHARGES

Residential - R1 Malahide

Service Charge	$	12.97
Distribution Volumetric Rate	$ / kWh	0.0240
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0034
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0004)
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0047
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0046
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service Less Than 50 kW (Energy-Billed) - GSe Malahide

Service Charge	$	19.13
Distribution Volumetric Rate	$ / kWh	0.0321
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0049
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0006)
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0035
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0032
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service 50 kW or Greater (Demand-Billed) - GSd Malahide

Service Charge	$	22.69
Distribution Volumetric Rate	$ / kW	9.22
Regulatory Asset Recovery - Rider #2	$ / kW	1.32
Regulatory Asset Recovery - Rider #3	$ / kW	(0.22)
Retail Transmission Rate - Network Service Rate (4)	$ / kW	1.11
Retail Transmission Rate - Line and Transformation Connection Service Rate (4)	$ / kW	1.00
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
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Effective Date: May 1, 2008

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Unmetered, Scattered Load

Service Charge	$	11.52
Distribution Volumetric Rate	$ / kWh	0.0200
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0049
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0006)
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0035
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0032
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

(3) For energy-only metered customers, the billing determinant is the customer's metered energy consumption adjusted by the total loss factor as approved by the Board for Acquired LDC customers.
(4) For demand billed customers, appropriate loss factors must be applied to the applicable tariffs. Also the billing determinant for the Line and Transformation Connection Services rate is the customer's peak demand in the billing period. The billing determinant for the Network Services rate is: for non-interval-metered customers, the peak demand in the billing period, and for interval-metered customers, the peak demand between 7 AM and 7 PM local time on IESO business days

Customer-Supplied Transformation Allowance

Applicable to customers providing their own transformers

Demand-billed	$ / kW	0.60
Energy-billed	$ / kWh	0.0014

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Hydro-Electric Power Commission of the Township of Malahide
Effective Date: May 1, 2008

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

Loss Factors

Residential	1.085
General Service Less Than 50 kW (Energy-Billed)	1.092
General Service 50 kW or Greater (Demand-Billed)	1.061
Unmetered Scattered Load	1.092

Transformer Loss Allowance

Applicable to customers requiring a billing adjustment for transformer losses as the result of being metered on the primary side of a transformer. The following uniform values shall be applied to measured demand and energy to calculate transformer losses for voltages up to and including 50 kV (as metered on the primary side):

(a) 1.5% for transformer installations up to an individual bank capacity of 400 kVA,
(b) 1.0% for bank capacities over 400 kVA.

Alternatively, transformer losses may be determined from transformer test data, and measured demand and energy adjusted accordingly

For services which are not demand metered, an assumed demand of 50% of the transformer capacity will be used to calculate the loss allowance. Where several transformers are involved, the bank capacity is assumed to be the arithmetic sum of all transformer capacities

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
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MISCELLANEOUS CHARGES

Specific Service Charges: Standard Amounts

Rate Code	Specific Service Charge - Standard Name	Calculation Method			
		2006 Rate Handbook	Standard Formula	Other Formula	Time and Materials
1	Temporary Service	$500			
2	Dispute Meter Test	$30 plus Measurement Canada fees			
3	Collection of account – no disconnection/load limiter	$30			
4	Collection/Disconnect/load limiter/reconnect (at meter) trip – regular hours	$65			
5	Collection/Disconnect/load limiter/reconnect (at meter) trip – after regular hours	$185			
6	Collection/Disconnect/load limiter/reconnect (at pole) trip – regular hours	$185			
7	Collection/Disconnect/load limiter/reconnect (at pole) trip – after regular hours	$415			
8	Account Set-up Charge	$30			
9	Arrears Certificate	$15			
10	NSF Cheque Charge	$15 + bank charges			
11	Easement Charge for Unregistered Rights	$15			
12	Late Payment Charge	1.5%/month			
13a	Retailer Services – Establishing Service Agreements (refer to Handbook for all charges)	$100/agreement/Retailer +$20/month/Retailer +$0.50/month/customer + other			
13b	Retailer Services – Other (includes Bill Ready for Retailers and Service Transactions Requests) as per the Handbook, Chapter 12	$0.30/month/customer + $0.25/request for request fee + $0.50/request for process fee			
14	Special Meter Reads	$30			
15	Service Layout Fee – Basic		$495		
16	Service Layout Fee – Complex		$690		
17	Crossing Application – Pipeline		$2,445		
18	Crossing Application – Water		$3,045		
19	Crossing Application – Railroad		$2,945		
20	Line Staking – per meter		$3.70		
21	Central Metering – New service < 45 kW		$115		
22	Conversion to Central Metering < 45 kW		$915		
23	Conversion to Central Metering > 45 kW		$800		
24	Tingle Voltage Test – In Excess of 4 Hours (per hour – average 2 additional hours)		$125		
25	Standby Administration Charge per month		$440		
26	Sentinel Lights Rental Rate per month			$7.10	
27	Sentinel Pole Rental Rate per month			$4.15	
28	Joint Use for Cable and Telecom companies per pole			$22.35	
29	Joint Use for LDCs per pole			$28.61	

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
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Hydro-Electric Power Commission of the Township of Malahide
Effective Date: May 1, 2007

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

APPLICATION

The application of these rates and charges shall be in accordance with The Licence of The Distributor and any Codes, Guidelines or Orders of The Board, and amendments thereto as approved by The Board, which may be applicable to the administration of this schedule.
No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code, Guideline or Order of the Board, and amendments thereto as approved by the Board, or as specified herein
This schedule does not contain any rates and charges relating to the electricity commodity (e.g. the Regulated Price Plan).

EFFECTIVE DATES

DISTRIBUTION RATES - May 1, 2007 for all consumption or deemed consumption services used on or after that date.

MISCELLANEOUS CHARGES - May 1, 2007 for all charges billed to customers on or after that date.
RETAIL TRANSMISSION RATES - May 1, 2007 for all consumption or deemed consumption services used on or after that date.
LOSS FACTOR ADJUSTMENT – May 1, 2007

SERVICE CLASSIFICATIONS

Residential
This classification (note 1) refers to all service supplied to single-family dwelling units for domestic or household purpose. Multi-unit residential establishments such as apartment buildings supplied through one service (bulk metered) will normally be classified as General Service, but, at Hydro One's discretion, up to four residential units may be classified as residential. Where electricity service is provided to combined residential and business (including agricultural usage) and the wiring does not provide for separate metering, the classification shall be at the discretion of Hydro One based on such considerations as the estimated predominant consumption.
Further servicing details are available in the utility's Conditions of Service.

General Service
This classification (note 1) refers to all service supplied to premises other than those classified as Residential or Lighting. Some General Service accounts are energy(kWh)-billed, and some are demand(kW)-billed. Further servicing details are available in the utility's Conditions of Service. Also, see note 2.

Unmetered Scattered Load
This classification refers to certain instances where connections can be provided without metering. These loads are generally small in size and consistent in magnitude of load. Hydro One reserves the right to review all cases and may require that a meter be installed at its sole discretion. Services that can be unmetered include cable TV amplifiers, telephone switching devices, phone booths, bus shelters, rail way crossing signals, traffic signals, and other small fixed loads.
Further servicing details are available in the utility's Conditions of Service (including in the "Unmetered Connections" section).

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
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Hydro-Electric Power Commission of the Township of Malahide
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Street Lighting

This classification refers to accounts for the distribution and supply of electrical energy for street lighting. Street lights are devices owned by or operated for the road authority and/or the municipal corporation. These street lights in fact belong to the Street Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Sentinel Lighting

This classification refers to accounts for a separate service to a sentinel light. These sentinel lights in fact belong to the Sentinel Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Interim Demand-Side Management Time-of-Use

This is potentially applicable to Demand-billed General Service accounts. See Note 2 below.

Note (1): Classification descriptions are paraphrases from the document "Hydro One Networks Inc. - Distribution Customers Conditions of Service - August 2004"

Note (2):

Interim Demand-Side Management Time-of-Use Rates: demand charges will be based on demand during the on-peak periods.

Criteria: Customers' electricity consumption (kW) in the off-peak period is at least twice the electricity consumption (kW) during the on-peak period.

Definition of Time Periods: The on-peak hours will be between 0700 hours to 1900 hours Eastern Standard Time during the winter (standard time) on IESO business days and 0600 hours to 1800 hours Eastern Standard Time during the summer (daylight savings time) on IESO business days. The off-peak period constitutes all of the remaining hours.

Hydro One Networks Inc.
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MONTHLY RATES AND CHARGES

Residential

Service Charge	$	11.17
Distribution Volumetric Rate	$ / kWh	0.0087
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0078
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0034
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0055
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0047
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service - Energy Billed (less than 50 kW)

Service Charge	$	15.84
Distribution Volumetric Rate	$ / kWh	0.0198
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0081
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0049
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0050
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0043
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service - Demand Billed (50 kW or greater)

Service Charge	$	15.99
Distribution Volumetric Rate	$ / kW	5.42
Regulatory Asset Recovery - Rider #1	$ / kW	2.57
Regulatory Asset Recovery - Rider #2	$ / kW	1.32
Retail Transmission Rate - Network Service Rate (4)	$ / kW	1.94
Retail Transmission Rate - Line and Transformation Connection Service Rate (4)	$ / kW	1.61
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

Hydro One Networks Inc.
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Unmetered, Scattered Load

Service Charge	$	7.45
Distribution Volumetric Rate	$ / kWh	0.0198
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0081
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0049
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0050
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0043
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

(3) For energy-only metered customers, the billing determinant is the customer's metered energy consumption adjusted by the total loss factor as approved by the Board for Acquired LDC customers.
(4) For demand billed customers, appropriate loss factors must be applied to the applicable tariffs. Also the billing determinant for the Line and Transformation Connection Services rate is the customer's peak demand in the billing period. The billing determinant for the Network Services rate is: for non-interval-metered customers, the peak demand in the billing period, and for interval-metered customers, the peak demand between 7 AM and 7 PM local time on IESO business days

Interim Demand-Side Management Time-of-Use

See the "Service Classifications" section of this schedule.

Customer-Supplied Transformation Allowance

Applicable to demand-billed customers providing their own transformers
Primary Voltage under 50 kV (per kW)

Single Phase	$ / kW	0.20
Three Phase	$ / kW	0.60

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Loss Factors

Supply Facilities Loss Factor	1.0045
Distribution Loss Factors	
Customer less than 5,000 kW	1.0500
Customer greater than or equal to 5,000 kW	1.0100
Total Loss Factors	
Customer less than 5,000 kW	1.0545
Customer greater than or equal to 5,000 kW	1.0145

Transformer Loss Allowance

Applicable to customers requiring a billing adjustment for transformer losses as the result of being metered on the primary side of a transformer. The following uniform values shall be applied to measured demand and energy to calculate transformer losses for voltages up to and including 50 kV (as metered on the primary side):

(a) 1.5% for transformer installations up to an individual bank capacity of 400 kVA,
(b) 1.0% for bank capacities over 400 kVA.

Alternatively, transformer losses may be determined from transformer test data, and measured demand and energy adjusted accordingly

For services which are not demand metered, an assumed demand of 50% of the transformer capacity will be used to calculate the loss allowance. Where several transformers are involved, the bank capacity is assumed to be the arithmetic sum of all transformer capacities

Hydro One Networks Inc.
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MISCELLANEOUS CHARGES

Specific Service Charges: Standard Amounts

Rate Code	Specific Service Charge - Standard Name	Calculation Method			
		2006 Rate Handbook	Standard Formula	Other Formula	Time and Materials
1	Temporary Service	$500			
2	Dispute Meter Test	$30 plus Measurement Canada fees			
3	Collection of account – no disconnection/load limiter	$30			
4	Collection/Disconnect/load limiter/reconnect (at meter) trip – regular hours	$65			
5	Collection/Disconnect/load limiter/reconnect (at meter) trip – after regular hours	$185			
6	Collection/Disconnect/load limiter/reconnect (at pole) trip – regular hours	$185			
7	Collection/Disconnect/load limiter/reconnect (at pole) trip – after regular hours	$415			
8	Account Set-up Charge	$30			
9	Arrears Certificate	$15			
10	NSF Cheque Charge	$15 + bank charges			
11	Easement Charge for Unregistered Rights	$15			
12	Late Payment Charge	1.5%/month			
13a	Retailer Services – Establishing Service Agreements (refer to Handbook for all charges)	$100/agreement/Retailer +$20/month/Retailer +$0.50/month/customer + other			
13b	Retailer Services – Other (includes Bill Ready for Retailers and Service Transactions Requests) as per the Handbook, Chapter 12	$0.30/month/customer + $0.25/request for request fee + $0.50/request for process fee			
14	Special Meter Reads	$30			
15	Billing Suspension and Terminations in Trailer Parks		$130		
16	Service Layout Fee – Basic		$405		
17	Service Layout Fee – Complex		$580		

Hydro One Networks Inc.
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18	Crossing Application – Pipeline		$2,065		
19	Crossing Application – Water		$2,525		
20	Crossing Application – Railroad		$2,565		
21	Line Staking – per meter		$3.10		
22	Central Metering – New service < 45 kW		$115		
23	Conversion to Central Metering < 45 kW		$795		
24	Conversion to Central Metering > 45 kW		$680		
25	Tingle Voltage Test – In Excess of 4 Hours (per hour – average 2 additional hours)		$105		
26	Standby Administration Charge per month (interim)		$375		
27	Sentinel Lights Rental Rate per month – Mercury Vapor			$7.00	
28	Guaranteed Units from Jan 01/91 to Aug 01/91			$26.50 / month	
29	Guaranteed Units from Jan 01/87 to Dec 31/90			$23.50 / month	
30	Joint Use for Cable and Telecom companies per pole			$22.35	
31	Joint Use for LDCs per pole			$28.61	

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Hydro-Electric Commission of the Township of Mapleton
Effective Date: May 1, 2008

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APPLICATION

The application of these rates and charges shall be in accordance with The Licence of The Distributor and any Codes, Guidelines or Orders of The Board, and amendments thereto as approved by The Board, which may be applicable to the administration of this schedule.
No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code, Guideline or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.
This schedule does not contain any rates and charges relating to the electricity commodity (e.g. the Regulated Price Plan).

EFFECTIVE DATES

DISTRIBUTION RATES - May 1, 2008 for all consumption or deemed consumption services used on or after that date.

MISCELLANEOUS CHARGES - May 1, 2008 for all charges billed to customers on or after that date.
RETAIL TRANSMISSION RATES - May 1, 2008 for all consumption or deemed consumption services used on or after that date.
LOSS FACTOR ADJUSTMENT – for all consumption or deemed consumption services billed following May 1, 2008 or later

SERVICE CLASSIFICATIONS

Residential
This classification refers to all service supplied to single-family dwelling units for domestic or household purpose. Multi-unit residential establishments such as apartment buildings supplied through one service (bulk metered) will normally be classified as General Service, but, at Hydro One's discretion, up to four residential units may be classified as residential. Where electricity service is provided to combined residential and business (including agricultural usage) and the wiring does not provide for separate metering, the classification shall be at the discretion of Hydro One based on such considerations as the estimated predominant consumption.
Further servicing details are available in the utility's Conditions of Service.

General Service
This classification refers to all service supplied to premises other than those classified as Residential or Lighting. Some General Service accounts are energy(kWh)-billed, and some are demand(kW)-billed. Further servicing details are available in the utility's Conditions of Service.

Unmetered Scattered Load
This classification refers to certain instances where connections can be provided without metering. These loads are generally small in size and consistent in magnitude of load. Hydro One reserves the right to review all cases and may require that a meter be installed at its sole discretion. Services that can be unmetered include cable TV amplifiers, telephone switching devices, phone booths, bus shelters, rail way crossing signals, traffic signals, and other small fixed loads.
Further servicing details are available in the utility's Conditions of Service (including in the "Unmetered Connections" section).

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
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Effective Date: May 1, 2008

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Street Lighting

This classification refers to accounts for the distribution and supply of electrical energy for street lighting. Street lights are devices owned by or operated for the road authority and/or the municipal corporation. These street lights in fact belong to the Street Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Sentinel Lighting

This classification refers to accounts for a separate service to a sentinel light. These sentinel lights in fact belong to the Sentinel Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Urban Density Classification

Customers who meet the Urban Density Criteria of being in an area containing 3,000 or more customers with a line density of at least 60 customers per kilometre, will be mapped to an Urban customer classification.

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
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MONTHLY RATES AND CHARGES

Residential - R1 Mapleton

Service Charge	$	14.39
Distribution Volumetric Rate	$ / kWh	0.0240
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0039
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0004)
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0047
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0046
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service Less Than 50 kW (Energy-Billed) - GSe Mapleton

Service Charge	$	23.70
Distribution Volumetric Rate	$ / kWh	0.0311
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0029
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0006)
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0035
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0032
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service 50 kW or Greater (Demand-Billed) - GSd Mapleton

Service Charge	$	27.30
Distribution Volumetric Rate	$ / kW	9.22
Regulatory Asset Recovery - Rider #2	$ / kW	0.93
Regulatory Asset Recovery - Rider #3	$ / kW	(0.22)
Retail Transmission Rate - Network Service Rate (4)	$ / kW	1.11
Retail Transmission Rate - Line and Transformation Connection Service Rate (4)	$ / kW	1.00
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

Hydro One Networks Inc.
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Unmetered, Scattered Load

Service Charge	$	13.80
Distribution Volumetric Rate	$ / kWh	0.0200
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0029
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0006)
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0035
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0032
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

(3) For energy-only metered customers, the billing determinant is the customer's metered energy consumption adjusted by the total loss factor as approved by the Board for Acquired LDC customers.
(4) For demand billed customers, appropriate loss factors must be applied to the applicable tariffs. Also the billing determinant for the Line and Transformation Connection Services rate is the customer's peak demand in the billing period. The billing determinant for the Network Services rate is: for non-interval-metered customers, the peak demand in the billing period, and for interval-metered customers, the peak demand between 7 AM and 7 PM local time on IESO business days

Customer-Supplied Transformation Allowance

Applicable to customers providing their own transformers

Demand-billed	$ / kW	0.60
Energy-billed	$ / kWh	0.0014

Hydro One Networks Inc.
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Loss Factors

Residential	1.085
General Service Less Than 50 kW (Energy-Billed)	1.092
General Service 50 kW or Greater (Demand-Billed)	1.061
Unmetered Scattered Load	1.092

Transformer Loss Allowance

Applicable to customers requiring a billing adjustment for transformer losses as the result of being metered on the primary side of a transformer. The following uniform values shall be applied to measured demand and energy to calculate transformer losses for voltages up to and including 50 kV (as metered on the primary side):

(a) 1.5% for transformer installations up to an individual bank capacity of 400 kVA,
(b) 1.0% for bank capacities over 400 kVA.

Alternatively, transformer losses may be determined from transformer test data, and measured demand and energy adjusted accordingly

For services which are not demand metered, an assumed demand of 50% of the transformer capacity will be used to calculate the loss allowance. Where several transformers are involved, the bank capacity is assumed to be the arithmetic sum of all transformer capacities

Hydro One Networks Inc.
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MISCELLANEOUS CHARGES

Specific Service Charges: Standard Amounts

Rate Code	Specific Service Charge - Standard Name	Calculation Method			
		2006 Rate Handbook	Standard Formula	Other Formula	Time and Materials
1	Temporary Service	$500			
2	Dispute Meter Test	$30 plus Measurement Canada fees			
3	Collection of account – no disconnection/load limiter	$30			
4	Collection/Disconnect/load limiter/reconnect (at meter) trip – regular hours	$65			
5	Collection/Disconnect/load limiter/reconnect (at meter) trip – after regular hours	$185			
6	Collection/Disconnect/load limiter/reconnect (at pole) trip – regular hours	$185			
7	Collection/Disconnect/load limiter/reconnect (at pole) trip – after regular hours	$415			
8	Account Set-up Charge	$30			
9	Arrears Certificate	$15			
10	NSF Cheque Charge	$15 + bank charges			
11	Easement Charge for Unregistered Rights	$15			
12	Late Payment Charge	1.5%/month			
13a	Retailer Services – Establishing Service Agreements (refer to Handbook for all charges)	$100/agreement/Retailer +$20/month/Retailer +$0.50/month/customer + other			
13b	Retailer Services – Other (includes Bill Ready for Retailers and Service Transactions Requests) as per the Handbook, Chapter 12	$0.30/month/customer + $0.25/request for request fee + $0.50/request for process fee			
14	Special Meter Reads	$30			
15	Service Layout Fee – Basic		$495		
16	Service Layout Fee – Complex		$690		
17	Crossing Application – Pipeline		$2,445		
18	Crossing Application – Water		$3,045		
19	Crossing Application – Railroad		$2,945		
20	Line Staking – per meter		$3.70		
21	Central Metering – New service < 45 kW		$115		
22	Conversion to Central Metering < 45 kW		$915		
23	Conversion to Central Metering > 45 kW		$800		
24	Tingle Voltage Test – In Excess of 4 Hours (per hour – average 2 additional hours)		$125		
25	Standby Administration Charge per month		$440		
26	Sentinel Lights Rental Rate per month			$7.10	
27	Sentinel Pole Rental Rate per month			$4.15	
28	Joint Use for Cable and Telecom companies per pole			$22.35	
29	Joint Use for LDCs per pole			$28.61	

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Hydro-Electric Commission of the Township of Mapleton
Effective Date: May 1, 2007

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

APPLICATION

The application of these rates and charges shall be in accordance with The Licence of The Distributor and any Codes, Guidelines or Orders of The Board, and amendments thereto as approved by The Board, which may be applicable to the administration of this schedule.
No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code, Guideline or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.
This schedule does not contain any rates and charges relating to the electricity commodity (e.g. the Regulated Price Plan).

EFFECTIVE DATES

DISTRIBUTION RATES - May 1, 2007 for all consumption or deemed consumption services used on or after that date.

MISCELLANEOUS CHARGES - May 1, 2007 for all charges billed to customers on or after that date.
RETAIL TRANSMISSION RATES - May 1, 2007 for all consumption or deemed consumption services used on or after that date.
LOSS FACTOR ADJUSTMENT – May 1, 2007

SERVICE CLASSIFICATIONS

Residential
This classification (note 1) refers to all service supplied to single-family dwelling units for domestic or household purpose. Multi-unit residential establishments such as apartment buildings supplied through one service (bulk metered) will normally be classified as General Service, but, at Hydro One's discretion, up to four residential units may be classified as residential. Where electricity service is provided to combined residential and business (including agricultural usage) and the wiring does not provide for separate metering, the classification shall be at the discretion of Hydro One based on such considerations as the estimated predominant consumption.
Further servicing details are available in the utility's Conditions of Service.

General Service
This classification (note 1) refers to all service supplied to premises other than those classified as Residential or Lighting. Some General Service accounts are energy(kWh)-billed, and some are demand(kW)-billed. Further servicing details are available in the utility's Conditions of Service. Also, see note 2.

Unmetered Scattered Load
This classification refers to certain instances where connections can be provided without metering. These loads are generally small in size and consistent in magnitude of load. Hydro One reserves the right to review all cases and may require that a meter be installed at its sole discretion. Services that can be unmetered include cable TV amplifiers, telephone switching devices, phone booths, bus shelters, rail way crossing signals, traffic signals, and other small fixed loads.
Further servicing details are available in the utility's Conditions of Service (including in the "Unmetered Connections" section).

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Street Lighting

This classification refers to accounts for the distribution and supply of electrical energy for street lighting. Street lights are devices owned by or operated for the road authority and/or the municipal corporation. These street lights in fact belong to the Street Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Sentinel Lighting

This classification refers to accounts for a separate service to a sentinel light. These sentinel lights in fact belong to the Sentinel Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Interim Demand-Side Management Time-of-Use

This is potentially applicable to Demand-billed General Service accounts. See Note 2 below.

Note (1): Classification descriptions are paraphrases from the document "Hydro One Networks Inc. - Distribution Customers Conditions of Service - August 2004"
Note (2):

Interim Demand-Side Management Time-of-Use Rates: demand charges will be based on demand during the on-peak periods.
Criteria: Customers' electricity consumption (kW) in the off-peak period is at least twice the electricity consumption (kW) during the on-peak period.
Definition of Time Periods: The on-peak hours will be between 0700 hours to 1900 hours Eastern Standard Time during the winter (standard time) on IESO business days and 0600 hours to 1800 hours Eastern Standard Time during the summer (daylight savings time) on IESO business days. The off-peak period constitutes all of the remaining hours.

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MONTHLY RATES AND CHARGES

Residential

Service Charge	$	13.47
Distribution Volumetric Rate	$ / kWh	0.0092
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0065
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0039
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0055
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0047
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service - Energy Billed (less than 50 kW)

Service Charge	$	21.55
Distribution Volumetric Rate	$ / kWh	0.0171
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0040
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0029
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0050
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0043
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service - Demand Billed (50 kW or greater)

Service Charge	$	21.55
Distribution Volumetric Rate	$ / kW	5.42
Regulatory Asset Recovery - Rider #1	$ / kW	1.26
Regulatory Asset Recovery - Rider #2	$ / kW	0.93
Retail Transmission Rate - Network Service Rate (4)	$ / kW	1.94
Retail Transmission Rate - Line and Transformation Connection Service Rate (4)	$ / kW	1.61
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

Hydro One Networks Inc.
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Unmetered, Scattered Load

Service Charge	$	10.32
Distribution Volumetric Rate	$ / kWh	0.0171
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0040
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0029
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0050
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0043
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

(3) For energy-only metered customers, the billing determinant is the customer’s metered energy consumption adjusted by the total loss factor as approved by the Board for Acquired LDC customers.
(4) For demand billed customers, appropriate loss factors must be applied to the applicable tariffs. Also the billing determinant for the Line and Transformation Connection Services rate is the customer’s peak demand in the billing period. The billing determinant for the Network Services rate is: for non-interval-metered customers, the peak demand in the billing period, and for interval-metered customers, the peak demand between 7 AM and 7 PM local time on IESO business days

Interim Demand-Side Management Time-of-Use

See the "Service Classifications" section of this schedule.

Customer-Supplied Transformation Allowance

Applicable to demand-billed customers providing their own transformers
Primary Voltage under 50 kV (per kW)

Single Phase	$ / kW	0.20
Three Phase	$ / kW	0.60

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Loss Factors

Supply Facilities Loss Factor	1.0045
Distribution Loss Factors	
Customer less than 5,000 kW	1.0500
Customer greater than or equal to 5,000 kW	1.0100
Total Loss Factors	
Customer less than 5,000 kW	1.0545
Customer greater than or equal to 5,000 kW	1.0145

Transformer Loss Allowance

Applicable to customers requiring a billing adjustment for transformer losses as the result of being metered on the primary side of a transformer. The following uniform values shall be applied to measured demand and energy to calculate transformer losses for voltages up to and including 50 kV (as metered on the primary side):

(a) 1.5% for transformer installations up to an individual bank capacity of 400 kVA,
(b) 1.0% for bank capacities over 400 kVA.

Alternatively, transformer losses may be determined from transformer test data, and measured demand and energy adjusted accordingly

For services which are not demand metered, an assumed demand of 50% of the transformer capacity will be used to calculate the loss allowance. Where several transformers are involved, the bank capacity is assumed to be the arithmetic sum of all transformer capacities

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
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Effective Date: May 1, 2007

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MISCELLANEOUS CHARGES

Specific Service Charges: Standard Amounts

Rate Code	Specific Service Charge - Standard Name	Calculation Method			
		2006 Rate Handbook	Standard Formula	Other Formula	Time and Materials
1	Temporary Service	$500			
2	Dispute Meter Test	$30 plus Measurement Canada fees			
3	Collection of account – no disconnection/load limiter	$30			
4	Collection/Disconnect/load limiter/reconnect (at meter) trip – regular hours	$65			
5	Collection/Disconnect/load limiter/reconnect (at meter) trip – after regular hours	$185			
6	Collection/Disconnect/load limiter/reconnect (at pole) trip – regular hours	$185			
7	Collection/Disconnect/load limiter/reconnect (at pole) trip – after regular hours	$415			
8	Account Set-up Charge	$30			
9	Arrears Certificate	$15			
10	NSF Cheque Charge	$15 + bank charges			
11	Easement Charge for Unregistered Rights	$15			
12	Late Payment Charge	1.5%/month			
13a	Retailer Services – Establishing Service Agreements (refer to Handbook for all charges)	$100/agreement/Retailer +$20/month/Retailer +$0.50/month/customer + other			
13b	Retailer Services – Other (includes Bill Ready for Retailers and Service Transactions Requests) as per the Handbook, Chapter 12	$0.30/month/customer + $0.25/request for request fee + $0.50/request for process fee			
14	Special Meter Reads	$30			
15	Billing Suspension and Terminations in Trailer Parks		$130		
16	Service Layout Fee – Basic		$405		
17	Service Layout Fee – Complex		$580		

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18	Crossing Application – Pipeline		$2,065		
19	Crossing Application – Water		$2,525		
20	Crossing Application – Railroad		$2,565		
21	Line Staking – per meter		$3.10		
22	Central Metering – New service < 45 kW		$115		
23	Conversion to Central Metering < 45 kW		$795		
24	Conversion to Central Metering > 45 kW		$680		
25	Tingle Voltage Test – In Excess of 4 Hours (per hour – average 2 additional hours)		$105		
26	Standby Administration Charge per month (interim)		$375		
27	Sentinel Lights Rental Rate per month – Mercury Vapor			$7.00	
28	Guaranteed Units from Jan 01/91 to Aug 01/91			$26.50 / month	
29	Guaranteed Units from Jan 01/87 to Dec 31/90			$23.50 / month	
30	Joint Use for Cable and Telecom companies per pole			$22.35	
31	Joint Use for LDCs per pole			$28.61	

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
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Markdale Hydro System
Effective Date: May 1, 2008

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

APPLICATION

The application of these rates and charges shall be in accordance with The Licence of The Distributor and any Codes, Guidelines or Orders of The Board, and amendments thereto as approved by The Board, which may be applicable to the administration of this schedule.
No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code, Guideline or Order of the Board, and amendments thereto as approved by the Board, or as specified herein
This schedule does not contain any rates and charges relating to the electricity commodity (e.g. the Regulated Price Plan).

EFFECTIVE DATES

DISTRIBUTION RATES - May 1, 2008 for all consumption or deemed consumption services used on or after that date.

MISCELLANEOUS CHARGES - May 1, 2008 for all charges billed to customers on or after that date.
RETAIL TRANSMISSION RATES - May 1, 2008 for all consumption or deemed consumption services used on or after that date.
LOSS FACTOR ADJUSTMENT – for all consumption or deemed consumption services billed following May 1, 2008 or later

SERVICE CLASSIFICATIONS

Residential
This classification refers to all service supplied to single-family dwelling units for domestic or household purpose. Multi-unit residential establishments such as apartment buildings supplied through one service (bulk metered) will normally be classified as General Service, but, at Hydro One's discretion, up to four residential units may be classified as residential. Where electricity service is provided to combined residential and business (including agricultural usage) and the wiring does not provide for separate metering, the classification shall be at the discretion of Hydro One based on such considerations as the estimated predominant consumption.
Further servicing details are available in the utility's Conditions of Service.

General Service
This classification refers to all service supplied to premises other than those classified as Residential or Lighting. Some General Service accounts are energy(kWh)-billed, and some are demand(kW)-billed. Further servicing details are available in the utility's Conditions of Service.

Unmetered Scattered Load
This classification refers to certain instances where connections can be provided without metering. These loads are generally small in size and consistent in magnitude of load. Hydro One reserves the right to review all cases and may require that a meter be installed at its sole discretion. Services that can be unmetered include cable TV amplifiers, telephone switching devices, phone booths, bus shelters, rail way crossing signals, traffic signals, and other small fixed loads.
Further servicing details are available in the utility's Conditions of Service (including in the "Unmetered Connections" section).

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TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Markdale Hydro System
Effective Date: May 1, 2008

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Street Lighting

This classification refers to accounts for the distribution and supply of electrical energy for street lighting. Street lights are devices owned by or operated for the road authority and/or the municipal corporation. These street lights in fact belong to the Street Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Sentinel Lighting

This classification refers to accounts for a separate service to a sentinel light. These sentinel lights in fact belong to the Sentinel Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Urban Density Classification

Customers who meet the Urban Density Criteria of being in an area containing 3,000 or more customers with a line density of at least 60 customers per kilometre, will be mapped to an Urban customer classification.

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
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Effective Date: May 1, 2008

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MONTHLY RATES AND CHARGES

Residential - R1 Markdale

Service Charge	$	15.19
Distribution Volumetric Rate	$ / kWh	0.0210
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0016
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0004)
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0047
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0046
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service Less Than 50 kW (Energy-Billed) - GSe Markdale

Service Charge	$	25.34
Distribution Volumetric Rate	$ / kWh	0.0182
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0004
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0006)
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0035
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0032
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service 50 kW or Greater (Demand-Billed) - GSd Markdale

Service Charge	$	28.94
Distribution Volumetric Rate	$ / kW	7.25
Regulatory Asset Recovery - Rider #2	$ / kW	0.13
Regulatory Asset Recovery - Rider #3	$ / kW	(0.22)
Retail Transmission Rate - Network Service Rate (4)	$ / kW	1.11
Retail Transmission Rate - Line and Transformation Connection Service Rate (4)	$ / kW	1.00
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

Hydro One Networks Inc.
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Unmetered, Scattered Load

Service Charge	$	14.62
Distribution Volumetric Rate	$ / kWh	0.0200
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0004
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0006)
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0035
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0032
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

(3) For energy-only metered customers, the billing determinant is the customer’s metered energy consumption adjusted by the total loss factor as approved by the Board for Acquired LDC customers.

(4) For demand billed customers, appropriate loss factors must be applied to the applicable tariffs. Also the billing determinant for the Line and Transformation Connection Services rate is the customer’s peak demand in the billing period. The billing determinant for the Network Services rate is: for non-interval-metered customers, the peak demand in the billing period, and for interval-metered customers, the peak demand between 7 AM and 7 PM local time on IESO business days

Customer-Supplied Transformation Allowance

Applicable to customers providing their own transformers

Demand-billed	$ / kW	0.60
Energy-billed	$ / kWh	0.0014

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Loss Factors

Residential	1.085
General Service Less Than 50 kW (Energy-Billed)	1.092
General Service 50 kW or Greater (Demand-Billed)	1.061
Unmetered Scattered Load	1.092

Transformer Loss Allowance

Applicable to customers requiring a billing adjustment for transformer losses as the result of being metered on the primary side of a transformer. The following uniform values shall be applied to measured demand and energy to calculate transformer losses for voltages up to and including 50 kV (as metered on the primary side):

(a) 1.5% for transformer installations up to an individual bank capacity of 400 kVA,
(b) 1.0% for bank capacities over 400 kVA.

Alternatively, transformer losses may be determined from transformer test data, and measured demand and energy adjusted accordingly

For services which are not demand metered, an assumed demand of 50% of the transformer capacity will be used to calculate the loss allowance. Where several transformers are involved, the bank capacity is assumed to be the arithmetic sum of all transformer capacities

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MISCELLANEOUS CHARGES

Specific Service Charges: Standard Amounts

Rate Code	Specific Service Charge - Standard Name	Calculation Method			
		2006 Rate Handbook	Standard Formula	Other Formula	Time and Materials
1	Temporary Service	$500			
2	Dispute Meter Test	$30 plus Measurement Canada fees			
3	Collection of account – no disconnection/load limiter	$30			
4	Collection/Disconnect/load limiter/reconnect (at meter) trip – regular hours	$65			
5	Collection/Disconnect/load limiter/reconnect (at meter) trip – after regular hours	$185			
6	Collection/Disconnect/load limiter/reconnect (at pole) trip – regular hours	$185			
7	Collection/Disconnect/load limiter/reconnect (at pole) trip – after regular hours	$415			
8	Account Set-up Charge	$30			
9	Arrears Certificate	$15			
10	NSF Cheque Charge	$15 + bank charges			
11	Easement Charge for Unregistered Rights	$15			
12	Late Payment Charge	1.5%/month			
13a	Retailer Services – Establishing Service Agreements (refer to Handbook for all charges)	$100/agreement/Retailer +$20/month/Retailer +$0.50/month/customer + other			
13b	Retailer Services – Other (includes Bill Ready for Retailers and Service Transactions Requests) as per the Handbook, Chapter 12	$0.30/month/customer + $0.25/request for request fee + $0.50/request for process fee			
14	Special Meter Reads	$30			
15	Service Layout Fee – Basic		$495		
16	Service Layout Fee – Complex		$690		
17	Crossing Application – Pipeline		$2,445		
18	Crossing Application – Water		$3,045		
19	Crossing Application – Railroad		$2,945		
20	Line Staking – per meter		$3.70		
21	Central Metering – New service < 45 kW		$115		
22	Conversion to Central Metering < 45 kW		$915		
23	Conversion to Central Metering > 45 kW		$800		
24	Tingle Voltage Test – In Excess of 4 Hours (per hour – average 2 additional hours)		$125		
25	Standby Administration Charge per month		$440		
26	Sentinel Lights Rental Rate per month			$7.10	
27	Sentinel Pole Rental Rate per month			$4.15	
28	Joint Use for Cable and Telecom companies per pole			$22.35	
29	Joint Use for LDCs per pole			$28.61	

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APPLICATION

The application of these rates and charges shall be in accordance with The Licence of The Distributor and any Codes, Guidelines or Orders of The Board, and amendments thereto as approved by The Board, which may be applicable to the administration of this schedule.
No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code, Guideline or Order of the Board, and amendments thereto as approved by the Board, or as specified herein
This schedule does not contain any rates and charges relating to the electricity commodity (e.g. the Regulated Price Plan).

EFFECTIVE DATES

DISTRIBUTION RATES - May 1, 2007 for all consumption or deemed consumption services used on or after that date.

MISCELLANEOUS CHARGES - May 1, 2007 for all charges billed to customers on or after that date.
RETAIL TRANSMISSION RATES - May 1, 2007 for all consumption or deemed consumption services used on or after that date.
LOSS FACTOR ADJUSTMENT – May 1, 2007

SERVICE CLASSIFICATIONS

Residential
This classification (note 1) refers to all service supplied to single-family dwelling units for domestic or household purpose. Multi-unit residential establishments such as apartment buildings supplied through one service (bulk metered) will normally be classified as General Service, but, at Hydro One's discretion, up to four residential units may be classified as residential. Where electricity service is provided to combined residential and business (including agricultural usage) and the wiring does not provide for separate metering, the classification shall be at the discretion of Hydro One based on such considerations as the estimated predominant consumption.
Further servicing details are available in the utility's Conditions of Service.

General Service
This classification (note 1) refers to all service supplied to premises other than those classified as Residential or Lighting. Some General Service accounts are energy(kWh)-billed, and some are demand(kW)-billed. Further servicing details are available in the utility's Conditions of Service. Also, see note 2.

Unmetered Scattered Load
This classification refers to certain instances where connections can be provided without metering. These loads are generally small in size and consistent in magnitude of load. Hydro One reserves the right to review all cases and may require that a meter be installed at its sole discretion. Services that can be unmetered include cable TV amplifiers, telephone switching devices, phone booths, bus shelters, rail way crossing signals, traffic signals, and other small fixed loads.
Further servicing details are available in the utility's Conditions of Service (including in the "Unmetered Connections" section).

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Street Lighting

This classification refers to accounts for the distribution and supply of electrical energy for street lighting. Street lights are devices owned by or operated for the road authority and/or the municipal corporation. These street lights in fact belong to the Street Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Sentinel Lighting

This classification refers to accounts for a separate service to a sentinel light. These sentinel lights in fact belong to the Sentinel Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Interim Demand-Side Management Time-of-Use

This is potentially applicable to Demand-billed General Service accounts. See Note 2 below.

Note (1): Classification descriptions are paraphrases from the document "Hydro One Networks Inc. - Distribution Customers Conditions of Service - August 2004"

Note (2):

Interim Demand-Side Management Time-of-Use Rates: demand charges will be based on demand during the on-peak periods.

Criteria: Customers' electricity consumption (kW) in the off-peak period is at least twice the electricity consumption (kW) during the on-peak period.

Definition of Time Periods: The on-peak hours will be between 0700 hours to 1900 hours Eastern Standard Time during the winter (standard time) on IESO business days and 0600 hours to 1800 hours Eastern Standard Time during the summer (daylight savings time) on IESO business days. The off-peak period constitutes all of the remaining hours.

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MONTHLY RATES AND CHARGES

Residential

Service Charge	$	14.30
Distribution Volumetric Rate	$ / kWh	0.0086
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0044
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0016
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0055
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0047
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service - Energy Billed (less than 50 kW)

Service Charge	$	23.00
Distribution Volumetric Rate	$ / kWh	0.0080
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0015
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0004
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0050
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0043
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service - Demand Billed (50 kW or greater)

Service Charge	$	23.00
Distribution Volumetric Rate	$ / kW	2.54
Regulatory Asset Recovery - Rider #1	$ / kW	0.49
Regulatory Asset Recovery - Rider #2	$ / kW	0.13
Retail Transmission Rate - Network Service Rate (4)	$ / kW	1.94
Retail Transmission Rate - Line and Transformation Connection Service Rate (4)	$ / kW	1.61
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Markdale Hydro System
Effective Date: May 1, 2007

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

Unmetered, Scattered Load

Service Charge	$	11.04
Distribution Volumetric Rate	$ / kWh	0.0080
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0015
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0004
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0050
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0043
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

(3) For energy-only metered customers, the billing determinant is the customer’s metered energy consumption adjusted by the total loss factor as approved by the Board for Acquired LDC customers.
(4) For demand billed customers, appropriate loss factors must be applied to the applicable tariffs. Also the billing determinant for the Line and Transformation Connection Services rate is the customer’s peak demand in the billing period. The billing determinant for the Network Services rate is: for non-interval-metered customers, the peak demand in the billing period, and for interval-metered customers, the peak demand between 7 AM and 7 PM local time on IESO business days

Interim Demand-Side Management Time-of-Use

See the "Service Classifications" section of this schedule.

Customer-Supplied Transformation Allowance

Applicable to demand-billed customers providing their own transformers
Primary Voltage under 50 kV (per kW)

Single Phase	$ / kW	0.20
Three Phase	$ / kW	0.60

Hydro One Networks Inc.
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for the Service Area Formerly Served by
Markdale Hydro System
Effective Date: May 1, 2007

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

Loss Factors

Supply Facilities Loss Factor	1.0045
Distribution Loss Factors	
Customer less than 5,000 kW	1.0500
Customer greater than or equal to 5,000 kW	1.0100
Total Loss Factors	
Customer less than 5,000 kW	1.0545
Customer greater than or equal to 5,000 kW	1.0145

Transformer Loss Allowance

Applicable to customers requiring a billing adjustment for transformer losses as the result of being metered on the primary side of a transformer. The following uniform values shall be applied to measured demand and energy to calculate transformer losses for voltages up to and including 50 kV (as metered on the primary side):

(a) 1.5% for transformer installations up to an individual bank capacity of 400 kVA,
(b) 1.0% for bank capacities over 400 kVA.

Alternatively, transformer losses may be determined from transformer test data, and measured demand and energy adjusted accordingly

For services which are not demand metered, an assumed demand of 50% of the transformer capacity will be used to calculate the loss allowance. Where several transformers are involved, the bank capacity is assumed to be the arithmetic sum of all transformer capacities

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
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Effective Date: May 1, 2007

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

MISCELLANEOUS CHARGES

Specific Service Charges: Standard Amounts

Rate Code	Specific Service Charge - Standard Name	Calculation Method			
		2006 Rate Handbook	Standard Formula	Other Formula	Time and Materials
1	Temporary Service	$500			
2	Dispute Meter Test	$30 plus Measurement Canada fees			
3	Collection of account – no disconnection/load limiter	$30			
4	Collection/Disconnect/load limiter/reconnect (at meter) trip – regular hours	$65			
5	Collection/Disconnect/load limiter/reconnect (at meter) trip – after regular hours	$185			
6	Collection/Disconnect/load limiter/reconnect (at pole) trip – regular hours	$185			
7	Collection/Disconnect/load limiter/reconnect (at pole) trip – after regular hours	$415			
8	Account Set-up Charge	$30			
9	Arrears Certificate	$15			
10	NSF Cheque Charge	$15 + bank charges			
11	Easement Charge for Unregistered Rights	$15			
12	Late Payment Charge	1.5%/month			
13a	Retailer Services – Establishing Service Agreements (refer to Handbook for all charges)	$100/agreement/Retailer +$20/month/Retailer +$0.50/month/customer + other			
13b	Retailer Services – Other (includes Bill Ready for Retailers and Service Transactions Requests) as per the Handbook, Chapter 12	$0.30/month/customer + $0.25/request for request fee + $0.50/request for process fee			
14	Special Meter Reads	$30			
15	Billing Suspension and Terminations in Trailer Parks		$130		
16	Service Layout Fee – Basic		$405		
17	Service Layout Fee – Complex		$580		

Hydro One Networks Inc.
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Effective Date: May 1, 2007

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18	Crossing Application – Pipeline		$2,065		
19	Crossing Application – Water		$2,525		
20	Crossing Application – Railroad		$2,565		
21	Line Staking – per meter		$3.10		
22	Central Metering – New service < 45 kW		$115		
23	Conversion to Central Metering < 45 kW		$795		
24	Conversion to Central Metering > 45 kW		$680		
25	Tingle Voltage Test – In Excess of 4 Hours (per hour – average 2 additional hours)		$105		
26	Standby Administration Charge per month (interim)		$375		
27	Sentinel Lights Rental Rate per month – Mercury Vapor			$7.00	
28	Guaranteed Units from Jan 01/91 to Aug 01/91			$26.50 / month	
29	Guaranteed Units from Jan 01/87 to Dec 31/90			$23.50 / month	
30	Joint Use for Cable and Telecom companies per pole			$22.35	
31	Joint Use for LDCs per pole			$28.61	

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Marmora Hydro Electric Commission
Effective Date: May 1, 2008

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

APPLICATION

The application of these rates and charges shall be in accordance with The Licence of The Distributor and any Codes, Guidelines or Orders of The Board, and amendments thereto as approved by The Board, which may be applicable to the administration of this schedule.
No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code, Guideline or Order of the Board, and amendments thereto as approved by the Board, or as specified herein
This schedule does not contain any rates and charges relating to the electricity commodity (e.g. the Regulated Price Plan).

EFFECTIVE DATES

DISTRIBUTION RATES - May 1, 2008 for all consumption or deemed consumption services used on or after that date.

MISCELLANEOUS CHARGES - May 1, 2008 for all charges billed to customers on or after that date.
RETAIL TRANSMISSION RATES - May 1, 2008 for all consumption or deemed consumption services used on or after that date.
LOSS FACTOR ADJUSTMENT – for all consumption or deemed consumption services billed following May 1, 2008 or later

SERVICE CLASSIFICATIONS

Residential
This classification refers to all service supplied to single-family dwelling units for domestic or household purpose. Multi-unit residential establishments such as apartment buildings supplied through one service (bulk metered) will normally be classified as General Service, but, at Hydro One's discretion, up to four residential units may be classified as residential. Where electricity service is provided to combined residential and business (including agricultural usage) and the wiring does not provide for separate metering, the classification shall be at the discretion of Hydro One based on such considerations as the estimated predominant consumption.
Further servicing details are available in the utility's Conditions of Service.

General Service
This classification refers to all service supplied to premises other than those classified as Residential or Lighting. Some General Service accounts are energy(kWh)-billed, and some are demand(kW)-billed. Further servicing details are available in the utility's Conditions of Service.

Unmetered Scattered Load
This classification refers to certain instances where connections can be provided without metering. These loads are generally small in size and consistent in magnitude of load. Hydro One reserves the right to review all cases and may require that a meter be installed at its sole discretion. Services that can be unmetered include cable TV amplifiers, telephone switching devices, phone booths, bus shelters, rail way crossing signals, traffic signals, and other small fixed loads.
Further servicing details are available in the utility's Conditions of Service (including in the "Unmetered Connections" section).

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Marmora Hydro Electric Commission
Effective Date: May 1, 2008

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

Street Lighting

This classification refers to accounts for the distribution and supply of electrical energy for street lighting. Street lights are devices owned by or operated for the road authority and/or the municipal corporation. These street lights in fact belong to the Street Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Sentinel Lighting

This classification refers to accounts for a separate service to a sentinel light. These sentinel lights in fact belong to the Sentinel Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Urban Density Classification

Customers who meet the Urban Density Criteria of being in an area containing 3,000 or more customers with a line density of at least 60 customers per kilometre, will be mapped to an Urban customer classification.

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
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Effective Date: May 1, 2008

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MONTHLY RATES AND CHARGES

Residential - R1 Marmora

Service Charge	$	12.86
Distribution Volumetric Rate	$ / kWh	0.0200
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0011
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0004)
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0047
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0046
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service Less Than 50 kW (Energy-Billed) - GSe Marmora

Service Charge	$	15.59
Distribution Volumetric Rate	$ / kWh	0.0188
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0005
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0006)
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0035
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0032
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service 50 kW or Greater (Demand-Billed) - GSd Marmora

Service Charge	$	19.18
Distribution Volumetric Rate	$ / kW	8.00
Regulatory Asset Recovery - Rider #2	$ / kW	0.16
Regulatory Asset Recovery - Rider #3	$ / kW	(0.22)
Retail Transmission Rate - Network Service Rate (4)	$ / kW	1.11
Retail Transmission Rate - Line and Transformation Connection Service Rate (4)	$ / kW	1.00
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

Hydro One Networks Inc.
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Unmetered, Scattered Load

Service Charge	$	9.24
Distribution Volumetric Rate	$ / kWh	0.0200
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0005
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0006)
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0035
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0032
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

(3) For energy-only metered customers, the billing determinant is the customer's metered energy consumption adjusted by the total loss factor as approved by the Board for Acquired LDC customers.

(4) For demand billed customers, appropriate loss factors must be applied to the applicable tariffs. Also the billing determinant for the Line and Transformation Connection Services rate is the customer's peak demand in the billing period. The billing determinant for the Network Services rate is: for non-interval-metered customers, the peak demand in the billing period, and for interval-metered customers, the peak demand between 7 AM and 7 PM local time on IESO business days

Customer-Supplied Transformation Allowance

Applicable to customers providing their own transformers

Demand-billed	$ / kW	0.60
Energy-billed	$ / kWh	0.0014

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Loss Factors

Residential	1.085
General Service Less Than 50 kW (Energy-Billed)	1.092
General Service 50 kW or Greater (Demand-Billed)	1.061
Unmetered Scattered Load	1.092

Transformer Loss Allowance

Applicable to customers requiring a billing adjustment for transformer losses as the result of being metered on the primary side of a transformer. The following uniform values shall be applied to measured demand and energy to calculate transformer losses for voltages up to and including 50 kV (as metered on the primary side):

(a) 1.5% for transformer installations up to an individual bank capacity of 400 kVA,
(b) 1.0% for bank capacities over 400 kVA.

Alternatively, transformer losses may be determined from transformer test data, and measured demand and energy adjusted accordingly

For services which are not demand metered, an assumed demand of 50% of the transformer capacity will be used to calculate the loss allowance. Where several transformers are involved, the bank capacity is assumed to be the arithmetic sum of all transformer capacities

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
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Effective Date: May 1, 2008

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

MISCELLANEOUS CHARGES

Specific Service Charges: Standard Amounts

Rate Code	Specific Service Charge - Standard Name	Calculation Method			
		2006 Rate Handbook	Standard Formula	Other Formula	Time and Materials
1	Temporary Service	$500			
2	Dispute Meter Test	$30 plus Measurement Canada fees			
3	Collection of account – no disconnection/load limiter	$30			
4	Collection/Disconnect/load limiter/reconnect (at meter) trip – regular hours	$65			
5	Collection/Disconnect/load limiter/reconnect (at meter) trip – after regular hours	$185			
6	Collection/Disconnect/load limiter/reconnect (at pole) trip – regular hours	$185			
7	Collection/Disconnect/load limiter/reconnect (at pole) trip – after regular hours	$415			
8	Account Set-up Charge	$30			
9	Arrears Certificate	$15			
10	NSF Cheque Charge	$15 + bank charges			
11	Easement Charge for Unregistered Rights	$15			
12	Late Payment Charge	1.5%/month			
13a	Retailer Services – Establishing Service Agreements (refer to Handbook for all charges)	$100/agreement/Retailer +$20/month/Retailer +$0.50/month/customer + other			
13b	Retailer Services – Other (includes Bill Ready for Retailers and Service Transactions Requests) as per the Handbook, Chapter 12	$0.30/month/customer + $0.25/request for request fee + $0.50/request for process fee			
14	Special Meter Reads	$30			
15	Service Layout Fee – Basic		$495		
16	Service Layout Fee – Complex		$690		
17	Crossing Application – Pipeline		$2,445		
18	Crossing Application – Water		$3,045		
19	Crossing Application – Railroad		$2,945		
20	Line Staking – per meter		$3.70		
21	Central Metering – New service < 45 kW		$115		
22	Conversion to Central Metering < 45 kW		$915		
23	Conversion to Central Metering > 45 kW		$800		
24	Tingle Voltage Test – In Excess of 4 Hours (per hour – average 2 additional hours)		$125		
25	Standby Administration Charge per month		$440		
26	Sentinel Lights Rental Rate per month			$7.10	
27	Sentinel Pole Rental Rate per month			$4.15	
28	Joint Use for Cable and Telecom companies per pole			$22.35	
29	Joint Use for LDCs per pole			$28.61	

Hydro One Networks Inc.
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APPLICATION

The application of these rates and charges shall be in accordance with The Licence of The Distributor and any Codes, Guidelines or Orders of The Board, and amendments thereto as approved by The Board, which may be applicable to the administration of this schedule.
No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code, Guideline or Order of the Board, and amendments thereto as approved by the Board, or as specified herein
This schedule does not contain any rates and charges relating to the electricity commodity (e.g. the Regulated Price Plan).

EFFECTIVE DATES

DISTRIBUTION RATES - May 1, 2007 for all consumption or deemed consumption services used on or after that date.

MISCELLANEOUS CHARGES - May 1, 2007 for all charges billed to customers on or after that date.
RETAIL TRANSMISSION RATES - May 1, 2007 for all consumption or deemed consumption services used on or after that date.
LOSS FACTOR ADJUSTMENT – May 1, 2007

SERVICE CLASSIFICATIONS

Residential
This classification (note 1) refers to all service supplied to single-family dwelling units for domestic or household purpose. Multi-unit residential establishments such as apartment buildings supplied through one service (bulk metered) will normally be classified as General Service, but, at Hydro One's discretion, up to four residential units may be classified as residential. Where electricity service is provided to combined residential and business (including agricultural usage) and the wiring does not provide for separate metering, the classification shall be at the discretion of Hydro One based on such considerations as the estimated predominant consumption.
Further servicing details are available in the utility's Conditions of Service.

General Service
This classification (note 1) refers to all service supplied to premises other than those classified as Residential or Lighting. Some General Service accounts are energy(kWh)-billed, and some are demand(kW)-billed. Further servicing details are available in the utility's Conditions of Service. Also, see note 2.

Unmetered Scattered Load
This classification refers to certain instances where connections can be provided without metering. These loads are generally small in size and consistent in magnitude of load. Hydro One reserves the right to review all cases and may require that a meter be installed at its sole discretion. Services that can be unmetered include cable TV amplifiers, telephone switching devices, phone booths, bus shelters, rail way crossing signals, traffic signals, and other small fixed loads.
Further servicing details are available in the utility's Conditions of Service (including in the "Unmetered Connections" section).

Hydro One Networks Inc.
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Street Lighting

This classification refers to accounts for the distribution and supply of electrical energy for street lighting. Street lights are devices owned by or operated for the road authority and/or the municipal corporation. These street lights in fact belong to the Street Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Sentinel Lighting

This classification refers to accounts for a separate service to a sentinel light. These sentinel lights in fact belong to the Sentinel Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Interim Demand-Side Management Time-of-Use

This is potentially applicable to Demand-billed General Service accounts. See Note 2 below.

Note (1): Classification descriptions are paraphrases from the document "Hydro One Networks Inc. - Distribution Customers Conditions of Service - August 2004"

Note (2):

Interim Demand-Side Management Time-of-Use Rates: demand charges will be based on demand during the on-peak periods.

Criteria: Customers' electricity consumption (kW) in the off-peak period is at least twice the electricity consumption (kW) during the on-peak period.

Definition of Time Periods: The on-peak hours will be between 0700 hours to 1900 hours Eastern Standard Time during the winter (standard time) on IESO business days and 0600 hours to 1800 hours Eastern Standard Time during the summer (daylight savings time) on IESO business days. The off-peak period constitutes all of the remaining hours.

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MONTHLY RATES AND CHARGES

Residential

Service Charge	$	11.59
Distribution Volumetric Rate	$ / kWh	0.0092
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0033
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0011
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0055
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0047
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service - Energy Billed (less than 50 kW)

Service Charge	$	10.02
Distribution Volumetric Rate	$ / kWh	0.0105
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0015
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0005
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0050
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0043
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service - Demand Billed (50 kW or greater)

Service Charge	$	10.02
Distribution Volumetric Rate	$ / kW	3.33
Regulatory Asset Recovery - Rider #1	$ / kW	0.49
Regulatory Asset Recovery - Rider #2	$ / kW	0.16
Retail Transmission Rate - Network Service Rate (4)	$ / kW	1.94
Retail Transmission Rate - Line and Transformation Connection Service Rate (4)	$ / kW	1.61
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

Hydro One Networks Inc.
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Unmetered, Scattered Load

Service Charge	$	4.54
Distribution Volumetric Rate	$ / kWh	0.0105
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0015
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0005
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0050
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0043
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

(3) For energy-only metered customers, the billing determinant is the customer’s metered energy consumption adjusted by the total loss factor as approved by the Board for Acquired LDC customers.
(4) For demand billed customers, appropriate loss factors must be applied to the applicable tariffs. Also the billing determinant for the Line and Transformation Connection Services rate is the customer’s peak demand in the billing period. The billing determinant for the Network Services rate is: for non-interval-metered customers, the peak demand in the billing period, and for interval-metered customers, the peak demand between 7 AM and 7 PM local time on IESO business days

Interim Demand-Side Management Time-of-Use

See the "Service Classifications" section of this schedule.

Customer-Supplied Transformation Allowance

Applicable to demand-billed customers providing their own transformers
Primary Voltage under 50 kV (per kW)

Single Phase	$ / kW	0.20
Three Phase	$ / kW	0.60

Hydro One Networks Inc.
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Loss Factors

Supply Facilities Loss Factor	1.0045
Distribution Loss Factors	
Customer less than 5,000 kW	1.0500
Customer greater than or equal to 5,000 kW	1.0100
Total Loss Factors	
Customer less than 5,000 kW	1.0545
Customer greater than or equal to 5,000 kW	1.0145

Transformer Loss Allowance

Applicable to customers requiring a billing adjustment for transformer losses as the result of being metered on the primary side of a transformer. The following uniform values shall be applied to measured demand and energy to calculate transformer losses for voltages up to and including 50 kV (as metered on the primary side):

(a) 1.5% for transformer installations up to an individual bank capacity of 400 kVA,
(b) 1.0% for bank capacities over 400 kVA.

Alternatively, transformer losses may be determined from transformer test data, and measured demand and energy adjusted accordingly

For services which are not demand metered, an assumed demand of 50% of the transformer capacity will be used to calculate the loss allowance. Where several transformers are involved, the bank capacity is assumed to be the arithmetic sum of all transformer capacities

Hydro One Networks Inc.
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MISCELLANEOUS CHARGES

Specific Service Charges: Standard Amounts

Rate Code	Specific Service Charge - Standard Name	Calculation Method			
		2006 Rate Handbook	Standard Formula	Other Formula	Time and Materials
1	Temporary Service	$500			
2	Dispute Meter Test	$30 plus Measurement Canada fees			
3	Collection of account – no disconnection/load limiter	$30			
4	Collection/Disconnect/load limiter/reconnect (at meter) trip – regular hours	$65			
5	Collection/Disconnect/load limiter/reconnect (at meter) trip – after regular hours	$185			
6	Collection/Disconnect/load limiter/reconnect (at pole) trip – regular hours	$185			
7	Collection/Disconnect/load limiter/reconnect (at pole) trip – after regular hours	$415			
8	Account Set-up Charge	$30			
9	Arrears Certificate	$15			
10	NSF Cheque Charge	$15 + bank charges			
11	Easement Charge for Unregistered Rights	$15			
12	Late Payment Charge	1.5%/month			
13a	Retailer Services – Establishing Service Agreements (refer to Handbook for all charges)	$100/agreement/Retailer +$20/month/Retailer +$0.50/month/customer + other			
13b	Retailer Services – Other (includes Bill Ready for Retailers and Service Transactions Requests) as per the Handbook, Chapter 12	$0.30/month/customer + $0.25/request for request fee + $0.50/request for process fee			
14	Special Meter Reads	$30			
15	Billing Suspension and Terminations in Trailer Parks		$130		
16	Service Layout Fee – Basic		$405		
17	Service Layout Fee – Complex		$580		

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Marmora Hydro Electric Commission
Effective Date: May 1, 2007

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

18	Crossing Application – Pipeline		$2,065		
19	Crossing Application – Water		$2,525		
20	Crossing Application – Railroad		$2,565		
21	Line Staking – per meter		$3.10		
22	Central Metering – New service < 45 kW		$115		
23	Conversion to Central Metering < 45 kW		$795		
24	Conversion to Central Metering > 45 kW		$680		
25	Tingle Voltage Test – In Excess of 4 Hours (per hour – average 2 additional hours)		$105		
26	Standby Administration Charge per month (interim)		$375		
27	Sentinel Lights Rental Rate per month – Mercury Vapor			$7.00	
28	Guaranteed Units from Jan 01/91 to Aug 01/91			$26.50 / month	
29	Guaranteed Units from Jan 01/87 to Dec 31/90			$23.50 / month	
30	Joint Use for Cable and Telecom companies per pole			$22.35	
31	Joint Use for LDCs per pole			$28.61	

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
McGarry Hydro Electric Commission
Effective Date: May 1, 2008

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

APPLICATION

The application of these rates and charges shall be in accordance with The Licence of The Distributor and any Codes, Guidelines or Orders of The Board, and amendments thereto as approved by The Board, which may be applicable to the administration of this schedule.
No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code, Guideline or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.
This schedule does not contain any rates and charges relating to the electricity commodity (e.g. the Regulated Price Plan).

EFFECTIVE DATES

DISTRIBUTION RATES - May 1, 2008 for all consumption or deemed consumption services used on or after that date.

MISCELLANEOUS CHARGES - May 1, 2008 for all charges billed to customers on or after that date.
RETAIL TRANSMISSION RATES - May 1, 2008 for all consumption or deemed consumption services used on or after that date.
LOSS FACTOR ADJUSTMENT – for all consumption or deemed consumption services billed following May 1, 2008 or later

SERVICE CLASSIFICATIONS

Residential
This classification refers to all service supplied to single-family dwelling units for domestic or household purpose. Multi-unit residential establishments such as apartment buildings supplied through one service (bulk metered) will normally be classified as General Service, but, at Hydro One's discretion, up to four residential units may be classified as residential. Where electricity service is provided to combined residential and business (including agricultural usage) and the wiring does not provide for separate metering, the classification shall be at the discretion of Hydro One based on such considerations as the estimated predominant consumption.
Further servicing details are available in the utility's Conditions of Service.

General Service
This classification refers to all service supplied to premises other than those classified as Residential or Lighting. Some General Service accounts are energy(kWh)-billed, and some are demand(kW)-billed. Further servicing details are available in the utility's Conditions of Service.

Unmetered Scattered Load
This classification refers to certain instances where connections can be provided without metering. These loads are generally small in size and consistent in magnitude of load. Hydro One reserves the right to review all cases and may require that a meter be installed at its sole discretion. Services that can be unmetered include cable TV amplifiers, telephone switching devices, phone booths, bus shelters, rail way crossing signals, traffic signals, and other small fixed loads.
Further servicing details are available in the utility's Conditions of Service (including in the "Unmetered Connections" section).

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
McGarry Hydro Electric Commission
Effective Date: May 1, 2008

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

Street Lighting

This classification refers to accounts for the distribution and supply of electrical energy for street lighting. Street lights are devices owned by or operated for the road authority and/or the municipal corporation. These street lights in fact belong to the Street Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Sentinel Lighting

This classification refers to accounts for a separate service to a sentinel light. These sentinel lights in fact belong to the Sentinel Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Urban Density Classification

Customers who meet the Urban Density Criteria of being in an area containing 3,000 or more customers with a line density of at least 60 customers per kilometre, will be mapped to an Urban customer classification.

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
McGarry Hydro Electric Commission
Effective Date: May 1, 2008

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

MONTHLY RATES AND CHARGES

Residential - R1 McGarry

Service Charge	$	13.55
Distribution Volumetric Rate	$ / kWh	0.0250
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0045
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0004)
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0047
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0046
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service Less Than 50 kW (Energy-Billed) - GSe McGarry

Service Charge	$	22.09
Distribution Volumetric Rate	$ / kWh	0.0321
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0050
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0006)
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0035
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0032
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service 50 kW or Greater (Demand-Billed) - GSd McGarry

Service Charge	$	26.64
Distribution Volumetric Rate	$ / kW	9.22
Regulatory Asset Recovery - Rider #2	$ / kW	1.42
Regulatory Asset Recovery - Rider #3	$ / kW	(0.22)
Retail Transmission Rate - Network Service Rate (4)	$ / kW	1.11
Retail Transmission Rate - Line and Transformation Connection Service Rate (4)	$ / kW	1.00
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
McGarry Hydro Electric Commission
Effective Date: May 1, 2008

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

Unmetered, Scattered Load

Service Charge	$	13.00
Distribution Volumetric Rate	$ / kWh	0.0200
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0050
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0006)
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0035
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0032
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

(3) For energy-only metered customers, the billing determinant is the customer's metered energy consumption adjusted by the total loss factor as approved by the Board for Acquired LDC customers.
(4) For demand billed customers, appropriate loss factors must be applied to the applicable tariffs. Also the billing determinant for the Line and Transformation Connection Services rate is the customer's peak demand in the billing period. The billing determinant for the Network Services rate is: for non-interval-metered customers, the peak demand in the billing period, and for interval-metered customers, the peak demand between 7 AM and 7 PM local time on IESO business days

Customer-Supplied Transformation Allowance

Applicable to customers providing their own transformers

Demand-billed	$ / kW	0.60
Energy-billed	$ / kWh	0.0014

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
McGarry Hydro Electric Commission
Effective Date: May 1, 2008

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

Loss Factors

Residential	1.085
General Service Less Than 50 kW (Energy-Billed)	1.092
General Service 50 kW or Greater (Demand-Billed)	1.061
Unmetered Scattered Load	1.092

Transformer Loss Allowance

Applicable to customers requiring a billing adjustment for transformer losses as the result of being metered on the primary side of a transformer. The following uniform values shall be applied to measured demand and energy to calculate transformer losses for voltages up to and including 50 kV (as metered on the primary side):

(a) 1.5% for transformer installations up to an individual bank capacity of 400 kVA,
(b) 1.0% for bank capacities over 400 kVA.

Alternatively, transformer losses may be determined from transformer test data, and measured demand and energy adjusted accordingly

For services which are not demand metered, an assumed demand of 50% of the transformer capacity will be used to calculate the loss allowance. Where several transformers are involved, the bank capacity is assumed to be the arithmetic sum of all transformer capacities

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
McGarry Hydro Electric Commission
Effective Date: May 1, 2008

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

MISCELLANEOUS CHARGES

Specific Service Charges: Standard Amounts

Rate Code	Specific Service Charge - Standard Name	Calculation Method			
		2006 Rate Handbook	Standard Formula	Other Formula	Time and Materials
1	Temporary Service	$500			
2	Dispute Meter Test	$30 plus Measurement Canada fees			
3	Collection of account – no disconnection/load limiter	$30			
4	Collection/Disconnect/load limiter/reconnect (at meter) trip – regular hours	$65			
5	Collection/Disconnect/load limiter/reconnect (at meter) trip – after regular hours	$185			
6	Collection/Disconnect/load limiter/reconnect (at pole) trip – regular hours	$185			
7	Collection/Disconnect/load limiter/reconnect (at pole) trip – after regular hours	$415			
8	Account Set-up Charge	$30			
9	Arrears Certificate	$15			
10	NSF Cheque Charge	$15 + bank charges			
11	Easement Charge for Unregistered Rights	$15			
12	Late Payment Charge	1.5%/month			
13a	Retailer Services – Establishing Service Agreements (refer to Handbook for all charges)	$100/agreement/Retailer +$20/month/Retailer +$0.50/month/customer + other			
13b	Retailer Services – Other (includes Bill Ready for Retailers and Service Transactions Requests) as per the Handbook, Chapter 12	$0.30/month/customer + $0.25/request for request fee + $0.50/request for process fee			
14	Special Meter Reads	$30			
15	Service Layout Fee – Basic		$495		
16	Service Layout Fee – Complex		$690		
17	Crossing Application – Pipeline		$2,445		
18	Crossing Application – Water		$3,045		
19	Crossing Application – Railroad		$2,945		
20	Line Staking – per meter		$3.70		
21	Central Metering – New service < 45 kW		$115		
22	Conversion to Central Metering < 45 kW		$915		
23	Conversion to Central Metering > 45 kW		$800		
24	Tingle Voltage Test – In Excess of 4 Hours (per hour – average 2 additional hours)		$125		
25	Standby Administration Charge per month		$440		
26	Sentinel Lights Rental Rate per month			$7.10	
27	Sentinel Pole Rental Rate per month			$4.15	
28	Joint Use for Cable and Telecom companies per pole			$22.35	
29	Joint Use for LDCs per pole			$28.61	

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
McGarry Hydro Electric Commission
Effective Date: May 1, 2007

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

APPLICATION

The application of these rates and charges shall be in accordance with The Licence of The Distributor and any Codes, Guidelines or Orders of The Board, and amendments thereto as approved by The Board, which may be applicable to the administration of this schedule.
No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code, Guideline or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.
This schedule does not contain any rates and charges relating to the electricity commodity (e.g. the Regulated Price Plan).

EFFECTIVE DATES

DISTRIBUTION RATES - May 1, 2007 for all consumption or deemed consumption services used on or after that date.

MISCELLANEOUS CHARGES - May 1, 2007 for all charges billed to customers on or after that date.
RETAIL TRANSMISSION RATES - May 1, 2007 for all consumption or deemed consumption services used on or after that date.
LOSS FACTOR ADJUSTMENT – May 1, 2007

SERVICE CLASSIFICATIONS

Residential
This classification (note 1) refers to all service supplied to single-family dwelling units for domestic or household purpose. Multi-unit residential establishments such as apartment buildings supplied through one service (bulk metered) will normally be classified as General Service, but, at Hydro One’s discretion, up to four residential units may be classified as residential. Where electricity service is provided to combined residential and business (including agricultural usage) and the wiring does not provide for separate metering, the classification shall be at the discretion of Hydro One based on such considerations as the estimated predominant consumption.
Further servicing details are available in the utility’s Conditions of Service.

General Service
This classification (note 1) refers to all service supplied to premises other than those classified as Residential or Lighting. Some General Service accounts are energy(kWh)-billed, and some are demand(kW)-billed. Further servicing details are available in the utility’s Conditions of Service. Also, see note 2.

Unmetered Scattered Load
This classification refers to certain instances where connections can be provided without metering. These loads are generally small in size and consistent in magnitude of load. Hydro One reserves the right to review all cases and may require that a meter be installed at its sole discretion. Services that can be unmetered include cable TV amplifiers, telephone switching devices, phone booths, bus shelters, rail way crossing signals, traffic signals, and other small fixed loads.
Further servicing details are available in the utility’s Conditions of Service (including in the "Unmetered Connections" section).

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
McGarry Hydro Electric Commission
Effective Date: May 1, 2007

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

Street Lighting

This classification refers to accounts for the distribution and supply of electrical energy for street lighting. Street lights are devices owned by or operated for the road authority and/or the municipal corporation. These street lights in fact belong to the Street Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Sentinel Lighting

This classification refers to accounts for a separate service to a sentinel light. These sentinel lights in fact belong to the Sentinel Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Interim Demand-Side Management Time-of-Use

This is potentially applicable to Demand-billed General Service accounts. See Note 2 below.

Note (1): Classification descriptions are paraphrases from the document "Hydro One Networks Inc. - Distribution Customers Conditions of Service - August 2004"

Note (2):

Interim Demand-Side Management Time-of-Use Rates: demand charges will be based on demand during the on-peak periods.

Criteria: Customers' electricity consumption (kW) in the off-peak period is at least twice the electricity consumption (kW) during the on-peak period.

Definition of Time Periods: The on-peak hours will be between 0700 hours to 1900 hours Eastern Standard Time during the winter (standard time) on IESO business days and 0600 hours to 1800 hours Eastern Standard Time during the summer (daylight savings time) on IESO business days. The off-peak period constitutes all of the remaining hours.

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
McGarry Hydro Electric Commission
Effective Date: May 1, 2007

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

MONTHLY RATES AND CHARGES

Residential

Service Charge	$	12.85
Distribution Volumetric Rate	$ / kWh	0.0093
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0071
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0045
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0055
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0047
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service - Energy Billed (less than 50 kW)

Service Charge	$	19.99
Distribution Volumetric Rate	$ / kWh	0.0200
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0057
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0050
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0050
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0043
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service - Demand Billed (50 kW or greater)

Service Charge	$	20.18
Distribution Volumetric Rate	$ / kW	5.68
Regulatory Asset Recovery - Rider #1	$ / kW	1.80
Regulatory Asset Recovery - Rider #2	$ / kW	1.42
Retail Transmission Rate - Network Service Rate (4)	$ / kW	1.94
Retail Transmission Rate - Line and Transformation Connection Service Rate (4)	$ / kW	1.61
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
McGarry Hydro Electric Commission
Effective Date: May 1, 2007

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

Unmetered, Scattered Load

Service Charge	$	9.52
Distribution Volumetric Rate	$ / kWh	0.0200
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0057
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0050
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0050
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0043
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

(3) For energy-only metered customers, the billing determinant is the customer’s metered energy consumption adjusted by the total loss factor as approved by the Board for Acquired LDC customers.
(4) For demand billed customers, appropriate loss factors must be applied to the applicable tariffs. Also the billing determinant for the Line and Transformation Connection Services rate is the customer’s peak demand in the billing period. The billing determinant for the Network Services rate is: for non-interval-metered customers, the peak demand in the billing period, and for interval-metered customers, the peak demand between 7 AM and 7 PM local time on IESO business days

Interim Demand-Side Management Time-of-Use

See the "Service Classifications" section of this schedule.

Customer-Supplied Transformation Allowance

Applicable to demand-billed customers providing their own transformers
Primary Voltage under 50 kV (per kW)

Single Phase	$ / kW	0.20
Three Phase	$ / kW	0.60

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
McGarry Hydro Electric Commission
Effective Date: May 1, 2007

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

Loss Factors

Supply Facilities Loss Factor	1.0045
Distribution Loss Factors	
Customer less than 5,000 kW	1.0500
Customer greater than or equal to 5,000 kW	1.0100
Total Loss Factors	
Customer less than 5,000 kW	1.0545
Customer greater than or equal to 5,000 kW	1.0145

Transformer Loss Allowance

Applicable to customers requiring a billing adjustment for transformer losses as the result of being metered on the primary side of a transformer. The following uniform values shall be applied to measured demand and energy to calculate transformer losses for voltages up to and including 50 kV (as metered on the primary side):

(a) 1.5% for transformer installations up to an individual bank capacity of 400 kVA,
(b) 1.0% for bank capacities over 400 kVA.

Alternatively, transformer losses may be determined from transformer test data, and measured demand and energy adjusted accordingly

For services which are not demand metered, an assumed demand of 50% of the transformer capacity will be used to calculate the loss allowance. Where several transformers are involved, the bank capacity is assumed to be the arithmetic sum of all transformer capacities

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
McGarry Hydro Electric Commission
Effective Date: May 1, 2007

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

MISCELLANEOUS CHARGES

Specific Service Charges: Standard Amounts

Rate Code	Specific Service Charge - Standard Name	Calculation Method			
		2006 Rate Handbook	Standard Formula	Other Formula	Time and Materials
1	Temporary Service	$500			
2	Dispute Meter Test	$30 plus Measurement Canada fees			
3	Collection of account – no disconnection/load limiter	$30			
4	Collection/Disconnect/load limiter/reconnect (at meter) trip – regular hours	$65			
5	Collection/Disconnect/load limiter/reconnect (at meter) trip – after regular hours	$185			
6	Collection/Disconnect/load limiter/reconnect (at pole) trip – regular hours	$185			
7	Collection/Disconnect/load limiter/reconnect (at pole) trip – after regular hours	$415			
8	Account Set-up Charge	$30			
9	Arrears Certificate	$15			
10	NSF Cheque Charge	$15 + bank charges			
11	Easement Charge for Unregistered Rights	$15			
12	Late Payment Charge	1.5%/month			
13a	Retailer Services – Establishing Service Agreements (refer to Handbook for all charges)	$100/agreement/Retailer +$20/month/Retailer +$0.50/month/customer + other			
13b	Retailer Services – Other (includes Bill Ready for Retailers and Service Transactions Requests) as per the Handbook, Chapter 12	$0.30/month/customer + $0.25/request for request fee + $0.50/request for process fee			
14	Special Meter Reads	$30			
15	Billing Suspension and Terminations in Trailer Parks		$130		
16	Service Layout Fee – Basic		$405		
17	Service Layout Fee – Complex		$580		

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
McGarry Hydro Electric Commission
Effective Date: May 1, 2007

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

18	Crossing Application – Pipeline		$2,065		
19	Crossing Application – Water		$2,525		
20	Crossing Application – Railroad		$2,565		
21	Line Staking – per meter		$3.10		
22	Central Metering – New service < 45 kW		$115		
23	Conversion to Central Metering < 45 kW		$795		
24	Conversion to Central Metering > 45 kW		$680		
25	Tingle Voltage Test – In Excess of 4 Hours (per hour – average 2 additional hours)		$105		
26	Standby Administration Charge per month (interim)		$375		
27	Sentinel Lights Rental Rate per month – Mercury Vapor			$7.00	
28	Guaranteed Units from Jan 01/91 to Aug 01/91			$26.50 / month	
29	Guaranteed Units from Jan 01/87 to Dec 31/90			$23.50 / month	
30	Joint Use for Cable and Telecom companies per pole			$22.35	
31	Joint Use for LDCs per pole			$28.61	

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Public Utilities Commission of the Town of Meaford
Effective Date: May 1, 2008

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

APPLICATION

The application of these rates and charges shall be in accordance with The Licence of The Distributor and any Codes, Guidelines or Orders of The Board, and amendments thereto as approved by The Board, which may be applicable to the administration of this schedule.
No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code, Guideline or Order of the Board, and amendments thereto as approved by the Board, or as specified herein
This schedule does not contain any rates and charges relating to the electricity commodity (e.g. the Regulated Price Plan).

EFFECTIVE DATES

DISTRIBUTION RATES - May 1, 2008 for all consumption or deemed consumption services used on or after that date.

MISCELLANEOUS CHARGES - May 1, 2008 for all charges billed to customers on or after that date.
RETAIL TRANSMISSION RATES - May 1, 2008 for all consumption or deemed consumption services used on or after that date.
LOSS FACTOR ADJUSTMENT – for all consumption or deemed consumption services billed following May 1, 2008 or later

SERVICE CLASSIFICATIONS

Residential
This classification refers to all service supplied to single-family dwelling units for domestic or household purpose. Multi-unit residential establishments such as apartment buildings supplied through one service (bulk metered) will normally be classified as General Service, but, at Hydro One's discretion, up to four residential units may be classified as residential. Where electricity service is provided to combined residential and business (including agricultural usage) and the wiring does not provide for separate metering, the classification shall be at the discretion of Hydro One based on such considerations as the estimated predominant consumption.
Further servicing details are available in the utility's Conditions of Service.

General Service
This classification refers to all service supplied to premises other than those classified as Residential or Lighting. Some General Service accounts are energy(kWh)-billed, and some are demand(kW)-billed. Further servicing details are available in the utility's Conditions of Service.

Unmetered Scattered Load
This classification refers to certain instances where connections can be provided without metering. These loads are generally small in size and consistent in magnitude of load. Hydro One reserves the right to review all cases and may require that a meter be installed at its sole discretion. Services that can be unmetered include cable TV amplifiers, telephone switching devices, phone booths, bus shelters, rail way crossing signals, traffic signals, and other small fixed loads.
Further servicing details are available in the utility's Conditions of Service (including in the "Unmetered Connections" section).

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Public Utilities Commission of the Town of Meaford
Effective Date: May 1, 2008

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

Street Lighting

This classification refers to accounts for the distribution and supply of electrical energy for street lighting. Street lights are devices owned by or operated for the road authority and/or the municipal corporation. These street lights in fact belong to the Street Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Sentinel Lighting

This classification refers to accounts for a separate service to a sentinel light. These sentinel lights in fact belong to the Sentinel Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Urban Density Classification

Customers who meet the Urban Density Criteria of being in an area containing 3,000 or more customers with a line density of at least 60 customers per kilometre, will be mapped to an Urban customer classification.

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Public Utilities Commission of the Town of Meaford
Effective Date: May 1, 2008

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

MONTHLY RATES AND CHARGES

Residential - R1 Meaford

Service Charge	$	13.57
Distribution Volumetric Rate	$ / kWh	0.0220
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0012
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0004)
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0047
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0046
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service Less Than 50 kW (Energy-Billed) - GSe Meaford

Service Charge	$	26.08
Distribution Volumetric Rate	$ / kWh	0.0232
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0007
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0006)
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0035
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0032
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service 50 kW or Greater (Demand-Billed) - GSd Meaford

Service Charge	$	29.68
Distribution Volumetric Rate	$ / kW	8.75
Regulatory Asset Recovery - Rider #2	$ / kW	0.21
Regulatory Asset Recovery - Rider #3	$ / kW	(0.22)
Retail Transmission Rate - Network Service Rate (4)	$ / kW	1.11
Retail Transmission Rate - Line and Transformation Connection Service Rate (4)	$ / kW	1.00
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

Hydro One Networks Inc.
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Unmetered, Scattered Load

Service Charge	$	14.49
Distribution Volumetric Rate	$ / kWh	0.0200
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0007
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0006)
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0035
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0032
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

(3) For energy-only metered customers, the billing determinant is the customer's metered energy consumption adjusted by the total loss factor as approved by the Board for Acquired LDC customers.

(4) For demand billed customers, appropriate loss factors must be applied to the applicable tariffs. Also the billing determinant for the Line and Transformation Connection Services rate is the customer's peak demand in the billing period. The billing determinant for the Network Services rate is: for non-interval-metered customers, the peak demand in the billing period, and for interval-metered customers, the peak demand between 7 AM and 7 PM local time on IESO business days

Customer-Supplied Transformation Allowance

Applicable to customers providing their own transformers

Demand-billed	$ / kW	0.60
Energy-billed	$ / kWh	0.0014

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Loss Factors

Residential	1.085
General Service Less Than 50 kW (Energy-Billed)	1.092
General Service 50 kW or Greater (Demand-Billed)	1.061
Unmetered Scattered Load	1.092

Transformer Loss Allowance

Applicable to customers requiring a billing adjustment for transformer losses as the result of being metered on the primary side of a transformer. The following uniform values shall be applied to measured demand and energy to calculate transformer losses for voltages up to and including 50 kV (as metered on the primary side):

(a) 1.5% for transformer installations up to an individual bank capacity of 400 kVA,
(b) 1.0% for bank capacities over 400 kVA.

Alternatively, transformer losses may be determined from transformer test data, and measured demand and energy adjusted accordingly

For services which are not demand metered, an assumed demand of 50% of the transformer capacity will be used to calculate the loss allowance. Where several transformers are involved, the bank capacity is assumed to be the arithmetic sum of all transformer capacities

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
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Effective Date: May 1, 2008

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MISCELLANEOUS CHARGES

Specific Service Charges: Standard Amounts

Rate Code	Specific Service Charge - Standard Name	Calculation Method			
		2006 Rate Handbook	Standard Formula	Other Formula	Time and Materials
1	Temporary Service	$500			
2	Dispute Meter Test	$30 plus Measurement Canada fees			
3	Collection of account – no disconnection/load limiter	$30			
4	Collection/Disconnect/load limiter/reconnect (at meter) trip – regular hours	$65			
5	Collection/Disconnect/load limiter/reconnect (at meter) trip – after regular hours	$185			
6	Collection/Disconnect/load limiter/reconnect (at pole) trip – regular hours	$185			
7	Collection/Disconnect/load limiter/reconnect (at pole) trip – after regular hours	$415			
8	Account Set-up Charge	$30			
9	Arrears Certificate	$15			
10	NSF Cheque Charge	$15 + bank charges			
11	Easement Charge for Unregistered Rights	$15			
12	Late Payment Charge	1.5%/month			
13a	Retailer Services – Establishing Service Agreements (refer to Handbook for all charges)	$100/agreement/Retailer +$20/month/Retailer +$0.50/month/customer + other			
13b	Retailer Services – Other (includes Bill Ready for Retailers and Service Transactions Requests) as per the Handbook, Chapter 12	$0.30/month/customer + $0.25/request for request fee + $0.50/request for process fee			
14	Special Meter Reads	$30			
15	Service Layout Fee – Basic		$495		
16	Service Layout Fee – Complex		$690		
17	Crossing Application – Pipeline		$2,445		
18	Crossing Application – Water		$3,045		
19	Crossing Application – Railroad		$2,945		
20	Line Staking – per meter		$3.70		
21	Central Metering – New service < 45 kW		$115		
22	Conversion to Central Metering < 45 kW		$915		
23	Conversion to Central Metering > 45 kW		$800		
24	Tingle Voltage Test – In Excess of 4 Hours (per hour – average 2 additional hours)		$125		
25	Standby Administration Charge per month		$440		
26	Sentinel Lights Rental Rate per month			$7.10	
27	Sentinel Pole Rental Rate per month			$4.15	
28	Joint Use for Cable and Telecom companies per pole			$22.35	
29	Joint Use for LDCs per pole			$28.61	

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
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Public Utilities Commission of the Town of Meaford
Effective Date: May 1, 2007

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

APPLICATION

The application of these rates and charges shall be in accordance with The Licence of The Distributor and any Codes, Guidelines or Orders of The Board, and amendments thereto as approved by The Board, which may be applicable to the administration of this schedule.
No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code, Guideline or Order of the Board, and amendments thereto as approved by the Board, or as specified herein
This schedule does not contain any rates and charges relating to the electricity commodity (e.g. the Regulated Price Plan).

EFFECTIVE DATES

DISTRIBUTION RATES - May 1, 2007 for all consumption or deemed consumption services used on or after that date.

MISCELLANEOUS CHARGES - May 1, 2007 for all charges billed to customers on or after that date.
RETAIL TRANSMISSION RATES - May 1, 2007 for all consumption or deemed consumption services used on or after that date.
LOSS FACTOR ADJUSTMENT – May 1, 2007

SERVICE CLASSIFICATIONS

Residential
This classification (note 1) refers to all service supplied to single-family dwelling units for domestic or household purpose. Multi-unit residential establishments such as apartment buildings supplied through one service (bulk metered) will normally be classified as General Service, but, at Hydro One's discretion, up to four residential units may be classified as residential. Where electricity service is provided to combined residential and business (including agricultural usage) and the wiring does not provide for separate metering, the classification shall be at the discretion of Hydro One based on such considerations as the estimated predominant consumption.
Further servicing details are available in the utility's Conditions of Service.

General Service
This classification (note 1) refers to all service supplied to premises other than those classified as Residential or Lighting. Some General Service accounts are energy(kWh)-billed, and some are demand(kW)-billed. Further servicing details are available in the utility's Conditions of Service. Also, see note 2.

Unmetered Scattered Load
This classification refers to certain instances where connections can be provided without metering. These loads are generally small in size and consistent in magnitude of load. Hydro One reserves the right to review all cases and may require that a meter be installed at its sole discretion. Services that can be unmetered include cable TV amplifiers, telephone switching devices, phone booths, bus shelters, rail way crossing signals, traffic signals, and other small fixed loads.
Further servicing details are available in the utility's Conditions of Service (including in the "Unmetered Connections" section).

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
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Public Utilities Commission of the Town of Meaford
Effective Date: May 1, 2007

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Street Lighting

This classification refers to accounts for the distribution and supply of electrical energy for street lighting. Street lights are devices owned by or operated for the road authority and/or the municipal corporation. These street lights in fact belong to the Street Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Sentinel Lighting

This classification refers to accounts for a separate service to a sentinel light. These sentinel lights in fact belong to the Sentinel Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Interim Demand-Side Management Time-of-Use

This is potentially applicable to Demand-billed General Service accounts. See Note 2 below.

Note (1): Classification descriptions are paraphrases from the document "Hydro One Networks Inc. - Distribution Customers Conditions of Service - August 2004"

Note (2):

Interim Demand-Side Management Time-of-Use Rates: demand charges will be based on demand during the on-peak periods.

Criteria: Customers' electricity consumption (kW) in the off-peak period is at least twice the electricity consumption (kW) during the on-peak period.

Definition of Time Periods: The on-peak hours will be between 0700 hours to 1900 hours Eastern Standard Time during the winter (standard time) on IESO business days and 0600 hours to 1800 hours Eastern Standard Time during the summer (daylight savings time) on IESO business days. The off-peak period constitutes all of the remaining hours.

Hydro One Networks Inc.
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Effective Date: May 1, 2007

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MONTHLY RATES AND CHARGES

Residential

Service Charge	$	12.75
Distribution Volumetric Rate	$ / kWh	0.0097
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0040
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0012
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0055
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0047
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service - Energy Billed (less than 50 kW)

Service Charge	$	24.05
Distribution Volumetric Rate	$ / kWh	0.0123
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0016
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0007
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0050
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0043
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service - Demand Billed (50 kW or greater)

Service Charge	$	24.05
Distribution Volumetric Rate	$ / kW	3.90
Regulatory Asset Recovery - Rider #1	$ / kW	0.50
Regulatory Asset Recovery - Rider #2	$ / kW	0.21
Retail Transmission Rate - Network Service Rate (4)	$ / kW	1.94
Retail Transmission Rate - Line and Transformation Connection Service Rate (4)	$ / kW	1.61
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

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Unmetered, Scattered Load

Service Charge	$	11.55
Distribution Volumetric Rate	$ / kWh	0.0123
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0016
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0007
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0050
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0043
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

(3) For energy-only metered customers, the billing determinant is the customer’s metered energy consumption adjusted by the total loss factor as approved by the Board for Acquired LDC customers.
(4) For demand billed customers, appropriate loss factors must be applied to the applicable tariffs. Also the billing determinant for the Line and Transformation Connection Services rate is the customer’s peak demand in the billing period. The billing determinant for the Network Services rate is: for non-interval-metered customers, the peak demand in the billing period, and for interval-metered customers, the peak demand between 7 AM and 7 PM local time on IESO business days

Interim Demand-Side Management Time-of-Use

See the "Service Classifications" section of this schedule.

Customer-Supplied Transformation Allowance

Applicable to demand-billed customers providing their own transformers
Primary Voltage under 50 kV (per kW)

Single Phase	$ / kW	0.20
Three Phase	$ / kW	0.60

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Loss Factors

Supply Facilities Loss Factor	1.0045
Distribution Loss Factors	
Customer less than 5,000 kW	1.0500
Customer greater than or equal to 5,000 kW	1.0100
Total Loss Factors	
Customer less than 5,000 kW	1.0545
Customer greater than or equal to 5,000 kW	1.0145

Transformer Loss Allowance

Applicable to customers requiring a billing adjustment for transformer losses as the result of being metered on the primary side of a transformer. The following uniform values shall be applied to measured demand and energy to calculate transformer losses for voltages up to and including 50 kV (as metered on the primary side):

(a) 1.5% for transformer installations up to an individual bank capacity of 400 kVA,
(b) 1.0% for bank capacities over 400 kVA.

Alternatively, transformer losses may be determined from transformer test data, and measured demand and energy adjusted accordingly

For services which are not demand metered, an assumed demand of 50% of the transformer capacity will be used to calculate the loss allowance. Where several transformers are involved, the bank capacity is assumed to be the arithmetic sum of all transformer capacities

Hydro One Networks Inc.
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MISCELLANEOUS CHARGES

Specific Service Charges: Standard Amounts

Rate Code	Specific Service Charge - Standard Name	Calculation Method			
		2006 Rate Handbook	Standard Formula	Other Formula	Time and Materials
1	Temporary Service	$500			
2	Dispute Meter Test	$30 plus Measurement Canada fees			
3	Collection of account – no disconnection/load limiter	$30			
4	Collection/Disconnect/load limiter/reconnect (at meter) trip – regular hours	$65			
5	Collection/Disconnect/load limiter/reconnect (at meter) trip – after regular hours	$185			
6	Collection/Disconnect/load limiter/reconnect (at pole) trip – regular hours	$185			
7	Collection/Disconnect/load limiter/reconnect (at pole) trip – after regular hours	$415			
8	Account Set-up Charge	$30			
9	Arrears Certificate	$15			
10	NSF Cheque Charge	$15 + bank charges			
11	Easement Charge for Unregistered Rights	$15			
12	Late Payment Charge	1.5%/month			
13a	Retailer Services – Establishing Service Agreements (refer to Handbook for all charges)	$100/agreement/Retailer +$20/month/Retailer +$0.50/month/customer + other			
13b	Retailer Services – Other (includes Bill Ready for Retailers and Service Transactions Requests) as per the Handbook, Chapter 12	$0.30/month/customer + $0.25/request for request fee + $0.50/request for process fee			
14	Special Meter Reads	$30			
15	Billing Suspension and Terminations in Trailer Parks		$130		
16	Service Layout Fee – Basic		$405		
17	Service Layout Fee – Complex		$580		

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18	Crossing Application – Pipeline		$2,065		
19	Crossing Application – Water		$2,525		
20	Crossing Application – Railroad		$2,565		
21	Line Staking – per meter		$3.10		
22	Central Metering – New service < 45 kW		$115		
23	Conversion to Central Metering < 45 kW		$795		
24	Conversion to Central Metering > 45 kW		$680		
25	Tingle Voltage Test – In Excess of 4 Hours (per hour – average 2 additional hours)		$105		
26	Standby Administration Charge per month (interim)		$375		
27	Sentinel Lights Rental Rate per month – Mercury Vapor			$7.00	
28	Guaranteed Units from Jan 01/91 to Aug 01/91			$26.50 / month	
29	Guaranteed Units from Jan 01/87 to Dec 31/90			$23.50 / month	
30	Joint Use for Cable and Telecom companies per pole			$22.35	
31	Joint Use for LDCs per pole			$28.61	

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Hydro-Electric Commission of the Corporation of the Township of Middlesex Centre
Effective Date: May 1, 2008

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

APPLICATION

The application of these rates and charges shall be in accordance with The Licence of The Distributor and any Codes, Guidelines or Orders of The Board, and amendments thereto as approved by The Board, which may be applicable to the administration of this schedule.
No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code, Guideline or Order of the Board, and amendments thereto as approved by the Board, or as specified herein
This schedule does not contain any rates and charges relating to the electricity commodity (e.g. the Regulated Price Plan).

EFFECTIVE DATES

DISTRIBUTION RATES - May 1, 2008 for all consumption or deemed consumption services used on or after that date.

MISCELLANEOUS CHARGES - May 1, 2008 for all charges billed to customers on or after that date.
RETAIL TRANSMISSION RATES - May 1, 2008 for all consumption or deemed consumption services used on or after that date.
LOSS FACTOR ADJUSTMENT – for all consumption or deemed consumption services billed following May 1, 2008 or later

SERVICE CLASSIFICATIONS

Residential
This classification refers to all service supplied to single-family dwelling units for domestic or household purpose. Multi-unit residential establishments such as apartment buildings supplied through one service (bulk metered) will normally be classified as General Service, but, at Hydro One's discretion, up to four residential units may be classified as residential. Where electricity service is provided to combined residential and business (including agricultural usage) and the wiring does not provide for separate metering, the classification shall be at the discretion of Hydro One based on such considerations as the estimated predominant consumption.
Further servicing details are available in the utility's Conditions of Service.

General Service
This classification refers to all service supplied to premises other than those classified as Residential or Lighting. Some General Service accounts are energy(kWh)-billed, and some are demand(kW)-billed. Further servicing details are available in the utility's Conditions of Service.

Unmetered Scattered Load
This classification refers to certain instances where connections can be provided without metering. These loads are generally small in size and consistent in magnitude of load. Hydro One reserves the right to review all cases and may require that a meter be installed at its sole discretion. Services that can be unmetered include cable TV amplifiers, telephone switching devices, phone booths, bus shelters, rail way crossing signals, traffic signals, and other small fixed loads.
Further servicing details are available in the utility's Conditions of Service (including in the "Unmetered Connections" section).

Hydro One Networks Inc.
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Effective Date: May 1, 2008

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Street Lighting

This classification refers to accounts for the distribution and supply of electrical energy for street lighting. Street lights are devices owned by or operated for the road authority and/or the municipal corporation. These street lights in fact belong to the Street Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Sentinel Lighting

This classification refers to accounts for a separate service to a sentinel light. These sentinel lights in fact belong to the Sentinel Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Urban Density Classification

Customers who meet the Urban Density Criteria of being in an area containing 3,000 or more customers with a line density of at least 60 customers per kilometre, will be mapped to an Urban customer classification.

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
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Effective Date: May 1, 2008

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MONTHLY RATES AND CHARGES

Residential - R1 Middlesex Centre

Service Charge	$	15.21
Distribution Volumetric Rate	$ / kWh	0.0225
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0040
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0004)
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0047
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0046
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service Less Than 50 kW (Energy-Billed) - GSe Middlesex Centre

Service Charge	$	20.75
Distribution Volumetric Rate	$ / kWh	0.0270
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0035
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0006)
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0035
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0032
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service 50 kW or Greater (Demand-Billed) - GSd Middlesex Centre

Service Charge	$	24.35
Distribution Volumetric Rate	$ / kW	9.00
Regulatory Asset Recovery - Rider #2	$ / kW	0.84
Regulatory Asset Recovery - Rider #3	$ / kW	(0.22)
Retail Transmission Rate - Network Service Rate (4)	$ / kW	1.11
Retail Transmission Rate - Line and Transformation Connection Service Rate (4)	$ / kW	1.00
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

Hydro One Networks Inc.
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Unmetered, Scattered Load

Service Charge	$	12.33
Distribution Volumetric Rate	$ / kWh	0.0200
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0035
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0006)
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0035
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0032
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

(3) For energy-only metered customers, the billing determinant is the customer's metered energy consumption adjusted by the total loss factor as approved by the Board for Acquired LDC customers.
(4) For demand billed customers, appropriate loss factors must be applied to the applicable tariffs. Also the billing determinant for the Line and Transformation Connection Services rate is the customer's peak demand in the billing period. The billing determinant for the Network Services rate is: for non-interval-metered customers, the peak demand in the billing period, and for interval-metered customers, the peak demand between 7 AM and 7 PM local time on IESO business days

Customer-Supplied Transformation Allowance

Applicable to customers providing their own transformers

Demand-billed	$ / kW	0.60
Energy-billed	$ / kWh	0.0014

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
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Effective Date: May 1, 2008

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Loss Factors

Residential	1.085
General Service Less Than 50 kW (Energy-Billed)	1.092
General Service 50 kW or Greater (Demand-Billed)	1.061
Unmetered Scattered Load	1.092

Transformer Loss Allowance

Applicable to customers requiring a billing adjustment for transformer losses as the result of being metered on the primary side of a transformer. The following uniform values shall be applied to measured demand and energy to calculate transformer losses for voltages up to and including 50 kV (as metered on the primary side):

(a) 1.5% for transformer installations up to an individual bank capacity of 400 kVA,

(b) 1.0% for bank capacities over 400 kVA.

Alternatively, transformer losses may be determined from transformer test data, and measured demand and energy adjusted accordingly

For services which are not demand metered, an assumed demand of 50% of the transformer capacity will be used to calculate the loss allowance. Where several transformers are involved, the bank capacity is assumed to be the arithmetic sum of all transformer capacities

Hydro One Networks Inc.

TARIFF OF RATES AND CHARGES

for the Service Area Formerly Served by

Hydro-Electric Commission of the Corporation of the Township of Middlesex Centre

Effective Date: May 1, 2008

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

MISCELLANEOUS CHARGES

Specific Service Charges: Standard Amounts

Rate Code	Specific Service Charge - Standard Name	Calculation Method			
		2006 Rate Handbook	Standard Formula	Other Formula	Time and Materials
1	Temporary Service	$500			
2	Dispute Meter Test	$30 plus Measurement Canada fees			
3	Collection of account – no disconnection/load limiter	$30			
4	Collection/Disconnect/load limiter/reconnect (at meter) trip – regular hours	$65			
5	Collection/Disconnect/load limiter/reconnect (at meter) trip – after regular hours	$185			
6	Collection/Disconnect/load limiter/reconnect (at pole) trip – regular hours	$185			
7	Collection/Disconnect/load limiter/reconnect (at pole) trip – after regular hours	$415			
8	Account Set-up Charge	$30			
9	Arrears Certificate	$15			
10	NSF Cheque Charge	$15 + bank charges			
11	Easement Charge for Unregistered Rights	$15			
12	Late Payment Charge	1.5%/month			
13a	Retailer Services – Establishing Service Agreements (refer to Handbook for all charges)	$100/agreement/Retailer +$20/month/Retailer +$0.50/month/customer + other			
13b	Retailer Services – Other (includes Bill Ready for Retailers and Service Transactions Requests) as per the Handbook, Chapter 12	$0.30/month/customer + $0.25/request for request fee + $0.50/request for process fee			
14	Special Meter Reads	$30			
15	Service Layout Fee – Basic		$495		
16	Service Layout Fee – Complex		$690		
17	Crossing Application – Pipeline		$2,445		
18	Crossing Application – Water		$3,045		
19	Crossing Application – Railroad		$2,945		
20	Line Staking – per meter		$3.70		
21	Central Metering – New service < 45 kW		$115		
22	Conversion to Central Metering < 45 kW		$915		
23	Conversion to Central Metering > 45 kW		$800		
24	Tingle Voltage Test – In Excess of 4 Hours (per hour – average 2 additional hours)		$125		
25	Standby Administration Charge per month		$440		
26	Sentinel Lights Rental Rate per month			$7.10	
27	Sentinel Pole Rental Rate per month			$4.15	
28	Joint Use for Cable and Telecom companies per pole			$22.35	
29	Joint Use for LDCs per pole			$28.61	

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Hydro-Electric Commission of the Corporation of the Township of Middlesex Centre
Effective Date: May 1, 2007

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

APPLICATION

The application of these rates and charges shall be in accordance with The Licence of The Distributor and any Codes, Guidelines or Orders of The Board, and amendments thereto as approved by The Board, which may be applicable to the administration of this schedule.
No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code, Guideline or Order of the Board, and amendments thereto as approved by the Board, or as specified herein
This schedule does not contain any rates and charges relating to the electricity commodity (e.g. the Regulated Price Plan).

EFFECTIVE DATES

DISTRIBUTION RATES - May 1, 2007 for all consumption or deemed consumption services used on or after that date.

MISCELLANEOUS CHARGES - May 1, 2007 for all charges billed to customers on or after that date.
RETAIL TRANSMISSION RATES - May 1, 2007 for all consumption or deemed consumption services used on or after that date.
LOSS FACTOR ADJUSTMENT – May 1, 2007

SERVICE CLASSIFICATIONS

Residential
This classification (note 1) refers to all service supplied to single-family dwelling units for domestic or household purpose. Multi-unit residential establishments such as apartment buildings supplied through one service (bulk metered) will normally be classified as General Service, but, at Hydro One's discretion, up to four residential units may be classified as residential. Where electricity service is provided to combined residential and business (including agricultural usage) and the wiring does not provide for separate metering, the classification shall be at the discretion of Hydro One based on such considerations as the estimated predominant consumption.
Further servicing details are available in the utility's Conditions of Service.

General Service
This classification (note 1) refers to all service supplied to premises other than those classified as Residential or Lighting. Some General Service accounts are energy(kWh)-billed, and some are demand(kW)-billed. Further servicing details are available in the utility's Conditions of Service. Also, see note 2.

Unmetered Scattered Load
This classification refers to certain instances where connections can be provided without metering. These loads are generally small in size and consistent in magnitude of load. Hydro One reserves the right to review all cases and may require that a meter be installed at its sole discretion. Services that can be unmetered include cable TV amplifiers, telephone switching devices, phone booths, bus shelters, rail way crossing signals, traffic signals, and other small fixed loads.
Further servicing details are available in the utility's Conditions of Service (including in the "Unmetered Connections" section).

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Hydro-Electric Commission of the Corporation of the Township of Middlesex Centre
Effective Date: May 1, 2007

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

Street Lighting

This classification refers to accounts for the distribution and supply of electrical energy for street lighting. Street lights are devices owned by or operated for the road authority and/or the municipal corporation. These street lights in fact belong to the Street Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Sentinel Lighting

This classification refers to accounts for a separate service to a sentinel light. These sentinel lights in fact belong to the Sentinel Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Interim Demand-Side Management Time-of-Use

This is potentially applicable to Demand-billed General Service accounts. See Note 2 below.

Note (1): Classification descriptions are paraphrases from the document "Hydro One Networks Inc. - Distribution Customers Conditions of Service - August 2004"

Note (2):

Interim Demand-Side Management Time-of-Use Rates: demand charges will be based on demand during the on-peak periods.

Criteria: Customers' electricity consumption (kW) in the off-peak period is at least twice the electricity consumption (kW) during the on-peak period.

Definition of Time Periods: The on-peak hours will be between 0700 hours to 1900 hours Eastern Standard Time during the winter (standard time) on IESO business days and 0600 hours to 1800 hours Eastern Standard Time during the summer (daylight savings time) on IESO business days. The off-peak period constitutes all of the remaining hours.

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Hydro-Electric Commission of the Corporation of the Township of Middlesex Centre
Effective Date: May 1, 2007

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MONTHLY RATES AND CHARGES

Residential

Service Charge	$	14.19
Distribution Volumetric Rate	$ / kWh	0.0078
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0065
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0040
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0055
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0047
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service - Energy Billed (less than 50 kW)

Service Charge	$	17.35
Distribution Volumetric Rate	$ / kWh	0.0137
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0044
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0035
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0050
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0043
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service - Demand Billed (50 kW or greater)

Service Charge	$	17.35
Distribution Volumetric Rate	$ / kW	3.29
Regulatory Asset Recovery - Rider #1	$ / kW	1.39
Regulatory Asset Recovery - Rider #2	$ / kW	0.84
Retail Transmission Rate - Network Service Rate (4)	$ / kW	1.94
Retail Transmission Rate - Line and Transformation Connection Service Rate (4)	$ / kW	1.61
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
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Unmetered, Scattered Load

Service Charge	$	8.21
Distribution Volumetric Rate	$ / kWh	0.0137
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0044
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0035
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0050
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0043
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

(3) For energy-only metered customers, the billing determinant is the customer's metered energy consumption adjusted by the total loss factor as approved by the Board for Acquired LDC customers.
(4) For demand billed customers, appropriate loss factors must be applied to the applicable tariffs. Also the billing determinant for the Line and Transformation Connection Services rate is the customer's peak demand in the billing period. The billing determinant for the Network Services rate is: for non-interval-metered customers, the peak demand in the billing period, and for interval-metered customers, the peak demand between 7 AM and 7 PM local time on IESO business days

Interim Demand-Side Management Time-of-Use

See the "Service Classifications" section of this schedule.

Customer-Supplied Transformation Allowance

Applicable to demand-billed customers providing their own transformers
Primary Voltage under 50 kV (per kW)

Single Phase	$ / kW	0.20
Three Phase	$ / kW	0.60

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Loss Factors

Supply Facilities Loss Factor	1.0045
Distribution Loss Factors	
Customer less than 5,000 kW	1.0500
Customer greater than or equal to 5,000 kW	1.0100
Total Loss Factors	
Customer less than 5,000 kW	1.0545
Customer greater than or equal to 5,000 kW	1.0145

Transformer Loss Allowance

Applicable to customers requiring a billing adjustment for transformer losses as the result of being metered on the primary side of a transformer. The following uniform values shall be applied to measured demand and energy to calculate transformer losses for voltages up to and including 50 kV (as metered on the primary side):

(a) 1.5% for transformer installations up to an individual bank capacity of 400 kVA,
(b) 1.0% for bank capacities over 400 kVA.

Alternatively, transformer losses may be determined from transformer test data, and measured demand and energy adjusted accordingly

For services which are not demand metered, an assumed demand of 50% of the transformer capacity will be used to calculate the loss allowance. Where several transformers are involved, the bank capacity is assumed to be the arithmetic sum of all transformer capacities

Hydro One Networks Inc.
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Hydro-Electric Commission of the Corporation of the Township of Middlesex Centre
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MISCELLANEOUS CHARGES

Specific Service Charges: Standard Amounts

Rate Code	Specific Service Charge - Standard Name	Calculation Method			
		2006 Rate Handbook	Standard Formula	Other Formula	Time and Materials
1	Temporary Service	$500			
2	Dispute Meter Test	$30 plus Measurement Canada fees			
3	Collection of account – no disconnection/load limiter	$30			
4	Collection/Disconnect/load limiter/reconnect (at meter) trip – regular hours	$65			
5	Collection/Disconnect/load limiter/reconnect (at meter) trip – after regular hours	$185			
6	Collection/Disconnect/load limiter/reconnect (at pole) trip – regular hours	$185			
7	Collection/Disconnect/load limiter/reconnect (at pole) trip – after regular hours	$415			
8	Account Set-up Charge	$30			
9	Arrears Certificate	$15			
10	NSF Cheque Charge	$15 + bank charges			
11	Easement Charge for Unregistered Rights	$15			
12	Late Payment Charge	1.5%/month			
13a	Retailer Services – Establishing Service Agreements (refer to Handbook for all charges)	$100/agreement/Retailer +$20/month/Retailer +$0.50/month/customer + other			
13b	Retailer Services – Other (includes Bill Ready for Retailers and Service Transactions Requests) as per the Handbook, Chapter 12	$0.30/month/customer + $0.25/request for request fee + $0.50/request for process fee			
14	Special Meter Reads	$30			
15	Billing Suspension and Terminations in Trailer Parks		$130		
16	Service Layout Fee – Basic		$405		
17	Service Layout Fee – Complex		$580		

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18	Crossing Application – Pipeline		$2,065		
19	Crossing Application – Water		$2,525		
20	Crossing Application – Railroad		$2,565		
21	Line Staking – per meter		$3.10		
22	Central Metering – New service < 45 kW		$115		
23	Conversion to Central Metering < 45 kW		$795		
24	Conversion to Central Metering > 45 kW		$680		
25	Tingle Voltage Test – In Excess of 4 Hours (per hour – average 2 additional hours)		$105		
26	Standby Administration Charge per month (interim)		$375		
27	Sentinel Lights Rental Rate per month – Mercury Vapor			$7.00	
28	Guaranteed Units from Jan 01/91 to Aug 01/91			$26.50 / month	
29	Guaranteed Units from Jan 01/87 to Dec 31/90			$23.50 / month	
30	Joint Use for Cable and Telecom companies per pole			$22.35	
31	Joint Use for LDCs per pole			$28.61	

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Napanee Electric Commission
Effective Date: May 1, 2008

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

APPLICATION

The application of these rates and charges shall be in accordance with The Licence of The Distributor and any Codes, Guidelines or Orders of The Board, and amendments thereto as approved by The Board, which may be applicable to the administration of this schedule.
No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code, Guideline or Order of the Board, and amendments thereto as approved by the Board, or as specified herein
This schedule does not contain any rates and charges relating to the electricity commodity (e.g. the Regulated Price Plan).

EFFECTIVE DATES

DISTRIBUTION RATES - May 1, 2008 for all consumption or deemed consumption services used on or after that date.

MISCELLANEOUS CHARGES - May 1, 2008 for all charges billed to customers on or after that date.
RETAIL TRANSMISSION RATES - May 1, 2008 for all consumption or deemed consumption services used on or after that date.
LOSS FACTOR ADJUSTMENT – for all consumption or deemed consumption services billed following May 1, 2008 or later

SERVICE CLASSIFICATIONS

Residential
This classification refers to all service supplied to single-family dwelling units for domestic or household purpose. Multi-unit residential establishments such as apartment buildings supplied through one service (bulk metered) will normally be classified as General Service, but, at Hydro One's discretion, up to four residential units may be classified as residential. Where electricity service is provided to combined residential and business (including agricultural usage) and the wiring does not provide for separate metering, the classification shall be at the discretion of Hydro One based on such considerations as the estimated predominant consumption.
Further servicing details are available in the utility's Conditions of Service.

General Service
This classification refers to all service supplied to premises other than those classified as Residential or Lighting. Some General Service accounts are energy(kWh)-billed, and some are demand(kW)-billed. Further servicing details are available in the utility's Conditions of Service.

Unmetered Scattered Load
This classification refers to certain instances where connections can be provided without metering. These loads are generally small in size and consistent in magnitude of load. Hydro One reserves the right to review all cases and may require that a meter be installed at its sole discretion. Services that can be unmetered include cable TV amplifiers, telephone switching devices, phone booths, bus shelters, rail way crossing signals, traffic signals, and other small fixed loads.
Further servicing details are available in the utility's Conditions of Service (including in the "Unmetered Connections" section).

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Napanee Electric Commission
Effective Date: May 1, 2008

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

Street Lighting

This classification refers to accounts for the distribution and supply of electrical energy for street lighting. Street lights are devices owned by or operated for the road authority and/or the municipal corporation. These street lights in fact belong to the Street Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Sentinel Lighting

This classification refers to accounts for a separate service to a sentinel light. These sentinel lights in fact belong to the Sentinel Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Urban Density Classification

Customers who meet the Urban Density Criteria of being in an area containing 3,000 or more customers with a line density of at least 60 customers per kilometre, will be mapped to an Urban customer classification.

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
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Napanee Electric Commission
Effective Date: May 1, 2008

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MONTHLY RATES AND CHARGES

Residential - R1 Napanee

Service Charge	$	15.09
Distribution Volumetric Rate	$ / kWh	0.0235
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0014
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0004)
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0047
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0046
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service Less Than 50 kW (Energy-Billed) - GSe Napanee

Service Charge	$	24.55
Distribution Volumetric Rate	$ / kWh	0.0235
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0006
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0006)
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0035
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0032
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service 50 kW or Greater (Demand-Billed) - GSd Napanee

Service Charge	$	28.15
Distribution Volumetric Rate	$ / kW	8.90
Regulatory Asset Recovery - Rider #2	$ / kW	0.20
Regulatory Asset Recovery - Rider #3	$ / kW	(0.22)
Retail Transmission Rate - Network Service Rate (4)	$ / kW	1.11
Retail Transmission Rate - Line and Transformation Connection Service Rate (4)	$ / kW	1.00
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
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Napanee Electric Commission
Effective Date: May 1, 2008

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Unmetered, Scattered Load

Service Charge	$	13.72
Distribution Volumetric Rate	$ / kWh	0.0200
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0006
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0006)
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0035
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0032
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

(3) For energy-only metered customers, the billing determinant is the customer’s metered energy consumption adjusted by the total loss factor as approved by the Board for Acquired LDC customers.
(4) For demand billed customers, appropriate loss factors must be applied to the applicable tariffs. Also the billing determinant for the Line and Transformation Connection Services rate is the customer’s peak demand in the billing period. The billing determinant for the Network Services rate is: for non-interval-metered customers, the peak demand in the billing period, and for interval-metered customers, the peak demand between 7 AM and 7 PM local time on IESO business days

Customer-Supplied Transformation Allowance

Applicable to customers providing their own transformers		
Demand-billed	$ / kW	0.60
Energy-billed	$ / kWh	0.0014

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
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Loss Factors

Residential	1.085
General Service Less Than 50 kW (Energy-Billed)	1.092
General Service 50 kW or Greater (Demand-Billed)	1.061
Unmetered Scattered Load	1.092

Transformer Loss Allowance

Applicable to customers requiring a billing adjustment for transformer losses as the result of being metered on the primary side of a transformer. The following uniform values shall be applied to measured demand and energy to calculate transformer losses for voltages up to and including 50 kV (as metered on the primary side):

(a) 1.5% for transformer installations up to an individual bank capacity of 400 kVA,
(b) 1.0% for bank capacities over 400 kVA.

Alternatively, transformer losses may be determined from transformer test data, and measured demand and energy adjusted accordingly

For services which are not demand metered, an assumed demand of 50% of the transformer capacity will be used to calculate the loss allowance. Where several transformers are involved, the bank capacity is assumed to be the arithmetic sum of all transformer capacities

Hydro One Networks Inc.
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MISCELLANEOUS CHARGES

Specific Service Charges: Standard Amounts

Rate Code	Specific Service Charge - Standard Name	Calculation Method			
		2006 Rate Handbook	Standard Formula	Other Formula	Time and Materials
1	Temporary Service	$500			
2	Dispute Meter Test	$30 plus Measurement Canada fees			
3	Collection of account – no disconnection/load limiter	$30			
4	Collection/Disconnect/load limiter/reconnect (at meter) trip – regular hours	$65			
5	Collection/Disconnect/load limiter/reconnect (at meter) trip – after regular hours	$185			
6	Collection/Disconnect/load limiter/reconnect (at pole) trip – regular hours	$185			
7	Collection/Disconnect/load limiter/reconnect (at pole) trip – after regular hours	$415			
8	Account Set-up Charge	$30			
9	Arrears Certificate	$15			
10	NSF Cheque Charge	$15 + bank charges			
11	Easement Charge for Unregistered Rights	$15			
12	Late Payment Charge	1.5%/month			
13a	Retailer Services – Establishing Service Agreements (refer to Handbook for all charges)	$100/agreement/Retailer +$20/month/Retailer +$0.50/month/customer + other			
13b	Retailer Services – Other (includes Bill Ready for Retailers and Service Transactions Requests) as per the Handbook, Chapter 12	$0.30/month/customer + $0.25/request for request fee + $0.50/request for process fee			
14	Special Meter Reads	$30			
15	Service Layout Fee – Basic		$495		
16	Service Layout Fee – Complex		$690		
17	Crossing Application – Pipeline		$2,445		
18	Crossing Application – Water		$3,045		
19	Crossing Application – Railroad		$2,945		
20	Line Staking – per meter		$3.70		
21	Central Metering – New service < 45 kW		$115		
22	Conversion to Central Metering < 45 kW		$915		
23	Conversion to Central Metering > 45 kW		$800		
24	Tingle Voltage Test – In Excess of 4 Hours (per hour – average 2 additional hours)		$125		
25	Standby Administration Charge per month		$440		
26	Sentinel Lights Rental Rate per month			$7.10	
27	Sentinel Pole Rental Rate per month			$4.15	
28	Joint Use for Cable and Telecom companies per pole			$22.35	
29	Joint Use for LDCs per pole			$28.61	

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
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Effective Date: May 1, 2007

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APPLICATION

The application of these rates and charges shall be in accordance with The Licence of The Distributor and any Codes, Guidelines or Orders of The Board, and amendments thereto as approved by The Board, which may be applicable to the administration of this schedule.
No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code, Guideline or Order of the Board, and amendments thereto as approved by the Board, or as specified herein
This schedule does not contain any rates and charges relating to the electricity commodity (e.g. the Regulated Price Plan).

EFFECTIVE DATES

DISTRIBUTION RATES - May 1, 2007 for all consumption or deemed consumption services used on or after that date.

MISCELLANEOUS CHARGES - May 1, 2007 for all charges billed to customers on or after that date.
RETAIL TRANSMISSION RATES - May 1, 2007 for all consumption or deemed consumption services used on or after that date.
LOSS FACTOR ADJUSTMENT – May 1, 2007

SERVICE CLASSIFICATIONS

Residential
This classification (note 1) refers to all service supplied to single-family dwelling units for domestic or household purpose. Multi-unit residential establishments such as apartment buildings supplied through one service (bulk metered) will normally be classified as General Service, but, at Hydro One's discretion, up to four residential units may be classified as residential. Where electricity service is provided to combined residential and business (including agricultural usage) and the wiring does not provide for separate metering, the classification shall be at the discretion of Hydro One based on such considerations as the estimated predominant consumption.
Further servicing details are available in the utility's Conditions of Service.

General Service
This classification (note 1) refers to all service supplied to premises other than those classified as Residential or Lighting. Some General Service accounts are energy(kWh)-billed, and some are demand(kW)-billed. Further servicing details are available in the utility's Conditions of Service. Also, see note 2.

Unmetered Scattered Load
This classification refers to certain instances where connections can be provided without metering. These loads are generally small in size and consistent in magnitude of load. Hydro One reserves the right to review all cases and may require that a meter be installed at its sole discretion. Services that can be unmetered include cable TV amplifiers, telephone switching devices, phone booths, bus shelters, rail way crossing signals, traffic signals, and other small fixed loads.
Further servicing details are available in the utility's Conditions of Service (including in the "Unmetered Connections" section).

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Napanee Electric Commission
Effective Date: May 1, 2007

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

Street Lighting

This classification refers to accounts for the distribution and supply of electrical energy for street lighting. Street lights are devices owned by or operated for the road authority and/or the municipal corporation. These street lights in fact belong to the Street Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Sentinel Lighting

This classification refers to accounts for a separate service to a sentinel light. These sentinel lights in fact belong to the Sentinel Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Interim Demand-Side Management Time-of-Use

This is potentially applicable to Demand-billed General Service accounts. See Note 2 below.

Note (1): Classification descriptions are paraphrases from the document "Hydro One Networks Inc. - Distribution Customers Conditions of Service - August 2004"

Note (2):

Interim Demand-Side Management Time-of-Use Rates: demand charges will be based on demand during the on-peak periods.

Criteria: Customers' electricity consumption (kW) in the off-peak period is at least twice the electricity consumption (kW) during the on-peak period.

Definition of Time Periods: The on-peak hours will be between 0700 hours to 1900 hours Eastern Standard Time during the winter (standard time) on IESO business days and 0600 hours to 1800 hours Eastern Standard Time during the summer (daylight savings time) on IESO business days. The off-peak period constitutes all of the remaining hours.

Hydro One Networks Inc.
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MONTHLY RATES AND CHARGES

Residential

Service Charge	$	14.70
Distribution Volumetric Rate	$ / kWh	0.0102
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0043
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0014
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0055
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0047
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service - Energy Billed (less than 50 kW)

Service Charge	$	22.17
Distribution Volumetric Rate	$ / kWh	0.0128
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0016
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0006
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0050
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0043
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service - Demand Billed (50 kW or greater)

Service Charge	$	22.17
Distribution Volumetric Rate	$ / kW	4.04
Regulatory Asset Recovery - Rider #1	$ / kW	0.52
Regulatory Asset Recovery - Rider #2	$ / kW	0.20
Retail Transmission Rate - Network Service Rate (4)	$ / kW	1.94
Retail Transmission Rate - Line and Transformation Connection Service Rate (4)	$ / kW	1.61
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

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Unmetered, Scattered Load

Service Charge	$	10.62
Distribution Volumetric Rate	$ / kWh	0.0128
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0016
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0006
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0050
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0043
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

(3) For energy-only metered customers, the billing determinant is the customer's metered energy consumption adjusted by the total loss factor as approved by the Board for Acquired LDC customers.
(4) For demand billed customers, appropriate loss factors must be applied to the applicable tariffs. Also the billing determinant for the Line and Transformation Connection Services rate is the customer's peak demand in the billing period. The billing determinant for the Network Services rate is: for non-interval-metered customers, the peak demand in the billing period, and for interval-metered customers, the peak demand between 7 AM and 7 PM local time on IESO business days

Interim Demand-Side Management Time-of-Use

See the "Service Classifications" section of this schedule.

Customer-Supplied Transformation Allowance

Applicable to demand-billed customers providing their own transformers
Primary Voltage under 50 kV (per kW)

Single Phase	$ / kW	0.20
Three Phase	$ / kW	0.60

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Loss Factors

Supply Facilities Loss Factor	1.0045
Distribution Loss Factors	
Customer less than 5,000 kW	1.0500
Customer greater than or equal to 5,000 kW	1.0100
Total Loss Factors	
Customer less than 5,000 kW	1.0545
Customer greater than or equal to 5,000 kW	1.0145

Transformer Loss Allowance

Applicable to customers requiring a billing adjustment for transformer losses as the result of being metered on the primary side of a transformer. The following uniform values shall be applied to measured demand and energy to calculate transformer losses for voltages up to and including 50 kV (as metered on the primary side):

(a) 1.5% for transformer installations up to an individual bank capacity of 400 kVA,
(b) 1.0% for bank capacities over 400 kVA.

Alternatively, transformer losses may be determined from transformer test data, and measured demand and energy adjusted accordingly

For services which are not demand metered, an assumed demand of 50% of the transformer capacity will be used to calculate the loss allowance. Where several transformers are involved, the bank capacity is assumed to be the arithmetic sum of all transformer capacities

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MISCELLANEOUS CHARGES

Specific Service Charges: Standard Amounts

Rate Code	Specific Service Charge - Standard Name	Calculation Method			
		2006 Rate Handbook	Standard Formula	Other Formula	Time and Materials
1	Temporary Service	$500			
2	Dispute Meter Test	$30 plus Measurement Canada fees			
3	Collection of account – no disconnection/load limiter	$30			
4	Collection/Disconnect/load limiter/reconnect (at meter) trip – regular hours	$65			
5	Collection/Disconnect/load limiter/reconnect (at meter) trip – after regular hours	$185			
6	Collection/Disconnect/load limiter/reconnect (at pole) trip – regular hours	$185			
7	Collection/Disconnect/load limiter/reconnect (at pole) trip – after regular hours	$415			
8	Account Set-up Charge	$30			
9	Arrears Certificate	$15			
10	NSF Cheque Charge	$15 + bank charges			
11	Easement Charge for Unregistered Rights	$15			
12	Late Payment Charge	1.5%/month			
13a	Retailer Services – Establishing Service Agreements (refer to Handbook for all charges)	$100/agreement/Retailer +$20/month/Retailer +$0.50/month/customer + other			
13b	Retailer Services – Other (includes Bill Ready for Retailers and Service Transactions Requests) as per the Handbook, Chapter 12	$0.30/month/customer + $0.25/request for request fee + $0.50/request for process fee			
14	Special Meter Reads	$30			
15	Billing Suspension and Terminations in Trailer Parks		$130		
16	Service Layout Fee – Basic		$405		
17	Service Layout Fee – Complex		$580		

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18	Crossing Application – Pipeline		$2,065		
19	Crossing Application – Water		$2,525		
20	Crossing Application – Railroad		$2,565		
21	Line Staking – per meter		$3.10		
22	Central Metering – New service < 45 kW		$115		
23	Conversion to Central Metering < 45 kW		$795		
24	Conversion to Central Metering > 45 kW		$680		
25	Tingle Voltage Test – In Excess of 4 Hours (per hour – average 2 additional hours)		$105		
26	Standby Administration Charge per month (interim)		$375		
27	Sentinel Lights Rental Rate per month – Mercury Vapor			$7.00	
28	Guaranteed Units from Jan 01/91 to Aug 01/91			$26.50 / month	
29	Guaranteed Units from Jan 01/87 to Dec 31/90			$23.50 / month	
30	Joint Use for Cable and Telecom companies per pole			$22.35	
31	Joint Use for LDCs per pole			$28.61	

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Nipigon Hydro Electric Commission
Effective Date: May 1, 2008

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

APPLICATION

The application of these rates and charges shall be in accordance with The Licence of The Distributor and any Codes, Guidelines or Orders of The Board, and amendments thereto as approved by The Board, which may be applicable to the administration of this schedule.
No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code, Guideline or Order of the Board, and amendments thereto as approved by the Board, or as specified herein
This schedule does not contain any rates and charges relating to the electricity commodity (e.g. the Regulated Price Plan).

EFFECTIVE DATES

DISTRIBUTION RATES - May 1, 2008 for all consumption or deemed consumption services used on or after that date.

MISCELLANEOUS CHARGES - May 1, 2008 for all charges billed to customers on or after that date.
RETAIL TRANSMISSION RATES - May 1, 2008 for all consumption or deemed consumption services used on or after that date.
LOSS FACTOR ADJUSTMENT – for all consumption or deemed consumption services billed following May 1, 2008 or later

SERVICE CLASSIFICATIONS

Residential
This classification refers to all service supplied to single-family dwelling units for domestic or household purpose. Multi-unit residential establishments such as apartment buildings supplied through one service (bulk metered) will normally be classified as General Service, but, at Hydro One's discretion, up to four residential units may be classified as residential. Where electricity service is provided to combined residential and business (including agricultural usage) and the wiring does not provide for separate metering, the classification shall be at the discretion of Hydro One based on such considerations as the estimated predominant consumption.
Further servicing details are available in the utility's Conditions of Service.

General Service
This classification refers to all service supplied to premises other than those classified as Residential or Lighting. Some General Service accounts are energy(kWh)-billed, and some are demand(kW)-billed. Further servicing details are available in the utility's Conditions of Service.

Unmetered Scattered Load
This classification refers to certain instances where connections can be provided without metering. These loads are generally small in size and consistent in magnitude of load. Hydro One reserves the right to review all cases and may require that a meter be installed at its sole discretion. Services that can be unmetered include cable TV amplifiers, telephone switching devices, phone booths, bus shelters, rail way crossing signals, traffic signals, and other small fixed loads.
Further servicing details are available in the utility's Conditions of Service (including in the "Unmetered Connections" section).

Hydro One Networks Inc.
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Street Lighting

This classification refers to accounts for the distribution and supply of electrical energy for street lighting. Street lights are devices owned by or operated for the road authority and/or the municipal corporation. These street lights in fact belong to the Street Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Sentinel Lighting

This classification refers to accounts for a separate service to a sentinel light. These sentinel lights in fact belong to the Sentinel Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Urban Density Classification

Customers who meet the Urban Density Criteria of being in an area containing 3,000 or more customers with a line density of at least 60 customers per kilometre, will be mapped to an Urban customer classification.

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MONTHLY RATES AND CHARGES

Residential - R1 Nipigon

Service Charge	$	15.20
Distribution Volumetric Rate	$ / kWh	0.0271
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0072
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0004)
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0047
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0046
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service Less Than 50 kW (Energy-Billed) - GSe Nipigon

Service Charge	$	25.26
Distribution Volumetric Rate	$ / kWh	0.0234
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0021
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0006)
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0035
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0032
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service 50 kW or Greater (Demand-Billed) - GSd Nipigon

Service Charge	$	28.86
Distribution Volumetric Rate	$ / kW	8.80
Regulatory Asset Recovery - Rider #2	$ / kW	0.68
Regulatory Asset Recovery - Rider #3	$ / kW	(0.22)
Retail Transmission Rate - Network Service Rate (4)	$ / kW	1.11
Retail Transmission Rate - Line and Transformation Connection Service Rate (4)	$ / kW	1.00
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

Hydro One Networks Inc.
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Unmetered, Scattered Load

Service Charge	$	14.58
Distribution Volumetric Rate	$ / kWh	0.0200
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0021
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0006)
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0035
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0032
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

(3) For energy-only metered customers, the billing determinant is the customer's metered energy consumption adjusted by the total loss factor as approved by the Board for Acquired LDC customers.
(4) For demand billed customers, appropriate loss factors must be applied to the applicable tariffs. Also the billing determinant for the Line and Transformation Connection Services rate is the customer's peak demand in the billing period. The billing determinant for the Network Services rate is: for non-interval-metered customers, the peak demand in the billing period, and for interval-metered customers, the peak demand between 7 AM and 7 PM local time on IESO business days

Customer-Supplied Transformation Allowance

Applicable to customers providing their own transformers

Demand-billed	$ / kW	0.60
Energy-billed	$ / kWh	0.0014

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Loss Factors

Residential	1.085
General Service Less Than 50 kW (Energy-Billed)	1.092
General Service 50 kW or Greater (Demand-Billed)	1.061
Unmetered Scattered Load	1.092

Transformer Loss Allowance

Applicable to customers requiring a billing adjustment for transformer losses as the result of being metered on the primary side of a transformer. The following uniform values shall be applied to measured demand and energy to calculate transformer losses for voltages up to and including 50 kV (as metered on the primary side):

(a) 1.5% for transformer installations up to an individual bank capacity of 400 kVA,
(b) 1.0% for bank capacities over 400 kVA.

Alternatively, transformer losses may be determined from transformer test data, and measured demand and energy adjusted accordingly

For services which are not demand metered, an assumed demand of 50% of the transformer capacity will be used to calculate the loss allowance. Where several transformers are involved, the bank capacity is assumed to be the arithmetic sum of all transformer capacities

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MISCELLANEOUS CHARGES

Specific Service Charges: Standard Amounts

Rate Code	Specific Service Charge - Standard Name	Calculation Method			
		2006 Rate Handbook	Standard Formula	Other Formula	Time and Materials
1	Temporary Service	$500			
2	Dispute Meter Test	$30 plus Measurement Canada fees			
3	Collection of account – no disconnection/load limiter	$30			
4	Collection/Disconnect/load limiter/reconnect (at meter) trip – regular hours	$65			
5	Collection/Disconnect/load limiter/reconnect (at meter) trip – after regular hours	$185			
6	Collection/Disconnect/load limiter/reconnect (at pole) trip – regular hours	$185			
7	Collection/Disconnect/load limiter/reconnect (at pole) trip – after regular hours	$415			
8	Account Set-up Charge	$30			
9	Arrears Certificate	$15			
10	NSF Cheque Charge	$15 + bank charges			
11	Easement Charge for Unregistered Rights	$15			
12	Late Payment Charge	1.5%/month			
13a	Retailer Services – Establishing Service Agreements (refer to Handbook for all charges)	$100/agreement/Retailer +$20/month/Retailer +$0.50/month/customer + other			
13b	Retailer Services – Other (includes Bill Ready for Retailers and Service Transactions Requests) as per the Handbook, Chapter 12	$0.30/month/customer + $0.25/request for request fee + $0.50/request for process fee			
14	Special Meter Reads	$30			
15	Service Layout Fee – Basic		$495		
16	Service Layout Fee – Complex		$690		
17	Crossing Application – Pipeline		$2,445		
18	Crossing Application – Water		$3,045		
19	Crossing Application – Railroad		$2,945		
20	Line Staking – per meter		$3.70		
21	Central Metering – New service < 45 kW		$115		
22	Conversion to Central Metering < 45 kW		$915		
23	Conversion to Central Metering > 45 kW		$800		
24	Tingle Voltage Test – In Excess of 4 Hours (per hour – average 2 additional hours)		$125		
25	Standby Administration Charge per month		$440		
26	Sentinel Lights Rental Rate per month			$7.10	
27	Sentinel Pole Rental Rate per month			$4.15	
28	Joint Use for Cable and Telecom companies per pole			$22.35	
29	Joint Use for LDCs per pole			$28.61	

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APPLICATION

The application of these rates and charges shall be in accordance with The Licence of The Distributor and any Codes, Guidelines or Orders of The Board, and amendments thereto as approved by The Board, which may be applicable to the administration of this schedule.
No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code, Guideline or Order of the Board, and amendments thereto as approved by the Board, or as specified herein
This schedule does not contain any rates and charges relating to the electricity commodity (e.g. the Regulated Price Plan).

EFFECTIVE DATES

DISTRIBUTION RATES - May 1, 2007 for all consumption or deemed consumption services used on or after that date.

MISCELLANEOUS CHARGES - May 1, 2007 for all charges billed to customers on or after that date.
RETAIL TRANSMISSION RATES - May 1, 2007 for all consumption or deemed consumption services used on or after that date.
LOSS FACTOR ADJUSTMENT – May 1, 2007

SERVICE CLASSIFICATIONS

Residential
This classification (note 1) refers to all service supplied to single-family dwelling units for domestic or household purpose. Multi-unit residential establishments such as apartment buildings supplied through one service (bulk metered) will normally be classified as General Service, but, at Hydro One's discretion, up to four residential units may be classified as residential. Where electricity service is provided to combined residential and business (including agricultural usage) and the wiring does not provide for separate metering, the classification shall be at the discretion of Hydro One based on such considerations as the estimated predominant consumption.
Further servicing details are available in the utility's Conditions of Service.

General Service
This classification (note 1) refers to all service supplied to premises other than those classified as Residential or Lighting. Some General Service accounts are energy(kWh)-billed, and some are demand(kW)-billed. Further servicing details are available in the utility's Conditions of Service. Also, see note 2.

Unmetered Scattered Load
This classification refers to certain instances where connections can be provided without metering. These loads are generally small in size and consistent in magnitude of load. Hydro One reserves the right to review all cases and may require that a meter be installed at its sole discretion. Services that can be unmetered include cable TV amplifiers, telephone switching devices, phone booths, bus shelters, rail way crossing signals, traffic signals, and other small fixed loads.
Further servicing details are available in the utility's Conditions of Service (including in the "Unmetered Connections" section).

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Street Lighting

This classification refers to accounts for the distribution and supply of electrical energy for street lighting. Street lights are devices owned by or operated for the road authority and/or the municipal corporation. These street lights in fact belong to the Street Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Sentinel Lighting

This classification refers to accounts for a separate service to a sentinel light. These sentinel lights in fact belong to the Sentinel Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Interim Demand-Side Management Time-of-Use

This is potentially applicable to Demand-billed General Service accounts. See Note 2 below.

Note (1): Classification descriptions are paraphrases from the document "Hydro One Networks Inc. - Distribution Customers Conditions of Service - August 2004"

Note (2):

Interim Demand-Side Management Time-of-Use Rates: demand charges will be based on demand during the on-peak periods.

Criteria: Customers' electricity consumption (kW) in the off-peak period is at least twice the electricity consumption (kW) during the on-peak period.

Definition of Time Periods: The on-peak hours will be between 0700 hours to 1900 hours Eastern Standard Time during the winter (standard time) on IESO business days and 0600 hours to 1800 hours Eastern Standard Time during the summer (daylight savings time) on IESO business days. The off-peak period constitutes all of the remaining hours.

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MONTHLY RATES AND CHARGES

Residential

Service Charge	$	14.23
Distribution Volumetric Rate	$ / kWh	0.0142
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0127
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0072
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0055
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0047
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service - Energy Billed (less than 50 kW)

Service Charge	$	23.32
Distribution Volumetric Rate	$ / kWh	0.0105
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0034
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0021
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0050
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0043
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service - Demand Billed (50 kW or greater)

Service Charge	$	23.32
Distribution Volumetric Rate	$ / kW	3.38
Regulatory Asset Recovery - Rider #1	$ / kW	1.07
Regulatory Asset Recovery - Rider #2	$ / kW	0.68
Retail Transmission Rate - Network Service Rate (4)	$ / kW	1.94
Retail Transmission Rate - Line and Transformation Connection Service Rate (4)	$ / kW	1.61
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

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Unmetered, Scattered Load

Service Charge	$	11.19
Distribution Volumetric Rate	$ / kWh	0.0105
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0034
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0021
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0050
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0043
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

(3) For energy-only metered customers, the billing determinant is the customer’s metered energy consumption adjusted by the total loss factor as approved by the Board for Acquired LDC customers.
(4) For demand billed customers, appropriate loss factors must be applied to the applicable tariffs. Also the billing determinant for the Line and Transformation Connection Services rate is the customer’s peak demand in the billing period. The billing determinant for the Network Services rate is: for non-interval-metered customers, the peak demand in the billing period, and for interval-metered customers, the peak demand between 7 AM and 7 PM local time on IESO business days

Interim Demand-Side Management Time-of-Use

See the "Service Classifications" section of this schedule.

Customer-Supplied Transformation Allowance

Applicable to demand-billed customers providing their own transformers
Primary Voltage under 50 kV (per kW)

Single Phase	$ / kW	0.20
Three Phase	$ / kW	0.60

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Nipigon Hydro Electric Commission
Effective Date: May 1, 2007

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

Loss Factors

Supply Facilities Loss Factor	1.0045
Distribution Loss Factors	
Customer less than 5,000 kW	1.0500
Customer greater than or equal to 5,000 kW	1.0100
Total Loss Factors	
Customer less than 5,000 kW	1.0545
Customer greater than or equal to 5,000 kW	1.0145

Transformer Loss Allowance

Applicable to customers requiring a billing adjustment for transformer losses as the result of being metered on the primary side of a transformer. The following uniform values shall be applied to measured demand and energy to calculate transformer losses for voltages up to and including 50 kV (as metered on the primary side):

(a) 1.5% for transformer installations up to an individual bank capacity of 400 kVA,
(b) 1.0% for bank capacities over 400 kVA.

Alternatively, transformer losses may be determined from transformer test data, and measured demand and energy adjusted accordingly

For services which are not demand metered, an assumed demand of 50% of the transformer capacity will be used to calculate the loss allowance. Where several transformers are involved, the bank capacity is assumed to be the arithmetic sum of all transformer capacities

Hydro One Networks Inc.
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Effective Date: May 1, 2007

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MISCELLANEOUS CHARGES

Specific Service Charges: Standard Amounts

Rate Code	Specific Service Charge - Standard Name	Calculation Method			
		2006 Rate Handbook	Standard Formula	Other Formula	Time and Materials
1	Temporary Service	$500			
2	Dispute Meter Test	$30 plus Measurement Canada fees			
3	Collection of account – no disconnection/load limiter	$30			
4	Collection/Disconnect/load limiter/reconnect (at meter) trip – regular hours	$65			
5	Collection/Disconnect/load limiter/reconnect (at meter) trip – after regular hours	$185			
6	Collection/Disconnect/load limiter/reconnect (at pole) trip – regular hours	$185			
7	Collection/Disconnect/load limiter/reconnect (at pole) trip – after regular hours	$415			
8	Account Set-up Charge	$30			
9	Arrears Certificate	$15			
10	NSF Cheque Charge	$15 + bank charges			
11	Easement Charge for Unregistered Rights	$15			
12	Late Payment Charge	1.5%/month			
13a	Retailer Services – Establishing Service Agreements (refer to Handbook for all charges)	$100/agreement/Retailer +$20/month/Retailer +$0.50/month/customer + other			
13b	Retailer Services – Other (includes Bill Ready for Retailers and Service Transactions Requests) as per the Handbook, Chapter 12	$0.30/month/customer + $0.25/request for request fee + $0.50/request for process fee			
14	Special Meter Reads	$30			
15	Billing Suspension and Terminations in Trailer Parks		$130		
16	Service Layout Fee – Basic		$405		
17	Service Layout Fee – Complex		$580		

Hydro One Networks Inc.
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Nipigon Hydro Electric Commission
Effective Date: May 1, 2007

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

18	Crossing Application – Pipeline		$2,065		
19	Crossing Application – Water		$2,525		
20	Crossing Application – Railroad		$2,565		
21	Line Staking – per meter		$3.10		
22	Central Metering – New service < 45 kW		$115		
23	Conversion to Central Metering < 45 kW		$795		
24	Conversion to Central Metering > 45 kW		$680		
25	Tingle Voltage Test – In Excess of 4 Hours (per hour – average 2 additional hours)		$105		
26	Standby Administration Charge per month (interim)		$375		
27	Sentinel Lights Rental Rate per month – Mercury Vapor			$7.00	
28	Guaranteed Units from Jan 01/91 to Aug 01/91			$26.50 / month	
29	Guaranteed Units from Jan 01/87 to Dec 31/90			$23.50 / month	
30	Joint Use for Cable and Telecom companies per pole			$22.35	
31	Joint Use for LDCs per pole			$28.61	

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Township of North Dorchester Hydro Electric Commission
Effective Date: May 1, 2008

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

APPLICATION

The application of these rates and charges shall be in accordance with The Licence of The Distributor and any Codes, Guidelines or Orders of The Board, and amendments thereto as approved by The Board, which may be applicable to the administration of this schedule.
No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code, Guideline or Order of the Board, and amendments thereto as approved by the Board, or as specified herein
This schedule does not contain any rates and charges relating to the electricity commodity (e.g. the Regulated Price Plan).

EFFECTIVE DATES

DISTRIBUTION RATES - May 1, 2008 for all consumption or deemed consumption services used on or after that date.

MISCELLANEOUS CHARGES - May 1, 2008 for all charges billed to customers on or after that date.
RETAIL TRANSMISSION RATES - May 1, 2008 for all consumption or deemed consumption services used on or after that date.
LOSS FACTOR ADJUSTMENT – for all consumption or deemed consumption services billed following May 1, 2008 or later

SERVICE CLASSIFICATIONS

Residential
This classification refers to all service supplied to single-family dwelling units for domestic or household purpose. Multi-unit residential establishments such as apartment buildings supplied through one service (bulk metered) will normally be classified as General Service, but, at Hydro One's discretion, up to four residential units may be classified as residential. Where electricity service is provided to combined residential and business (including agricultural usage) and the wiring does not provide for separate metering, the classification shall be at the discretion of Hydro One based on such considerations as the estimated predominant consumption.
Further servicing details are available in the utility's Conditions of Service.

General Service
This classification refers to all service supplied to premises other than those classified as Residential or Lighting. Some General Service accounts are energy(kWh)-billed, and some are demand(kW)-billed. Further servicing details are available in the utility's Conditions of Service.

Unmetered Scattered Load
This classification refers to certain instances where connections can be provided without metering. These loads are generally small in size and consistent in magnitude of load. Hydro One reserves the right to review all cases and may require that a meter be installed at its sole discretion. Services that can be unmetered include cable TV amplifiers, telephone switching devices, phone booths, bus shelters, rail way crossing signals, traffic signals, and other small fixed loads.
Further servicing details are available in the utility's Conditions of Service (including in the "Unmetered Connections" section).

Hydro One Networks Inc.
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Effective Date: May 1, 2008

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

Street Lighting

This classification refers to accounts for the distribution and supply of electrical energy for street lighting. Street lights are devices owned by or operated for the road authority and/or the municipal corporation. These street lights in fact belong to the Street Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Sentinel Lighting

This classification refers to accounts for a separate service to a sentinel light. These sentinel lights in fact belong to the Sentinel Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Urban Density Classification

Customers who meet the Urban Density Criteria of being in an area containing 3,000 or more customers with a line density of at least 60 customers per kilometre, will be mapped to an Urban customer classification.

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MONTHLY RATES AND CHARGES

Residential - R1 North Dorchester

Service Charge	$	10.52
Distribution Volumetric Rate	$ / kWh	0.0225
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0040
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0004)
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0047
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0046
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service Less Than 50 kW (Energy-Billed) - GSe North Dorchester

Service Charge	$	19.12
Distribution Volumetric Rate	$ / kWh	0.0208
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0026
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0006)
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0035
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0032
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service 50 kW or Greater (Demand-Billed) - GSd North Dorchester

Service Charge	$	22.72
Distribution Volumetric Rate	$ / kW	8.30
Regulatory Asset Recovery - Rider #2	$ / kW	0.81
Regulatory Asset Recovery - Rider #3	$ / kW	(0.22)
Retail Transmission Rate - Network Service Rate (4)	$ / kW	1.11
Retail Transmission Rate - Line and Transformation Connection Service Rate (4)	$ / kW	1.00
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

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Unmetered, Scattered Load

Service Charge	$	11.51
Distribution Volumetric Rate	$ / kWh	0.0200
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0026
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0006)
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0035
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0032
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

(3) For energy-only metered customers, the billing determinant is the customer's metered energy consumption adjusted by the total loss factor as approved by the Board for Acquired LDC customers.
(4) For demand billed customers, appropriate loss factors must be applied to the applicable tariffs. Also the billing determinant for the Line and Transformation Connection Services rate is the customer's peak demand in the billing period. The billing determinant for the Network Services rate is: for non-interval-metered customers, the peak demand in the billing period, and for interval-metered customers, the peak demand between 7 AM and 7 PM local time on IESO business days

Customer-Supplied Transformation Allowance

Applicable to customers providing their own transformers

Demand-billed	$ / kW	0.60
Energy-billed	$ / kWh	0.0014

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Loss Factors

Residential	1.085
General Service Less Than 50 kW (Energy-Billed)	1.092
General Service 50 kW or Greater (Demand-Billed)	1.061
Unmetered Scattered Load	1.092

Transformer Loss Allowance

Applicable to customers requiring a billing adjustment for transformer losses as the result of being metered on the primary side of a transformer. The following uniform values shall be applied to measured demand and energy to calculate transformer losses for voltages up to and including 50 kV (as metered on the primary side):

(a) 1.5% for transformer installations up to an individual bank capacity of 400 kVA,
(b) 1.0% for bank capacities over 400 kVA.

Alternatively, transformer losses may be determined from transformer test data, and measured demand and energy adjusted accordingly

For services which are not demand metered, an assumed demand of 50% of the transformer capacity will be used to calculate the loss allowance. Where several transformers are involved, the bank capacity is assumed to be the arithmetic sum of all transformer capacities

Hydro One Networks Inc.
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MISCELLANEOUS CHARGES

Specific Service Charges: Standard Amounts

Rate Code	Specific Service Charge - Standard Name	Calculation Method			
		2006 Rate Handbook	Standard Formula	Other Formula	Time and Materials
1	Temporary Service	$500			
2	Dispute Meter Test	$30 plus Measurement Canada fees			
3	Collection of account – no disconnection/load limiter	$30			
4	Collection/Disconnect/load limiter/reconnect (at meter) trip – regular hours	$65			
5	Collection/Disconnect/load limiter/reconnect (at meter) trip – after regular hours	$185			
6	Collection/Disconnect/load limiter/reconnect (at pole) trip – regular hours	$185			
7	Collection/Disconnect/load limiter/reconnect (at pole) trip – after regular hours	$415			
8	Account Set-up Charge	$30			
9	Arrears Certificate	$15			
10	NSF Cheque Charge	$15 + bank charges			
11	Easement Charge for Unregistered Rights	$15			
12	Late Payment Charge	1.5%/month			
13a	Retailer Services – Establishing Service Agreements (refer to Handbook for all charges)	$100/agreement/Retailer +$20/month/Retailer +$0.50/month/customer + other			
13b	Retailer Services – Other (includes Bill Ready for Retailers and Service Transactions Requests) as per the Handbook, Chapter 12	$0.30/month/customer + $0.25/request for request fee + $0.50/request for process fee			
14	Special Meter Reads	$30			
15	Service Layout Fee – Basic		$495		
16	Service Layout Fee – Complex		$690		
17	Crossing Application – Pipeline		$2,445		
18	Crossing Application – Water		$3,045		
19	Crossing Application – Railroad		$2,945		
20	Line Staking – per meter		$3.70		
21	Central Metering – New service < 45 kW		$115		
22	Conversion to Central Metering < 45 kW		$915		
23	Conversion to Central Metering > 45 kW		$800		
24	Tingle Voltage Test – In Excess of 4 Hours (per hour – average 2 additional hours)		$125		
25	Standby Administration Charge per month		$440		
26	Sentinel Lights Rental Rate per month			$7.10	
27	Sentinel Pole Rental Rate per month			$4.15	
28	Joint Use for Cable and Telecom companies per pole			$22.35	
29	Joint Use for LDCs per pole			$28.61	

Hydro One Networks Inc.
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Effective Date: May 1, 2007

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APPLICATION

The application of these rates and charges shall be in accordance with The Licence of The Distributor and any Codes, Guidelines or Orders of The Board, and amendments thereto as approved by The Board, which may be applicable to the administration of this schedule.
No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code, Guideline or Order of the Board, and amendments thereto as approved by the Board, or as specified herein
This schedule does not contain any rates and charges relating to the electricity commodity (e.g. the Regulated Price Plan).

EFFECTIVE DATES

DISTRIBUTION RATES - May 1, 2007 for all consumption or deemed consumption services used on or after that date.

MISCELLANEOUS CHARGES - May 1, 2007 for all charges billed to customers on or after that date.
RETAIL TRANSMISSION RATES - May 1, 2007 for all consumption or deemed consumption services used on or after that date.
LOSS FACTOR ADJUSTMENT – May 1, 2007

SERVICE CLASSIFICATIONS

Residential
This classification (note 1) refers to all service supplied to single-family dwelling units for domestic or household purpose. Multi-unit residential establishments such as apartment buildings supplied through one service (bulk metered) will normally be classified as General Service, but, at Hydro One's discretion, up to four residential units may be classified as residential. Where electricity service is provided to combined residential and business (including agricultural usage) and the wiring does not provide for separate metering, the classification shall be at the discretion of Hydro One based on such considerations as the estimated predominant consumption.
Further servicing details are available in the utility's Conditions of Service.

General Service
This classification (note 1) refers to all service supplied to premises other than those classified as Residential or Lighting. Some General Service accounts are energy(kWh)-billed, and some are demand(kW)-billed. Further servicing details are available in the utility's Conditions of Service. Also, see note 2.

Unmetered Scattered Load
This classification refers to certain instances where connections can be provided without metering. These loads are generally small in size and consistent in magnitude of load. Hydro One reserves the right to review all cases and may require that a meter be installed at its sole discretion. Services that can be unmetered include cable TV amplifiers, telephone switching devices, phone booths, bus shelters, rail way crossing signals, traffic signals, and other small fixed loads.
Further servicing details are available in the utility's Conditions of Service (including in the "Unmetered Connections" section).

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Street Lighting

This classification refers to accounts for the distribution and supply of electrical energy for street lighting. Street lights are devices owned by or operated for the road authority and/or the municipal corporation. These street lights in fact belong to the Street Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility’s Conditions of Service.

Sentinel Lighting

This classification refers to accounts for a separate service to a sentinel light. These sentinel lights in fact belong to the Sentinel Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility’s Conditions of Service.

Interim Demand-Side Management Time-of-Use

This is potentially applicable to Demand-billed General Service accounts. See Note 2 below.

Note (1): Classification descriptions are paraphrases from the document "Hydro One Networks Inc. - Distribution Customers Conditions of Service - August 2004"

Note (2):

Interim Demand-Side Management Time-of-Use Rates: demand charges will be based on demand during the on-peak periods.

Criteria: Customers' electricity consumption (kW) in the off-peak period is at least twice the electricity consumption (kW) during the on-peak period.

Definition of Time Periods: The on-peak hours will be between 0700 hours to 1900 hours Eastern Standard Time during the winter (standard time) on IESO business days and 0600 hours to 1800 hours Eastern Standard Time during the summer (daylight savings time) on IESO business days. The off-peak period constitutes all of the remaining hours.

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MONTHLY RATES AND CHARGES

Residential

Service Charge	$	8.97
Distribution Volumetric Rate	$ / kWh	0.0086
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0067
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0040
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0055
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0047
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service - Energy Billed (less than 50 kW)

Service Charge	$	15.88
Distribution Volumetric Rate	$ / kWh	0.0090
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0035
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0026
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0050
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0043
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service - Demand Billed (50 kW or greater)

Service Charge	$	15.88
Distribution Volumetric Rate	$ / kW	2.85
Regulatory Asset Recovery - Rider #1	$ / kW	1.12
Regulatory Asset Recovery - Rider #2	$ / kW	0.81
Retail Transmission Rate - Network Service Rate (4)	$ / kW	1.94
Retail Transmission Rate - Line and Transformation Connection Service Rate (4)	$ / kW	1.61
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

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Unmetered, Scattered Load

Service Charge	$	7.47
Distribution Volumetric Rate	$ / kWh	0.0090
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0035
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0026
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0050
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0043
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

(3) For energy-only metered customers, the billing determinant is the customer's metered energy consumption adjusted by the total loss factor as approved by the Board for Acquired LDC customers.
(4) For demand billed customers, appropriate loss factors must be applied to the applicable tariffs. Also the billing determinant for the Line and Transformation Connection Services rate is the customer's peak demand in the billing period. The billing determinant for the Network Services rate is: for non-interval-metered customers, the peak demand in the billing period, and for interval-metered customers, the peak demand between 7 AM and 7 PM local time on IESO business days

Interim Demand-Side Management Time-of-Use

See the "Service Classifications" section of this schedule.

Customer-Supplied Transformation Allowance

Applicable to demand-billed customers providing their own transformers
Primary Voltage under 50 kV (per kW)

Single Phase	$ / kW	0.20
Three Phase	$ / kW	0.60

Hydro One Networks Inc.
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Loss Factors

Supply Facilities Loss Factor	1.0045
Distribution Loss Factors	
Customer less than 5,000 kW	1.0500
Customer greater than or equal to 5,000 kW	1.0100
Total Loss Factors	
Customer less than 5,000 kW	1.0545
Customer greater than or equal to 5,000 kW	1.0145

Transformer Loss Allowance

Applicable to customers requiring a billing adjustment for transformer losses as the result of being metered on the primary side of a transformer. The following uniform values shall be applied to measured demand and energy to calculate transformer losses for voltages up to and including 50 kV (as metered on the primary side):

(a) 1.5% for transformer installations up to an individual bank capacity of 400 kVA,
(b) 1.0% for bank capacities over 400 kVA.

Alternatively, transformer losses may be determined from transformer test data, and measured demand and energy adjusted accordingly

For services which are not demand metered, an assumed demand of 50% of the transformer capacity will be used to calculate the loss allowance. Where several transformers are involved, the bank capacity is assumed to be the arithmetic sum of all transformer capacities

Hydro One Networks Inc.

TARIFF OF RATES AND CHARGES

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MISCELLANEOUS CHARGES

Specific Service Charges: Standard Amounts

Rate Code	Specific Service Charge - Standard Name	Calculation Method: 2006 Rate Handbook	Calculation Method: Standard Formula	Calculation Method: Other Formula	Calculation Method: Time and Materials
1	Temporary Service	$500			
2	Dispute Meter Test	$30 plus Measurement Canada fees			
3	Collection of account – no disconnection/load limiter	$30			
4	Collection/Disconnect/load limiter/reconnect (at meter) trip – regular hours	$65			
5	Collection/Disconnect/load limiter/reconnect (at meter) trip – after regular hours	$185			
6	Collection/Disconnect/load limiter/reconnect (at pole) trip – regular hours	$185			
7	Collection/Disconnect/load limiter/reconnect (at pole) trip – after regular hours	$415			
8	Account Set-up Charge	$30			
9	Arrears Certificate	$15			
10	NSF Cheque Charge	$15 + bank charges			
11	Easement Charge for Unregistered Rights	$15			
12	Late Payment Charge	1.5%/month			
13a	Retailer Services – Establishing Service Agreements (refer to Handbook for all charges)	$100/agreement/Retailer +$20/month/Retailer +$0.50/month/customer + other			
13b	Retailer Services – Other (includes Bill Ready for Retailers and Service Transactions Requests) as per the Handbook, Chapter 12	$0.30/month/customer + $0.25/request for request fee + $0.50/request for process fee			
14	Special Meter Reads	$30			
15	Billing Suspension and Terminations in Trailer Parks		$130		
16	Service Layout Fee – Basic		$405		
17	Service Layout Fee – Complex		$580		

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18	Crossing Application – Pipeline		$2,065		
19	Crossing Application – Water		$2,525		
20	Crossing Application – Railroad		$2,565		
21	Line Staking – per meter		$3.10		
22	Central Metering – New service < 45 kW		$115		
23	Conversion to Central Metering < 45 kW		$795		
24	Conversion to Central Metering > 45 kW		$680		
25	Tingle Voltage Test – In Excess of 4 Hours (per hour – average 2 additional hours)		$105		
26	Standby Administration Charge per month (interim)		$375		
27	Sentinel Lights Rental Rate per month – Mercury Vapor			$7.00	
28	Guaranteed Units from Jan 01/91 to Aug 01/91			$26.50 / month	
29	Guaranteed Units from Jan 01/87 to Dec 31/90			$23.50 / month	
30	Joint Use for Cable and Telecom companies per pole			$22.35	
31	Joint Use for LDCs per pole			$28.61	

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Hydro-Electric Commission of the Corporation of the Township of North Dundas
Effective Date: May 1, 2008

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

APPLICATION

The application of these rates and charges shall be in accordance with The Licence of The Distributor and any Codes, Guidelines or Orders of The Board, and amendments thereto as approved by The Board, which may be applicable to the administration of this schedule.
No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code, Guideline or Order of the Board, and amendments thereto as approved by the Board, or as specified herein
This schedule does not contain any rates and charges relating to the electricity commodity (e.g. the Regulated Price Plan).

EFFECTIVE DATES

DISTRIBUTION RATES - May 1, 2008 for all consumption or deemed consumption services used on or after that date.

MISCELLANEOUS CHARGES - May 1, 2008 for all charges billed to customers on or after that date.
RETAIL TRANSMISSION RATES - May 1, 2008 for all consumption or deemed consumption services used on or after that date.
LOSS FACTOR ADJUSTMENT – for all consumption or deemed consumption services billed following May 1, 2008 or later

SERVICE CLASSIFICATIONS

Residential
This classification refers to all service supplied to single-family dwelling units for domestic or household purpose. Multi-unit residential establishments such as apartment buildings supplied through one service (bulk metered) will normally be classified as General Service, but, at Hydro One's discretion, up to four residential units may be classified as residential. Where electricity service is provided to combined residential and business (including agricultural usage) and the wiring does not provide for separate metering, the classification shall be at the discretion of Hydro One based on such considerations as the estimated predominant consumption.
Further servicing details are available in the utility's Conditions of Service.

General Service
This classification refers to all service supplied to premises other than those classified as Residential or Lighting. Some General Service accounts are energy(kWh)-billed, and some are demand(kW)-billed. Further servicing details are available in the utility's Conditions of Service.

Unmetered Scattered Load
This classification refers to certain instances where connections can be provided without metering. These loads are generally small in size and consistent in magnitude of load. Hydro One reserves the right to review all cases and may require that a meter be installed at its sole discretion. Services that can be unmetered include cable TV amplifiers, telephone switching devices, phone booths, bus shelters, rail way crossing signals, traffic signals, and other small fixed loads.
Further servicing details are available in the utility's Conditions of Service (including in the "Unmetered Connections" section).

Hydro One Networks Inc.
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Hydro-Electric Commission of the Corporation of the Township of North Dundas
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Street Lighting

This classification refers to accounts for the distribution and supply of electrical energy for street lighting. Street lights are devices owned by or operated for the road authority and/or the municipal corporation. These street lights in fact belong to the Street Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Sentinel Lighting

This classification refers to accounts for a separate service to a sentinel light. These sentinel lights in fact belong to the Sentinel Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Urban Density Classification

Customers who meet the Urban Density Criteria of being in an area containing 3,000 or more customers with a line density of at least 60 customers per kilometre, will be mapped to an Urban customer classification.

Hydro One Networks Inc.
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MONTHLY RATES AND CHARGES

Residential - R1 North Dundas

Service Charge	$	12.97
Distribution Volumetric Rate	$ / kWh	0.0225
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0014
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0004)
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0047
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0046
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service Less Than 50 kW (Energy-Billed) - GSe North Dundas

Service Charge	$	17.71
Distribution Volumetric Rate	$ / kWh	0.0172
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0004
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0006)
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0035
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0032
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service 50 kW or Greater (Demand-Billed) - GSd North Dundas

Service Charge	$	21.31
Distribution Volumetric Rate	$ / kW	7.00
Regulatory Asset Recovery - Rider #2	$ / kW	0.11
Regulatory Asset Recovery - Rider #3	$ / kW	(0.22)
Retail Transmission Rate - Network Service Rate (4)	$ / kW	1.11
Retail Transmission Rate - Line and Transformation Connection Service Rate (4)	$ / kW	1.00
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

Hydro One Networks Inc.
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Unmetered, Scattered Load

Service Charge	$	10.81
Distribution Volumetric Rate	$ / kWh	0.0200
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0004
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0006)
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0035
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0032
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

(3) For energy-only metered customers, the billing determinant is the customer's metered energy consumption adjusted by the total loss factor as approved by the Board for Acquired LDC customers.
(4) For demand billed customers, appropriate loss factors must be applied to the applicable tariffs. Also the billing determinant for the Line and Transformation Connection Services rate is the customer's peak demand in the billing period. The billing determinant for the Network Services rate is: for non-interval-metered customers, the peak demand in the billing period, and for interval-metered customers, the peak demand between 7 AM and 7 PM local time on IESO business days

Customer-Supplied Transformation Allowance

Applicable to customers providing their own transformers

Demand-billed	$ / kW	0.60
Energy-billed	$ / kWh	0.0014

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Loss Factors

Residential	1.085
General Service Less Than 50 kW (Energy-Billed)	1.092
General Service 50 kW or Greater (Demand-Billed)	1.061
Unmetered Scattered Load	1.092

Transformer Loss Allowance

Applicable to customers requiring a billing adjustment for transformer losses as the result of being metered on the primary side of a transformer. The following uniform values shall be applied to measured demand and energy to calculate transformer losses for voltages up to and including 50 kV (as metered on the primary side):

(a) 1.5% for transformer installations up to an individual bank capacity of 400 kVA,
(b) 1.0% for bank capacities over 400 kVA.

Alternatively, transformer losses may be determined from transformer test data, and measured demand and energy adjusted accordingly

For services which are not demand metered, an assumed demand of 50% of the transformer capacity will be used to calculate the loss allowance. Where several transformers are involved, the bank capacity is assumed to be the arithmetic sum of all transformer capacities

Hydro One Networks Inc.
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MISCELLANEOUS CHARGES

Specific Service Charges: Standard Amounts

Rate Code	Specific Service Charge - Standard Name	Calculation Method			
		2006 Rate Handbook	Standard Formula	Other Formula	Time and Materials
1	Temporary Service	$500			
2	Dispute Meter Test	$30 plus Measurement Canada fees			
3	Collection of account – no disconnection/load limiter	$30			
4	Collection/Disconnect/load limiter/reconnect (at meter) trip – regular hours	$65			
5	Collection/Disconnect/load limiter/reconnect (at meter) trip – after regular hours	$185			
6	Collection/Disconnect/load limiter/reconnect (at pole) trip – regular hours	$185			
7	Collection/Disconnect/load limiter/reconnect (at pole) trip – after regular hours	$415			
8	Account Set-up Charge	$30			
9	Arrears Certificate	$15			
10	NSF Cheque Charge	$15 + bank charges			
11	Easement Charge for Unregistered Rights	$15			
12	Late Payment Charge	1.5%/month			
13a	Retailer Services – Establishing Service Agreements (refer to Handbook for all charges)	$100/agreement/Retailer +$20/month/Retailer +$0.50/month/customer + other			
13b	Retailer Services – Other (includes Bill Ready for Retailers and Service Transactions Requests) as per the Handbook, Chapter 12	$0.30/month/customer + $0.25/request for request fee + $0.50/request for process fee			
14	Special Meter Reads	$30			
15	Service Layout Fee – Basic		$495		
16	Service Layout Fee – Complex		$690		
17	Crossing Application – Pipeline		$2,445		
18	Crossing Application – Water		$3,045		
19	Crossing Application – Railroad		$2,945		
20	Line Staking – per meter		$3.70		
21	Central Metering – New service < 45 kW		$115		
22	Conversion to Central Metering < 45 kW		$915		
23	Conversion to Central Metering > 45 kW		$800		
24	Tingle Voltage Test – In Excess of 4 Hours (per hour – average 2 additional hours)		$125		
25	Standby Administration Charge per month		$440		
26	Sentinel Lights Rental Rate per month			$7.10	
27	Sentinel Pole Rental Rate per month			$4.15	
28	Joint Use for Cable and Telecom companies per pole			$22.35	
29	Joint Use for LDCs per pole			$28.61	

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APPLICATION

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No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code, Guideline or Order of the Board, and amendments thereto as approved by the Board, or as specified herein
This schedule does not contain any rates and charges relating to the electricity commodity (e.g. the Regulated Price Plan).

EFFECTIVE DATES

DISTRIBUTION RATES - May 1, 2007 for all consumption or deemed consumption services used on or after that date.

MISCELLANEOUS CHARGES - May 1, 2007 for all charges billed to customers on or after that date.
RETAIL TRANSMISSION RATES - May 1, 2007 for all consumption or deemed consumption services used on or after that date.
LOSS FACTOR ADJUSTMENT – May 1, 2007

SERVICE CLASSIFICATIONS

Residential
This classification (note 1) refers to all service supplied to single-family dwelling units for domestic or household purpose. Multi-unit residential establishments such as apartment buildings supplied through one service (bulk metered) will normally be classified as General Service, but, at Hydro One’s discretion, up to four residential units may be classified as residential. Where electricity service is provided to combined residential and business (including agricultural usage) and the wiring does not provide for separate metering, the classification shall be at the discretion of Hydro One based on such considerations as the estimated predominant consumption.
Further servicing details are available in the utility’s Conditions of Service.

General Service
This classification (note 1) refers to all service supplied to premises other than those classified as Residential or Lighting. Some General Service accounts are energy(kWh)-billed, and some are demand(kW)-billed. Further servicing details are available in the utility’s Conditions of Service. Also, see note 2.

Unmetered Scattered Load
This classification refers to certain instances where connections can be provided without metering. These loads are generally small in size and consistent in magnitude of load. Hydro One reserves the right to review all cases and may require that a meter be installed at its sole discretion. Services that can be unmetered include cable TV amplifiers, telephone switching devices, phone booths, bus shelters, rail way crossing signals, traffic signals, and other small fixed loads.
Further servicing details are available in the utility’s Conditions of Service (including in the "Unmetered Connections" section).

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Street Lighting

This classification refers to accounts for the distribution and supply of electrical energy for street lighting. Street lights are devices owned by or operated for the road authority and/or the municipal corporation. These street lights in fact belong to the Street Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Sentinel Lighting

This classification refers to accounts for a separate service to a sentinel light. These sentinel lights in fact belong to the Sentinel Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Interim Demand-Side Management Time-of-Use

This is potentially applicable to Demand-billed General Service accounts. See Note 2 below.

Note (1): Classification descriptions are paraphrases from the document "Hydro One Networks Inc. - Distribution Customers Conditions of Service - August 2004"
Note (2):

Interim Demand-Side Management Time-of-Use Rates: demand charges will be based on demand during the on-peak periods.
Criteria: Customers' electricity consumption (kW) in the off-peak period is at least twice the electricity consumption (kW) during the on-peak period.
Definition of Time Periods: The on-peak hours will be between 0700 hours to 1900 hours Eastern Standard Time during the winter (standard time) on IESO business days and 0600 hours to 1800 hours Eastern Standard Time during the summer (daylight savings time) on IESO business days. The off-peak period constitutes all of the remaining hours.

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MONTHLY RATES AND CHARGES

Residential

Service Charge	$	11.17
Distribution Volumetric Rate	$ / kWh	0.0097
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0055
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0014
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0055
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0047
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service - Energy Billed (less than 50 kW)

Service Charge	$	13.52
Distribution Volumetric Rate	$ / kWh	0.0083
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0016
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0004
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0050
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0043
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service - Demand Billed (50 kW or greater)

Service Charge	$	13.52
Distribution Volumetric Rate	$ / kW	2.42
Regulatory Asset Recovery - Rider #1	$ / kW	0.52
Regulatory Asset Recovery - Rider #2	$ / kW	0.11
Retail Transmission Rate - Network Service Rate (4)	$ / kW	1.94
Retail Transmission Rate - Line and Transformation Connection Service Rate (4)	$ / kW	1.61
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

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Unmetered, Scattered Load

Service Charge	$	6.29
Distribution Volumetric Rate	$ / kWh	0.0083
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0016
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0004
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0050
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0043
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

(3) For energy-only metered customers, the billing determinant is the customer's metered energy consumption adjusted by the total loss factor as approved by the Board for Acquired LDC customers.
(4) For demand billed customers, appropriate loss factors must be applied to the applicable tariffs. Also the billing determinant for the Line and Transformation Connection Services rate is the customer's peak demand in the billing period. The billing determinant for the Network Services rate is: for non-interval-metered customers, the peak demand in the billing period, and for interval-metered customers, the peak demand between 7 AM and 7 PM local time on IESO business days

Interim Demand-Side Management Time-of-Use

See the "Service Classifications" section of this schedule.

Customer-Supplied Transformation Allowance

Applicable to demand-billed customers providing their own transformers
Primary Voltage under 50 kV (per kW)

Single Phase	$ / kW	0.20
Three Phase	$ / kW	0.60

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Loss Factors

Supply Facilities Loss Factor	1.0045
Distribution Loss Factors	
Customer less than 5,000 kW	1.0500
Customer greater than or equal to 5,000 kW	1.0100
Total Loss Factors	
Customer less than 5,000 kW	1.0545
Customer greater than or equal to 5,000 kW	1.0145

Transformer Loss Allowance

Applicable to customers requiring a billing adjustment for transformer losses as the result of being metered on the primary side of a transformer. The following uniform values shall be applied to measured demand and energy to calculate transformer losses for voltages up to and including 50 kV (as metered on the primary side):

(a) 1.5% for transformer installations up to an individual bank capacity of 400 kVA,
(b) 1.0% for bank capacities over 400 kVA.

Alternatively, transformer losses may be determined from transformer test data, and measured demand and energy adjusted accordingly

For services which are not demand metered, an assumed demand of 50% of the transformer capacity will be used to calculate the loss allowance. Where several transformers are involved, the bank capacity is assumed to be the arithmetic sum of all transformer capacities

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MISCELLANEOUS CHARGES

Specific Service Charges: Standard Amounts

Rate Code	Specific Service Charge - Standard Name	Calculation Method			
		2006 Rate Handbook	Standard Formula	Other Formula	Time and Materials
1	Temporary Service	$500			
2	Dispute Meter Test	$30 plus Measurement Canada fees			
3	Collection of account – no disconnection/load limiter	$30			
4	Collection/Disconnect/load limiter/reconnect (at meter) trip – regular hours	$65			
5	Collection/Disconnect/load limiter/reconnect (at meter) trip – after regular hours	$185			
6	Collection/Disconnect/load limiter/reconnect (at pole) trip – regular hours	$185			
7	Collection/Disconnect/load limiter/reconnect (at pole) trip – after regular hours	$415			
8	Account Set-up Charge	$30			
9	Arrears Certificate	$15			
10	NSF Cheque Charge	$15 + bank charges			
11	Easement Charge for Unregistered Rights	$15			
12	Late Payment Charge	1.5%/month			
13a	Retailer Services – Establishing Service Agreements (refer to Handbook for all charges)	$100/agreement/Retailer +$20/month/Retailer +$0.50/month/customer + other			
13b	Retailer Services – Other (includes Bill Ready for Retailers and Service Transactions Requests) as per the Handbook, Chapter 12	$0.30/month/customer + $0.25/request for request fee + $0.50/request for process fee			
14	Special Meter Reads	$30			
15	Billing Suspension and Terminations in Trailer Parks		$130		
16	Service Layout Fee – Basic		$405		
17	Service Layout Fee – Complex		$580		

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18	Crossing Application – Pipeline		$2,065		
19	Crossing Application – Water		$2,525		
20	Crossing Application – Railroad		$2,565		
21	Line Staking – per meter		$3.10		
22	Central Metering – New service < 45 kW		$115		
23	Conversion to Central Metering < 45 kW		$795		
24	Conversion to Central Metering > 45 kW		$680		
25	Tingle Voltage Test – In Excess of 4 Hours (per hour – average 2 additional hours)		$105		
26	Standby Administration Charge per month (interim)		$375		
27	Sentinel Lights Rental Rate per month – Mercury Vapor			$7.00	
28	Guaranteed Units from Jan 01/91 to Aug 01/91			$26.50 / month	
29	Guaranteed Units from Jan 01/87 to Dec 31/90			$23.50 / month	
30	Joint Use for Cable and Telecom companies per pole			$22.35	
31	Joint Use for LDCs per pole			$28.61	

Hydro One Networks Inc.
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APPLICATION

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This schedule does not contain any rates and charges relating to the electricity commodity (e.g. the Regulated Price Plan).

EFFECTIVE DATES

DISTRIBUTION RATES - May 1, 2008 for all consumption or deemed consumption services used on or after that date.

MISCELLANEOUS CHARGES - May 1, 2008 for all charges billed to customers on or after that date.
RETAIL TRANSMISSION RATES - May 1, 2008 for all consumption or deemed consumption services used on or after that date.
LOSS FACTOR ADJUSTMENT – for all consumption or deemed consumption services billed following May 1, 2008 or later

SERVICE CLASSIFICATIONS

Residential
This classification refers to all service supplied to single-family dwelling units for domestic or household purpose. Multi-unit residential establishments such as apartment buildings supplied through one service (bulk metered) will normally be classified as General Service, but, at Hydro One's discretion, up to four residential units may be classified as residential. Where electricity service is provided to combined residential and business (including agricultural usage) and the wiring does not provide for separate metering, the classification shall be at the discretion of Hydro One based on such considerations as the estimated predominant consumption.
Further servicing details are available in the utility's Conditions of Service.

General Service
This classification refers to all service supplied to premises other than those classified as Residential or Lighting. Some General Service accounts are energy(kWh)-billed, and some are demand(kW)-billed. Further servicing details are available in the utility's Conditions of Service.

Unmetered Scattered Load
This classification refers to certain instances where connections can be provided without metering. These loads are generally small in size and consistent in magnitude of load. Hydro One reserves the right to review all cases and may require that a meter be installed at its sole discretion. Services that can be unmetered include cable TV amplifiers, telephone switching devices, phone booths, bus shelters, rail way crossing signals, traffic signals, and other small fixed loads.
Further servicing details are available in the utility's Conditions of Service (including in the "Unmetered Connections" section).

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Street Lighting

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Sentinel Lighting

This classification refers to accounts for a separate service to a sentinel light. These sentinel lights in fact belong to the Sentinel Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Urban Density Classification

Customers who meet the Urban Density Criteria of being in an area containing 3,000 or more customers with a line density of at least 60 customers per kilometre, will be mapped to an Urban customer classification.

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MONTHLY RATES AND CHARGES

Residential - R1 North Glengarry

Service Charge	$	9.83
Distribution Volumetric Rate	$ / kWh	0.0220
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0022
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0004)
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0047
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0046
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service Less Than 50 kW (Energy-Billed) - GSe North Glengarry

Service Charge	$	20.66
Distribution Volumetric Rate	$ / kWh	0.0195
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0012
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0006)
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0035
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0032
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service 50 kW or Greater (Demand-Billed) - GSd North Glengarry

Service Charge	$	24.26
Distribution Volumetric Rate	$ / kW	7.70
Regulatory Asset Recovery - Rider #2	$ / kW	0.39
Regulatory Asset Recovery - Rider #3	$ / kW	(0.22)
Retail Transmission Rate - Network Service Rate (4)	$ / kW	1.11
Retail Transmission Rate - Line and Transformation Connection Service Rate (4)	$ / kW	1.00
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

Hydro One Networks Inc.
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Unmetered, Scattered Load

Service Charge	$	12.28
Distribution Volumetric Rate	$ / kWh	0.0200
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0012
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0006)
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0035
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0032
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

(3) For energy-only metered customers, the billing determinant is the customer's metered energy consumption adjusted by the total loss factor as approved by the Board for Acquired LDC customers.
(4) For demand billed customers, appropriate loss factors must be applied to the applicable tariffs. Also the billing determinant for the Line and Transformation Connection Services rate is the customer's peak demand in the billing period. The billing determinant for the Network Services rate is: for non-interval-metered customers, the peak demand in the billing period, and for interval-metered customers, the peak demand between 7 AM and 7 PM local time on IESO business days

Customer-Supplied Transformation Allowance

Applicable to customers providing their own transformers

Demand-billed	$ / kW	0.60
Energy-billed	$ / kWh	0.0014

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Loss Factors

Residential	1.085
General Service Less Than 50 kW (Energy-Billed)	1.092
General Service 50 kW or Greater (Demand-Billed)	1.061
Unmetered Scattered Load	1.092

Transformer Loss Allowance

Applicable to customers requiring a billing adjustment for transformer losses as the result of being metered on the primary side of a transformer. The following uniform values shall be applied to measured demand and energy to calculate transformer losses for voltages up to and including 50 kV (as metered on the primary side):

(a) 1.5% for transformer installations up to an individual bank capacity of 400 kVA,
(b) 1.0% for bank capacities over 400 kVA.

Alternatively, transformer losses may be determined from transformer test data, and measured demand and energy adjusted accordingly

For services which are not demand metered, an assumed demand of 50% of the transformer capacity will be used to calculate the loss allowance. Where several transformers are involved, the bank capacity is assumed to be the arithmetic sum of all transformer capacities

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MISCELLANEOUS CHARGES

Specific Service Charges: Standard Amounts

Rate Code	Specific Service Charge - Standard Name	Calculation Method			
		2006 Rate Handbook	Standard Formula	Other Formula	Time and Materials
1	Temporary Service	$500			
2	Dispute Meter Test	$30 plus Measurement Canada fees			
3	Collection of account – no disconnection/load limiter	$30			
4	Collection/Disconnect/load limiter/reconnect (at meter) trip – regular hours	$65			
5	Collection/Disconnect/load limiter/reconnect (at meter) trip – after regular hours	$185			
6	Collection/Disconnect/load limiter/reconnect (at pole) trip – regular hours	$185			
7	Collection/Disconnect/load limiter/reconnect (at pole) trip – after regular hours	$415			
8	Account Set-up Charge	$30			
9	Arrears Certificate	$15			
10	NSF Cheque Charge	$15 + bank charges			
11	Easement Charge for Unregistered Rights	$15			
12	Late Payment Charge	1.5%/month			
13a	Retailer Services – Establishing Service Agreements (refer to Handbook for all charges)	$100/agreement/Retailer +$20/month/Retailer +$0.50/month/customer + other			
13b	Retailer Services – Other (includes Bill Ready for Retailers and Service Transactions Requests) as per the Handbook, Chapter 12	$0.30/month/customer + $0.25/request for request fee + $0.50/request for process fee			
14	Special Meter Reads	$30			
15	Service Layout Fee – Basic		$495		
16	Service Layout Fee – Complex		$690		
17	Crossing Application – Pipeline		$2,445		
18	Crossing Application – Water		$3,045		
19	Crossing Application – Railroad		$2,945		
20	Line Staking – per meter		$3.70		
21	Central Metering – New service < 45 kW		$115		
22	Conversion to Central Metering < 45 kW		$915		
23	Conversion to Central Metering > 45 kW		$800		
24	Tingle Voltage Test – In Excess of 4 Hours (per hour – average 2 additional hours)		$125		
25	Standby Administration Charge per month		$440		
26	Sentinel Lights Rental Rate per month			$7.10	
27	Sentinel Pole Rental Rate per month			$4.15	
28	Joint Use for Cable and Telecom companies per pole			$22.35	
29	Joint Use for LDCs per pole			$28.61	

Hydro One Networks Inc.
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North Glengarry Public Utilities Commission
Effective Date: May 1, 2007

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

APPLICATION

The application of these rates and charges shall be in accordance with The Licence of The Distributor and any Codes, Guidelines or Orders of The Board, and amendments thereto as approved by The Board, which may be applicable to the administration of this schedule.
No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code, Guideline or Order of the Board, and amendments thereto as approved by the Board, or as specified herein
This schedule does not contain any rates and charges relating to the electricity commodity (e.g. the Regulated Price Plan).

EFFECTIVE DATES

DISTRIBUTION RATES - May 1, 2007 for all consumption or deemed consumption services used on or after that date.

MISCELLANEOUS CHARGES - May 1, 2007 for all charges billed to customers on or after that date.
RETAIL TRANSMISSION RATES - May 1, 2007 for all consumption or deemed consumption services used on or after that date.
LOSS FACTOR ADJUSTMENT – May 1, 2007

SERVICE CLASSIFICATIONS

Residential
This classification (note 1) refers to all service supplied to single-family dwelling units for domestic or household purpose. Multi-unit residential establishments such as apartment buildings supplied through one service (bulk metered) will normally be classified as General Service, but, at Hydro One's discretion, up to four residential units may be classified as residential. Where electricity service is provided to combined residential and business (including agricultural usage) and the wiring does not provide for separate metering, the classification shall be at the discretion of Hydro One based on such considerations as the estimated predominant consumption.
Further servicing details are available in the utility's Conditions of Service.

General Service
This classification (note 1) refers to all service supplied to premises other than those classified as Residential or Lighting. Some General Service accounts are energy(kWh)-billed, and some are demand(kW)-billed. Further servicing details are available in the utility's Conditions of Service. Also, see note 2.

Unmetered Scattered Load
This classification refers to certain instances where connections can be provided without metering. These loads are generally small in size and consistent in magnitude of load. Hydro One reserves the right to review all cases and may require that a meter be installed at its sole discretion. Services that can be unmetered include cable TV amplifiers, telephone switching devices, phone booths, bus shelters, rail way crossing signals, traffic signals, and other small fixed loads.
Further servicing details are available in the utility's Conditions of Service (including in the "Unmetered Connections" section).

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Street Lighting

This classification refers to accounts for the distribution and supply of electrical energy for street lighting. Street lights are devices owned by or operated for the road authority and/or the municipal corporation. These street lights in fact belong to the Street Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility’s Conditions of Service.

Sentinel Lighting

This classification refers to accounts for a separate service to a sentinel light. These sentinel lights in fact belong to the Sentinel Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility’s Conditions of Service.

Interim Demand-Side Management Time-of-Use

This is potentially applicable to Demand-billed General Service accounts. See Note 2 below.

Note (1): Classification descriptions are paraphrases from the document "Hydro One Networks Inc. - Distribution Customers Conditions of Service - August 2004"

Note (2):

Interim Demand-Side Management Time-of-Use Rates: demand charges will be based on demand during the on-peak periods.

Criteria: Customers' electricity consumption (kW) in the off-peak period is at least twice the electricity consumption (kW) during the on-peak period.

Definition of Time Periods: The on-peak hours will be between 0700 hours to 1900 hours Eastern Standard Time during the winter (standard time) on IESO business days and 0600 hours to 1800 hours Eastern Standard Time during the summer (daylight savings time) on IESO business days. The off-peak period constitutes all of the remaining hours.

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MONTHLY RATES AND CHARGES

Residential

Service Charge	$	7.74
Distribution Volumetric Rate	$ / kWh	0.0102
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0052
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0022
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0055
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0047
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service - Energy Billed (less than 50 kW)

Service Charge	$	17.72
Distribution Volumetric Rate	$ / kWh	0.0090
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0021
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0012
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0050
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0043
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service - Demand Billed (50 kW or greater)

Service Charge	$	17.72
Distribution Volumetric Rate	$ / kW	2.82
Regulatory Asset Recovery - Rider #1	$ / kW	0.69
Regulatory Asset Recovery - Rider #2	$ / kW	0.39
Retail Transmission Rate - Network Service Rate (4)	$ / kW	1.94
Retail Transmission Rate - Line and Transformation Connection Service Rate (4)	$ / kW	1.61
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

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Unmetered, Scattered Load

Service Charge	$	8.40
Distribution Volumetric Rate	$ / kWh	0.0090
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0021
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0012
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0050
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0043
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

(3) For energy-only metered customers, the billing determinant is the customer's metered energy consumption adjusted by the total loss factor as approved by the Board for Acquired LDC customers.
(4) For demand billed customers, appropriate loss factors must be applied to the applicable tariffs. Also the billing determinant for the Line and Transformation Connection Services rate is the customer's peak demand in the billing period. The billing determinant for the Network Services rate is: for non-interval-metered customers, the peak demand in the billing period, and for interval-metered customers, the peak demand between 7 AM and 7 PM local time on IESO business days

Interim Demand-Side Management Time-of-Use

See the "Service Classifications" section of this schedule.

Customer-Supplied Transformation Allowance

Applicable to demand-billed customers providing their own transformers
Primary Voltage under 50 kV (per kW)

Single Phase	$ / kW	0.20
Three Phase	$ / kW	0.60

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Loss Factors

Supply Facilities Loss Factor	1.0045
Distribution Loss Factors	
Customer less than 5,000 kW	1.0500
Customer greater than or equal to 5,000 kW	1.0100
Total Loss Factors	
Customer less than 5,000 kW	1.0545
Customer greater than or equal to 5,000 kW	1.0145

Transformer Loss Allowance

Applicable to customers requiring a billing adjustment for transformer losses as the result of being metered on the primary side of a transformer. The following uniform values shall be applied to measured demand and energy to calculate transformer losses for voltages up to and including 50 kV (as metered on the primary side):

(a) 1.5% for transformer installations up to an individual bank capacity of 400 kVA,
(b) 1.0% for bank capacities over 400 kVA.

Alternatively, transformer losses may be determined from transformer test data, and measured demand and energy adjusted accordingly

For services which are not demand metered, an assumed demand of 50% of the transformer capacity will be used to calculate the loss allowance. Where several transformers are involved, the bank capacity is assumed to be the arithmetic sum of all transformer capacities

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MISCELLANEOUS CHARGES

Specific Service Charges: Standard Amounts

Rate Code	Specific Service Charge - Standard Name	Calculation Method			
		2006 Rate Handbook	Standard Formula	Other Formula	Time and Materials
1	Temporary Service	$500			
2	Dispute Meter Test	$30 plus Measurement Canada fees			
3	Collection of account – no disconnection/load limiter	$30			
4	Collection/Disconnect/load limiter/reconnect (at meter) trip – regular hours	$65			
5	Collection/Disconnect/load limiter/reconnect (at meter) trip – after regular hours	$185			
6	Collection/Disconnect/load limiter/reconnect (at pole) trip – regular hours	$185			
7	Collection/Disconnect/load limiter/reconnect (at pole) trip – after regular hours	$415			
8	Account Set-up Charge	$30			
9	Arrears Certificate	$15			
10	NSF Cheque Charge	$15 + bank charges			
11	Easement Charge for Unregistered Rights	$15			
12	Late Payment Charge	1.5%/month			
13a	Retailer Services – Establishing Service Agreements (refer to Handbook for all charges)	$100/agreement/Retailer +$20/month/Retailer +$0.50/month/customer + other			
13b	Retailer Services – Other (includes Bill Ready for Retailers and Service Transactions Requests) as per the Handbook, Chapter 12	$0.30/month/customer + $0.25/request for request fee + $0.50/request for process fee			
14	Special Meter Reads	$30			
15	Billing Suspension and Terminations in Trailer Parks		$130		
16	Service Layout Fee – Basic		$405		
17	Service Layout Fee – Complex		$580		

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18	Crossing Application – Pipeline		$2,065		
19	Crossing Application – Water		$2,525		
20	Crossing Application – Railroad		$2,565		
21	Line Staking – per meter		$3.10		
22	Central Metering – New service < 45 kW		$115		
23	Conversion to Central Metering < 45 kW		$795		
24	Conversion to Central Metering > 45 kW		$680		
25	Tingle Voltage Test – In Excess of 4 Hours (per hour – average 2 additional hours)		$105		
26	Standby Administration Charge per month (interim)		$375		
27	Sentinel Lights Rental Rate per month – Mercury Vapor			$7.00	
28	Guaranteed Units from Jan 01/91 to Aug 01/91			$26.50 / month	
29	Guaranteed Units from Jan 01/87 to Dec 31/90			$23.50 / month	
30	Joint Use for Cable and Telecom companies per pole			$22.35	
31	Joint Use for LDCs per pole			$28.61	

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APPLICATION

The application of these rates and charges shall be in accordance with The Licence of The Distributor and any Codes, Guidelines or Orders of The Board, and amendments thereto as approved by The Board, which may be applicable to the administration of this schedule.
No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code, Guideline or Order of the Board, and amendments thereto as approved by the Board, or as specified herein
This schedule does not contain any rates and charges relating to the electricity commodity (e.g. the Regulated Price Plan).

EFFECTIVE DATES

DISTRIBUTION RATES - May 1, 2008 for all consumption or deemed consumption services used on or after that date.

MISCELLANEOUS CHARGES - May 1, 2008 for all charges billed to customers on or after that date.
RETAIL TRANSMISSION RATES - May 1, 2008 for all consumption or deemed consumption services used on or after that date.
LOSS FACTOR ADJUSTMENT – for all consumption or deemed consumption services billed following May 1, 2008 or later

SERVICE CLASSIFICATIONS

Residential
This classification refers to all service supplied to single-family dwelling units for domestic or household purpose. Multi-unit residential establishments such as apartment buildings supplied through one service (bulk metered) will normally be classified as General Service, but, at Hydro One's discretion, up to four residential units may be classified as residential. Where electricity service is provided to combined residential and business (including agricultural usage) and the wiring does not provide for separate metering, the classification shall be at the discretion of Hydro One based on such considerations as the estimated predominant consumption.
Further servicing details are available in the utility's Conditions of Service.

General Service
This classification refers to all service supplied to premises other than those classified as Residential or Lighting. Some General Service accounts are energy(kWh)-billed, and some are demand(kW)-billed. Further servicing details are available in the utility's Conditions of Service.

Unmetered Scattered Load
This classification refers to certain instances where connections can be provided without metering. These loads are generally small in size and consistent in magnitude of load. Hydro One reserves the right to review all cases and may require that a meter be installed at its sole discretion. Services that can be unmetered include cable TV amplifiers, telephone switching devices, phone booths, bus shelters, rail way crossing signals, traffic signals, and other small fixed loads.
Further servicing details are available in the utility's Conditions of Service (including in the "Unmetered Connections" section).

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Street Lighting

This classification refers to accounts for the distribution and supply of electrical energy for street lighting. Street lights are devices owned by or operated for the road authority and/or the municipal corporation. These street lights in fact belong to the Street Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Sentinel Lighting

This classification refers to accounts for a separate service to a sentinel light. These sentinel lights in fact belong to the Sentinel Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Urban Density Classification

Customers who meet the Urban Density Criteria of being in an area containing 3,000 or more customers with a line density of at least 60 customers per kilometre, will be mapped to an Urban customer classification.

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MONTHLY RATES AND CHARGES

Residential - R1 North Grenville

Service Charge	$	15.16
Distribution Volumetric Rate	$ / kWh	0.0271
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0016
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0004)
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0047
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0046
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service Less Than 50 kW (Energy-Billed) - GSe North Grenville

Service Charge	$	22.99
Distribution Volumetric Rate	$ / kWh	0.0279
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0008
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0006)
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0035
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0032
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service 50 kW or Greater (Demand-Billed) - GSd North Grenville

Service Charge	$	26.58
Distribution Volumetric Rate	$ / kW	9.22
Regulatory Asset Recovery - Rider #2	$ / kW	0.25
Regulatory Asset Recovery - Rider #3	$ / kW	(0.22)
Retail Transmission Rate - Network Service Rate (4)	$ / kW	1.11
Retail Transmission Rate - Line and Transformation Connection Service Rate (4)	$ / kW	1.00
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

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Unmetered, Scattered Load

Service Charge	$	12.94
Distribution Volumetric Rate	$ / kWh	0.0200
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0008
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0006)
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0035
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0032
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

(3) For energy-only metered customers, the billing determinant is the customer’s metered energy consumption adjusted by the total loss factor as approved by the Board for Acquired LDC customers.
(4) For demand billed customers, appropriate loss factors must be applied to the applicable tariffs. Also the billing determinant for the Line and Transformation Connection Services rate is the customer’s peak demand in the billing period. The billing determinant for the Network Services rate is: for non-interval-metered customers, the peak demand in the billing period, and for interval-metered customers, the peak demand between 7 AM and 7 PM local time on IESO business days

Customer-Supplied Transformation Allowance

Applicable to customers providing their own transformers

Demand-billed	$ / kW	0.60
Energy-billed	$ / kWh	0.0014

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Loss Factors

Residential	1.085
General Service Less Than 50 kW (Energy-Billed)	1.092
General Service 50 kW or Greater (Demand-Billed)	1.061
Unmetered Scattered Load	1.092

Transformer Loss Allowance

Applicable to customers requiring a billing adjustment for transformer losses as the result of being metered on the primary side of a transformer. The following uniform values shall be applied to measured demand and energy to calculate transformer losses for voltages up to and including 50 kV (as metered on the primary side):

(a) 1.5% for transformer installations up to an individual bank capacity of 400 kVA,
(b) 1.0% for bank capacities over 400 kVA.

Alternatively, transformer losses may be determined from transformer test data, and measured demand and energy adjusted accordingly

For services which are not demand metered, an assumed demand of 50% of the transformer capacity will be used to calculate the loss allowance. Where several transformers are involved, the bank capacity is assumed to be the arithmetic sum of all transformer capacities

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MISCELLANEOUS CHARGES

Specific Service Charges: Standard Amounts

Rate Code	Specific Service Charge - Standard Name	Calculation Method			
		2006 Rate Handbook	Standard Formula	Other Formula	Time and Materials
1	Temporary Service	$500			
2	Dispute Meter Test	$30 plus Measurement Canada fees			
3	Collection of account – no disconnection/load limiter	$30			
4	Collection/Disconnect/load limiter/reconnect (at meter) trip – regular hours	$65			
5	Collection/Disconnect/load limiter/reconnect (at meter) trip – after regular hours	$185			
6	Collection/Disconnect/load limiter/reconnect (at pole) trip – regular hours	$185			
7	Collection/Disconnect/load limiter/reconnect (at pole) trip – after regular hours	$415			
8	Account Set-up Charge	$30			
9	Arrears Certificate	$15			
10	NSF Cheque Charge	$15 + bank charges			
11	Easement Charge for Unregistered Rights	$15			
12	Late Payment Charge	1.5%/month			
13a	Retailer Services – Establishing Service Agreements (refer to Handbook for all charges)	$100/agreement/Retailer +$20/month/Retailer +$0.50/month/customer + other			
13b	Retailer Services – Other (includes Bill Ready for Retailers and Service Transactions Requests) as per the Handbook, Chapter 12	$0.30/month/customer + $0.25/request for request fee + $0.50/request for process fee			
14	Special Meter Reads	$30			
15	Service Layout Fee – Basic		$495		
16	Service Layout Fee – Complex		$690		
17	Crossing Application – Pipeline		$2,445		
18	Crossing Application – Water		$3,045		
19	Crossing Application – Railroad		$2,945		
20	Line Staking – per meter		$3.70		
21	Central Metering – New service < 45 kW		$115		
22	Conversion to Central Metering < 45 kW		$915		
23	Conversion to Central Metering > 45 kW		$800		
24	Tingle Voltage Test – In Excess of 4 Hours (per hour – average 2 additional hours)		$125		
25	Standby Administration Charge per month		$440		
26	Sentinel Lights Rental Rate per month			$7.10	
27	Sentinel Pole Rental Rate per month			$4.15	
28	Joint Use for Cable and Telecom companies per pole			$22.35	
29	Joint Use for LDCs per pole			$28.61	

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
North Grenville Hydro Electric Commission
Effective Date: May 1, 2007

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

APPLICATION

The application of these rates and charges shall be in accordance with The Licence of The Distributor and any Codes, Guidelines or Orders of The Board, and amendments thereto as approved by The Board, which may be applicable to the administration of this schedule.
No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code, Guideline or Order of the Board, and amendments thereto as approved by the Board, or as specified herein
This schedule does not contain any rates and charges relating to the electricity commodity (e.g. the Regulated Price Plan).

EFFECTIVE DATES

DISTRIBUTION RATES - May 1, 2007 for all consumption or deemed consumption services used on or after that date.

MISCELLANEOUS CHARGES - May 1, 2007 for all charges billed to customers on or after that date.
RETAIL TRANSMISSION RATES - May 1, 2007 for all consumption or deemed consumption services used on or after that date.
LOSS FACTOR ADJUSTMENT – May 1, 2007

SERVICE CLASSIFICATIONS

Residential
This classification (note 1) refers to all service supplied to single-family dwelling units for domestic or household purpose. Multi-unit residential establishments such as apartment buildings supplied through one service (bulk metered) will normally be classified as General Service, but, at Hydro One's discretion, up to four residential units may be classified as residential. Where electricity service is provided to combined residential and business (including agricultural usage) and the wiring does not provide for separate metering, the classification shall be at the discretion of Hydro One based on such considerations as the estimated predominant consumption.
Further servicing details are available in the utility's Conditions of Service.

General Service
This classification (note 1) refers to all service supplied to premises other than those classified as Residential or Lighting. Some General Service accounts are energy(kWh)-billed, and some are demand(kW)-billed. Further servicing details are available in the utility's Conditions of Service. Also, see note 2.

Unmetered Scattered Load
This classification refers to certain instances where connections can be provided without metering. These loads are generally small in size and consistent in magnitude of load. Hydro One reserves the right to review all cases and may require that a meter be installed at its sole discretion. Services that can be unmetered include cable TV amplifiers, telephone switching devices, phone booths, bus shelters, rail way crossing signals, traffic signals, and other small fixed loads.
Further servicing details are available in the utility's Conditions of Service (including in the "Unmetered Connections" section).

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
North Grenville Hydro Electric Commission
Effective Date: May 1, 2007

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

Street Lighting

This classification refers to accounts for the distribution and supply of electrical energy for street lighting. Street lights are devices owned by or operated for the road authority and/or the municipal corporation. These street lights in fact belong to the Street Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility’s Conditions of Service.

Sentinel Lighting

This classification refers to accounts for a separate service to a sentinel light. These sentinel lights in fact belong to the Sentinel Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility’s Conditions of Service.

Interim Demand-Side Management Time-of-Use

This is potentially applicable to Demand-billed General Service accounts. See Note 2 below.

Note (1): Classification descriptions are paraphrases from the document "Hydro One Networks Inc. - Distribution Customers Conditions of Service - August 2004"

Note (2):

Interim Demand-Side Management Time-of-Use Rates: demand charges will be based on demand during the on-peak periods.

Criteria: Customers' electricity consumption (kW) in the off-peak period is at least twice the electricity consumption (kW) during the on-peak period.

Definition of Time Periods: The on-peak hours will be between 0700 hours to 1900 hours Eastern Standard Time during the winter (standard time) on IESO business days and 0600 hours to 1800 hours Eastern Standard Time during the summer (daylight savings time) on IESO business days. The off-peak period constitutes all of the remaining hours.

Hydro One Networks Inc.
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North Grenville Hydro Electric Commission
Effective Date: May 1, 2007

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MONTHLY RATES AND CHARGES

Residential

Service Charge	$	14.40
Distribution Volumetric Rate	$ / kWh	0.0165
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0037
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0016
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0055
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0047
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service - Energy Billed (less than 50 kW)

Service Charge	$	20.42
Distribution Volumetric Rate	$ / kWh	0.0171
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0014
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0008
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0050
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0043
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service - Demand Billed (50 kW or greater)

Service Charge	$	20.42
Distribution Volumetric Rate	$ / kW	5.41
Regulatory Asset Recovery - Rider #1	$ / kW	0.45
Regulatory Asset Recovery - Rider #2	$ / kW	0.25
Retail Transmission Rate - Network Service Rate (4)	$ / kW	1.94
Retail Transmission Rate - Line and Transformation Connection Service Rate (4)	$ / kW	1.61
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

Hydro One Networks Inc.
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Unmetered, Scattered Load

Service Charge	$	9.74
Distribution Volumetric Rate	$ / kWh	0.0171
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0014
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0008
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0050
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0043
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

(3) For energy-only metered customers, the billing determinant is the customer’s metered energy consumption adjusted by the total loss factor as approved by the Board for Acquired LDC customers.
(4) For demand billed customers, appropriate loss factors must be applied to the applicable tariffs. Also the billing determinant for the Line and Transformation Connection Services rate is the customer’s peak demand in the billing period. The billing determinant for the Network Services rate is: for non-interval-metered customers, the peak demand in the billing period, and for interval-metered customers, the peak demand between 7 AM and 7 PM local time on IESO business days

Interim Demand-Side Management Time-of-Use

See the "Service Classifications" section of this schedule.

Customer-Supplied Transformation Allowance

Applicable to demand-billed customers providing their own transformers
Primary Voltage under 50 kV (per kW)

Single Phase	$ / kW	0.20
Three Phase	$ / kW	0.60

Hydro One Networks Inc.
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Loss Factors

Supply Facilities Loss Factor	1.0045
Distribution Loss Factors	
Customer less than 5,000 kW	1.0500
Customer greater than or equal to 5,000 kW	1.0100
Total Loss Factors	
Customer less than 5,000 kW	1.0545
Customer greater than or equal to 5,000 kW	1.0145

Transformer Loss Allowance

Applicable to customers requiring a billing adjustment for transformer losses as the result of being metered on the primary side of a transformer. The following uniform values shall be applied to measured demand and energy to calculate transformer losses for voltages up to and including 50 kV (as metered on the primary side):

(a) 1.5% for transformer installations up to an individual bank capacity of 400 kVA,
(b) 1.0% for bank capacities over 400 kVA.

Alternatively, transformer losses may be determined from transformer test data, and measured demand and energy adjusted accordingly

For services which are not demand metered, an assumed demand of 50% of the transformer capacity will be used to calculate the loss allowance. Where several transformers are involved, the bank capacity is assumed to be the arithmetic sum of all transformer capacities

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
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Effective Date: May 1, 2007

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

MISCELLANEOUS CHARGES

Specific Service Charges: Standard Amounts

Rate Code	Specific Service Charge - Standard Name	Calculation Method			
		2006 Rate Handbook	Standard Formula	Other Formula	Time and Materials
1	Temporary Service	$500			
2	Dispute Meter Test	$30 plus Measurement Canada fees			
3	Collection of account – no disconnection/load limiter	$30			
4	Collection/Disconnect/load limiter/reconnect (at meter) trip – regular hours	$65			
5	Collection/Disconnect/load limiter/reconnect (at meter) trip – after regular hours	$185			
6	Collection/Disconnect/load limiter/reconnect (at pole) trip – regular hours	$185			
7	Collection/Disconnect/load limiter/reconnect (at pole) trip – after regular hours	$415			
8	Account Set-up Charge	$30			
9	Arrears Certificate	$15			
10	NSF Cheque Charge	$15 + bank charges			
11	Easement Charge for Unregistered Rights	$15			
12	Late Payment Charge	1.5%/month			
13a	Retailer Services – Establishing Service Agreements (refer to Handbook for all charges)	$100/agreement/Retailer +$20/month/Retailer +$0.50/month/customer + other			
13b	Retailer Services – Other (includes Bill Ready for Retailers and Service Transactions Requests) as per the Handbook, Chapter 12	$0.30/month/customer + $0.25/request for request fee + $0.50/request for process fee			
14	Special Meter Reads	$30			
15	Billing Suspension and Terminations in Trailer Parks		$130		
16	Service Layout Fee – Basic		$405		
17	Service Layout Fee – Complex		$580		

Hydro One Networks Inc.
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18	Crossing Application – Pipeline		$2,065		
19	Crossing Application – Water		$2,525		
20	Crossing Application – Railroad		$2,565		
21	Line Staking – per meter		$3.10		
22	Central Metering – New service < 45 kW		$115		
23	Conversion to Central Metering < 45 kW		$795		
24	Conversion to Central Metering > 45 kW		$680		
25	Tingle Voltage Test – In Excess of 4 Hours (per hour – average 2 additional hours)		$105		
26	Standby Administration Charge per month (interim)		$375		
27	Sentinel Lights Rental Rate per month – Mercury Vapor			$7.00	
28	Guaranteed Units from Jan 01/91 to Aug 01/91			$26.50 / month	
29	Guaranteed Units from Jan 01/87 to Dec 31/90			$23.50 / month	
30	Joint Use for Cable and Telecom companies per pole			$22.35	
31	Joint Use for LDCs per pole			$28.61	

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Public Utility Commission of the Town of North Perth
Effective Date: May 1, 2008

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

APPLICATION

The application of these rates and charges shall be in accordance with The Licence of The Distributor and any Codes, Guidelines or Orders of The Board, and amendments thereto as approved by The Board, which may be applicable to the administration of this schedule.
No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code, Guideline or Order of the Board, and amendments thereto as approved by the Board, or as specified herein
This schedule does not contain any rates and charges relating to the electricity commodity (e.g. the Regulated Price Plan).

EFFECTIVE DATES

DISTRIBUTION RATES - May 1, 2008 for all consumption or deemed consumption services used on or after that date.

MISCELLANEOUS CHARGES - May 1, 2008 for all charges billed to customers on or after that date.
RETAIL TRANSMISSION RATES - May 1, 2008 for all consumption or deemed consumption services used on or after that date.
LOSS FACTOR ADJUSTMENT – for all consumption or deemed consumption services billed following May 1, 2008 or later

SERVICE CLASSIFICATIONS

Residential
This classification refers to all service supplied to single-family dwelling units for domestic or household purpose. Multi-unit residential establishments such as apartment buildings supplied through one service (bulk metered) will normally be classified as General Service, but, at Hydro One's discretion, up to four residential units may be classified as residential. Where electricity service is provided to combined residential and business (including agricultural usage) and the wiring does not provide for separate metering, the classification shall be at the discretion of Hydro One based on such considerations as the estimated predominant consumption.
Further servicing details are available in the utility's Conditions of Service.

General Service
This classification refers to all service supplied to premises other than those classified as Residential or Lighting. Some General Service accounts are energy(kWh)-billed, and some are demand(kW)-billed. Further servicing details are available in the utility's Conditions of Service.

Unmetered Scattered Load
This classification refers to certain instances where connections can be provided without metering. These loads are generally small in size and consistent in magnitude of load. Hydro One reserves the right to review all cases and may require that a meter be installed at its sole discretion. Services that can be unmetered include cable TV amplifiers, telephone switching devices, phone booths, bus shelters, rail way crossing signals, traffic signals, and other small fixed loads.
Further servicing details are available in the utility's Conditions of Service (including in the "Unmetered Connections" section).

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Public Utility Commission of the Town of North Perth
Effective Date: May 1, 2008

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

Street Lighting

This classification refers to accounts for the distribution and supply of electrical energy for street lighting. Street lights are devices owned by or operated for the road authority and/or the municipal corporation. These street lights in fact belong to the Street Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Sentinel Lighting

This classification refers to accounts for a separate service to a sentinel light. These sentinel lights in fact belong to the Sentinel Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Urban Density Classification

Customers who meet the Urban Density Criteria of being in an area containing 3,000 or more customers with a line density of at least 60 customers per kilometre, will be mapped to an Urban customer classification.

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Public Utility Commission of the Town of North Perth
Effective Date: May 1, 2008

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MONTHLY RATES AND CHARGES

Residential - R1 North Perth

Service Charge	$	15.08
Distribution Volumetric Rate	$ / kWh	0.0240
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0016
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0004)
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0047
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0046
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service Less Than 50 kW (Energy-Billed) - GSe North Perth

Service Charge	$	29.71
Distribution Volumetric Rate	$ / kWh	0.0215
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0004
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0006)
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0035
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0032
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service 50 kW or Greater (Demand-Billed) - GSd North Perth

Service Charge	$	33.31
Distribution Volumetric Rate	$ / kW	7.70
Regulatory Asset Recovery - Rider #2	$ / kW	0.13
Regulatory Asset Recovery - Rider #3	$ / kW	(0.22)
Retail Transmission Rate - Network Service Rate (4)	$ / kW	1.11
Retail Transmission Rate - Line and Transformation Connection Service Rate (4)	$ / kW	1.00
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

Hydro One Networks Inc.
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Effective Date: May 1, 2008

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Unmetered, Scattered Load

Service Charge	$	16.80
Distribution Volumetric Rate	$ / kWh	0.0200
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0004
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0006)
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0035
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0032
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

(3) For energy-only metered customers, the billing determinant is the customer's metered energy consumption adjusted by the total loss factor as approved by the Board for Acquired LDC customers.

(4) For demand billed customers, appropriate loss factors must be applied to the applicable tariffs. Also the billing determinant for the Line and Transformation Connection Services rate is the customer's peak demand in the billing period. The billing determinant for the Network Services rate is: for non-interval-metered customers, the peak demand in the billing period, and for interval-metered customers, the peak demand between 7 AM and 7 PM local time on IESO business days

Customer-Supplied Transformation Allowance

Applicable to customers providing their own transformers

Demand-billed	$ / kW	0.60
Energy-billed	$ / kWh	0.0014

Hydro One Networks Inc.
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Effective Date: May 1, 2008

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Loss Factors

Residential	1.085
General Service Less Than 50 kW (Energy-Billed)	1.092
General Service 50 kW or Greater (Demand-Billed)	1.061
Unmetered Scattered Load	1.092

Transformer Loss Allowance

Applicable to customers requiring a billing adjustment for transformer losses as the result of being metered on the primary side of a transformer. The following uniform values shall be applied to measured demand and energy to calculate transformer losses for voltages up to and including 50 kV (as metered on the primary side):

(a) 1.5% for transformer installations up to an individual bank capacity of 400 kVA,
(b) 1.0% for bank capacities over 400 kVA.

Alternatively, transformer losses may be determined from transformer test data, and measured demand and energy adjusted accordingly

For services which are not demand metered, an assumed demand of 50% of the transformer capacity will be used to calculate the loss allowance. Where several transformers are involved, the bank capacity is assumed to be the arithmetic sum of all transformer capacities

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
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Effective Date: May 1, 2008

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MISCELLANEOUS CHARGES

Specific Service Charges: Standard Amounts

Rate Code	Specific Service Charge - Standard Name	Calculation Method			
		2006 Rate Handbook	Standard Formula	Other Formula	Time and Materials
1	Temporary Service	$500			
2	Dispute Meter Test	$30 plus Measurement Canada fees			
3	Collection of account – no disconnection/load limiter	$30			
4	Collection/Disconnect/load limiter/reconnect (at meter) trip – regular hours	$65			
5	Collection/Disconnect/load limiter/reconnect (at meter) trip – after regular hours	$185			
6	Collection/Disconnect/load limiter/reconnect (at pole) trip – regular hours	$185			
7	Collection/Disconnect/load limiter/reconnect (at pole) trip – after regular hours	$415			
8	Account Set-up Charge	$30			
9	Arrears Certificate	$15			
10	NSF Cheque Charge	$15 + bank charges			
11	Easement Charge for Unregistered Rights	$15			
12	Late Payment Charge	1.5%/month			
13a	Retailer Services – Establishing Service Agreements (refer to Handbook for all charges)	$100/agreement/Retailer +$20/month/Retailer +$0.50/month/customer + other			
13b	Retailer Services – Other (includes Bill Ready for Retailers and Service Transactions Requests) as per the Handbook, Chapter 12	$0.30/month/customer + $0.25/request for request fee + $0.50/request for process fee			
14	Special Meter Reads	$30			
15	Service Layout Fee – Basic		$495		
16	Service Layout Fee – Complex		$690		
17	Crossing Application – Pipeline		$2,445		
18	Crossing Application – Water		$3,045		
19	Crossing Application – Railroad		$2,945		
20	Line Staking – per meter		$3.70		
21	Central Metering – New service < 45 kW		$115		
22	Conversion to Central Metering < 45 kW		$915		
23	Conversion to Central Metering > 45 kW		$800		
24	Tingle Voltage Test – In Excess of 4 Hours (per hour – average 2 additional hours)		$125		
25	Standby Administration Charge per month		$440		
26	Sentinel Lights Rental Rate per month			$7.10	
27	Sentinel Pole Rental Rate per month			$4.15	
28	Joint Use for Cable and Telecom companies per pole			$22.35	
29	Joint Use for LDCs per pole			$28.61	

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
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Effective Date: May 1, 2007

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APPLICATION

The application of these rates and charges shall be in accordance with The Licence of The Distributor and any Codes, Guidelines or Orders of The Board, and amendments thereto as approved by The Board, which may be applicable to the administration of this schedule.
No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code, Guideline or Order of the Board, and amendments thereto as approved by the Board, or as specified herein
This schedule does not contain any rates and charges relating to the electricity commodity (e.g. the Regulated Price Plan).

EFFECTIVE DATES

DISTRIBUTION RATES - May 1, 2007 for all consumption or deemed consumption services used on or after that date.

MISCELLANEOUS CHARGES - May 1, 2007 for all charges billed to customers on or after that date.
RETAIL TRANSMISSION RATES - May 1, 2007 for all consumption or deemed consumption services used on or after that date.
LOSS FACTOR ADJUSTMENT – May 1, 2007

SERVICE CLASSIFICATIONS

Residential
This classification (note 1) refers to all service supplied to single-family dwelling units for domestic or household purpose. Multi-unit residential establishments such as apartment buildings supplied through one service (bulk metered) will normally be classified as General Service, but, at Hydro One's discretion, up to four residential units may be classified as residential. Where electricity service is provided to combined residential and business (including agricultural usage) and the wiring does not provide for separate metering, the classification shall be at the discretion of Hydro One based on such considerations as the estimated predominant consumption.
Further servicing details are available in the utility's Conditions of Service.

General Service
This classification (note 1) refers to all service supplied to premises other than those classified as Residential or Lighting. Some General Service accounts are energy(kWh)-billed, and some are demand(kW)-billed. Further servicing details are available in the utility's Conditions of Service. Also, see note 2.

Unmetered Scattered Load
This classification refers to certain instances where connections can be provided without metering. These loads are generally small in size and consistent in magnitude of load. Hydro One reserves the right to review all cases and may require that a meter be installed at its sole discretion. Services that can be unmetered include cable TV amplifiers, telephone switching devices, phone booths, bus shelters, rail way crossing signals, traffic signals, and other small fixed loads.
Further servicing details are available in the utility's Conditions of Service (including in the "Unmetered Connections" section).

Hydro One Networks Inc.
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Street Lighting

This classification refers to accounts for the distribution and supply of electrical energy for street lighting. Street lights are devices owned by or operated for the road authority and/or the municipal corporation. These street lights in fact belong to the Street Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Sentinel Lighting

This classification refers to accounts for a separate service to a sentinel light. These sentinel lights in fact belong to the Sentinel Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Interim Demand-Side Management Time-of-Use

This is potentially applicable to Demand-billed General Service accounts. See Note 2 below.

Note (1): Classification descriptions are paraphrases from the document "Hydro One Networks Inc. - Distribution Customers Conditions of Service - August 2004"

Note (2):

Interim Demand-Side Management Time-of-Use Rates: demand charges will be based on demand during the on-peak periods.

Criteria: Customers' electricity consumption (kW) in the off-peak period is at least twice the electricity consumption (kW) during the on-peak period.

Definition of Time Periods: The on-peak hours will be between 0700 hours to 1900 hours Eastern Standard Time during the winter (standard time) on IESO business days and 0600 hours to 1800 hours Eastern Standard Time during the summer (daylight savings time) on IESO business days. The off-peak period constitutes all of the remaining hours.

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Public Utility Commission of the Town of North Perth
Effective Date: May 1, 2007

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

MONTHLY RATES AND CHARGES

Residential

Service Charge	$	14.73
Distribution Volumetric Rate	$ / kWh	0.0105
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0047
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0016
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0055
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0047
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service - Energy Billed (less than 50 kW)

Service Charge	$	29.52
Distribution Volumetric Rate	$ / kWh	0.0100
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0012
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0004
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0050
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0043
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service - Demand Billed (50 kW or greater)

Service Charge	$	29.52
Distribution Volumetric Rate	$ / kW	3.16
Regulatory Asset Recovery - Rider #1	$ / kW	0.36
Regulatory Asset Recovery - Rider #2	$ / kW	0.13
Retail Transmission Rate - Network Service Rate (4)	$ / kW	1.94
Retail Transmission Rate - Line and Transformation Connection Service Rate (4)	$ / kW	1.61
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

Hydro One Networks Inc.
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Unmetered, Scattered Load

Service Charge	$	14.30
Distribution Volumetric Rate	$ / kWh	0.0100
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0012
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0004
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0050
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0043
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

(3) For energy-only metered customers, the billing determinant is the customer's metered energy consumption adjusted by the total loss factor as approved by the Board for Acquired LDC customers.
(4) For demand billed customers, appropriate loss factors must be applied to the applicable tariffs. Also the billing determinant for the Line and Transformation Connection Services rate is the customer's peak demand in the billing period. The billing determinant for the Network Services rate is: for non-interval-metered customers, the peak demand in the billing period, and for interval-metered customers, the peak demand between 7 AM and 7 PM local time on IESO business days

Interim Demand-Side Management Time-of-Use

See the "Service Classifications" section of this schedule.

Customer-Supplied Transformation Allowance

Applicable to demand-billed customers providing their own transformers
Primary Voltage under 50 kV (per kW)

Single Phase	$ / kW	0.20
Three Phase	$ / kW	0.60

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Loss Factors

Supply Facilities Loss Factor	1.0045
Distribution Loss Factors	
Customer less than 5,000 kW	1.0500
Customer greater than or equal to 5,000 kW	1.0100
Total Loss Factors	
Customer less than 5,000 kW	1.0545
Customer greater than or equal to 5,000 kW	1.0145

Transformer Loss Allowance

Applicable to customers requiring a billing adjustment for transformer losses as the result of being metered on the primary side of a transformer. The following uniform values shall be applied to measured demand and energy to calculate transformer losses for voltages up to and including 50 kV (as metered on the primary side):

(a) 1.5% for transformer installations up to an individual bank capacity of 400 kVA,
(b) 1.0% for bank capacities over 400 kVA.

Alternatively, transformer losses may be determined from transformer test data, and measured demand and energy adjusted accordingly

For services which are not demand metered, an assumed demand of 50% of the transformer capacity will be used to calculate the loss allowance. Where several transformers are involved, the bank capacity is assumed to be the arithmetic sum of all transformer capacities

Hydro One Networks Inc.
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MISCELLANEOUS CHARGES

Specific Service Charges: Standard Amounts

Rate Code	Specific Service Charge - Standard Name	Calculation Method			
		2006 Rate Handbook	Standard Formula	Other Formula	Time and Materials
1	Temporary Service	$500			
2	Dispute Meter Test	$30 plus Measurement Canada fees			
3	Collection of account – no disconnection/load limiter	$30			
4	Collection/Disconnect/load limiter/reconnect (at meter) trip – regular hours	$65			
5	Collection/Disconnect/load limiter/reconnect (at meter) trip – after regular hours	$185			
6	Collection/Disconnect/load limiter/reconnect (at pole) trip – regular hours	$185			
7	Collection/Disconnect/load limiter/reconnect (at pole) trip – after regular hours	$415			
8	Account Set-up Charge	$30			
9	Arrears Certificate	$15			
10	NSF Cheque Charge	$15 + bank charges			
11	Easement Charge for Unregistered Rights	$15			
12	Late Payment Charge	1.5%/month			
13a	Retailer Services – Establishing Service Agreements (refer to Handbook for all charges)	$100/agreement/Retailer +$20/month/Retailer +$0.50/month/customer + other			
13b	Retailer Services – Other (includes Bill Ready for Retailers and Service Transactions Requests) as per the Handbook, Chapter 12	$0.30/month/customer + $0.25/request for request fee + $0.50/request for process fee			
14	Special Meter Reads	$30			
15	Billing Suspension and Terminations in Trailer Parks		$130		
16	Service Layout Fee – Basic		$405		
17	Service Layout Fee – Complex		$580		

Hydro One Networks Inc.
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18	Crossing Application – Pipeline		$2,065		
19	Crossing Application – Water		$2,525		
20	Crossing Application – Railroad		$2,565		
21	Line Staking – per meter		$3.10		
22	Central Metering – New service < 45 kW		$115		
23	Conversion to Central Metering < 45 kW		$795		
24	Conversion to Central Metering > 45 kW		$680		
25	Tingle Voltage Test – In Excess of 4 Hours (per hour – average 2 additional hours)		$105		
26	Standby Administration Charge per month (interim)		$375		
27	Sentinel Lights Rental Rate per month – Mercury Vapor			$7.00	
28	Guaranteed Units from Jan 01/91 to Aug 01/91			$26.50 / month	
29	Guaranteed Units from Jan 01/87 to Dec 31/90			$23.50 / month	
30	Joint Use for Cable and Telecom companies per pole			$22.35	
31	Joint Use for LDCs per pole			$28.61	

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
North Stormont Hydro-Electric Commission
Effective Date: May 1, 2008

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

APPLICATION

The application of these rates and charges shall be in accordance with The Licence of The Distributor and any Codes, Guidelines or Orders of The Board, and amendments thereto as approved by The Board, which may be applicable to the administration of this schedule.
No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code, Guideline or Order of the Board, and amendments thereto as approved by the Board, or as specified herein
This schedule does not contain any rates and charges relating to the electricity commodity (e.g. the Regulated Price Plan).

EFFECTIVE DATES

DISTRIBUTION RATES - May 1, 2008 for all consumption or deemed consumption services used on or after that date.

MISCELLANEOUS CHARGES - May 1, 2008 for all charges billed to customers on or after that date.
RETAIL TRANSMISSION RATES - May 1, 2008 for all consumption or deemed consumption services used on or after that date.
LOSS FACTOR ADJUSTMENT – for all consumption or deemed consumption services billed following May 1, 2008 or later

SERVICE CLASSIFICATIONS

Residential
This classification refers to all service supplied to single-family dwelling units for domestic or household purpose. Multi-unit residential establishments such as apartment buildings supplied through one service (bulk metered) will normally be classified as General Service, but, at Hydro One's discretion, up to four residential units may be classified as residential. Where electricity service is provided to combined residential and business (including agricultural usage) and the wiring does not provide for separate metering, the classification shall be at the discretion of Hydro One based on such considerations as the estimated predominant consumption.
Further servicing details are available in the utility's Conditions of Service.

General Service
This classification refers to all service supplied to premises other than those classified as Residential or Lighting. Some General Service accounts are energy(kWh)-billed, and some are demand(kW)-billed. Further servicing details are available in the utility's Conditions of Service.

Unmetered Scattered Load
This classification refers to certain instances where connections can be provided without metering. These loads are generally small in size and consistent in magnitude of load. Hydro One reserves the right to review all cases and may require that a meter be installed at its sole discretion. Services that can be unmetered include cable TV amplifiers, telephone switching devices, phone booths, bus shelters, rail way crossing signals, traffic signals, and other small fixed loads.
Further servicing details are available in the utility's Conditions of Service (including in the "Unmetered Connections" section).

Hydro One Networks Inc.
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Street Lighting

This classification refers to accounts for the distribution and supply of electrical energy for street lighting. Street lights are devices owned by or operated for the road authority and/or the municipal corporation. These street lights in fact belong to the Street Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Sentinel Lighting

This classification refers to accounts for a separate service to a sentinel light. These sentinel lights in fact belong to the Sentinel Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Urban Density Classification

Customers who meet the Urban Density Criteria of being in an area containing 3,000 or more customers with a line density of at least 60 customers per kilometre, will be mapped to an Urban customer classification.

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MONTHLY RATES AND CHARGES

Residential - R1 North Stormont

Service Charge	$	8.41
Distribution Volumetric Rate	$ / kWh	0.0210
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0036
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0004)
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0047
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0046
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service Less Than 50 kW (Energy-Billed) - GSe North Stormont

Service Charge	$	11.75
Distribution Volumetric Rate	$ / kWh	0.0178
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0026
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0006)
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0035
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0032
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service 50 kW or Greater (Demand-Billed) - GSd North Stormont

Service Charge	$	15.35
Distribution Volumetric Rate	$ / kW	9.22
Regulatory Asset Recovery - Rider #2	$ / kW	0.82
Regulatory Asset Recovery - Rider #3	$ / kW	(0.22)
Retail Transmission Rate - Network Service Rate (4)	$ / kW	1.11
Retail Transmission Rate - Line and Transformation Connection Service Rate (4)	$ / kW	1.00
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

Hydro One Networks Inc.
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Unmetered, Scattered Load

Service Charge	$	7.82
Distribution Volumetric Rate	$ / kWh	0.0200
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0026
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0006)
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0035
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0032
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

(3) For energy-only metered customers, the billing determinant is the customer's metered energy consumption adjusted by the total loss factor as approved by the Board for Acquired LDC customers.
(4) For demand billed customers, appropriate loss factors must be applied to the applicable tariffs. Also the billing determinant for the Line and Transformation Connection Services rate is the customer's peak demand in the billing period. The billing determinant for the Network Services rate is: for non-interval-metered customers, the peak demand in the billing period, and for interval-metered customers, the peak demand between 7 AM and 7 PM local time on IESO business days

Customer-Supplied Transformation Allowance

Applicable to customers providing their own transformers		
Demand-billed	$ / kW	0.60
Energy-billed	$ / kWh	0.0014

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Loss Factors

Residential	1.085
General Service Less Than 50 kW (Energy-Billed)	1.092
General Service 50 kW or Greater (Demand-Billed)	1.061
Unmetered Scattered Load	1.092

Transformer Loss Allowance

Applicable to customers requiring a billing adjustment for transformer losses as the result of being metered on the primary side of a transformer. The following uniform values shall be applied to measured demand and energy to calculate transformer losses for voltages up to and including 50 kV (as metered on the primary side):

(a) 1.5% for transformer installations up to an individual bank capacity of 400 kVA,
(b) 1.0% for bank capacities over 400 kVA.

Alternatively, transformer losses may be determined from transformer test data, and measured demand and energy adjusted accordingly

For services which are not demand metered, an assumed demand of 50% of the transformer capacity will be used to calculate the loss allowance. Where several transformers are involved, the bank capacity is assumed to be the arithmetic sum of all transformer capacities

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MISCELLANEOUS CHARGES

Specific Service Charges: Standard Amounts

Rate Code	Specific Service Charge - Standard Name	Calculation Method			
		2006 Rate Handbook	Standard Formula	Other Formula	Time and Materials
1	Temporary Service	$500			
2	Dispute Meter Test	$30 plus Measurement Canada fees			
3	Collection of account – no disconnection/load limiter	$30			
4	Collection/Disconnect/load limiter/reconnect (at meter) trip – regular hours	$65			
5	Collection/Disconnect/load limiter/reconnect (at meter) trip – after regular hours	$185			
6	Collection/Disconnect/load limiter/reconnect (at pole) trip – regular hours	$185			
7	Collection/Disconnect/load limiter/reconnect (at pole) trip – after regular hours	$415			
8	Account Set-up Charge	$30			
9	Arrears Certificate	$15			
10	NSF Cheque Charge	$15 + bank charges			
11	Easement Charge for Unregistered Rights	$15			
12	Late Payment Charge	1.5%/month			
13a	Retailer Services – Establishing Service Agreements (refer to Handbook for all charges)	$100/agreement/Retailer +$20/month/Retailer +$0.50/month/customer + other			
13b	Retailer Services – Other (includes Bill Ready for Retailers and Service Transactions Requests) as per the Handbook, Chapter 12	$0.30/month/customer + $0.25/request for request fee + $0.50/request for process fee			
14	Special Meter Reads	$30			
15	Service Layout Fee – Basic		$495		
16	Service Layout Fee – Complex		$690		
17	Crossing Application – Pipeline		$2,445		
18	Crossing Application – Water		$3,045		
19	Crossing Application – Railroad		$2,945		
20	Line Staking – per meter		$3.70		
21	Central Metering – New service < 45 kW		$115		
22	Conversion to Central Metering < 45 kW		$915		
23	Conversion to Central Metering > 45 kW		$800		
24	Tingle Voltage Test – In Excess of 4 Hours (per hour – average 2 additional hours)		$125		
25	Standby Administration Charge per month		$440		
26	Sentinel Lights Rental Rate per month			$7.10	
27	Sentinel Pole Rental Rate per month			$4.15	
28	Joint Use for Cable and Telecom companies per pole			$22.35	
29	Joint Use for LDCs per pole			$28.61	

Hydro One Networks Inc.
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Effective Date: May 1, 2007

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APPLICATION

The application of these rates and charges shall be in accordance with The Licence of The Distributor and any Codes, Guidelines or Orders of The Board, and amendments thereto as approved by The Board, which may be applicable to the administration of this schedule.
No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code, Guideline or Order of the Board, and amendments thereto as approved by the Board, or as specified herein
This schedule does not contain any rates and charges relating to the electricity commodity (e.g. the Regulated Price Plan).

EFFECTIVE DATES

DISTRIBUTION RATES - May 1, 2007 for all consumption or deemed consumption services used on or after that date.

MISCELLANEOUS CHARGES - May 1, 2007 for all charges billed to customers on or after that date.
RETAIL TRANSMISSION RATES - May 1, 2007 for all consumption or deemed consumption services used on or after that date.
LOSS FACTOR ADJUSTMENT – May 1, 2007

SERVICE CLASSIFICATIONS

Residential
This classification (note 1) refers to all service supplied to single-family dwelling units for domestic or household purpose. Multi-unit residential establishments such as apartment buildings supplied through one service (bulk metered) will normally be classified as General Service, but, at Hydro One's discretion, up to four residential units may be classified as residential. Where electricity service is provided to combined residential and business (including agricultural usage) and the wiring does not provide for separate metering, the classification shall be at the discretion of Hydro One based on such considerations as the estimated predominant consumption.
Further servicing details are available in the utility's Conditions of Service.

General Service
This classification (note 1) refers to all service supplied to premises other than those classified as Residential or Lighting. Some General Service accounts are energy(kWh)-billed, and some are demand(kW)-billed. Further servicing details are available in the utility's Conditions of Service. Also, see note 2.

Unmetered Scattered Load
This classification refers to certain instances where connections can be provided without metering. These loads are generally small in size and consistent in magnitude of load. Hydro One reserves the right to review all cases and may require that a meter be installed at its sole discretion. Services that can be unmetered include cable TV amplifiers, telephone switching devices, phone booths, bus shelters, rail way crossing signals, traffic signals, and other small fixed loads.
Further servicing details are available in the utility's Conditions of Service (including in the "Unmetered Connections" section).

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Street Lighting
This classification refers to accounts for the distribution and supply of electrical energy for street lighting. Street lights are devices owned by or operated for the road authority and/or the municipal corporation. These street lights in fact belong to the Street Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility’s Conditions of Service.

Sentinel Lighting
This classification refers to accounts for a separate service to a sentinel light. These sentinel lights in fact belong to the Sentinel Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility’s Conditions of Service.

Interim Demand-Side Management Time-of-Use
This is potentially applicable to Demand-billed General Service accounts. See Note 2 below.

Note (1): Classification descriptions are paraphrases from the document "Hydro One Networks Inc. - Distribution Customers Conditions of Service - August 2004"
Note (2):
Interim Demand-Side Management Time-of-Use Rates: demand charges will be based on demand during the on-peak periods.
Criteria: Customers' electricity consumption (kW) in the off-peak period is at least twice the electricity consumption (kW) during the on-peak period.
Definition of Time Periods: The on-peak hours will be between 0700 hours to 1900 hours Eastern Standard Time during the winter (standard time) on IESO business days and 0600 hours to 1800 hours Eastern Standard Time during the summer (daylight savings time) on IESO business days. The off-peak period constitutes all of the remaining hours.

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MONTHLY RATES AND CHARGES

Residential

Service Charge	$	5.42
Distribution Volumetric Rate	$ / kWh	0.0092
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0062
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0036
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0055
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0047
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service - Energy Billed (less than 50 kW)

Service Charge	$	5.37
Distribution Volumetric Rate	$ / kWh	0.0078
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0037
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0026
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0050
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0043
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service - Demand Billed (50 kW or greater)

Service Charge	$	5.37
Distribution Volumetric Rate	$ / kW	2.52
Regulatory Asset Recovery - Rider #1	$ / kW	1.17
Regulatory Asset Recovery - Rider #2	$ / kW	0.82
Retail Transmission Rate - Network Service Rate (4)	$ / kW	1.94
Retail Transmission Rate - Line and Transformation Connection Service Rate (4)	$ / kW	1.61
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

Hydro One Networks Inc.
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Unmetered, Scattered Load

Service Charge	$	2.22
Distribution Volumetric Rate	$ / kWh	0.0078
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0037
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0026
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0050
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0043
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

(3) For energy-only metered customers, the billing determinant is the customer’s metered energy consumption adjusted by the total loss factor as approved by the Board for Acquired LDC customers.
(4) For demand billed customers, appropriate loss factors must be applied to the applicable tariffs. Also the billing determinant for the Line and Transformation Connection Services rate is the customer’s peak demand in the billing period. The billing determinant for the Network Services rate is: for non-interval-metered customers, the peak demand in the billing period, and for interval-metered customers, the peak demand between 7 AM and 7 PM local time on IESO business days

Interim Demand-Side Management Time-of-Use

See the "Service Classifications" section of this schedule.

Customer-Supplied Transformation Allowance

Applicable to demand-billed customers providing their own transformers
Primary Voltage under 50 kV (per kW)

Single Phase	$ / kW	0.20
Three Phase	$ / kW	0.60

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Loss Factors

Supply Facilities Loss Factor	1.0045
Distribution Loss Factors	
Customer less than 5,000 kW	1.0500
Customer greater than or equal to 5,000 kW	1.0100
Total Loss Factors	
Customer less than 5,000 kW	1.0545
Customer greater than or equal to 5,000 kW	1.0145

Transformer Loss Allowance

Applicable to customers requiring a billing adjustment for transformer losses as the result of being metered on the primary side of a transformer. The following uniform values shall be applied to measured demand and energy to calculate transformer losses for voltages up to and including 50 kV (as metered on the primary side):

(a) 1.5% for transformer installations up to an individual bank capacity of 400 kVA,
(b) 1.0% for bank capacities over 400 kVA.

Alternatively, transformer losses may be determined from transformer test data, and measured demand and energy adjusted accordingly
For services which are not demand metered, an assumed demand of 50% of the transformer capacity will be used to calculate the loss allowance. Where several transformers are involved, the bank capacity is assumed to be the arithmetic sum of all transformer capacities

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
North Stormont Hydro-Electric Commission
Effective Date: May 1, 2007

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

MISCELLANEOUS CHARGES

Specific Service Charges: Standard Amounts

Rate Code	Specific Service Charge - Standard Name	Calculation Method			
		2006 Rate Handbook	Standard Formula	Other Formula	Time and Materials
1	Temporary Service	$500			
2	Dispute Meter Test	$30 plus Measurement Canada fees			
3	Collection of account – no disconnection/load limiter	$30			
4	Collection/Disconnect/load limiter/reconnect (at meter) trip – regular hours	$65			
5	Collection/Disconnect/load limiter/reconnect (at meter) trip – after regular hours	$185			
6	Collection/Disconnect/load limiter/reconnect (at pole) trip – regular hours	$185			
7	Collection/Disconnect/load limiter/reconnect (at pole) trip – after regular hours	$415			
8	Account Set-up Charge	$30			
9	Arrears Certificate	$15			
10	NSF Cheque Charge	$15 + bank charges			
11	Easement Charge for Unregistered Rights	$15			
12	Late Payment Charge	1.5%/month			
13a	Retailer Services – Establishing Service Agreements (refer to Handbook for all charges)	$100/agreement/Retailer +$20/month/Retailer +$0.50/month/customer + other			
13b	Retailer Services – Other (includes Bill Ready for Retailers and Service Transactions Requests) as per the Handbook, Chapter 12	$0.30/month/customer + $0.25/request for request fee + $0.50/request for process fee			
14	Special Meter Reads	$30			
15	Billing Suspension and Terminations in Trailer Parks		$130		
16	Service Layout Fee – Basic		$405		
17	Service Layout Fee – Complex		$580		

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
North Stormont Hydro-Electric Commission
Effective Date: May 1, 2007

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

18	Crossing Application – Pipeline		$2,065		
19	Crossing Application – Water		$2,525		
20	Crossing Application – Railroad		$2,565		
21	Line Staking – per meter		$3.10		
22	Central Metering – New service < 45 kW		$115		
23	Conversion to Central Metering < 45 kW		$795		
24	Conversion to Central Metering > 45 kW		$680		
25	Tingle Voltage Test – In Excess of 4 Hours (per hour – average 2 additional hours)		$105		
26	Standby Administration Charge per month (interim)		$375		
27	Sentinel Lights Rental Rate per month – Mercury Vapor			$7.00	
28	Guaranteed Units from Jan 01/91 to Aug 01/91			$26.50 / month	
29	Guaranteed Units from Jan 01/87 to Dec 31/90			$23.50 / month	
30	Joint Use for Cable and Telecom companies per pole			$22.35	
31	Joint Use for LDCs per pole			$28.61	

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Omemee Hydro-Electric Commission
Effective Date: May 1, 2008

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

APPLICATION

The application of these rates and charges shall be in accordance with The Licence of The Distributor and any Codes, Guidelines or Orders of The Board, and amendments thereto as approved by The Board, which may be applicable to the administration of this schedule.
No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code, Guideline or Order of the Board, and amendments thereto as approved by the Board, or as specified herein
This schedule does not contain any rates and charges relating to the electricity commodity (e.g. the Regulated Price Plan).

EFFECTIVE DATES

DISTRIBUTION RATES - May 1, 2008 for all consumption or deemed consumption services used on or after that date.

MISCELLANEOUS CHARGES - May 1, 2008 for all charges billed to customers on or after that date.
RETAIL TRANSMISSION RATES - May 1, 2008 for all consumption or deemed consumption services used on or after that date.
LOSS FACTOR ADJUSTMENT – for all consumption or deemed consumption services billed following May 1, 2008 or later

SERVICE CLASSIFICATIONS

Residential
This classification refers to all service supplied to single-family dwelling units for domestic or household purpose. Multi-unit residential establishments such as apartment buildings supplied through one service (bulk metered) will normally be classified as General Service, but, at Hydro One's discretion, up to four residential units may be classified as residential. Where electricity service is provided to combined residential and business (including agricultural usage) and the wiring does not provide for separate metering, the classification shall be at the discretion of Hydro One based on such considerations as the estimated predominant consumption.
Further servicing details are available in the utility's Conditions of Service.

General Service
This classification refers to all service supplied to premises other than those classified as Residential or Lighting. Some General Service accounts are energy(kWh)-billed, and some are demand(kW)-billed. Further servicing details are available in the utility's Conditions of Service.

Unmetered Scattered Load
This classification refers to certain instances where connections can be provided without metering. These loads are generally small in size and consistent in magnitude of load. Hydro One reserves the right to review all cases and may require that a meter be installed at its sole discretion. Services that can be unmetered include cable TV amplifiers, telephone switching devices, phone booths, bus shelters, rail way crossing signals, traffic signals, and other small fixed loads.
Further servicing details are available in the utility's Conditions of Service (including in the "Unmetered Connections" section).

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Omemee Hydro-Electric Commission
Effective Date: May 1, 2008

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

Street Lighting

This classification refers to accounts for the distribution and supply of electrical energy for street lighting. Street lights are devices owned by or operated for the road authority and/or the municipal corporation. These street lights in fact belong to the Street Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Sentinel Lighting

This classification refers to accounts for a separate service to a sentinel light. These sentinel lights in fact belong to the Sentinel Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Urban Density Classification

Customers who meet the Urban Density Criteria of being in an area containing 3,000 or more customers with a line density of at least 60 customers per kilometre, will be mapped to an Urban customer classification.

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Omemee Hydro-Electric Commission
Effective Date: May 1, 2008

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

MONTHLY RATES AND CHARGES

Residential - R1 Omemee

Service Charge	$	15.01
Distribution Volumetric Rate	$ / kWh	0.0271
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0014
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0004)
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0047
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0046
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service Less Than 50 kW (Energy-Billed) - GSe Omemee

Service Charge	$	23.77
Distribution Volumetric Rate	$ / kWh	0.0255
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0009
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0006)
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0035
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0032
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service 50 kW or Greater (Demand-Billed) - GSd Omemee

Service Charge	$	27.37
Distribution Volumetric Rate	$ / kW	9.22
Regulatory Asset Recovery - Rider #2	$ / kW	0.27
Regulatory Asset Recovery - Rider #3	$ / kW	(0.22)
Retail Transmission Rate - Network Service Rate (4)	$ / kW	1.11
Retail Transmission Rate - Line and Transformation Connection Service Rate (4)	$ / kW	1.00
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Omemee Hydro-Electric Commission
Effective Date: May 1, 2008

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

Unmetered, Scattered Load

Service Charge	$	13.83
Distribution Volumetric Rate	$ / kWh	0.0200
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0009
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0006)
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0035
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0032
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

(3) For energy-only metered customers, the billing determinant is the customer's metered energy consumption adjusted by the total loss factor as approved by the Board for Acquired LDC customers.
(4) For demand billed customers, appropriate loss factors must be applied to the applicable tariffs. Also the billing determinant for the Line and Transformation Connection Services rate is the customer's peak demand in the billing period. The billing determinant for the Network Services rate is: for non-interval-metered customers, the peak demand in the billing period, and for interval-metered customers, the peak demand between 7 AM and 7 PM local time on IESO business days

Customer-Supplied Transformation Allowance

Applicable to customers providing their own transformers		
Demand-billed	$ / kW	0.60
Energy-billed	$ / kWh	0.0014

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Omemee Hydro-Electric Commission
Effective Date: May 1, 2008

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

Loss Factors

Residential	1.085
General Service Less Than 50 kW (Energy-Billed)	1.092
General Service 50 kW or Greater (Demand-Billed)	1.061
Unmetered Scattered Load	1.092

Transformer Loss Allowance

Applicable to customers requiring a billing adjustment for transformer losses as the result of being metered on the primary side of a transformer. The following uniform values shall be applied to measured demand and energy to calculate transformer losses for voltages up to and including 50 kV (as metered on the primary side):

(a) 1.5% for transformer installations up to an individual bank capacity of 400 kVA,
(b) 1.0% for bank capacities over 400 kVA.

Alternatively, transformer losses may be determined from transformer test data, and measured demand and energy adjusted accordingly

For services which are not demand metered, an assumed demand of 50% of the transformer capacity will be used to calculate the loss allowance. Where several transformers are involved, the bank capacity is assumed to be the arithmetic sum of all transformer capacities

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Omemee Hydro-Electric Commission
Effective Date: May 1, 2008

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

MISCELLANEOUS CHARGES

Specific Service Charges: Standard Amounts

Rate Code	Specific Service Charge - Standard Name	Calculation Method			
		2006 Rate Handbook	Standard Formula	Other Formula	Time and Materials
1	Temporary Service	$500			
2	Dispute Meter Test	$30 plus Measurement Canada fees			
3	Collection of account – no disconnection/load limiter	$30			
4	Collection/Disconnect/load limiter/reconnect (at meter) trip – regular hours	$65			
5	Collection/Disconnect/load limiter/reconnect (at meter) trip – after regular hours	$185			
6	Collection/Disconnect/load limiter/reconnect (at pole) trip – regular hours	$185			
7	Collection/Disconnect/load limiter/reconnect (at pole) trip – after regular hours	$415			
8	Account Set-up Charge	$30			
9	Arrears Certificate	$15			
10	NSF Cheque Charge	$15 + bank charges			
11	Easement Charge for Unregistered Rights	$15			
12	Late Payment Charge	1.5%/month			
13a	Retailer Services – Establishing Service Agreements (refer to Handbook for all charges)	$100/agreement/Retailer +$20/month/Retailer +$0.50/month/customer + other			
13b	Retailer Services – Other (includes Bill Ready for Retailers and Service Transactions Requests) as per the Handbook, Chapter 12	$0.30/month/customer + $0.25/request for request fee + $0.50/request for process fee			
14	Special Meter Reads	$30			
15	Service Layout Fee – Basic		$495		
16	Service Layout Fee – Complex		$690		
17	Crossing Application – Pipeline		$2,445		
18	Crossing Application – Water		$3,045		
19	Crossing Application – Railroad		$2,945		
20	Line Staking – per meter		$3.70		
21	Central Metering – New service < 45 kW		$115		
22	Conversion to Central Metering < 45 kW		$915		
23	Conversion to Central Metering > 45 kW		$800		
24	Tingle Voltage Test – In Excess of 4 Hours (per hour – average 2 additional hours)		$125		
25	Standby Administration Charge per month		$440		
26	Sentinel Lights Rental Rate per month			$7.10	
27	Sentinel Pole Rental Rate per month			$4.15	
28	Joint Use for Cable and Telecom companies per pole			$22.35	
29	Joint Use for LDCs per pole			$28.61	

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Omemee Hydro-Electric Commission
Effective Date: May 1, 2007

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

APPLICATION

The application of these rates and charges shall be in accordance with The Licence of The Distributor and any Codes, Guidelines or Orders of The Board, and amendments thereto as approved by The Board, which may be applicable to the administration of this schedule.
No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code, Guideline or Order of the Board, and amendments thereto as approved by the Board, or as specified herein
This schedule does not contain any rates and charges relating to the electricity commodity (e.g. the Regulated Price Plan).

EFFECTIVE DATES

DISTRIBUTION RATES - May 1, 2007 for all consumption or deemed consumption services used on or after that date.

MISCELLANEOUS CHARGES - May 1, 2007 for all charges billed to customers on or after that date.
RETAIL TRANSMISSION RATES - May 1, 2007 for all consumption or deemed consumption services used on or after that date.
LOSS FACTOR ADJUSTMENT – May 1, 2007

SERVICE CLASSIFICATIONS

Residential
This classification (note 1) refers to all service supplied to single-family dwelling units for domestic or household purpose. Multi-unit residential establishments such as apartment buildings supplied through one service (bulk metered) will normally be classified as General Service, but, at Hydro One's discretion, up to four residential units may be classified as residential. Where electricity service is provided to combined residential and business (including agricultural usage) and the wiring does not provide for separate metering, the classification shall be at the discretion of Hydro One based on such considerations as the estimated predominant consumption.
Further servicing details are available in the utility's Conditions of Service.

General Service
This classification (note 1) refers to all service supplied to premises other than those classified as Residential or Lighting. Some General Service accounts are energy(kWh)-billed, and some are demand(kW)-billed. Further servicing details are available in the utility's Conditions of Service. Also, see note 2.

Unmetered Scattered Load
This classification refers to certain instances where connections can be provided without metering. These loads are generally small in size and consistent in magnitude of load. Hydro One reserves the right to review all cases and may require that a meter be installed at its sole discretion. Services that can be unmetered include cable TV amplifiers, telephone switching devices, phone booths, bus shelters, rail way crossing signals, traffic signals, and other small fixed loads.
Further servicing details are available in the utility's Conditions of Service (including in the "Unmetered Connections" section).

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Omemee Hydro-Electric Commission
Effective Date: May 1, 2007

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

Street Lighting

This classification refers to accounts for the distribution and supply of electrical energy for street lighting. Street lights are devices owned by or operated for the road authority and/or the municipal corporation. These street lights in fact belong to the Street Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Sentinel Lighting

This classification refers to accounts for a separate service to a sentinel light. These sentinel lights in fact belong to the Sentinel Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Interim Demand-Side Management Time-of-Use

This is potentially applicable to Demand-billed General Service accounts. See Note 2 below.

Note (1): Classification descriptions are paraphrases from the document "Hydro One Networks Inc. - Distribution Customers Conditions of Service - August 2004"

Note (2):

Interim Demand-Side Management Time-of-Use Rates: demand charges will be based on demand during the on-peak periods.

Criteria: Customers' electricity consumption (kW) in the off-peak period is at least twice the electricity consumption (kW) during the on-peak period.

Definition of Time Periods: The on-peak hours will be between 0700 hours to 1900 hours Eastern Standard Time during the winter (standard time) on IESO business days and 0600 hours to 1800 hours Eastern Standard Time during the summer (daylight savings time) on IESO business days. The off-peak period constitutes all of the remaining hours.

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Omemee Hydro-Electric Commission
Effective Date: May 1, 2007

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

MONTHLY RATES AND CHARGES

Residential

Service Charge	$	14.99
Distribution Volumetric Rate	$ / kWh	0.0150
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0036
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0014
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0055
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0047
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service - Energy Billed (less than 50 kW)

Service Charge	$	21.28
Distribution Volumetric Rate	$ / kWh	0.0147
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0018
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0009
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0050
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0043
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service - Demand Billed (50 kW or greater)

Service Charge	$	21.28
Distribution Volumetric Rate	$ / kW	4.64
Regulatory Asset Recovery - Rider #1	$ / kW	0.55
Regulatory Asset Recovery - Rider #2	$ / kW	0.27
Retail Transmission Rate - Network Service Rate (4)	$ / kW	1.94
Retail Transmission Rate - Line and Transformation Connection Service Rate (4)	$ / kW	1.61
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Omemee Hydro-Electric Commission
Effective Date: May 1, 2007

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

Unmetered, Scattered Load

Service Charge	$	10.18
Distribution Volumetric Rate	$ / kWh	0.0147
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0018
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0009
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0050
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0043
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

(3) For energy-only metered customers, the billing determinant is the customer’s metered energy consumption adjusted by the total loss factor as approved by the Board for Acquired LDC customers.
(4) For demand billed customers, appropriate loss factors must be applied to the applicable tariffs. Also the billing determinant for the Line and Transformation Connection Services rate is the customer’s peak demand in the billing period. The billing determinant for the Network Services rate is: for non-interval-metered customers, the peak demand in the billing period, and for interval-metered customers, the peak demand between 7 AM and 7 PM local time on IESO business days

Interim Demand-Side Management Time-of-Use

See the "Service Classifications" section of this schedule.

Customer-Supplied Transformation Allowance

Applicable to demand-billed customers providing their own transformers
Primary Voltage under 50 kV (per kW)

Single Phase	$ / kW	0.20
Three Phase	$ / kW	0.60

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
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Omemee Hydro-Electric Commission
Effective Date: May 1, 2007

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

Loss Factors

Supply Facilities Loss Factor	1.0045
Distribution Loss Factors	
Customer less than 5,000 kW	1.0500
Customer greater than or equal to 5,000 kW	1.0100
Total Loss Factors	
Customer less than 5,000 kW	1.0545
Customer greater than or equal to 5,000 kW	1.0145

Transformer Loss Allowance

Applicable to customers requiring a billing adjustment for transformer losses as the result of being metered on the primary side of a transformer. The following uniform values shall be applied to measured demand and energy to calculate transformer losses for voltages up to and including 50 kV (as metered on the primary side):

(a) 1.5% for transformer installations up to an individual bank capacity of 400 kVA,
(b) 1.0% for bank capacities over 400 kVA.

Alternatively, transformer losses may be determined from transformer test data, and measured demand and energy adjusted accordingly

For services which are not demand metered, an assumed demand of 50% of the transformer capacity will be used to calculate the loss allowance. Where several transformers are involved, the bank capacity is assumed to be the arithmetic sum of all transformer capacities

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Omemee Hydro-Electric Commission
Effective Date: May 1, 2007

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

MISCELLANEOUS CHARGES

Specific Service Charges: Standard Amounts

Rate Code	Specific Service Charge - Standard Name	Calculation Method			
		2006 Rate Handbook	Standard Formula	Other Formula	Time and Materials
1	Temporary Service	$500			
2	Dispute Meter Test	$30 plus Measurement Canada fees			
3	Collection of account – no disconnection/load limiter	$30			
4	Collection/Disconnect/load limiter/reconnect (at meter) trip – regular hours	$65			
5	Collection/Disconnect/load limiter/reconnect (at meter) trip – after regular hours	$185			
6	Collection/Disconnect/load limiter/reconnect (at pole) trip – regular hours	$185			
7	Collection/Disconnect/load limiter/reconnect (at pole) trip – after regular hours	$415			
8	Account Set-up Charge	$30			
9	Arrears Certificate	$15			
10	NSF Cheque Charge	$15 + bank charges			
11	Easement Charge for Unregistered Rights	$15			
12	Late Payment Charge	1.5%/month			
13a	Retailer Services – Establishing Service Agreements (refer to Handbook for all charges)	$100/agreement/Retailer +$20/month/Retailer +$0.50/month/customer + other			
13b	Retailer Services – Other (includes Bill Ready for Retailers and Service Transactions Requests) as per the Handbook, Chapter 12	$0.30/month/customer + $0.25/request for request fee + $0.50/request for process fee			
14	Special Meter Reads	$30			
15	Billing Suspension and Terminations in Trailer Parks		$130		
16	Service Layout Fee – Basic		$405		
17	Service Layout Fee – Complex		$580		

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Omemee Hydro-Electric Commission
Effective Date: May 1, 2007

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

18	Crossing Application – Pipeline		$2,065		
19	Crossing Application – Water		$2,525		
20	Crossing Application – Railroad		$2,565		
21	Line Staking – per meter		$3.10		
22	Central Metering – New service < 45 kW		$115		
23	Conversion to Central Metering < 45 kW		$795		
24	Conversion to Central Metering > 45 kW		$680		
25	Tingle Voltage Test – In Excess of 4 Hours (per hour – average 2 additional hours)		$105		
26	Standby Administration Charge per month (interim)		$375		
27	Sentinel Lights Rental Rate per month – Mercury Vapor			$7.00	
28	Guaranteed Units from Jan 01/91 to Aug 01/91			$26.50 / month	
29	Guaranteed Units from Jan 01/87 to Dec 31/90			$23.50 / month	
30	Joint Use for Cable and Telecom companies per pole			$22.35	
31	Joint Use for LDCs per pole			$28.61	

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Public Utility Commission of the Town of Perth
Effective Date: May 1, 2008

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

APPLICATION

The application of these rates and charges shall be in accordance with The Licence of The Distributor and any Codes, Guidelines or Orders of The Board, and amendments thereto as approved by The Board, which may be applicable to the administration of this schedule.
No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code, Guideline or Order of the Board, and amendments thereto as approved by the Board, or as specified herein
This schedule does not contain any rates and charges relating to the electricity commodity (e.g. the Regulated Price Plan).

EFFECTIVE DATES

DISTRIBUTION RATES - May 1, 2008 for all consumption or deemed consumption services used on or after that date.

MISCELLANEOUS CHARGES - May 1, 2008 for all charges billed to customers on or after that date.
RETAIL TRANSMISSION RATES - May 1, 2008 for all consumption or deemed consumption services used on or after that date.
LOSS FACTOR ADJUSTMENT – for all consumption or deemed consumption services billed following May 1, 2008 or later

SERVICE CLASSIFICATIONS

Residential
This classification refers to all service supplied to single-family dwelling units for domestic or household purpose. Multi-unit residential establishments such as apartment buildings supplied through one service (bulk metered) will normally be classified as General Service, but, at Hydro One's discretion, up to four residential units may be classified as residential. Where electricity service is provided to combined residential and business (including agricultural usage) and the wiring does not provide for separate metering, the classification shall be at the discretion of Hydro One based on such considerations as the estimated predominant consumption.
Further servicing details are available in the utility's Conditions of Service.

General Service
This classification refers to all service supplied to premises other than those classified as Residential or Lighting. Some General Service accounts are energy(kWh)-billed, and some are demand(kW)-billed. Further servicing details are available in the utility's Conditions of Service.

Unmetered Scattered Load
This classification refers to certain instances where connections can be provided without metering. These loads are generally small in size and consistent in magnitude of load. Hydro One reserves the right to review all cases and may require that a meter be installed at its sole discretion. Services that can be unmetered include cable TV amplifiers, telephone switching devices, phone booths, bus shelters, rail way crossing signals, traffic signals, and other small fixed loads.
Further servicing details are available in the utility's Conditions of Service (including in the "Unmetered Connections" section).

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
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Public Utility Commission of the Town of Perth
Effective Date: May 1, 2008

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Street Lighting

This classification refers to accounts for the distribution and supply of electrical energy for street lighting. Street lights are devices owned by or operated for the road authority and/or the municipal corporation. These street lights in fact belong to the Street Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Sentinel Lighting

This classification refers to accounts for a separate service to a sentinel light. These sentinel lights in fact belong to the Sentinel Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Urban Density Classification

Customers who meet the Urban Density Criteria of being in an area containing 3,000 or more customers with a line density of at least 60 customers per kilometre, will be mapped to an Urban customer classification.

Hydro One Networks Inc.
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MONTHLY RATES AND CHARGES

Residential - UR/R1 Perth

Service Charge	$	13.96
Distribution Volumetric Rate	$ / kWh	0.0240
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0018
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0002)
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0047
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0045
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service Less Than 50 kW (Energy-Billed) - UGe/GSe Perth

Service Charge	$	17.10
Distribution Volumetric Rate	$ / kWh	0.0200
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0004
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0006)
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0036
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0033
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service 50 kW or Greater (Demand-Billed) - UGd/GSd Perth

Service Charge	$	21.32
Distribution Volumetric Rate	$ / kW	7.15
Regulatory Asset Recovery - Rider #2	$ / kW	0.12
Regulatory Asset Recovery - Rider #3	$ / kW	(0.27)
Retail Transmission Rate - Network Service Rate (4)	$ / kW	1.41
Retail Transmission Rate - Line and Transformation Connection Service Rate (4)	$ / kW	1.27
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

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Unmetered, Scattered Load

Service Charge	$	13.01
Distribution Volumetric Rate	$ / kWh	0.0200
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0004
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0006)
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0035
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0032
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

(3) For energy-only metered customers, the billing determinant is the customer’s metered energy consumption adjusted by the total loss factor as approved by the Board for Acquired LDC customers.
(4) For demand billed customers, appropriate loss factors must be applied to the applicable tariffs. Also the billing determinant for the Line and Transformation Connection Services rate is the customer’s peak demand in the billing period. The billing determinant for the Network Services rate is: for non-interval-metered customers, the peak demand in the billing period, and for interval-metered customers, the peak demand between 7 AM and 7 PM local time on IESO business days

Customer-Supplied Transformation Allowance

Applicable to customers providing their own transformers

Demand-billed	$ / kW	0.60
Energy-billed	$ / kWh	0.0014

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Loss Factors

Residential	1.078
General Service Less Than 50 kW (Energy-Billed)	1.092
General Service 50 kW or Greater (Demand-Billed)	1.061
Unmetered Scattered Load	1.092

Transformer Loss Allowance

Applicable to customers requiring a billing adjustment for transformer losses as the result of being metered on the primary side of a transformer. The following uniform values shall be applied to measured demand and energy to calculate transformer losses for voltages up to and including 50 kV (as metered on the primary side):

(a) 1.5% for transformer installations up to an individual bank capacity of 400 kVA,
(b) 1.0% for bank capacities over 400 kVA.

Alternatively, transformer losses may be determined from transformer test data, and measured demand and energy adjusted accordingly

For services which are not demand metered, an assumed demand of 50% of the transformer capacity will be used to calculate the loss allowance. Where several transformers are involved, the bank capacity is assumed to be the arithmetic sum of all transformer capacities

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MISCELLANEOUS CHARGES

Specific Service Charges: Standard Amounts

Rate Code	Specific Service Charge - Standard Name	Calculation Method			
		2006 Rate Handbook	Standard Formula	Other Formula	Time and Materials
1	Temporary Service	$500			
2	Dispute Meter Test	$30 plus Measurement Canada fees			
3	Collection of account – no disconnection/load limiter	$30			
4	Collection/Disconnect/load limiter/reconnect (at meter) trip – regular hours	$65			
5	Collection/Disconnect/load limiter/reconnect (at meter) trip – after regular hours	$185			
6	Collection/Disconnect/load limiter/reconnect (at pole) trip – regular hours	$185			
7	Collection/Disconnect/load limiter/reconnect (at pole) trip – after regular hours	$415			
8	Account Set-up Charge	$30			
9	Arrears Certificate	$15			
10	NSF Cheque Charge	$15 + bank charges			
11	Easement Charge for Unregistered Rights	$15			
12	Late Payment Charge	1.5%/month			
13a	Retailer Services – Establishing Service Agreements (refer to Handbook for all charges)	$100/agreement/Retailer +$20/month/Retailer +$0.50/month/customer + other			
13b	Retailer Services – Other (includes Bill Ready for Retailers and Service Transactions Requests) as per the Handbook, Chapter 12	$0.30/month/customer + $0.25/request for request fee + $0.50/request for process fee			
14	Special Meter Reads	$30			
15	Service Layout Fee – Basic		$495		
16	Service Layout Fee – Complex		$690		
17	Crossing Application – Pipeline		$2,445		
18	Crossing Application – Water		$3,045		
19	Crossing Application – Railroad		$2,945		
20	Line Staking – per meter		$3.70		
21	Central Metering – New service < 45 kW		$115		
22	Conversion to Central Metering < 45 kW		$915		
23	Conversion to Central Metering > 45 kW		$800		
24	Tingle Voltage Test – In Excess of 4 Hours (per hour – average 2 additional hours)		$125		
25	Standby Administration Charge per month		$440		
26	Sentinel Lights Rental Rate per month			$7.10	
27	Sentinel Pole Rental Rate per month			$4.15	
28	Joint Use for Cable and Telecom companies per pole			$22.35	
29	Joint Use for LDCs per pole			$28.61	

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Effective Date: May 1, 2007

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APPLICATION

The application of these rates and charges shall be in accordance with The Licence of The Distributor and any Codes, Guidelines or Orders of The Board, and amendments thereto as approved by The Board, which may be applicable to the administration of this schedule.
No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code, Guideline or Order of the Board, and amendments thereto as approved by the Board, or as specified herein
This schedule does not contain any rates and charges relating to the electricity commodity (e.g. the Regulated Price Plan).

EFFECTIVE DATES

DISTRIBUTION RATES - May 1, 2007 for all consumption or deemed consumption services used on or after that date.

MISCELLANEOUS CHARGES - May 1, 2007 for all charges billed to customers on or after that date.
RETAIL TRANSMISSION RATES - May 1, 2007 for all consumption or deemed consumption services used on or after that date.
LOSS FACTOR ADJUSTMENT – May 1, 2007

SERVICE CLASSIFICATIONS

Residential
This classification (note 1) refers to all service supplied to single-family dwelling units for domestic or household purpose. Multi-unit residential establishments such as apartment buildings supplied through one service (bulk metered) will normally be classified as General Service, but, at Hydro One's discretion, up to four residential units may be classified as residential. Where electricity service is provided to combined residential and business (including agricultural usage) and the wiring does not provide for separate metering, the classification shall be at the discretion of Hydro One based on such considerations as the estimated predominant consumption.
Further servicing details are available in the utility's Conditions of Service.

General Service
This classification (note 1) refers to all service supplied to premises other than those classified as Residential or Lighting. Some General Service accounts are energy(kWh)-billed, and some are demand(kW)-billed. Further servicing details are available in the utility's Conditions of Service. Also, see note 2.

Unmetered Scattered Load
This classification refers to certain instances where connections can be provided without metering. These loads are generally small in size and consistent in magnitude of load. Hydro One reserves the right to review all cases and may require that a meter be installed at its sole discretion. Services that can be unmetered include cable TV amplifiers, telephone switching devices, phone booths, bus shelters, rail way crossing signals, traffic signals, and other small fixed loads.
Further servicing details are available in the utility's Conditions of Service (including in the "Unmetered Connections" section).

Hydro One Networks Inc.
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Street Lighting

This classification refers to accounts for the distribution and supply of electrical energy for street lighting. Street lights are devices owned by or operated for the road authority and/or the municipal corporation. These street lights in fact belong to the Street Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Sentinel Lighting

This classification refers to accounts for a separate service to a sentinel light. These sentinel lights in fact belong to the Sentinel Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Interim Demand-Side Management Time-of-Use

This is potentially applicable to Demand-billed General Service accounts. See Note 2 below.

Note (1): Classification descriptions are paraphrases from the document "Hydro One Networks Inc. - Distribution Customers Conditions of Service - August 2004"

Note (2):

Interim Demand-Side Management Time-of-Use Rates: demand charges will be based on demand during the on-peak periods.

Criteria: Customers' electricity consumption (kW) in the off-peak period is at least twice the electricity consumption (kW) during the on-peak period.

Definition of Time Periods: The on-peak hours will be between 0700 hours to 1900 hours Eastern Standard Time during the winter (standard time) on IESO business days and 0600 hours to 1800 hours Eastern Standard Time during the summer (daylight savings time) on IESO business days. The off-peak period constitutes all of the remaining hours.

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MONTHLY RATES AND CHARGES

Residential

Service Charge	$	14.47
Distribution Volumetric Rate	$ / kWh	0.0122
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0050
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0018
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0055
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0047
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service - Energy Billed (less than 50 kW)

Service Charge	$	19.92
Distribution Volumetric Rate	$ / kWh	0.0092
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0013
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0004
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0050
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0043
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service - Demand Billed (50 kW or greater)

Service Charge	$	19.92
Distribution Volumetric Rate	$ / kW	2.87
Regulatory Asset Recovery - Rider #1	$ / kW	0.42
Regulatory Asset Recovery - Rider #2	$ / kW	0.12
Retail Transmission Rate - Network Service Rate (4)	$ / kW	1.94
Retail Transmission Rate - Line and Transformation Connection Service Rate (4)	$ / kW	1.61
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

Hydro One Networks Inc.
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Unmetered, Scattered Load

Service Charge	$	9.49
Distribution Volumetric Rate	$ / kWh	0.0092
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0013
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0004
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0050
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0043
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

(3) For energy-only metered customers, the billing determinant is the customer’s metered energy consumption adjusted by the total loss factor as approved by the Board for Acquired LDC customers.

(4) For demand billed customers, appropriate loss factors must be applied to the applicable tariffs. Also the billing determinant for the Line and Transformation Connection Services rate is the customer’s peak demand in the billing period. The billing determinant for the Network Services rate is: for non-interval-metered customers, the peak demand in the billing period, and for interval-metered customers, the peak demand between 7 AM and 7 PM local time on IESO business days

Interim Demand-Side Management Time-of-Use

See the "Service Classifications" section of this schedule.

Customer-Supplied Transformation Allowance

Applicable to demand-billed customers providing their own transformers

Primary Voltage under 50 kV (per kW)		
Single Phase	$ / kW	0.20
Three Phase	$ / kW	0.60

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Loss Factors

Supply Facilities Loss Factor	1.0045
Distribution Loss Factors	
Customer less than 5,000 kW	1.0500
Customer greater than or equal to 5,000 kW	1.0100
Total Loss Factors	
Customer less than 5,000 kW	1.0545
Customer greater than or equal to 5,000 kW	1.0145

Transformer Loss Allowance

Applicable to customers requiring a billing adjustment for transformer losses as the result of being metered on the primary side of a transformer. The following uniform values shall be applied to measured demand and energy to calculate transformer losses for voltages up to and including 50 kV (as metered on the primary side):

(a) 1.5% for transformer installations up to an individual bank capacity of 400 kVA,
(b) 1.0% for bank capacities over 400 kVA.

Alternatively, transformer losses may be determined from transformer test data, and measured demand and energy adjusted accordingly

For services which are not demand metered, an assumed demand of 50% of the transformer capacity will be used to calculate the loss allowance. Where several transformers are involved, the bank capacity is assumed to be the arithmetic sum of all transformer capacities

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MISCELLANEOUS CHARGES

Specific Service Charges: Standard Amounts

Rate Code	Specific Service Charge - Standard Name	Calculation Method			
		2006 Rate Handbook	Standard Formula	Other Formula	Time and Materials
1	Temporary Service	$500			
2	Dispute Meter Test	$30 plus Measurement Canada fees			
3	Collection of account – no disconnection/load limiter	$30			
4	Collection/Disconnect/load limiter/reconnect (at meter) trip – regular hours	$65			
5	Collection/Disconnect/load limiter/reconnect (at meter) trip – after regular hours	$185			
6	Collection/Disconnect/load limiter/reconnect (at pole) trip – regular hours	$185			
7	Collection/Disconnect/load limiter/reconnect (at pole) trip – after regular hours	$415			
8	Account Set-up Charge	$30			
9	Arrears Certificate	$15			
10	NSF Cheque Charge	$15 + bank charges			
11	Easement Charge for Unregistered Rights	$15			
12	Late Payment Charge	1.5%/month			
13a	Retailer Services – Establishing Service Agreements (refer to Handbook for all charges)	$100/agreement/Retailer +$20/month/Retailer +$0.50/month/customer + other			
13b	Retailer Services – Other (includes Bill Ready for Retailers and Service Transactions Requests) as per the Handbook, Chapter 12	$0.30/month/customer + $0.25/request for request fee + $0.50/request for process fee			
14	Special Meter Reads	$30			
15	Billing Suspension and Terminations in Trailer Parks		$130		
16	Service Layout Fee – Basic		$405		
17	Service Layout Fee – Complex		$580		

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18	Crossing Application – Pipeline		$2,065		
19	Crossing Application – Water		$2,525		
20	Crossing Application – Railroad		$2,565		
21	Line Staking – per meter		$3.10		
22	Central Metering – New service < 45 kW		$115		
23	Conversion to Central Metering < 45 kW		$795		
24	Conversion to Central Metering > 45 kW		$680		
25	Tingle Voltage Test – In Excess of 4 Hours (per hour – average 2 additional hours)		$105		
26	Standby Administration Charge per month (interim)		$375		
27	Sentinel Lights Rental Rate per month – Mercury Vapor			$7.00	
28	Guaranteed Units from Jan 01/91 to Aug 01/91			$26.50 / month	
29	Guaranteed Units from Jan 01/87 to Dec 31/90			$23.50 / month	
30	Joint Use for Cable and Telecom companies per pole			$22.35	
31	Joint Use for LDCs per pole			$28.61	

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
The Corporation of the Township of Perth East Hydro Electric Commission
Effective Date: May 1, 2008

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

APPLICATION

The application of these rates and charges shall be in accordance with The Licence of The Distributor and any Codes, Guidelines or Orders of The Board, and amendments thereto as approved by The Board, which may be applicable to the administration of this schedule.
No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code, Guideline or Order of the Board, and amendments thereto as approved by the Board, or as specified herein
This schedule does not contain any rates and charges relating to the electricity commodity (e.g. the Regulated Price Plan).

EFFECTIVE DATES

DISTRIBUTION RATES - May 1, 2008 for all consumption or deemed consumption services used on or after that date.

MISCELLANEOUS CHARGES - May 1, 2008 for all charges billed to customers on or after that date.
RETAIL TRANSMISSION RATES - May 1, 2008 for all consumption or deemed consumption services used on or after that date.
LOSS FACTOR ADJUSTMENT – for all consumption or deemed consumption services billed following May 1, 2008 or later

SERVICE CLASSIFICATIONS

Residential
This classification refers to all service supplied to single-family dwelling units for domestic or household purpose. Multi-unit residential establishments such as apartment buildings supplied through one service (bulk metered) will normally be classified as General Service, but, at Hydro One's discretion, up to four residential units may be classified as residential. Where electricity service is provided to combined residential and business (including agricultural usage) and the wiring does not provide for separate metering, the classification shall be at the discretion of Hydro One based on such considerations as the estimated predominant consumption.
Further servicing details are available in the utility's Conditions of Service.

General Service
This classification refers to all service supplied to premises other than those classified as Residential or Lighting. Some General Service accounts are energy(kWh)-billed, and some are demand(kW)-billed. Further servicing details are available in the utility's Conditions of Service.

Unmetered Scattered Load
This classification refers to certain instances where connections can be provided without metering. These loads are generally small in size and consistent in magnitude of load. Hydro One reserves the right to review all cases and may require that a meter be installed at its sole discretion. Services that can be unmetered include cable TV amplifiers, telephone switching devices, phone booths, bus shelters, rail way crossing signals, traffic signals, and other small fixed loads.
Further servicing details are available in the utility's Conditions of Service (including in the "Unmetered Connections" section).

Hydro One Networks Inc.
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Street Lighting

This classification refers to accounts for the distribution and supply of electrical energy for street lighting. Street lights are devices owned by or operated for the road authority and/or the municipal corporation. These street lights in fact belong to the Street Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Sentinel Lighting

This classification refers to accounts for a separate service to a sentinel light. These sentinel lights in fact belong to the Sentinel Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Urban Density Classification

Customers who meet the Urban Density Criteria of being in an area containing 3,000 or more customers with a line density of at least 60 customers per kilometre, will be mapped to an Urban customer classification.

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
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The Corporation of the Township of Perth East Hydro Electric Commission
Effective Date: May 1, 2008

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

MONTHLY RATES AND CHARGES

Residential - R1 Perth East

Service Charge	$	8.27
Distribution Volumetric Rate	$ / kWh	0.0160
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0006
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0004)
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0047
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0046
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service Less Than 50 kW (Energy-Billed) - GSe Perth East

Service Charge	$	18.43
Distribution Volumetric Rate	$ / kWh	0.0225
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0009
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0006)
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0035
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0032
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service 50 kW or Greater (Demand-Billed) - GSd Perth East

Service Charge	$	22.03
Distribution Volumetric Rate	$ / kW	8.95
Regulatory Asset Recovery - Rider #2	$ / kW	0.27
Regulatory Asset Recovery - Rider #3	$ / kW	(0.22)
Retail Transmission Rate - Network Service Rate (4)	$ / kW	1.11
Retail Transmission Rate - Line and Transformation Connection Service Rate (4)	$ / kW	1.00
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

Hydro One Networks Inc.

TARIFF OF RATES AND CHARGES

for the Service Area Formerly Served by

The Corporation of the Township of Perth East Hydro Electric Commission

Effective Date: May 1, 2008

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

Unmetered, Scattered Load

Service Charge	$	10.66
Distribution Volumetric Rate	$ / kWh	0.0200
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0009
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0006)
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0035
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0032
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

(3) For energy-only metered customers, the billing determinant is the customer's metered energy consumption adjusted by the total loss factor as approved by the Board for Acquired LDC customers.

(4) For demand billed customers, appropriate loss factors must be applied to the applicable tariffs. Also the billing determinant for the Line and Transformation Connection Services rate is the customer's peak demand in the billing period. The billing determinant for the Network Services rate is: for non-interval-metered customers, the peak demand in the billing period, and for interval-metered customers, the peak demand between 7 AM and 7 PM local time on IESO business days

Customer-Supplied Transformation Allowance

Applicable to customers providing their own transformers

Demand-billed	$ / kW	0.60
Energy-billed	$ / kWh	0.0014

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
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The Corporation of the Township of Perth East Hydro Electric Commission
Effective Date: May 1, 2008

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

Loss Factors

Residential	1.085
General Service Less Than 50 kW (Energy-Billed)	1.092
General Service 50 kW or Greater (Demand-Billed)	1.061
Unmetered Scattered Load	1.092

Transformer Loss Allowance

Applicable to customers requiring a billing adjustment for transformer losses as the result of being metered on the primary side of a transformer. The following uniform values shall be applied to measured demand and energy to calculate transformer losses for voltages up to and including 50 kV (as metered on the primary side):

(a) 1.5% for transformer installations up to an individual bank capacity of 400 kVA,
(b) 1.0% for bank capacities over 400 kVA.

Alternatively, transformer losses may be determined from transformer test data, and measured demand and energy adjusted accordingly

For services which are not demand metered, an assumed demand of 50% of the transformer capacity will be used to calculate the loss allowance. Where several transformers are involved, the bank capacity is assumed to be the arithmetic sum of all transformer capacities

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MISCELLANEOUS CHARGES

Specific Service Charges: Standard Amounts

Rate Code	Specific Service Charge - Standard Name	Calculation Method			
		2006 Rate Handbook	Standard Formula	Other Formula	Time and Materials
1	Temporary Service	$500			
2	Dispute Meter Test	$30 plus Measurement Canada fees			
3	Collection of account – no disconnection/load limiter	$30			
4	Collection/Disconnect/load limiter/reconnect (at meter) trip – regular hours	$65			
5	Collection/Disconnect/load limiter/reconnect (at meter) trip – after regular hours	$185			
6	Collection/Disconnect/load limiter/reconnect (at pole) trip – regular hours	$185			
7	Collection/Disconnect/load limiter/reconnect (at pole) trip – after regular hours	$415			
8	Account Set-up Charge	$30			
9	Arrears Certificate	$15			
10	NSF Cheque Charge	$15 + bank charges			
11	Easement Charge for Unregistered Rights	$15			
12	Late Payment Charge	1.5%/month			
13a	Retailer Services – Establishing Service Agreements (refer to Handbook for all charges)	$100/agreement/Retailer +$20/month/Retailer +$0.50/month/customer + other			
13b	Retailer Services – Other (includes Bill Ready for Retailers and Service Transactions Requests) as per the Handbook, Chapter 12	$0.30/month/customer + $0.25/request for request fee + $0.50/request for process fee			
14	Special Meter Reads	$30			
15	Service Layout Fee – Basic		$495		
16	Service Layout Fee – Complex		$690		
17	Crossing Application – Pipeline		$2,445		
18	Crossing Application – Water		$3,045		
19	Crossing Application – Railroad		$2,945		
20	Line Staking – per meter		$3.70		
21	Central Metering – New service < 45 kW		$115		
22	Conversion to Central Metering < 45 kW		$915		
23	Conversion to Central Metering > 45 kW		$800		
24	Tingle Voltage Test – In Excess of 4 Hours (per hour – average 2 additional hours)		$125		
25	Standby Administration Charge per month		$440		
26	Sentinel Lights Rental Rate per month			$7.10	
27	Sentinel Pole Rental Rate per month			$4.15	
28	Joint Use for Cable and Telecom companies per pole			$22.35	
29	Joint Use for LDCs per pole			$28.61	

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Effective Date: May 1, 2007

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APPLICATION

The application of these rates and charges shall be in accordance with The Licence of The Distributor and any Codes, Guidelines or Orders of The Board, and amendments thereto as approved by The Board, which may be applicable to the administration of this schedule.
No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code, Guideline or Order of the Board, and amendments thereto as approved by the Board, or as specified herein
This schedule does not contain any rates and charges relating to the electricity commodity (e.g. the Regulated Price Plan).

EFFECTIVE DATES

DISTRIBUTION RATES - May 1, 2007 for all consumption or deemed consumption services used on or after that date.

MISCELLANEOUS CHARGES - May 1, 2007 for all charges billed to customers on or after that date.
RETAIL TRANSMISSION RATES - May 1, 2007 for all consumption or deemed consumption services used on or after that date.
LOSS FACTOR ADJUSTMENT – May 1, 2007

SERVICE CLASSIFICATIONS

Residential
This classification (note 1) refers to all service supplied to single-family dwelling units for domestic or household purpose. Multi-unit residential establishments such as apartment buildings supplied through one service (bulk metered) will normally be classified as General Service, but, at Hydro One's discretion, up to four residential units may be classified as residential. Where electricity service is provided to combined residential and business (including agricultural usage) and the wiring does not provide for separate metering, the classification shall be at the discretion of Hydro One based on such considerations as the estimated predominant consumption.
Further servicing details are available in the utility's Conditions of Service.

General Service
This classification (note 1) refers to all service supplied to premises other than those classified as Residential or Lighting. Some General Service accounts are energy(kWh)-billed, and some are demand(kW)-billed. Further servicing details are available in the utility's Conditions of Service. Also, see note 2.

Unmetered Scattered Load
This classification refers to certain instances where connections can be provided without metering. These loads are generally small in size and consistent in magnitude of load. Hydro One reserves the right to review all cases and may require that a meter be installed at its sole discretion. Services that can be unmetered include cable TV amplifiers, telephone switching devices, phone booths, bus shelters, rail way crossing signals, traffic signals, and other small fixed loads.
Further servicing details are available in the utility's Conditions of Service (including in the "Unmetered Connections" section).

Hydro One Networks Inc.
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Street Lighting

This classification refers to accounts for the distribution and supply of electrical energy for street lighting. Street lights are devices owned by or operated for the road authority and/or the municipal corporation. These street lights in fact belong to the Street Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Sentinel Lighting

This classification refers to accounts for a separate service to a sentinel light. These sentinel lights in fact belong to the Sentinel Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Interim Demand-Side Management Time-of-Use

This is potentially applicable to Demand-billed General Service accounts. See Note 2 below.

Note (1): Classification descriptions are paraphrases from the document "Hydro One Networks Inc. - Distribution Customers Conditions of Service - August 2004"

Note (2):

Interim Demand-Side Management Time-of-Use Rates: demand charges will be based on demand during the on-peak periods.

Criteria: Customers' electricity consumption (kW) in the off-peak period is at least twice the electricity consumption (kW) during the on-peak period.

Definition of Time Periods: The on-peak hours will be between 0700 hours to 1900 hours Eastern Standard Time during the winter (standard time) on IESO business days and 0600 hours to 1800 hours Eastern Standard Time during the summer (daylight savings time) on IESO business days. The off-peak period constitutes all of the remaining hours.

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MONTHLY RATES AND CHARGES

Residential

Service Charge	$	5.95
Distribution Volumetric Rate	$ / kWh	0.0078
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0026
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0006
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0055
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0047
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service - Energy Billed (less than 50 kW)

Service Charge	$	14.65
Distribution Volumetric Rate	$ / kWh	0.0129
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0016
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0009
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0050
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0043
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service - Demand Billed (50 kW or greater)

Service Charge	$	14.65
Distribution Volumetric Rate	$ / kW	4.08
Regulatory Asset Recovery - Rider #1	$ / kW	0.52
Regulatory Asset Recovery - Rider #2	$ / kW	0.27
Retail Transmission Rate - Network Service Rate (4)	$ / kW	1.94
Retail Transmission Rate - Line and Transformation Connection Service Rate (4)	$ / kW	1.61
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

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Unmetered, Scattered Load

Service Charge	$	6.86
Distribution Volumetric Rate	$ / kWh	0.0129
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0016
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0009
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0050
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0043
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

(3) For energy-only metered customers, the billing determinant is the customer’s metered energy consumption adjusted by the total loss factor as approved by the Board for Acquired LDC customers.

(4) For demand billed customers, appropriate loss factors must be applied to the applicable tariffs. Also the billing determinant for the Line and Transformation Connection Services rate is the customer’s peak demand in the billing period. The billing determinant for the Network Services rate is: for non-interval-metered customers, the peak demand in the billing period, and for interval-metered customers, the peak demand between 7 AM and 7 PM local time on IESO business days

Interim Demand-Side Management Time-of-Use

See the "Service Classifications" section of this schedule.

Customer-Supplied Transformation Allowance

Applicable to demand-billed customers providing their own transformers
Primary Voltage under 50 kV (per kW)

Single Phase	$ / kW	0.20
Three Phase	$ / kW	0.60

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Loss Factors

Supply Facilities Loss Factor	1.0045
Distribution Loss Factors	
Customer less than 5,000 kW	1.0500
Customer greater than or equal to 5,000 kW	1.0100
Total Loss Factors	
Customer less than 5,000 kW	1.0545
Customer greater than or equal to 5,000 kW	1.0145

Transformer Loss Allowance

Applicable to customers requiring a billing adjustment for transformer losses as the result of being metered on the primary side of a transformer. The following uniform values shall be applied to measured demand and energy to calculate transformer losses for voltages up to and including 50 kV (as metered on the primary side):

(a) 1.5% for transformer installations up to an individual bank capacity of 400 kVA,
(b) 1.0% for bank capacities over 400 kVA.

Alternatively, transformer losses may be determined from transformer test data, and measured demand and energy adjusted accordingly

For services which are not demand metered, an assumed demand of 50% of the transformer capacity will be used to calculate the loss allowance. Where several transformers are involved, the bank capacity is assumed to be the arithmetic sum of all transformer capacities

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MISCELLANEOUS CHARGES

Specific Service Charges: Standard Amounts

Rate Code	Specific Service Charge - Standard Name	Calculation Method			
		2006 Rate Handbook	Standard Formula	Other Formula	Time and Materials
1	Temporary Service	$500			
2	Dispute Meter Test	$30 plus Measurement Canada fees			
3	Collection of account – no disconnection/load limiter	$30			
4	Collection/Disconnect/load limiter/reconnect (at meter) trip – regular hours	$65			
5	Collection/Disconnect/load limiter/reconnect (at meter) trip – after regular hours	$185			
6	Collection/Disconnect/load limiter/reconnect (at pole) trip – regular hours	$185			
7	Collection/Disconnect/load limiter/reconnect (at pole) trip – after regular hours	$415			
8	Account Set-up Charge	$30			
9	Arrears Certificate	$15			
10	NSF Cheque Charge	$15 + bank charges			
11	Easement Charge for Unregistered Rights	$15			
12	Late Payment Charge	1.5%/month			
13a	Retailer Services – Establishing Service Agreements (refer to Handbook for all charges)	$100/agreement/Retailer +$20/month/Retailer +$0.50/month/customer + other			
13b	Retailer Services – Other (includes Bill Ready for Retailers and Service Transactions Requests) as per the Handbook, Chapter 12	$0.30/month/customer + $0.25/request for request fee + $0.50/request for process fee			
14	Special Meter Reads	$30			
15	Billing Suspension and Terminations in Trailer Parks		$130		
16	Service Layout Fee – Basic		$405		
17	Service Layout Fee – Complex		$580		

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18	Crossing Application – Pipeline		$2,065		
19	Crossing Application – Water		$2,525		
20	Crossing Application – Railroad		$2,565		
21	Line Staking – per meter		$3.10		
22	Central Metering – New service < 45 kW		$115		
23	Conversion to Central Metering < 45 kW		$795		
24	Conversion to Central Metering > 45 kW		$680		
25	Tingle Voltage Test – In Excess of 4 Hours (per hour – average 2 additional hours)		$105		
26	Standby Administration Charge per month (interim)		$375		
27	Sentinel Lights Rental Rate per month – Mercury Vapor			$7.00	
28	Guaranteed Units from Jan 01/91 to Aug 01/91			$26.50 / month	
29	Guaranteed Units from Jan 01/87 to Dec 31/90			$23.50 / month	
30	Joint Use for Cable and Telecom companies per pole			$22.35	
31	Joint Use for LDCs per pole			$28.61	

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APPLICATION

The application of these rates and charges shall be in accordance with The Licence of The Distributor and any Codes, Guidelines or Orders of The Board, and amendments thereto as approved by The Board, which may be applicable to the administration of this schedule.
No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code, Guideline or Order of the Board, and amendments thereto as approved by the Board, or as specified herein
This schedule does not contain any rates and charges relating to the electricity commodity (e.g. the Regulated Price Plan).

EFFECTIVE DATES

DISTRIBUTION RATES - May 1, 2008 for all consumption or deemed consumption services used on or after that date.

MISCELLANEOUS CHARGES - May 1, 2008 for all charges billed to customers on or after that date.
RETAIL TRANSMISSION RATES - May 1, 2008 for all consumption or deemed consumption services used on or after that date.
LOSS FACTOR ADJUSTMENT – for all consumption or deemed consumption services billed following May 1, 2008 or later

SERVICE CLASSIFICATIONS

Residential
This classification refers to all service supplied to single-family dwelling units for domestic or household purpose. Multi-unit residential establishments such as apartment buildings supplied through one service (bulk metered) will normally be classified as General Service, but, at Hydro One's discretion, up to four residential units may be classified as residential. Where electricity service is provided to combined residential and business (including agricultural usage) and the wiring does not provide for separate metering, the classification shall be at the discretion of Hydro One based on such considerations as the estimated predominant consumption.
Further servicing details are available in the utility's Conditions of Service.

General Service
This classification refers to all service supplied to premises other than those classified as Residential or Lighting. Some General Service accounts are energy(kWh)-billed, and some are demand(kW)-billed. Further servicing details are available in the utility's Conditions of Service.

Unmetered Scattered Load
This classification refers to certain instances where connections can be provided without metering. These loads are generally small in size and consistent in magnitude of load. Hydro One reserves the right to review all cases and may require that a meter be installed at its sole discretion. Services that can be unmetered include cable TV amplifiers, telephone switching devices, phone booths, bus shelters, rail way crossing signals, traffic signals, and other small fixed loads.
Further servicing details are available in the utility's Conditions of Service (including in the "Unmetered Connections" section).

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Street Lighting

This classification refers to accounts for the distribution and supply of electrical energy for street lighting. Street lights are devices owned by or operated for the road authority and/or the municipal corporation. These street lights in fact belong to the Street Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Sentinel Lighting

This classification refers to accounts for a separate service to a sentinel light. These sentinel lights in fact belong to the Sentinel Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Urban Density Classification

Customers who meet the Urban Density Criteria of being in an area containing 3,000 or more customers with a line density of at least 60 customers per kilometre, will be mapped to an Urban customer classification.

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MONTHLY RATES AND CHARGES

Residential - R1 Prince Edward

Service Charge	$	15.20
Distribution Volumetric Rate	$ / kWh	0.0225
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0013
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0004)
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0047
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0046
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service Less Than 50 kW (Energy-Billed) - GSe Prince Edward

Service Charge	$	24.38
Distribution Volumetric Rate	$ / kWh	0.0257
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0008
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0006)
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0035
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0032
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service 50 kW or Greater (Demand-Billed) - GSd Prince Edward

Service Charge	$	27.98
Distribution Volumetric Rate	$ / kW	9.22
Regulatory Asset Recovery - Rider #2	$ / kW	0.24
Regulatory Asset Recovery - Rider #3	$ / kW	(0.22)
Retail Transmission Rate - Network Service Rate (4)	$ / kW	1.11
Retail Transmission Rate - Line and Transformation Connection Service Rate (4)	$ / kW	1.00
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

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Unmetered, Scattered Load

Service Charge	$	13.64
Distribution Volumetric Rate	$ / kWh	0.0200
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0008
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0006)
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0035
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0032
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

(3) For energy-only metered customers, the billing determinant is the customer's metered energy consumption adjusted by the total loss factor as approved by the Board for Acquired LDC customers.
(4) For demand billed customers, appropriate loss factors must be applied to the applicable tariffs. Also the billing determinant for the Line and Transformation Connection Services rate is the customer's peak demand in the billing period. The billing determinant for the Network Services rate is: for non-interval-metered customers, the peak demand in the billing period, and for interval-metered customers, the peak demand between 7 AM and 7 PM local time on IESO business days

Customer-Supplied Transformation Allowance

Applicable to customers providing their own transformers

Demand-billed	$ / kW	0.60
Energy-billed	$ / kWh	0.0014

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Loss Factors

Residential	1.085
General Service Less Than 50 kW (Energy-Billed)	1.092
General Service 50 kW or Greater (Demand-Billed)	1.061
Unmetered Scattered Load	1.092

Transformer Loss Allowance

Applicable to customers requiring a billing adjustment for transformer losses as the result of being metered on the primary side of a transformer. The following uniform values shall be applied to measured demand and energy to calculate transformer losses for voltages up to and including 50 kV (as metered on the primary side):

(a) 1.5% for transformer installations up to an individual bank capacity of 400 kVA,
(b) 1.0% for bank capacities over 400 kVA.

Alternatively, transformer losses may be determined from transformer test data, and measured demand and energy adjusted accordingly
For services which are not demand metered, an assumed demand of 50% of the transformer capacity will be used to calculate the loss allowance. Where several transformers are involved, the bank capacity is assumed to be the arithmetic sum of all transformer capacities

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MISCELLANEOUS CHARGES

Specific Service Charges: Standard Amounts

Rate Code	Specific Service Charge - Standard Name	Calculation Method			
		2006 Rate Handbook	Standard Formula	Other Formula	Time and Materials
1	Temporary Service	$500			
2	Dispute Meter Test	$30 plus Measurement Canada fees			
3	Collection of account – no disconnection/load limiter	$30			
4	Collection/Disconnect/load limiter/reconnect (at meter) trip – regular hours	$65			
5	Collection/Disconnect/load limiter/reconnect (at meter) trip – after regular hours	$185			
6	Collection/Disconnect/load limiter/reconnect (at pole) trip – regular hours	$185			
7	Collection/Disconnect/load limiter/reconnect (at pole) trip – after regular hours	$415			
8	Account Set-up Charge	$30			
9	Arrears Certificate	$15			
10	NSF Cheque Charge	$15 + bank charges			
11	Easement Charge for Unregistered Rights	$15			
12	Late Payment Charge	1.5%/month			
13a	Retailer Services – Establishing Service Agreements (refer to Handbook for all charges)	$100/agreement/Retailer +$20/month/Retailer +$0.50/month/customer + other			
13b	Retailer Services – Other (includes Bill Ready for Retailers and Service Transactions Requests) as per the Handbook, Chapter 12	$0.30/month/customer + $0.25/request for request fee + $0.50/request for process fee			
14	Special Meter Reads	$30			
15	Service Layout Fee – Basic		$495		
16	Service Layout Fee – Complex		$690		
17	Crossing Application – Pipeline		$2,445		
18	Crossing Application – Water		$3,045		
19	Crossing Application – Railroad		$2,945		
20	Line Staking – per meter		$3.70		
21	Central Metering – New service < 45 kW		$115		
22	Conversion to Central Metering < 45 kW		$915		
23	Conversion to Central Metering > 45 kW		$800		
24	Tingle Voltage Test – In Excess of 4 Hours (per hour – average 2 additional hours)		$125		
25	Standby Administration Charge per month		$440		
26	Sentinel Lights Rental Rate per month			$7.10	
27	Sentinel Pole Rental Rate per month			$4.15	
28	Joint Use for Cable and Telecom companies per pole			$22.35	
29	Joint Use for LDCs per pole			$28.61	

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APPLICATION

The application of these rates and charges shall be in accordance with The Licence of The Distributor and any Codes, Guidelines or Orders of The Board, and amendments thereto as approved by The Board, which may be applicable to the administration of this schedule.
No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code, Guideline or Order of the Board, and amendments thereto as approved by the Board, or as specified herein
This schedule does not contain any rates and charges relating to the electricity commodity (e.g. the Regulated Price Plan).

EFFECTIVE DATES

DISTRIBUTION RATES - May 1, 2007 for all consumption or deemed consumption services used on or after that date.

MISCELLANEOUS CHARGES - May 1, 2007 for all charges billed to customers on or after that date.
RETAIL TRANSMISSION RATES - May 1, 2007 for all consumption or deemed consumption services used on or after that date.
LOSS FACTOR ADJUSTMENT – May 1, 2007

SERVICE CLASSIFICATIONS

Residential
This classification (note 1) refers to all service supplied to single-family dwelling units for domestic or household purpose. Multi-unit residential establishments such as apartment buildings supplied through one service (bulk metered) will normally be classified as General Service, but, at Hydro One's discretion, up to four residential units may be classified as residential. Where electricity service is provided to combined residential and business (including agricultural usage) and the wiring does not provide for separate metering, the classification shall be at the discretion of Hydro One based on such considerations as the estimated predominant consumption.
Further servicing details are available in the utility's Conditions of Service.

General Service
This classification (note 1) refers to all service supplied to premises other than those classified as Residential or Lighting. Some General Service accounts are energy(kWh)-billed, and some are demand(kW)-billed. Further servicing details are available in the utility's Conditions of Service. Also, see note 2.

Unmetered Scattered Load
This classification refers to certain instances where connections can be provided without metering. These loads are generally small in size and consistent in magnitude of load. Hydro One reserves the right to review all cases and may require that a meter be installed at its sole discretion. Services that can be unmetered include cable TV amplifiers, telephone switching devices, phone booths, bus shelters, rail way crossing signals, traffic signals, and other small fixed loads.
Further servicing details are available in the utility's Conditions of Service (including in the "Unmetered Connections" section).

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Prince Edward Public Utilities Commission
Effective Date: May 1, 2007

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

Street Lighting

This classification refers to accounts for the distribution and supply of electrical energy for street lighting. Street lights are devices owned by or operated for the road authority and/or the municipal corporation. These street lights in fact belong to the Street Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Sentinel Lighting

This classification refers to accounts for a separate service to a sentinel light. These sentinel lights in fact belong to the Sentinel Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Interim Demand-Side Management Time-of-Use

This is potentially applicable to Demand-billed General Service accounts. See Note 2 below.

Note (1): Classification descriptions are paraphrases from the document "Hydro One Networks Inc. - Distribution Customers Conditions of Service - August 2004"

Note (2):

Interim Demand-Side Management Time-of-Use Rates: demand charges will be based on demand during the on-peak periods.

Criteria: Customers' electricity consumption (kW) in the off-peak period is at least twice the electricity consumption (kW) during the on-peak period.

Definition of Time Periods: The on-peak hours will be between 0700 hours to 1900 hours Eastern Standard Time during the winter (standard time) on IESO business days and 0600 hours to 1800 hours Eastern Standard Time during the summer (daylight savings time) on IESO business days. The off-peak period constitutes all of the remaining hours.

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Prince Edward Public Utilities Commission
Effective Date: May 1, 2007

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

MONTHLY RATES AND CHARGES

Residential

Service Charge	$	14.25
Distribution Volumetric Rate	$ / kWh	0.0105
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0039
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0013
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0055
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0047
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service - Energy Billed (less than 50 kW)

Service Charge	$	22.85
Distribution Volumetric Rate	$ / kWh	0.0142
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0018
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0008
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0050
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0043
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service - Demand Billed (50 kW or greater)

Service Charge	$	22.85
Distribution Volumetric Rate	$ / kW	4.45
Regulatory Asset Recovery - Rider #1	$ / kW	0.58
Regulatory Asset Recovery - Rider #2	$ / kW	0.24
Retail Transmission Rate - Network Service Rate (4)	$ / kW	1.94
Retail Transmission Rate - Line and Transformation Connection Service Rate (4)	$ / kW	1.61
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
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Prince Edward Public Utilities Commission
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This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

Unmetered, Scattered Load

Service Charge	$	10.96
Distribution Volumetric Rate	$ / kWh	0.0142
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0018
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0008
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0050
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0043
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

(3) For energy-only metered customers, the billing determinant is the customer's metered energy consumption adjusted by the total loss factor as approved by the Board for Acquired LDC customers.
(4) For demand billed customers, appropriate loss factors must be applied to the applicable tariffs. Also the billing determinant for the Line and Transformation Connection Services rate is the customer's peak demand in the billing period. The billing determinant for the Network Services rate is: for non-interval-metered customers, the peak demand in the billing period, and for interval-metered customers, the peak demand between 7 AM and 7 PM local time on IESO business days

Interim Demand-Side Management Time-of-Use

See the "Service Classifications" section of this schedule.

Customer-Supplied Transformation Allowance

Applicable to demand-billed customers providing their own transformers
Primary Voltage under 50 kV (per kW)

Single Phase	$ / kW	0.20
Three Phase	$ / kW	0.60

Hydro One Networks Inc.
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Loss Factors

Supply Facilities Loss Factor	1.0045
Distribution Loss Factors	
Customer less than 5,000 kW	1.0500
Customer greater than or equal to 5,000 kW	1.0100
Total Loss Factors	
Customer less than 5,000 kW	1.0545
Customer greater than or equal to 5,000 kW	1.0145

Transformer Loss Allowance

Applicable to customers requiring a billing adjustment for transformer losses as the result of being metered on the primary side of a transformer. The following uniform values shall be applied to measured demand and energy to calculate transformer losses for voltages up to and including 50 kV (as metered on the primary side):

(a) 1.5% for transformer installations up to an individual bank capacity of 400 kVA,
(b) 1.0% for bank capacities over 400 kVA.

Alternatively, transformer losses may be determined from transformer test data, and measured demand and energy adjusted accordingly

For services which are not demand metered, an assumed demand of 50% of the transformer capacity will be used to calculate the loss allowance. Where several transformers are involved, the bank capacity is assumed to be the arithmetic sum of all transformer capacities

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
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This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

MISCELLANEOUS CHARGES

Specific Service Charges: Standard Amounts

Rate Code	Specific Service Charge - Standard Name	Calculation Method			
		2006 Rate Handbook	Standard Formula	Other Formula	Time and Materials
1	Temporary Service	$500			
2	Dispute Meter Test	$30 plus Measurement Canada fees			
3	Collection of account – no disconnection/load limiter	$30			
4	Collection/Disconnect/load limiter/reconnect (at meter) trip – regular hours	$65			
5	Collection/Disconnect/load limiter/reconnect (at meter) trip – after regular hours	$185			
6	Collection/Disconnect/load limiter/reconnect (at pole) trip – regular hours	$185			
7	Collection/Disconnect/load limiter/reconnect (at pole) trip – after regular hours	$415			
8	Account Set-up Charge	$30			
9	Arrears Certificate	$15			
10	NSF Cheque Charge	$15 + bank charges			
11	Easement Charge for Unregistered Rights	$15			
12	Late Payment Charge	1.5%/month			
13a	Retailer Services – Establishing Service Agreements (refer to Handbook for all charges)	$100/agreement/Retailer +$20/month/Retailer +$0.50/month/customer + other			
13b	Retailer Services – Other (includes Bill Ready for Retailers and Service Transactions Requests) as per the Handbook, Chapter 12	$0.30/month/customer + $0.25/request for request fee + $0.50/request for process fee			
14	Special Meter Reads	$30			
15	Billing Suspension and Terminations in Trailer Parks		$130		
16	Service Layout Fee – Basic		$405		
17	Service Layout Fee – Complex		$580		

Hydro One Networks Inc.
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18	Crossing Application – Pipeline		$2,065		
19	Crossing Application – Water		$2,525		
20	Crossing Application – Railroad		$2,565		
21	Line Staking – per meter		$3.10		
22	Central Metering – New service < 45 kW		$115		
23	Conversion to Central Metering < 45 kW		$795		
24	Conversion to Central Metering > 45 kW		$680		
25	Tingle Voltage Test – In Excess of 4 Hours (per hour – average 2 additional hours)		$105		
26	Standby Administration Charge per month (interim)		$375		
27	Sentinel Lights Rental Rate per month – Mercury Vapor			$7.00	
28	Guaranteed Units from Jan 01/91 to Aug 01/91			$26.50 / month	
29	Guaranteed Units from Jan 01/87 to Dec 31/90			$23.50 / month	
30	Joint Use for Cable and Telecom companies per pole			$22.35	
31	Joint Use for LDCs per pole			$28.61	

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Quinte West Electric Distribution Inc.
Effective Date: May 1, 2008

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

APPLICATION

The application of these rates and charges shall be in accordance with The Licence of The Distributor and any Codes, Guidelines or Orders of The Board, and amendments thereto as approved by The Board, which may be applicable to the administration of this schedule.
No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code, Guideline or Order of the Board, and amendments thereto as approved by the Board, or as specified herein
This schedule does not contain any rates and charges relating to the electricity commodity (e.g. the Regulated Price Plan).

EFFECTIVE DATES

DISTRIBUTION RATES - May 1, 2008 for all consumption or deemed consumption services used on or after that date.

MISCELLANEOUS CHARGES - May 1, 2008 for all charges billed to customers on or after that date.
RETAIL TRANSMISSION RATES - May 1, 2008 for all consumption or deemed consumption services used on or after that date.
LOSS FACTOR ADJUSTMENT – for all consumption or deemed consumption services billed following May 1, 2008 or later

SERVICE CLASSIFICATIONS

Residential
This classification refers to all service supplied to single-family dwelling units for domestic or household purpose. Multi-unit residential establishments such as apartment buildings supplied through one service (bulk metered) will normally be classified as General Service, but, at Hydro One's discretion, up to four residential units may be classified as residential. Where electricity service is provided to combined residential and business (including agricultural usage) and the wiring does not provide for separate metering, the classification shall be at the discretion of Hydro One based on such considerations as the estimated predominant consumption.
Further servicing details are available in the utility's Conditions of Service.

General Service
This classification refers to all service supplied to premises other than those classified as Residential or Lighting. Some General Service accounts are energy(kWh)-billed, and some are demand(kW)-billed. Further servicing details are available in the utility's Conditions of Service.

Unmetered Scattered Load
This classification refers to certain instances where connections can be provided without metering. These loads are generally small in size and consistent in magnitude of load. Hydro One reserves the right to review all cases and may require that a meter be installed at its sole discretion. Services that can be unmetered include cable TV amplifiers, telephone switching devices, phone booths, bus shelters, rail way crossing signals, traffic signals, and other small fixed loads.
Further servicing details are available in the utility's Conditions of Service (including in the "Unmetered Connections" section).

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Quinte West Electric Distribution Inc.
Effective Date: May 1, 2008

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

Large Use - see Note 1

Street Lighting

This classification refers to accounts for the distribution and supply of electrical energy for street lighting. Street lights are devices owned by or operated for the road authority and/or the municipal corporation. These street lights in fact belong to the Street Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Sentinel Lighting

This classification refers to accounts for a separate service to a sentinel light. These sentinel lights in fact belong to the Sentinel Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Urban Density Classification

Customers who meet the Urban Density Criteria of being in an area containing 3,000 or more customers with a line density of at least 60 customers per kilometre, will be mapped to an Urban customer classification.

Note (1) The former Large Use class is now part of the ST class, which is separate from the classes for customers of acquired distribution companies.
This former class refered to individual Customers whose monthly measured maximum demand (kW) averaged over the most recent 12 consecutive months is equal to or greater than 5,000 kW.

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
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Quinte West Electric Distribution Inc.
Effective Date: May 1, 2008

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MONTHLY RATES AND CHARGES

Residential - UR/R1 Quinte West

Service Charge	$	7.94
Distribution Volumetric Rate	$ / kWh	0.0210
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0011
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0002)
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0047
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0045
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service Less Than 50 kW (Energy-Billed) - UGe/GSe Quinte West

Service Charge	$	5.15
Distribution Volumetric Rate	$ / kWh	0.0200
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0006
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0006)
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0036
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0033
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service 50 kW or Greater (Demand-Billed) - UGd/GSd Quinte West

Service Charge	$	9.36
Distribution Volumetric Rate	$ / kW	7.33
Regulatory Asset Recovery - Rider #2	$ / kW	0.18
Regulatory Asset Recovery - Rider #3	$ / kW	(0.27)
Retail Transmission Rate - Network Service Rate (4)	$ / kW	1.41
Retail Transmission Rate - Line and Transformation Connection Service Rate (4)	$ / kW	1.27
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
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Quinte West Electric Distribution Inc.
Effective Date: May 1, 2008

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

Unmetered, Scattered Load

Service Charge	$	7.03
Distribution Volumetric Rate	$ / kWh	0.0200
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0006
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0006)
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0035
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0032
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

(3) For energy-only metered customers, the billing determinant is the customer's metered energy consumption adjusted by the total loss factor as approved by the Board for Acquired LDC customers.
(4) For demand billed customers, appropriate loss factors must be applied to the applicable tariffs. Also the billing determinant for the Line and Transformation Connection Services rate is the customer's peak demand in the billing period. The billing determinant for the Network Services rate is: for non-interval-metered customers, the peak demand in the billing period, and for interval-metered customers, the peak demand between 7 AM and 7 PM local time on IESO business days

Customer-Supplied Transformation Allowance

Applicable to customers providing their own transformers		
Demand-billed	$ / kW	0.60
Energy-billed	$ / kWh	0.0014

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Loss Factors

Residential	1.078
General Service Less Than 50 kW (Energy-Billed)	1.092
General Service 50 kW or Greater (Demand-Billed)	1.061
Unmetered Scattered Load	1.092

Transformer Loss Allowance

Applicable to customers requiring a billing adjustment for transformer losses as the result of being metered on the primary side of a transformer. The following uniform values shall be applied to measured demand and energy to calculate transformer losses for voltages up to and including 50 kV (as metered on the primary side):

(a) 1.5% for transformer installations up to an individual bank capacity of 400 kVA,
(b) 1.0% for bank capacities over 400 kVA.

Alternatively, transformer losses may be determined from transformer test data, and measured demand and energy adjusted accordingly

For services which are not demand metered, an assumed demand of 50% of the transformer capacity will be used to calculate the loss allowance. Where several transformers are involved, the bank capacity is assumed to be the arithmetic sum of all transformer capacities

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Quinte West Electric Distribution Inc.
Effective Date: May 1, 2008

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

MISCELLANEOUS CHARGES

Specific Service Charges: Standard Amounts

Rate Code	Specific Service Charge - Standard Name	Calculation Method			
		2006 Rate Handbook	Standard Formula	Other Formula	Time and Materials
1	Temporary Service	$500			
2	Dispute Meter Test	$30 plus Measurement Canada fees			
3	Collection of account – no disconnection/load limiter	$30			
4	Collection/Disconnect/load limiter/reconnect (at meter) trip – regular hours	$65			
5	Collection/Disconnect/load limiter/reconnect (at meter) trip – after regular hours	$185			
6	Collection/Disconnect/load limiter/reconnect (at pole) trip – regular hours	$185			
7	Collection/Disconnect/load limiter/reconnect (at pole) trip – after regular hours	$415			
8	Account Set-up Charge	$30			
9	Arrears Certificate	$15			
10	NSF Cheque Charge	$15 + bank charges			
11	Easement Charge for Unregistered Rights	$15			
12	Late Payment Charge	1.5%/month			
13a	Retailer Services – Establishing Service Agreements (refer to Handbook for all charges)	$100/agreement/Retailer +$20/month/Retailer +$0.50/month/customer + other			
13b	Retailer Services – Other (includes Bill Ready for Retailers and Service Transactions Requests) as per the Handbook, Chapter 12	$0.30/month/customer + $0.25/request for request fee + $0.50/request for process fee			
14	Special Meter Reads	$30			
15	Service Layout Fee – Basic		$495		
16	Service Layout Fee – Complex		$690		
17	Crossing Application – Pipeline		$2,445		
18	Crossing Application – Water		$3,045		
19	Crossing Application – Railroad		$2,945		
20	Line Staking – per meter		$3.70		
21	Central Metering – New service < 45 kW		$115		
22	Conversion to Central Metering < 45 kW		$915		
23	Conversion to Central Metering > 45 kW		$800		
24	Tingle Voltage Test – In Excess of 4 Hours (per hour – average 2 additional hours)		$125		
25	Standby Administration Charge per month		$440		
26	Sentinel Lights Rental Rate per month			$7.10	
27	Sentinel Pole Rental Rate per month			$4.15	
28	Joint Use for Cable and Telecom companies per pole			$22.35	
29	Joint Use for LDCs per pole			$28.61	

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Quinte West Electric Distribution Inc.
Effective Date: May 1, 2007

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APPLICATION

The application of these rates and charges shall be in accordance with The Licence of The Distributor and any Codes, Guidelines or Orders of The Board, and amendments thereto as approved by The Board, which may be applicable to the administration of this schedule.
No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code, Guideline or Order of the Board, and amendments thereto as approved by the Board, or as specified herein
This schedule does not contain any rates and charges relating to the electricity commodity (e.g. the Regulated Price Plan).

EFFECTIVE DATES

DISTRIBUTION RATES - May 1, 2007 for all consumption or deemed consumption services used on or after that date.

MISCELLANEOUS CHARGES - May 1, 2007 for all charges billed to customers on or after that date.
RETAIL TRANSMISSION RATES - May 1, 2007 for all consumption or deemed consumption services used on or after that date.
LOSS FACTOR ADJUSTMENT – May 1, 2007

SERVICE CLASSIFICATIONS

Residential
This classification (note 1) refers to all service supplied to single-family dwelling units for domestic or household purpose. Multi-unit residential establishments such as apartment buildings supplied through one service (bulk metered) will normally be classified as General Service, but, at Hydro One's discretion, up to four residential units may be classified as residential. Where electricity service is provided to combined residential and business (including agricultural usage) and the wiring does not provide for separate metering, the classification shall be at the discretion of Hydro One based on such considerations as the estimated predominant consumption.
Further servicing details are available in the utility's Conditions of Service.

General Service
This classification (note 1) refers to all service supplied to premises other than those classified as Residential, Lighting or Large Use. Some General Service accounts are energy(kWh)-billed, and some are demand(kW)-billed. Further servicing details are available in the utility's Conditions of Service. Also, see note 2.

Unmetered Scattered Load
This classification refers to certain instances where connections can be provided without metering. These loads are generally small in size and consistent in magnitude of load. Hydro One reserves the right to review all cases and may require that a meter be installed at its sole discretion. Services that can be unmetered include cable TV amplifiers, telephone switching devices, phone booths, bus shelters, rail way crossing signals, traffic signals, and other small fixed loads.
Further servicing details are available in the utility's Conditions of Service (including in the "Unmetered Connections" section).

Hydro One Networks Inc.
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Effective Date: May 1, 2007

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

Large Use

This classification refers to individual Customers whose monthly measured maximum demand (kW) averaged over the Further servicing details are available in the utility's Conditions of Service. Also, see note 2.

Street Lighting

This classification refers to accounts for the distribution and supply of electrical energy for street lighting. Street lights are devices owned by or operated for the road authority and/or the municipal corporation. These street lights in fact belong to the Street Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Sentinel Lighting

This classification refers to accounts for a separate service to a sentinel light. These sentinel lights in fact belong to the Sentinel Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Interim Demand-Side Management Time-of-Use

This is potentially applicable to Demand-billed General Service and Large Use accounts. See Note 2 below.

Note (1): Classification descriptions are paraphrases from the document "Hydro One Networks Inc. - Distribution Customers Conditions of Service - August 2004"

Note (2):

Interim Demand-Side Management Time-of-Use Rates: demand charges will be based on demand during the on-peak periods.

Criteria: Customers' electricity consumption (kW) in the off-peak period is at least twice the electricity consumption (kW) during the on-peak period.

Definition of Time Periods: The on-peak hours will be between 0700 hours to 1900 hours Eastern Standard Time during the winter (standard time) on IESO business days and 0600 hours to 1800 hours Eastern Standard Time during the summer (daylight savings time) on IESO business days. The off-peak period constitutes all of the remaining hours.

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
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Quinte West Electric Distribution Inc.
Effective Date: May 1, 2007

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

MONTHLY RATES AND CHARGES

Residential

Service Charge	$	6.58
Distribution Volumetric Rate	$ / kWh	0.0092
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0039
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0011
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0055
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0047
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service - Energy Billed (less than 50 kW)

Service Charge	$	3.74
Distribution Volumetric Rate	$ / kWh	0.0105
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0014
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0006
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0050
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0043
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service - Demand Billed (50 kW or greater)

Service Charge	$	3.74
Distribution Volumetric Rate	$ / kW	3.32
Regulatory Asset Recovery - Rider #1	$ / kW	0.46
Regulatory Asset Recovery - Rider #2	$ / kW	0.18
Retail Transmission Rate - Network Service Rate (4)	$ / kW	1.94
Retail Transmission Rate - Line and Transformation Connection Service Rate (4)	$ / kW	1.61
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Quinte West Electric Distribution Inc.
Effective Date: May 1, 2007

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

Unmetered, Scattered Load

Service Charge	$	1.41
Distribution Volumetric Rate	$ / kWh	0.0105
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0014
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0006
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0050
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0043
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

Large User

Service Charge	$	2,305
Distribution Volumetric Rate	$ / kW	3.60
Regulatory Asset Recovery - Rider #1	$ / kW	0.37
Regulatory Asset Recovery - Rider #2	$ / kW	0.11
Retail Transmission Rate - Network Service Rate (4)	$ / kW	2.37
Retail Transmission Rate - Line and Transformation Connection Service Rate (4)	$ / kW	2.09
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

(3) For energy-only metered customers, the billing determinant is the customer’s metered energy consumption adjusted by the total loss factor as approved by the Board for Acquired LDC customers.
(4) For demand billed customers, appropriate loss factors must be applied to the applicable tariffs. Also the billing determinant for the Line and Transformation Connection Services rate is the customer’s peak demand in the billing period. The billing determinant for the Network Services rate is: for non-interval-metered customers, the peak demand in the billing period, and for interval-metered customers, the peak demand between 7 AM and 7 PM local time on IESO business days

Interim Demand-Side Management Time-of-Use

See the "Service Classifications" section of this schedule.

Customer-Supplied Transformation Allowance

Applicable to demand-billed customers (excluding Large Users) providing their own transformers
Primary Voltage under 50 kV (per kW)

Single Phase	$ / kW	0.20
Three Phase	$ / kW	0.60

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
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Quinte West Electric Distribution Inc.
Effective Date: May 1, 2007

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

Loss Factors

Supply Facilities Loss Factor	1.0045
Distribution Loss Factors	
Customer less than 5,000 kW	1.0500
Customer greater than or equal to 5,000 kW	1.0100
Total Loss Factors	
Customer less than 5,000 kW	1.0545
Customer greater than or equal to 5,000 kW	1.0145

Transformer Loss Allowance

Applicable to customers requiring a billing adjustment for transformer losses as the result of being metered on the primary side of a transformer. The following uniform values shall be applied to measured demand and energy to calculate transformer losses for voltages up to and including 50 kV (as metered on the primary side):

(a) 1.5% for transformer installations up to an individual bank capacity of 400 kVA,
(b) 1.0% for bank capacities over 400 kVA.

Alternatively, transformer losses may be determined from transformer test data, and measured demand and energy adjusted accordingly

For services which are not demand metered, an assumed demand of 50% of the transformer capacity will be used to calculate the loss allowance. Where several transformers are involved, the bank capacity is assumed to be the arithmetic sum of all transformer capacities

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
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Quinte West Electric Distribution Inc.
Effective Date: May 1, 2007

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

MISCELLANEOUS CHARGES

Specific Service Charges: Standard Amounts

Rate Code	Specific Service Charge - Standard Name	Calculation Method			
		2006 Rate Handbook	Standard Formula	Other Formula	Time and Materials
1	Temporary Service	$500			
2	Dispute Meter Test	$30 plus Measurement Canada fees			
3	Collection of account – no disconnection/load limiter	$30			
4	Collection/Disconnect/load limiter/reconnect (at meter) trip – regular hours	$65			
5	Collection/Disconnect/load limiter/reconnect (at meter) trip – after regular hours	$185			
6	Collection/Disconnect/load limiter/reconnect (at pole) trip – regular hours	$185			
7	Collection/Disconnect/load limiter/reconnect (at pole) trip – after regular hours	$415			
8	Account Set-up Charge	$30			
9	Arrears Certificate	$15			
10	NSF Cheque Charge	$15 + bank charges			
11	Easement Charge for Unregistered Rights	$15			
12	Late Payment Charge	1.5%/month			
13a	Retailer Services – Establishing Service Agreements (refer to Handbook for all charges)	$100/agreement/Retailer +$20/month/Retailer +$0.50/month/customer + other			
13b	Retailer Services – Other (includes Bill Ready for Retailers and Service Transactions Requests) as per the Handbook, Chapter 12	$0.30/month/customer + $0.25/request for request fee + $0.50/request for process fee			
14	Special Meter Reads	$30			
15	Billing Suspension and Terminations in Trailer Parks		$130		
16	Service Layout Fee – Basic		$405		
17	Service Layout Fee – Complex		$580		

Hydro One Networks Inc.
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Effective Date: May 1, 2007

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

18	Crossing Application – Pipeline		$2,065		
19	Crossing Application – Water		$2,525		
20	Crossing Application – Railroad		$2,565		
21	Line Staking – per meter		$3.10		
22	Central Metering – New service < 45 kW		$115		
23	Conversion to Central Metering < 45 kW		$795		
24	Conversion to Central Metering > 45 kW		$680		
25	Tingle Voltage Test – In Excess of 4 Hours (per hour – average 2 additional hours)		$105		
26	Standby Administration Charge per month (interim)		$375		
27	Sentinel Lights Rental Rate per month – Mercury Vapor			$7.00	
28	Guaranteed Units from Jan 01/91 to Aug 01/91			$26.50 / month	
29	Guaranteed Units from Jan 01/87 to Dec 31/90			$23.50 / month	
30	Joint Use for Cable and Telecom companies per pole			$22.35	
31	Joint Use for LDCs per pole			$28.61	

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Rainy River Public Utilities Commission
Effective Date: May 1, 2008

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

APPLICATION

The application of these rates and charges shall be in accordance with The Licence of The Distributor and any Codes, Guidelines or Orders of The Board, and amendments thereto as approved by The Board, which may be applicable to the administration of this schedule.
No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code, Guideline or Order of the Board, and amendments thereto as approved by the Board, or as specified herein
This schedule does not contain any rates and charges relating to the electricity commodity (e.g. the Regulated Price Plan).

EFFECTIVE DATES

DISTRIBUTION RATES - May 1, 2008 for all consumption or deemed consumption services used on or after that date.

MISCELLANEOUS CHARGES - May 1, 2008 for all charges billed to customers on or after that date.
RETAIL TRANSMISSION RATES - May 1, 2008 for all consumption or deemed consumption services used on or after that date.
LOSS FACTOR ADJUSTMENT – for all consumption or deemed consumption services billed following May 1, 2008 or later

SERVICE CLASSIFICATIONS

Residential
This classification refers to all service supplied to single-family dwelling units for domestic or household purpose. Multi-unit residential establishments such as apartment buildings supplied through one service (bulk metered) will normally be classified as General Service, but, at Hydro One's discretion, up to four residential units may be classified as residential. Where electricity service is provided to combined residential and business (including agricultural usage) and the wiring does not provide for separate metering, the classification shall be at the discretion of Hydro One based on such considerations as the estimated predominant consumption.
Further servicing details are available in the utility's Conditions of Service.

General Service
This classification refers to all service supplied to premises other than those classified as Residential or Lighting. Some General Service accounts are energy(kWh)-billed, and some are demand(kW)-billed. Further servicing details are available in the utility's Conditions of Service.

Unmetered Scattered Load
This classification refers to certain instances where connections can be provided without metering. These loads are generally small in size and consistent in magnitude of load. Hydro One reserves the right to review all cases and may require that a meter be installed at its sole discretion. Services that can be unmetered include cable TV amplifiers, telephone switching devices, phone booths, bus shelters, rail way crossing signals, traffic signals, and other small fixed loads.
Further servicing details are available in the utility's Conditions of Service (including in the "Unmetered Connections" section).

Hydro One Networks Inc.
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Rainy River Public Utilities Commission
Effective Date: May 1, 2008

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

Street Lighting

This classification refers to accounts for the distribution and supply of electrical energy for street lighting. Street lights are devices owned by or operated for the road authority and/or the municipal corporation. These street lights in fact belong to the Street Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Sentinel Lighting

This classification refers to accounts for a separate service to a sentinel light. These sentinel lights in fact belong to the Sentinel Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Urban Density Classification

Customers who meet the Urban Density Criteria of being in an area containing 3,000 or more customers with a line density of at least 60 customers per kilometre, will be mapped to an Urban customer classification.

Hydro One Networks Inc.
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MONTHLY RATES AND CHARGES

Residential - R1 Rainy River

Service Charge	$	16.00
Distribution Volumetric Rate	$ / kWh	0.0265
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0050
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0004)
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0047
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0046
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service Less Than 50 kW (Energy-Billed) - GSe Rainy River

Service Charge	$	22.27
Distribution Volumetric Rate	$ / kWh	0.0318
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0036
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0006)
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0035
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0032
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service 50 kW or Greater (Demand-Billed) - GSd Rainy River

Service Charge	$	25.87
Distribution Volumetric Rate	$ / kW	9.22
Regulatory Asset Recovery - Rider #2	$ / kW	1.14
Regulatory Asset Recovery - Rider #3	$ / kW	(0.22)
Retail Transmission Rate - Network Service Rate (4)	$ / kW	1.11
Retail Transmission Rate - Line and Transformation Connection Service Rate (4)	$ / kW	1.00
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

Hydro One Networks Inc.
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Unmetered, Scattered Load

Service Charge	$	13.08
Distribution Volumetric Rate	$ / kWh	0.0200
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0036
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0006)
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0035
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0032
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

(3) For energy-only metered customers, the billing determinant is the customer's metered energy consumption adjusted by the total loss factor as approved by the Board for Acquired LDC customers.
(4) For demand billed customers, appropriate loss factors must be applied to the applicable tariffs. Also the billing determinant for the Line and Transformation Connection Services rate is the customer's peak demand in the billing period. The billing determinant for the Network Services rate is: for non-interval-metered customers, the peak demand in the billing period, and for interval-metered customers, the peak demand between 7 AM and 7 PM local time on IESO business days

Customer-Supplied Transformation Allowance

Applicable to customers providing their own transformers

Demand-billed	$ / kW	0.60
Energy-billed	$ / kWh	0.0014

Hydro One Networks Inc.
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Loss Factors

Residential	1.085
General Service Less Than 50 kW (Energy-Billed)	1.092
General Service 50 kW or Greater (Demand-Billed)	1.061
Unmetered Scattered Load	1.092

Transformer Loss Allowance

Applicable to customers requiring a billing adjustment for transformer losses as the result of beinç metered on the primary side of a transformer. The following uniform values shall be applied tc measured demand and energy to calculate transformer losses for voltages up to and includinç 50 kV (as metered on the primary side):

(a) 1.5% for transformer installations up to an individual bank capacity of 400 kVA,
(b) 1.0% for bank capacities over 400 kVA.

Alternatively, transformer losses may be determined from transformer test data, anc measured demand and energy adjusted accordingly

For services which are not demand metered, an assumed demand of 50% of the transformeı capacity will be used to calculate the loss allowance. Where several transformers are involved the bank capacity is assumed to be the arithmetic sum of all transformer capacities

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
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Effective Date: May 1, 2008

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

MISCELLANEOUS CHARGES

Specific Service Charges: Standard Amounts

Rate Code	Specific Service Charge - Standard Name	Calculation Method			
		2006 Rate Handbook	Standard Formula	Other Formula	Time and Materials
1	Temporary Service	$500			
2	Dispute Meter Test	$30 plus Measurement Canada fees			
3	Collection of account – no disconnection/load limiter	$30			
4	Collection/Disconnect/load limiter/reconnect (at meter) trip – regular hours	$65			
5	Collection/Disconnect/load limiter/reconnect (at meter) trip – after regular hours	$185			
6	Collection/Disconnect/load limiter/reconnect (at pole) trip – regular hours	$185			
7	Collection/Disconnect/load limiter/reconnect (at pole) trip – after regular hours	$415			
8	Account Set-up Charge	$30			
9	Arrears Certificate	$15			
10	NSF Cheque Charge	$15 + bank charges			
11	Easement Charge for Unregistered Rights	$15			
12	Late Payment Charge	1.5%/month			
13a	Retailer Services – Establishing Service Agreements (refer to Handbook for all charges)	$100/agreement/Retailer +$20/month/Retailer +$0.50/month/customer + other			
13b	Retailer Services – Other (includes Bill Ready for Retailers and Service Transactions Requests) as per the Handbook, Chapter 12	$0.30/month/customer + $0.25/request for request fee + $0.50/request for process fee			
14	Special Meter Reads	$30			
15	Service Layout Fee – Basic		$495		
16	Service Layout Fee – Complex		$690		
17	Crossing Application – Pipeline		$2,445		
18	Crossing Application – Water		$3,045		
19	Crossing Application – Railroad		$2,945		
20	Line Staking – per meter		$3.70		
21	Central Metering – New service < 45 kW		$115		
22	Conversion to Central Metering < 45 kW		$915		
23	Conversion to Central Metering > 45 kW		$800		
24	Tingle Voltage Test – In Excess of 4 Hours (per hour – average 2 additional hours)		$125		
25	Standby Administration Charge per month		$440		
26	Sentinel Lights Rental Rate per month			$7.10	
27	Sentinel Pole Rental Rate per month			$4.15	
28	Joint Use for Cable and Telecom companies per pole			$22.35	
29	Joint Use for LDCs per pole			$28.61	

Hydro One Networks Inc.
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Rainy River Public Utilities Commission
Effective Date: May 1, 2007

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

APPLICATION

The application of these rates and charges shall be in accordance with The Licence of The Distributor and any Codes, Guidelines or Orders of The Board, and amendments thereto as approved by The Board, which may be applicable to the administration of this schedule.
No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code, Guideline or Order of the Board, and amendments thereto as approved by the Board, or as specified herein
This schedule does not contain any rates and charges relating to the electricity commodity (e.g. the Regulated Price Plan).

EFFECTIVE DATES

DISTRIBUTION RATES - May 1, 2007 for all consumption or deemed consumption services used on or after that date.

MISCELLANEOUS CHARGES - May 1, 2007 for all charges billed to customers on or after that date.
RETAIL TRANSMISSION RATES - May 1, 2007 for all consumption or deemed consumption services used on or after that date.
LOSS FACTOR ADJUSTMENT – May 1, 2007

SERVICE CLASSIFICATIONS

Residential
This classification (note 1) refers to all service supplied to single-family dwelling units for domestic or household purpose. Multi-unit residential establishments such as apartment buildings supplied through one service (bulk metered) will normally be classified as General Service, but, at Hydro One's discretion, up to four residential units may be classified as residential. Where electricity service is provided to combined residential and business (including agricultural usage) and the wiring does not provide for separate metering, the classification shall be at the discretion of Hydro One based on such considerations as the estimated predominant consumption.
Further servicing details are available in the utility's Conditions of Service.

General Service
This classification (note 1) refers to all service supplied to premises other than those classified as Residential or Lighting. Some General Service accounts are energy(kWh)-billed, and some are demand(kW)-billed. Further servicing details are available in the utility's Conditions of Service. Also, see note 2.

Unmetered Scattered Load
This classification refers to certain instances where connections can be provided without metering. These loads are generally small in size and consistent in magnitude of load. Hydro One reserves the right to review all cases and may require that a meter be installed at its sole discretion. Services that can be unmetered include cable TV amplifiers, telephone switching devices, phone booths, bus shelters, rail way crossing signals, traffic signals, and other small fixed loads.
Further servicing details are available in the utility's Conditions of Service (including in the "Unmetered Connections" section).

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Rainy River Public Utilities Commission
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Street Lighting

This classification refers to accounts for the distribution and supply of electrical energy for street lighting. Street lights are devices owned by or operated for the road authority and/or the municipal corporation. These street lights in fact belong to the Street Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Sentinel Lighting

This classification refers to accounts for a separate service to a sentinel light. These sentinel lights in fact belong to the Sentinel Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Interim Demand-Side Management Time-of-Use

This is potentially applicable to Demand-billed General Service accounts. See Note 2 below.

Note (1): Classification descriptions are paraphrases from the document "Hydro One Networks Inc. - Distribution Customers Conditions of Service - August 2004"

Note (2):

Interim Demand-Side Management Time-of-Use Rates: demand charges will be based on demand during the on-peak periods.

Criteria: Customers' electricity consumption (kW) in the off-peak period is at least twice the electricity consumption (kW) during the on-peak period.

Definition of Time Periods: The on-peak hours will be between 0700 hours to 1900 hours Eastern Standard Time during the winter (standard time) on IESO business days and 0600 hours to 1800 hours Eastern Standard Time during the summer (daylight savings time) on IESO business days. The off-peak period constitutes all of the remaining hours.

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MONTHLY RATES AND CHARGES

Residential

Service Charge	$	15.04
Distribution Volumetric Rate	$ / kWh	0.0102
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0075
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0050
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0055
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0047
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service - Energy Billed (less than 50 kW)

Service Charge	$	19.29
Distribution Volumetric Rate	$ / kWh	0.0176
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0045
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0036
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0050
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0043
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service - Demand Billed (50 kW or greater)

Service Charge	$	19.29
Distribution Volumetric Rate	$ / kW	5.59
Regulatory Asset Recovery - Rider #1	$ / kW	1.44
Regulatory Asset Recovery - Rider #2	$ / kW	1.14
Retail Transmission Rate - Network Service Rate (4)	$ / kW	1.94
Retail Transmission Rate - Line and Transformation Connection Service Rate (4)	$ / kW	1.61
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

Hydro One Networks Inc.
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Unmetered, Scattered Load

Service Charge	$	9.18
Distribution Volumetric Rate	$ / kWh	0.0176
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0045
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0036
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0050
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0043
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

(3) For energy-only metered customers, the billing determinant is the customer's metered energy consumption adjusted by the total loss factor as approved by the Board for Acquired LDC customers.

(4) For demand billed customers, appropriate loss factors must be applied to the applicable tariffs. Also the billing determinant for the Line and Transformation Connection Services rate is the customer's peak demand in the billing period. The billing determinant for the Network Services rate is: for non-interval-metered customers, the peak demand in the billing period, and for interval-metered customers, the peak demand between 7 AM and 7 PM local time on IESO business days

Interim Demand-Side Management Time-of-Use

See the "Service Classifications" section of this schedule.

Customer-Supplied Transformation Allowance

Applicable to demand-billed customers providing their own transformers
Primary Voltage under 50 kV (per kW)

Single Phase	$ / kW	0.20
Three Phase	$ / kW	0.60

Hydro One Networks Inc.
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Loss Factors

Supply Facilities Loss Factor	1.0045
Distribution Loss Factors	
Customer less than 5,000 kW	1.0500
Customer greater than or equal to 5,000 kW	1.0100
Total Loss Factors	
Customer less than 5,000 kW	1.0545
Customer greater than or equal to 5,000 kW	1.0145

Transformer Loss Allowance

Applicable to customers requiring a billing adjustment for transformer losses as the result of being metered on the primary side of a transformer. The following uniform values shall be applied to measured demand and energy to calculate transformer losses for voltages up to and including 50 kV (as metered on the primary side):

(a) 1.5% for transformer installations up to an individual bank capacity of 400 kVA,
(b) 1.0% for bank capacities over 400 kVA.

Alternatively, transformer losses may be determined from transformer test data, and measured demand and energy adjusted accordingly

For services which are not demand metered, an assumed demand of 50% of the transformer capacity will be used to calculate the loss allowance. Where several transformers are involved, the bank capacity is assumed to be the arithmetic sum of all transformer capacities

Hydro One Networks Inc.
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MISCELLANEOUS CHARGES

Specific Service Charges: Standard Amounts

Rate Code	Specific Service Charge - Standard Name	Calculation Method			
		2006 Rate Handbook	Standard Formula	Other Formula	Time and Materials
1	Temporary Service	$500			
2	Dispute Meter Test	$30 plus Measurement Canada fees			
3	Collection of account – no disconnection/load limiter	$30			
4	Collection/Disconnect/load limiter/reconnect (at meter) trip – regular hours	$65			
5	Collection/Disconnect/load limiter/reconnect (at meter) trip – after regular hours	$185			
6	Collection/Disconnect/load limiter/reconnect (at pole) trip – regular hours	$185			
7	Collection/Disconnect/load limiter/reconnect (at pole) trip – after regular hours	$415			
8	Account Set-up Charge	$30			
9	Arrears Certificate	$15			
10	NSF Cheque Charge	$15 + bank charges			
11	Easement Charge for Unregistered Rights	$15			
12	Late Payment Charge	1.5%/month			
13a	Retailer Services – Establishing Service Agreements (refer to Handbook for all charges)	$100/agreement/Retailer +$20/month/Retailer +$0.50/month/customer + other			
13b	Retailer Services – Other (includes Bill Ready for Retailers and Service Transactions Requests) as per the Handbook, Chapter 12	$0.30/month/customer + $0.25/request for request fee + $0.50/request for process fee			
14	Special Meter Reads	$30			
15	Billing Suspension and Terminations in Trailer Parks		$130		
16	Service Layout Fee – Basic		$405		
17	Service Layout Fee – Complex		$580		

Hydro One Networks Inc.

TARIFF OF RATES AND CHARGES

for the Service Area Formerly Served by

Rainy River Public Utilities Commission

Effective Date: May 1, 2007

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

18	Crossing Application – Pipeline		$2,065		
19	Crossing Application – Water		$2,525		
20	Crossing Application – Railroad		$2,565		
21	Line Staking – per meter		$3.10		
22	Central Metering – New service < 45 kW		$115		
23	Conversion to Central Metering < 45 kW		$795		
24	Conversion to Central Metering > 45 kW		$680		
25	Tingle Voltage Test – In Excess of 4 Hours (per hour – average 2 additional hours)		$105		
26	Standby Administration Charge per month (interim)		$375		
27	Sentinel Lights Rental Rate per month – Mercury Vapor			$7.00	
28	Guaranteed Units from Jan 01/91 to Aug 01/91			$26.50 / month	
29	Guaranteed Units from Jan 01/87 to Dec 31/90			$23.50 / month	
30	Joint Use for Cable and Telecom companies per pole			$22.35	
31	Joint Use for LDCs per pole			$28.61	

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Ramara Hydro Electric Commission
Effective Date: May 1, 2008

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

APPLICATION

The application of these rates and charges shall be in accordance with The Licence of The Distributor and any Codes, Guidelines or Orders of The Board, and amendments thereto as approved by The Board, which may be applicable to the administration of this schedule.
No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code, Guideline or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.
This schedule does not contain any rates and charges relating to the electricity commodity (e.g. the Regulated Price Plan).

EFFECTIVE DATES

DISTRIBUTION RATES - May 1, 2008 for all consumption or deemed consumption services used on or after that date.

MISCELLANEOUS CHARGES - May 1, 2008 for all charges billed to customers on or after that date.
RETAIL TRANSMISSION RATES - May 1, 2008 for all consumption or deemed consumption services used on or after that date.
LOSS FACTOR ADJUSTMENT – for all consumption or deemed consumption services billed following May 1, 2008 or later

SERVICE CLASSIFICATIONS

Residential
This classification refers to all service supplied to single-family dwelling units for domestic or household purpose. Multi-unit residential establishments such as apartment buildings supplied through one service (bulk metered) will normally be classified as General Service, but, at Hydro One's discretion, up to four residential units may be classified as residential. Where electricity service is provided to combined residential and business (including agricultural usage) and the wiring does not provide for separate metering, the classification shall be at the discretion of Hydro One based on such considerations as the estimated predominant consumption.
Further servicing details are available in the utility's Conditions of Service.

General Service
This classification refers to all service supplied to premises other than those classified as Residential or Lighting. Some General Service accounts are energy(kWh)-billed, and some are demand(kW)-billed. Further servicing details are available in the utility's Conditions of Service.

Unmetered Scattered Load
This classification refers to certain instances where connections can be provided without metering. These loads are generally small in size and consistent in magnitude of load. Hydro One reserves the right to review all cases and may require that a meter be installed at its sole discretion. Services that can be unmetered include cable TV amplifiers, telephone switching devices, phone booths, bus shelters, rail way crossing signals, traffic signals, and other small fixed loads.
Further servicing details are available in the utility's Conditions of Service (including in the "Unmetered Connections" section).

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Ramara Hydro Electric Commission
Effective Date: May 1, 2008

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

Street Lighting

This classification refers to accounts for the distribution and supply of electrical energy for street lighting. Street lights are devices owned by or operated for the road authority and/or the municipal corporation. These street lights in fact belong to the Street Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Sentinel Lighting

This classification refers to accounts for a separate service to a sentinel light. These sentinel lights in fact belong to the Sentinel Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Urban Density Classification

Customers who meet the Urban Density Criteria of being in an area containing 3,000 or more customers with a line density of at least 60 customers per kilometre, will be mapped to an Urban customer classification.

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Ramara Hydro Electric Commission
Effective Date: May 1, 2008

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

MONTHLY RATES AND CHARGES

Residential - R1 Ramara

Service Charge	$	9.13
Distribution Volumetric Rate	$ / kWh	0.0210
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0035
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0004)
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0047
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0046
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service Less Than 50 kW (Energy-Billed) - GSe Ramara

Service Charge	$	22.85
Distribution Volumetric Rate	$ / kWh	0.0248
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0037
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0006)
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0035
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0032
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service 50 kW or Greater (Demand-Billed) - GSd Ramara

Service Charge	$	26.45
Distribution Volumetric Rate	$ / kW	9.22
Regulatory Asset Recovery - Rider #2	$ / kW	1.16
Regulatory Asset Recovery - Rider #3	$ / kW	(0.22)
Retail Transmission Rate - Network Service Rate (4)	$ / kW	1.11
Retail Transmission Rate - Line and Transformation Connection Service Rate (4)	$ / kW	1.00
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Ramara Hydro Electric Commission
Effective Date: May 1, 2008

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

Unmetered, Scattered Load

Service Charge	$	13.87
Distribution Volumetric Rate	$ / kWh	0.0200
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0037
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0006)
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0035
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0032
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

(3) For energy-only metered customers, the billing determinant is the customer's metered energy consumption adjusted by the total loss factor as approved by the Board for Acquired LDC customers.
(4) For demand billed customers, appropriate loss factors must be applied to the applicable tariffs. Also the billing determinant for the Line and Transformation Connection Services rate is the customer's peak demand in the billing period. The billing determinant for the Network Services rate is: for non-interval-metered customers, the peak demand in the billing period, and for interval-metered customers, the peak demand between 7 AM and 7 PM local time on IESO business days

Customer-Supplied Transformation Allowance

Applicable to customers providing their own transformers		
Demand-billed	$ / kW	0.60
Energy-billed	$ / kWh	0.0014

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Ramara Hydro Electric Commission
Effective Date: May 1, 2008

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

Loss Factors

Residential	1.085
General Service Less Than 50 kW (Energy-Billed)	1.092
General Service 50 kW or Greater (Demand-Billed)	1.061
Unmetered Scattered Load	1.092

Transformer Loss Allowance

Applicable to customers requiring a billing adjustment for transformer losses as the result of being metered on the primary side of a transformer. The following uniform values shall be applied to measured demand and energy to calculate transformer losses for voltages up to and including 50 kV (as metered on the primary side):

(a) 1.5% for transformer installations up to an individual bank capacity of 400 kVA,
(b) 1.0% for bank capacities over 400 kVA.

Alternatively, transformer losses may be determined from transformer test data, and measured demand and energy adjusted accordingly

For services which are not demand metered, an assumed demand of 50% of the transformer capacity will be used to calculate the loss allowance. Where several transformers are involved, the bank capacity is assumed to be the arithmetic sum of all transformer capacities

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Ramara Hydro Electric Commission
Effective Date: May 1, 2008

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

MISCELLANEOUS CHARGES

Specific Service Charges: Standard Amounts

Rate Code	Specific Service Charge - Standard Name	Calculation Method			
		2006 Rate Handbook	Standard Formula	Other Formula	Time and Materials
1	Temporary Service	$500			
2	Dispute Meter Test	$30 plus Measurement Canada fees			
3	Collection of account – no disconnection/load limiter	$30			
4	Collection/Disconnect/load limiter/reconnect (at meter) trip – regular hours	$65			
5	Collection/Disconnect/load limiter/reconnect (at meter) trip – after regular hours	$185			
6	Collection/Disconnect/load limiter/reconnect (at pole) trip – regular hours	$185			
7	Collection/Disconnect/load limiter/reconnect (at pole) trip – after regular hours	$415			
8	Account Set-up Charge	$30			
9	Arrears Certificate	$15			
10	NSF Cheque Charge	$15 + bank charges			
11	Easement Charge for Unregistered Rights	$15			
12	Late Payment Charge	1.5%/month			
13a	Retailer Services – Establishing Service Agreements (refer to Handbook for all charges)	$100/agreement/Retailer +$20/month/Retailer +$0.50/month/customer + other			
13b	Retailer Services – Other (includes Bill Ready for Retailers and Service Transactions Requests) as per the Handbook, Chapter 12	$0.30/month/customer + $0.25/request for request fee + $0.50/request for process fee			
14	Special Meter Reads	$30			
15	Service Layout Fee – Basic		$495		
16	Service Layout Fee – Complex		$690		
17	Crossing Application – Pipeline		$2,445		
18	Crossing Application – Water		$3,045		
19	Crossing Application – Railroad		$2,945		
20	Line Staking – per meter		$3.70		
21	Central Metering – New service < 45 kW		$115		
22	Conversion to Central Metering < 45 kW		$915		
23	Conversion to Central Metering > 45 kW		$800		
24	Tingle Voltage Test – In Excess of 4 Hours (per hour – average 2 additional hours)		$125		
25	Standby Administration Charge per month		$440		
26	Sentinel Lights Rental Rate per month			$7.10	
27	Sentinel Pole Rental Rate per month			$4.15	
28	Joint Use for Cable and Telecom companies per pole			$22.35	
29	Joint Use for LDCs per pole			$28.61	

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Ramara Hydro Electric Commission
Effective Date: May 1, 2007

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

APPLICATION

The application of these rates and charges shall be in accordance with The Licence of The Distributor and any Codes, Guidelines or Orders of The Board, and amendments thereto as approved by The Board, which may be applicable to the administration of this schedule.
No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code, Guideline or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.
This schedule does not contain any rates and charges relating to the electricity commodity (e.g. the Regulated Price Plan).

EFFECTIVE DATES

DISTRIBUTION RATES - May 1, 2007 for all consumption or deemed consumption services used on or after that date.

MISCELLANEOUS CHARGES - May 1, 2007 for all charges billed to customers on or after that date.
RETAIL TRANSMISSION RATES - May 1, 2007 for all consumption or deemed consumption services used on or after that date.
LOSS FACTOR ADJUSTMENT – May 1, 2007

SERVICE CLASSIFICATIONS

Residential
This classification (note 1) refers to all service supplied to single-family dwelling units for domestic or household purpose. Multi-unit residential establishments such as apartment buildings supplied through one service (bulk metered) will normally be classified as General Service, but, at Hydro One's discretion, up to four residential units may be classified as residential. Where electricity service is provided to combined residential and business (including agricultural usage) and the wiring does not provide for separate metering, the classification shall be at the discretion of Hydro One based on such considerations as the estimated predominant consumption.
Further servicing details are available in the utility's Conditions of Service.

General Service
This classification (note 1) refers to all service supplied to premises other than those classified as Residential or Lighting. Some General Service accounts are energy(kWh)-billed, and some are demand(kW)-billed. Further servicing details are available in the utility's Conditions of Service. Also, see note 2.

Unmetered Scattered Load
This classification refers to certain instances where connections can be provided without metering. These loads are generally small in size and consistent in magnitude of load. Hydro One reserves the right to review all cases and may require that a meter be installed at its sole discretion. Services that can be unmetered include cable TV amplifiers, telephone switching devices, phone booths, bus shelters, rail way crossing signals, traffic signals, and other small fixed loads.
Further servicing details are available in the utility's Conditions of Service (including in the "Unmetered Connections" section).

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Ramara Hydro Electric Commission
Effective Date: May 1, 2007

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

Street Lighting

This classification refers to accounts for the distribution and supply of electrical energy for street lighting. Street lights are devices owned by or operated for the road authority and/or the municipal corporation. These street lights in fact belong to the Street Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Sentinel Lighting

This classification refers to accounts for a separate service to a sentinel light. These sentinel lights in fact belong to the Sentinel Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Interim Demand-Side Management Time-of-Use

This is potentially applicable to Demand-billed General Service accounts. See Note 2 below.

Note (1): Classification descriptions are paraphrases from the document "Hydro One Networks Inc. - Distribution Customers Conditions of Service - August 2004"

Note (2):

Interim Demand-Side Management Time-of-Use Rates: demand charges will be based on demand during the on-peak periods.

Criteria: Customers' electricity consumption (kW) in the off-peak period is at least twice the electricity consumption (kW) during the on-peak period.

Definition of Time Periods: The on-peak hours will be between 0700 hours to 1900 hours Eastern Standard Time during the winter (standard time) on IESO business days and 0600 hours to 1800 hours Eastern Standard Time during the summer (daylight savings time) on IESO business days. The off-peak period constitutes all of the remaining hours.

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Ramara Hydro Electric Commission
Effective Date: May 1, 2007

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

MONTHLY RATES AND CHARGES

Residential

Service Charge	$	6.52
Distribution Volumetric Rate	$ / kWh	0.0095
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0055
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0035
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0055
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0047
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service - Energy Billed (less than 50 kW)

Service Charge	$	20.97
Distribution Volumetric Rate	$ / kWh	0.0106
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0045
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0037
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0050
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0043
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service - Demand Billed (50 kW or greater)

Service Charge	$	20.97
Distribution Volumetric Rate	$ / kW	3.35
Regulatory Asset Recovery - Rider #1	$ / kW	1.43
Regulatory Asset Recovery - Rider #2	$ / kW	1.16
Retail Transmission Rate - Network Service Rate (4)	$ / kW	1.94
Retail Transmission Rate - Line and Transformation Connection Service Rate (4)	$ / kW	1.61
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Ramara Hydro Electric Commission
Effective Date: May 1, 2007

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

Unmetered, Scattered Load

Service Charge	$	10.02
Distribution Volumetric Rate	$ / kWh	0.0106
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0045
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0037
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0050
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0043
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

(3) For energy-only metered customers, the billing determinant is the customer's metered energy consumption adjusted by the total loss factor as approved by the Board for Acquired LDC customers.
(4) For demand billed customers, appropriate loss factors must be applied to the applicable tariffs. Also the billing determinant for the Line and Transformation Connection Services rate is the customer's peak demand in the billing period. The billing determinant for the Network Services rate is: for non-interval-metered customers, the peak demand in the billing period, and for interval-metered customers, the peak demand between 7 AM and 7 PM local time on IESO business days

Interim Demand-Side Management Time-of-Use

See the "Service Classifications" section of this schedule.

Customer-Supplied Transformation Allowance

Applicable to demand-billed customers providing their own transformers
Primary Voltage under 50 kV (per kW)

Single Phase	$ / kW	0.20
Three Phase	$ / kW	0.60

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Ramara Hydro Electric Commission
Effective Date: May 1, 2007

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

Loss Factors

Supply Facilities Loss Factor	1.0045
Distribution Loss Factors	
Customer less than 5,000 kW	1.0500
Customer greater than or equal to 5,000 kW	1.0100
Total Loss Factors	
Customer less than 5,000 kW	1.0545
Customer greater than or equal to 5,000 kW	1.0145

Transformer Loss Allowance

Applicable to customers requiring a billing adjustment for transformer losses as the result of being metered on the primary side of a transformer. The following uniform values shall be applied to measured demand and energy to calculate transformer losses for voltages up to and including 50 kV (as metered on the primary side):

(a) 1.5% for transformer installations up to an individual bank capacity of 400 kVA,
(b) 1.0% for bank capacities over 400 kVA.

Alternatively, transformer losses may be determined from transformer test data, and measured demand and energy adjusted accordingly

For services which are not demand metered, an assumed demand of 50% of the transformer capacity will be used to calculate the loss allowance. Where several transformers are involved, the bank capacity is assumed to be the arithmetic sum of all transformer capacities

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Ramara Hydro Electric Commission
Effective Date: May 1, 2007

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

MISCELLANEOUS CHARGES

Specific Service Charges: Standard Amounts

Rate Code	Specific Service Charge - Standard Name	Calculation Method			
		2006 Rate Handbook	Standard Formula	Other Formula	Time and Materials
1	Temporary Service	$500			
2	Dispute Meter Test	$30 plus Measurement Canada fees			
3	Collection of account – no disconnection/load limiter	$30			
4	Collection/Disconnect/load limiter/reconnect (at meter) trip – regular hours	$65			
5	Collection/Disconnect/load limiter/reconnect (at meter) trip – after regular hours	$185			
6	Collection/Disconnect/load limiter/reconnect (at pole) trip – regular hours	$185			
7	Collection/Disconnect/load limiter/reconnect (at pole) trip – after regular hours	$415			
8	Account Set-up Charge	$30			
9	Arrears Certificate	$15			
10	NSF Cheque Charge	$15 + bank charges			
11	Easement Charge for Unregistered Rights	$15			
12	Late Payment Charge	1.5%/month			
13a	Retailer Services – Establishing Service Agreements (refer to Handbook for all charges)	$100/agreement/Retailer +$20/month/Retailer +$0.50/month/customer + other			
13b	Retailer Services – Other (includes Bill Ready for Retailers and Service Transactions Requests) as per the Handbook, Chapter 12	$0.30/month/customer + $0.25/request for request fee + $0.50/request for process fee			
14	Special Meter Reads	$30			
15	Billing Suspension and Terminations in Trailer Parks		$130		
16	Service Layout Fee – Basic		$405		
17	Service Layout Fee – Complex		$580		

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Ramara Hydro Electric Commission
Effective Date: May 1, 2007

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

18	Crossing Application – Pipeline		$2,065		
19	Crossing Application – Water		$2,525		
20	Crossing Application – Railroad		$2,565		
21	Line Staking – per meter		$3.10		
22	Central Metering – New service < 45 kW		$115		
23	Conversion to Central Metering < 45 kW		$795		
24	Conversion to Central Metering > 45 kW		$680		
25	Tingle Voltage Test – In Excess of 4 Hours (per hour – average 2 additional hours)		$105		
26	Standby Administration Charge per month (interim)		$375		
27	Sentinel Lights Rental Rate per month – Mercury Vapor			$7.00	
28	Guaranteed Units from Jan 01/91 to Aug 01/91			$26.50 / month	
29	Guaranteed Units from Jan 01/87 to Dec 31/90			$23.50 / month	
30	Joint Use for Cable and Telecom companies per pole			$22.35	
31	Joint Use for LDCs per pole			$28.61	

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Red Rock Hydro System
Effective Date: May 1, 2008

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

APPLICATION

The application of these rates and charges shall be in accordance with The Licence of The Distributor and any Codes, Guidelines or Orders of The Board, and amendments thereto as approved by The Board, which may be applicable to the administration of this schedule.
No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code, Guideline or Order of the Board, and amendments thereto as approved by the Board, or as specified herein
This schedule does not contain any rates and charges relating to the electricity commodity (e.g. the Regulated Price Plan).

EFFECTIVE DATES

DISTRIBUTION RATES - May 1, 2008 for all consumption or deemed consumption services used on or after that date.

MISCELLANEOUS CHARGES - May 1, 2008 for all charges billed to customers on or after that date.
RETAIL TRANSMISSION RATES - May 1, 2008 for all consumption or deemed consumption services used on or after that date.
LOSS FACTOR ADJUSTMENT – for all consumption or deemed consumption services billed following May 1, 2008 or later

SERVICE CLASSIFICATIONS

Residential
This classification refers to all service supplied to single-family dwelling units for domestic or household purpose. Multi-unit residential establishments such as apartment buildings supplied through one service (bulk metered) will normally be classified as General Service, but, at Hydro One's discretion, up to four residential units may be classified as residential. Where electricity service is provided to combined residential and business (including agricultural usage) and the wiring does not provide for separate metering, the classification shall be at the discretion of Hydro One based on such considerations as the estimated predominant consumption.
Further servicing details are available in the utility's Conditions of Service.

General Service
This classification refers to all service supplied to premises other than those classified as Residential or Lighting. Some General Service accounts are energy(kWh)-billed, and some are demand(kW)-billed. Further servicing details are available in the utility's Conditions of Service.

Unmetered Scattered Load
This classification refers to certain instances where connections can be provided without metering. These loads are generally small in size and consistent in magnitude of load. Hydro One reserves the right to review all cases and may require that a meter be installed at its sole discretion. Services that can be unmetered include cable TV amplifiers, telephone switching devices, phone booths, bus shelters, rail way crossing signals, traffic signals, and other small fixed loads.
Further servicing details are available in the utility's Conditions of Service (including in the "Unmetered Connections" section).

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Red Rock Hydro System
Effective Date: May 1, 2008

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

Street Lighting

This classification refers to accounts for the distribution and supply of electrical energy for street lighting. Street lights are devices owned by or operated for the road authority and/or the municipal corporation. These street lights in fact belong to the Street Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Sentinel Lighting

This classification refers to accounts for a separate service to a sentinel light. These sentinel lights in fact belong to the Sentinel Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Urban Density Classification

Customers who meet the Urban Density Criteria of being in an area containing 3,000 or more customers with a line density of at least 60 customers per kilometre, will be mapped to an Urban customer classification.

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Red Rock Hydro System
Effective Date: May 1, 2008

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MONTHLY RATES AND CHARGES

Residential - R1 Red Rock

Service Charge	$	15.96
Distribution Volumetric Rate	$ / kWh	0.0271
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0054
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0004)
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0047
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0046
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service Less Than 50 kW (Energy-Billed) - GSe Red Rock

Service Charge	$	23.68
Distribution Volumetric Rate	$ / kWh	0.0321
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0024
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0006)
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0035
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0032
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service 50 kW or Greater (Demand-Billed) - GSd Red Rock

Service Charge	$	27.28
Distribution Volumetric Rate	$ / kW	9.22
Regulatory Asset Recovery - Rider #2	$ / kW	0.75
Regulatory Asset Recovery - Rider #3	$ / kW	(0.22)
Retail Transmission Rate - Network Service Rate (4)	$ / kW	1.11
Retail Transmission Rate - Line and Transformation Connection Service Rate (4)	$ / kW	1.00
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

Hydro One Networks Inc.
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Unmetered, Scattered Load

Service Charge	$	13.79
Distribution Volumetric Rate	$ / kWh	0.0200
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0024
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0006)
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0035
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0032
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

(3) For energy-only metered customers, the billing determinant is the customer's metered energy consumption adjusted by the total loss factor as approved by the Board for Acquired LDC customers.
(4) For demand billed customers, appropriate loss factors must be applied to the applicable tariffs. Also the billing determinant for the Line and Transformation Connection Services rate is the customer's peak demand in the billing period. The billing determinant for the Network Services rate is: for non-interval-metered customers, the peak demand in the billing period, and for interval-metered customers, the peak demand between 7 AM and 7 PM local time on IESO business days

Customer-Supplied Transformation Allowance

Applicable to customers providing their own transformers

Demand-billed	$ / kW	0.60
Energy-billed	$ / kWh	0.0014

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Loss Factors

Residential	1.085
General Service Less Than 50 kW (Energy-Billed)	1.092
General Service 50 kW or Greater (Demand-Billed)	1.061
Unmetered Scattered Load	1.092

Transformer Loss Allowance

Applicable to customers requiring a billing adjustment for transformer losses as the result of being metered on the primary side of a transformer. The following uniform values shall be applied to measured demand and energy to calculate transformer losses for voltages up to and including 50 kV (as metered on the primary side):

(a) 1.5% for transformer installations up to an individual bank capacity of 400 kVA,
(b) 1.0% for bank capacities over 400 kVA.

Alternatively, transformer losses may be determined from transformer test data, and measured demand and energy adjusted accordingly

For services which are not demand metered, an assumed demand of 50% of the transformer capacity will be used to calculate the loss allowance. Where several transformers are involved, the bank capacity is assumed to be the arithmetic sum of all transformer capacities

Hydro One Networks Inc.
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MISCELLANEOUS CHARGES

Specific Service Charges: Standard Amounts

Rate Code	Specific Service Charge - Standard Name	Calculation Method			
		2006 Rate Handbook	Standard Formula	Other Formula	Time and Materials
1	Temporary Service	$500			
2	Dispute Meter Test	$30 plus Measurement Canada fees			
3	Collection of account – no disconnection/load limiter	$30			
4	Collection/Disconnect/load limiter/reconnect (at meter) trip – regular hours	$65			
5	Collection/Disconnect/load limiter/reconnect (at meter) trip – after regular hours	$185			
6	Collection/Disconnect/load limiter/reconnect (at pole) trip – regular hours	$185			
7	Collection/Disconnect/load limiter/reconnect (at pole) trip – after regular hours	$415			
8	Account Set-up Charge	$30			
9	Arrears Certificate	$15			
10	NSF Cheque Charge	$15 + bank charges			
11	Easement Charge for Unregistered Rights	$15			
12	Late Payment Charge	1.5%/month			
13a	Retailer Services – Establishing Service Agreements (refer to Handbook for all charges)	$100/agreement/Retailer +$20/month/Retailer +$0.50/month/customer + other			
13b	Retailer Services – Other (includes Bill Ready for Retailers and Service Transactions Requests) as per the Handbook, Chapter 12	$0.30/month/customer + $0.25/request for request fee + $0.50/request for process fee			
14	Special Meter Reads	$30			
15	Service Layout Fee – Basic		$495		
16	Service Layout Fee – Complex		$690		
17	Crossing Application – Pipeline		$2,445		
18	Crossing Application – Water		$3,045		
19	Crossing Application – Railroad		$2,945		
20	Line Staking – per meter		$3.70		
21	Central Metering – New service < 45 kW		$115		
22	Conversion to Central Metering < 45 kW		$915		
23	Conversion to Central Metering > 45 kW		$800		
24	Tingle Voltage Test – In Excess of 4 Hours (per hour – average 2 additional hours)		$125		
25	Standby Administration Charge per month		$440		
26	Sentinel Lights Rental Rate per month			$7.10	
27	Sentinel Pole Rental Rate per month			$4.15	
28	Joint Use for Cable and Telecom companies per pole			$22.35	
29	Joint Use for LDCs per pole			$28.61	

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Red Rock Hydro System
Effective Date: May 1, 2007

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APPLICATION

The application of these rates and charges shall be in accordance with The Licence of The Distributor and any Codes, Guidelines or Orders of The Board, and amendments thereto as approved by The Board, which may be applicable to the administration of this schedule.
No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code, Guideline or Order of the Board, and amendments thereto as approved by the Board, or as specified herein
This schedule does not contain any rates and charges relating to the electricity commodity (e.g. the Regulated Price Plan).

EFFECTIVE DATES

DISTRIBUTION RATES - May 1, 2007 for all consumption or deemed consumption services used on or after that date.

MISCELLANEOUS CHARGES - May 1, 2007 for all charges billed to customers on or after that date.
RETAIL TRANSMISSION RATES - May 1, 2007 for all consumption or deemed consumption services used on or after that date.
LOSS FACTOR ADJUSTMENT – May 1, 2007

SERVICE CLASSIFICATIONS

Residential
This classification (note 1) refers to all service supplied to single-family dwelling units for domestic or household purpose. Multi-unit residential establishments such as apartment buildings supplied through one service (bulk metered) will normally be classified as General Service, but, at Hydro One's discretion, up to four residential units may be classified as residential. Where electricity service is provided to combined residential and business (including agricultural usage) and the wiring does not provide for separate metering, the classification shall be at the discretion of Hydro One based on such considerations as the estimated predominant consumption.
Further servicing details are available in the utility's Conditions of Service.

General Service
This classification (note 1) refers to all service supplied to premises other than those classified as Residential or Lighting. Some General Service accounts are energy(kWh)-billed, and some are demand(kW)-billed. Further servicing details are available in the utility's Conditions of Service. Also, see note 2.

Unmetered Scattered Load
This classification refers to certain instances where connections can be provided without metering. These loads are generally small in size and consistent in magnitude of load. Hydro One reserves the right to review all cases and may require that a meter be installed at its sole discretion. Services that can be unmetered include cable TV amplifiers, telephone switching devices, phone booths, bus shelters, rail way crossing signals, traffic signals, and other small fixed loads.
Further servicing details are available in the utility's Conditions of Service (including in the "Unmetered Connections" section).

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
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Red Rock Hydro System
Effective Date: May 1, 2007

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Street Lighting

This classification refers to accounts for the distribution and supply of electrical energy for street lighting. Street lights are devices owned by or operated for the road authority and/or the municipal corporation. These street lights in fact belong to the Street Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Sentinel Lighting

This classification refers to accounts for a separate service to a sentinel light. These sentinel lights in fact belong to the Sentinel Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Interim Demand-Side Management Time-of-Use

This is potentially applicable to Demand-billed General Service accounts. See Note 2 below.

Note (1): Classification descriptions are paraphrases from the document "Hydro One Networks Inc. - Distribution Customers Conditions of Service - August 2004"

Note (2):

Interim Demand-Side Management Time-of-Use Rates: demand charges will be based on demand during the on-peak periods.

Criteria: Customers' electricity consumption (kW) in the off-peak period is at least twice the electricity consumption (kW) during the on-peak period.

Definition of Time Periods: The on-peak hours will be between 0700 hours to 1900 hours Eastern Standard Time during the winter (standard time) on IESO business days and 0600 hours to 1800 hours Eastern Standard Time during the summer (daylight savings time) on IESO business days. The off-peak period constitutes all of the remaining hours.

Hydro One Networks Inc.
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MONTHLY RATES AND CHARGES

Residential

Service Charge	$	15.21
Distribution Volumetric Rate	$ / kWh	0.0207
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0077
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0054
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0055
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0047
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service - Energy Billed (less than 50 kW)

Service Charge	$	21.64
Distribution Volumetric Rate	$ / kWh	0.0194
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0027
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0024
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0050
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0043
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service - Demand Billed (50 kW or greater)

Service Charge	$	21.64
Distribution Volumetric Rate	$ / kW	6.15
Regulatory Asset Recovery - Rider #1	$ / kW	0.86
Regulatory Asset Recovery - Rider #2	$ / kW	0.75
Retail Transmission Rate - Network Service Rate (4)	$ / kW	1.94
Retail Transmission Rate - Line and Transformation Connection Service Rate (4)	$ / kW	1.61
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

Hydro One Networks Inc.
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Unmetered, Scattered Load

Service Charge	$	10.36
Distribution Volumetric Rate	$ / kWh	0.0194
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0027
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0024
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0050
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0043
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

(3) For energy-only metered customers, the billing determinant is the customer’s metered energy consumption adjusted by the total loss factor as approved by the Board for Acquired LDC customers.
(4) For demand billed customers, appropriate loss factors must be applied to the applicable tariffs. Also the billing determinant for the Line and Transformation Connection Services rate is the customer’s peak demand in the billing period. The billing determinant for the Network Services rate is: for non-interval-metered customers, the peak demand in the billing period, and for interval-metered customers, the peak demand between 7 AM and 7 PM local time on IESO business days

Interim Demand-Side Management Time-of-Use

See the "Service Classifications" section of this schedule.

Customer-Supplied Transformation Allowance

Applicable to demand-billed customers providing their own transformers
Primary Voltage under 50 kV (per kW)

Single Phase	$ / kW	0.20
Three Phase	$ / kW	0.60

Hydro One Networks Inc.
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Loss Factors

Supply Facilities Loss Factor	1.0045
Distribution Loss Factors	
Customer less than 5,000 kW	1.0500
Customer greater than or equal to 5,000 kW	1.0100
Total Loss Factors	
Customer less than 5,000 kW	1.0545
Customer greater than or equal to 5,000 kW	1.0145

Transformer Loss Allowance

Applicable to customers requiring a billing adjustment for transformer losses as the result of being metered on the primary side of a transformer. The following uniform values shall be applied to measured demand and energy to calculate transformer losses for voltages up to and including 50 kV (as metered on the primary side):

(a) 1.5% for transformer installations up to an individual bank capacity of 400 kVA,
(b) 1.0% for bank capacities over 400 kVA.

Alternatively, transformer losses may be determined from transformer test data, and measured demand and energy adjusted accordingly

For services which are not demand metered, an assumed demand of 50% of the transformer capacity will be used to calculate the loss allowance. Where several transformers are involved, the bank capacity is assumed to be the arithmetic sum of all transformer capacities

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
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Effective Date: May 1, 2007

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MISCELLANEOUS CHARGES

Specific Service Charges: Standard Amounts

Rate Code	Specific Service Charge - Standard Name	Calculation Method			
		2006 Rate Handbook	Standard Formula	Other Formula	Time and Materials
1	Temporary Service	$500			
2	Dispute Meter Test	$30 plus Measurement Canada fees			
3	Collection of account – no disconnection/load limiter	$30			
4	Collection/Disconnect/load limiter/reconnect (at meter) trip – regular hours	$65			
5	Collection/Disconnect/load limiter/reconnect (at meter) trip – after regular hours	$185			
6	Collection/Disconnect/load limiter/reconnect (at pole) trip – regular hours	$185			
7	Collection/Disconnect/load limiter/reconnect (at pole) trip – after regular hours	$415			
8	Account Set-up Charge	$30			
9	Arrears Certificate	$15			
10	NSF Cheque Charge	$15 + bank charges			
11	Easement Charge for Unregistered Rights	$15			
12	Late Payment Charge	1.5%/month			
13a	Retailer Services – Establishing Service Agreements (refer to Handbook for all charges)	$100/agreement/Retailer +$20/month/Retailer +$0.50/month/customer + other			
13b	Retailer Services – Other (includes Bill Ready for Retailers and Service Transactions Requests) as per the Handbook, Chapter 12	$0.30/month/customer + $0.25/request for request fee + $0.50/request for process fee			
14	Special Meter Reads	$30			
15	Billing Suspension and Terminations in Trailer Parks		$130		
16	Service Layout Fee – Basic		$405		
17	Service Layout Fee – Complex		$580		

Hydro One Networks Inc.
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18	Crossing Application – Pipeline		$2,065		
19	Crossing Application – Water		$2,525		
20	Crossing Application – Railroad		$2,565		
21	Line Staking – per meter		$3.10		
22	Central Metering – New service < 45 kW		$115		
23	Conversion to Central Metering < 45 kW		$795		
24	Conversion to Central Metering > 45 kW		$680		
25	Tingle Voltage Test – In Excess of 4 Hours (per hour – average 2 additional hours)		$105		
26	Standby Administration Charge per month (interim)		$375		
27	Sentinel Lights Rental Rate per month – Mercury Vapor			$7.00	
28	Guaranteed Units from Jan 01/91 to Aug 01/91			$26.50 / month	
29	Guaranteed Units from Jan 01/87 to Dec 31/90			$23.50 / month	
30	Joint Use for Cable and Telecom companies per pole			$22.35	
31	Joint Use for LDCs per pole			$28.61	

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Police Village of Russell Hydro-Electric System
Effective Date: May 1, 2008

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

APPLICATION

The application of these rates and charges shall be in accordance with The Licence of The Distributor and any Codes, Guidelines or Orders of The Board, and amendments thereto as approved by The Board, which may be applicable to the administration of this schedule.
No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code, Guideline or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.
This schedule does not contain any rates and charges relating to the electricity commodity (e.g. the Regulated Price Plan).

EFFECTIVE DATES

DISTRIBUTION RATES - May 1, 2008 for all consumption or deemed consumption services used on or after that date.

MISCELLANEOUS CHARGES - May 1, 2008 for all charges billed to customers on or after that date.
RETAIL TRANSMISSION RATES - May 1, 2008 for all consumption or deemed consumption services used on or after that date.
LOSS FACTOR ADJUSTMENT – for all consumption or deemed consumption services billed following May 1, 2008 or later

SERVICE CLASSIFICATIONS

Residential
This classification refers to all service supplied to single-family dwelling units for domestic or household purpose. Multi-unit residential establishments such as apartment buildings supplied through one service (bulk metered) will normally be classified as General Service, but, at Hydro One's discretion, up to four residential units may be classified as residential. Where electricity service is provided to combined residential and business (including agricultural usage) and the wiring does not provide for separate metering, the classification shall be at the discretion of Hydro One based on such considerations as the estimated predominant consumption.
Further servicing details are available in the utility's Conditions of Service.

General Service
This classification refers to all service supplied to premises other than those classified as Residential or Lighting. Some General Service accounts are energy(kWh)-billed, and some are demand(kW)-billed. Further servicing details are available in the utility's Conditions of Service.

Unmetered Scattered Load
This classification refers to certain instances where connections can be provided without metering. These loads are generally small in size and consistent in magnitude of load. Hydro One reserves the right to review all cases and may require that a meter be installed at its sole discretion. Services that can be unmetered include cable TV amplifiers, telephone switching devices, phone booths, bus shelters, rail way crossing signals, traffic signals, and other small fixed loads.
Further servicing details are available in the utility's Conditions of Service (including in the "Unmetered Connections" section).

Hydro One Networks Inc.
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Police Village of Russell Hydro-Electric System
Effective Date: May 1, 2008

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Street Lighting

This classification refers to accounts for the distribution and supply of electrical energy for street lighting. Street lights are devices owned by or operated for the road authority and/or the municipal corporation. These street lights in fact belong to the Street Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Sentinel Lighting

This classification refers to accounts for a separate service to a sentinel light. These sentinel lights in fact belong to the Sentinel Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Urban Density Classification

Customers who meet the Urban Density Criteria of being in an area containing 3,000 or more customers with a line density of at least 60 customers per kilometre, will be mapped to an Urban customer classification.

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
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Effective Date: May 1, 2008

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

MONTHLY RATES AND CHARGES

Residential - R1 Russell

Service Charge	$	14.48
Distribution Volumetric Rate	$ / kWh	0.0250
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0011
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0004)
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0047
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0046
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service Less Than 50 kW (Energy-Billed) - GSe Russell

Service Charge	$	22.28
Distribution Volumetric Rate	$ / kWh	0.0321
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0011
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0006)
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0035
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0032
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service 50 kW or Greater (Demand-Billed) - GSd Russell

Service Charge	$	25.87
Distribution Volumetric Rate	$ / kW	9.22
Regulatory Asset Recovery - Rider #2	$ / kW	0.36
Regulatory Asset Recovery - Rider #3	$ / kW	(0.22)
Retail Transmission Rate - Network Service Rate (4)	$ / kW	1.11
Retail Transmission Rate - Line and Transformation Connection Service Rate (4)	$ / kW	1.00
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
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Effective Date: May 1, 2008

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

Unmetered, Scattered Load

Service Charge	$	13.09
Distribution Volumetric Rate	$ / kWh	0.0200
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0011
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0006)
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0035
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0032
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

(3) For energy-only metered customers, the billing determinant is the customer's metered energy consumption adjusted by the total loss factor as approved by the Board for Acquired LDC customers.
(4) For demand billed customers, appropriate loss factors must be applied to the applicable tariffs. Also the billing determinant for the Line and Transformation Connection Services rate is the customer's peak demand in the billing period. The billing determinant for the Network Services rate is: for non-interval-metered customers, the peak demand in the billing period, and for interval-metered customers, the peak demand between 7 AM and 7 PM local time on IESO business days

Customer-Supplied Transformation Allowance

Applicable to customers providing their own transformers

Demand-billed	$ / kW	0.60
Energy-billed	$ / kWh	0.0014

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
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Police Village of Russell Hydro-Electric System
Effective Date: May 1, 2008

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Loss Factors

Residential	1.085
General Service Less Than 50 kW (Energy-Billed)	1.092
General Service 50 kW or Greater (Demand-Billed)	1.061
Unmetered Scattered Load	1.092

Transformer Loss Allowance

Applicable to customers requiring a billing adjustment for transformer losses as the result of beinç metered on the primary side of a transformer. The following uniform values shall be applied tc measured demand and energy to calculate transformer losses for voltages up to and includinç 50 kV (as metered on the primary side):

(a) 1.5% for transformer installations up to an individual bank capacity of 400 kVA,
(b) 1.0% for bank capacities over 400 kVA.

Alternatively, transformer losses may be determined from transformer test data, anc measured demand and energy adjusted accordingly

For services which are not demand metered, an assumed demand of 50% of the transformeı capacity will be used to calculate the loss allowance. Where several transformers are involved, the bank capacity is assumed to be the arithmetic sum of all transformer capacities

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Police Village of Russell Hydro-Electric System
Effective Date: May 1, 2008

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

MISCELLANEOUS CHARGES

Specific Service Charges: Standard Amounts

Rate Code	Specific Service Charge - Standard Name	Calculation Method			
		2006 Rate Handbook	Standard Formula	Other Formula	Time and Materials
1	Temporary Service	$500			
2	Dispute Meter Test	$30 plus Measurement Canada fees			
3	Collection of account – no disconnection/load limiter	$30			
4	Collection/Disconnect/load limiter/reconnect (at meter) trip – regular hours	$65			
5	Collection/Disconnect/load limiter/reconnect (at meter) trip – after regular hours	$185			
6	Collection/Disconnect/load limiter/reconnect (at pole) trip – regular hours	$185			
7	Collection/Disconnect/load limiter/reconnect (at pole) trip – after regular hours	$415			
8	Account Set-up Charge	$30			
9	Arrears Certificate	$15			
10	NSF Cheque Charge	$15 + bank charges			
11	Easement Charge for Unregistered Rights	$15			
12	Late Payment Charge	1.5%/month			
13a	Retailer Services – Establishing Service Agreements (refer to Handbook for all charges)	$100/agreement/Retailer +$20/month/Retailer +$0.50/month/customer + other			
13b	Retailer Services – Other (includes Bill Ready for Retailers and Service Transactions Requests) as per the Handbook, Chapter 12	$0.30/month/customer + $0.25/request for request fee + $0.50/request for process fee			
14	Special Meter Reads	$30			
15	Service Layout Fee – Basic		$495		
16	Service Layout Fee – Complex		$690		
17	Crossing Application – Pipeline		$2,445		
18	Crossing Application – Water		$3,045		
19	Crossing Application – Railroad		$2,945		
20	Line Staking – per meter		$3.70		
21	Central Metering – New service < 45 kW		$115		
22	Conversion to Central Metering < 45 kW		$915		
23	Conversion to Central Metering > 45 kW		$800		
24	Tingle Voltage Test – In Excess of 4 Hours (per hour – average 2 additional hours)		$125		
25	Standby Administration Charge per month		$440		
26	Sentinel Lights Rental Rate per month			$7.10	
27	Sentinel Pole Rental Rate per month			$4.15	
28	Joint Use for Cable and Telecom companies per pole			$22.35	
29	Joint Use for LDCs per pole			$28.61	

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
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Police Village of Russell Hydro-Electric System
Effective Date: May 1, 2007

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APPLICATION

The application of these rates and charges shall be in accordance with The Licence of The Distributor and any Codes, Guidelines or Orders of The Board, and amendments thereto as approved by The Board, which may be applicable to the administration of this schedule.
No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code, Guideline or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.
This schedule does not contain any rates and charges relating to the electricity commodity (e.g. the Regulated Price Plan).

EFFECTIVE DATES

DISTRIBUTION RATES - May 1, 2007 for all consumption or deemed consumption services used on or after that date.

MISCELLANEOUS CHARGES - May 1, 2007 for all charges billed to customers on or after that date.
RETAIL TRANSMISSION RATES - May 1, 2007 for all consumption or deemed consumption services used on or after that date.
LOSS FACTOR ADJUSTMENT – May 1, 2007

SERVICE CLASSIFICATIONS

Residential
This classification (note 1) refers to all service supplied to single-family dwelling units for domestic or household purpose. Multi-unit residential establishments such as apartment buildings supplied through one service (bulk metered) will normally be classified as General Service, but, at Hydro One’s discretion, up to four residential units may be classified as residential. Where electricity service is provided to combined residential and business (including agricultural usage) and the wiring does not provide for separate metering, the classification shall be at the discretion of Hydro One based on such considerations as the estimated predominant consumption.
Further servicing details are available in the utility’s Conditions of Service.

General Service
This classification (note 1) refers to all service supplied to premises other than those classified as Residential or Lighting. Some General Service accounts are energy(kWh)-billed, and some are demand(kW)-billed. Further servicing details are available in the utility’s Conditions of Service. Also, see note 2.

Unmetered Scattered Load
This classification refers to certain instances where connections can be provided without metering. These loads are generally small in size and consistent in magnitude of load. Hydro One reserves the right to review all cases and may require that a meter be installed at its sole discretion. Services that can be unmetered include cable TV amplifiers, telephone switching devices, phone booths, bus shelters, rail way crossing signals, traffic signals, and other small fixed loads.
Further servicing details are available in the utility’s Conditions of Service (including in the "Unmetered Connections" section).

Hydro One Networks Inc.
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Street Lighting

This classification refers to accounts for the distribution and supply of electrical energy for street lighting. Street lights are devices owned by or operated for the road authority and/or the municipal corporation. These street lights in fact belong to the Street Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Sentinel Lighting

This classification refers to accounts for a separate service to a sentinel light. These sentinel lights in fact belong to the Sentinel Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Interim Demand-Side Management Time-of-Use

This is potentially applicable to Demand-billed General Service accounts. See Note 2 below.

Note (1): Classification descriptions are paraphrases from the document "Hydro One Networks Inc. - Distribution Customers Conditions of Service - August 2004"

Note (2):

Interim Demand-Side Management Time-of-Use Rates: demand charges will be based on demand during the on-peak periods.

Criteria: Customers' electricity consumption (kW) in the off-peak period is at least twice the electricity consumption (kW) during the on-peak period.

Definition of Time Periods: The on-peak hours will be between 0700 hours to 1900 hours Eastern Standard Time during the winter (standard time) on IESO business days and 0600 hours to 1800 hours Eastern Standard Time during the summer (daylight savings time) on IESO business days. The off-peak period constitutes all of the remaining hours.

Hydro One Networks Inc.
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MONTHLY RATES AND CHARGES

Residential

Service Charge	$	13.11
Distribution Volumetric Rate	$ / kWh	0.0144
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0028
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0011
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0055
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0047
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service - Energy Billed (less than 50 kW)

Service Charge	$	19.26
Distribution Volumetric Rate	$ / kWh	0.0224
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0018
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0011
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0050
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0043
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service - Demand Billed (50 kW or greater)

Service Charge	$	19.26
Distribution Volumetric Rate	$ / kW	7.10
Regulatory Asset Recovery - Rider #1	$ / kW	0.58
Regulatory Asset Recovery - Rider #2	$ / kW	0.36
Retail Transmission Rate - Network Service Rate (4)	$ / kW	1.94
Retail Transmission Rate - Line and Transformation Connection Service Rate (4)	$ / kW	1.61
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

Hydro One Networks Inc.
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Unmetered, Scattered Load

Service Charge	$	9.17
Distribution Volumetric Rate	$ / kWh	0.0224
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0018
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0011
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0050
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0043
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

(3) For energy-only metered customers, the billing determinant is the customer’s metered energy consumption adjusted by the total loss factor as approved by the Board for Acquired LDC customers.
(4) For demand billed customers, appropriate loss factors must be applied to the applicable tariffs. Also the billing determinant for the Line and Transformation Connection Services rate is the customer’s peak demand in the billing period. The billing determinant for the Network Services rate is: for non-interval-metered customers, the peak demand in the billing period, and for interval-metered customers, the peak demand between 7 AM and 7 PM local time on IESO business days

Interim Demand-Side Management Time-of-Use

See the "Service Classifications" section of this schedule.

Customer-Supplied Transformation Allowance

Applicable to demand-billed customers providing their own transformers
Primary Voltage under 50 kV (per kW)

Single Phase	$ / kW	0.20
Three Phase	$ / kW	0.60

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Loss Factors

Supply Facilities Loss Factor	1.0045
Distribution Loss Factors	
Customer less than 5,000 kW	1.0500
Customer greater than or equal to 5,000 kW	1.0100
Total Loss Factors	
Customer less than 5,000 kW	1.0545
Customer greater than or equal to 5,000 kW	1.0145

Transformer Loss Allowance

Applicable to customers requiring a billing adjustment for transformer losses as the result of being metered on the primary side of a transformer. The following uniform values shall be applied to measured demand and energy to calculate transformer losses for voltages up to and including 50 kV (as metered on the primary side):

(a) 1.5% for transformer installations up to an individual bank capacity of 400 kVA,
(b) 1.0% for bank capacities over 400 kVA.

Alternatively, transformer losses may be determined from transformer test data, and measured demand and energy adjusted accordingly

For services which are not demand metered, an assumed demand of 50% of the transformer capacity will be used to calculate the loss allowance. Where several transformers are involved, the bank capacity is assumed to be the arithmetic sum of all transformer capacities

Hydro One Networks Inc.
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MISCELLANEOUS CHARGES

Specific Service Charges: Standard Amounts

Rate Code	Specific Service Charge - Standard Name	Calculation Method			
		2006 Rate Handbook	Standard Formula	Other Formula	Time and Materials
1	Temporary Service	$500			
2	Dispute Meter Test	$30 plus Measurement Canada fees			
3	Collection of account – no disconnection/load limiter	$30			
4	Collection/Disconnect/load limiter/reconnect (at meter) trip – regular hours	$65			
5	Collection/Disconnect/load limiter/reconnect (at meter) trip – after regular hours	$185			
6	Collection/Disconnect/load limiter/reconnect (at pole) trip – regular hours	$185			
7	Collection/Disconnect/load limiter/reconnect (at pole) trip – after regular hours	$415			
8	Account Set-up Charge	$30			
9	Arrears Certificate	$15			
10	NSF Cheque Charge	$15 + bank charges			
11	Easement Charge for Unregistered Rights	$15			
12	Late Payment Charge	1.5%/month			
13a	Retailer Services – Establishing Service Agreements (refer to Handbook for all charges)	$100/agreement/Retailer +$20/month/Retailer +$0.50/month/customer + other			
13b	Retailer Services – Other (includes Bill Ready for Retailers and Service Transactions Requests) as per the Handbook, Chapter 12	$0.30/month/customer + $0.25/request for request fee + $0.50/request for process fee			
14	Special Meter Reads	$30			
15	Billing Suspension and Terminations in Trailer Parks		$130		
16	Service Layout Fee – Basic		$405		
17	Service Layout Fee – Complex		$580		

Hydro One Networks Inc.
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18	Crossing Application – Pipeline		$2,065		
19	Crossing Application – Water		$2,525		
20	Crossing Application – Railroad		$2,565		
21	Line Staking – per meter		$3.10		
22	Central Metering – New service < 45 kW		$115		
23	Conversion to Central Metering < 45 kW		$795		
24	Conversion to Central Metering > 45 kW		$680		
25	Tingle Voltage Test – In Excess of 4 Hours (per hour – average 2 additional hours)		$105		
26	Standby Administration Charge per month (interim)		$375		
27	Sentinel Lights Rental Rate per month – Mercury Vapor			$7.00	
28	Guaranteed Units from Jan 01/91 to Aug 01/91			$26.50 / month	
29	Guaranteed Units from Jan 01/87 to Dec 31/90			$23.50 / month	
30	Joint Use for Cable and Telecom companies per pole			$22.35	
31	Joint Use for LDCs per pole			$28.61	

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
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Schreiber Hydro-Electric Commission
Effective Date: May 1, 2008

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APPLICATION

The application of these rates and charges shall be in accordance with The Licence of The Distributor and any Codes, Guidelines or Orders of The Board, and amendments thereto as approved by The Board, which may be applicable to the administration of this schedule.
No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code, Guideline or Order of the Board, and amendments thereto as approved by the Board, or as specified herein
This schedule does not contain any rates and charges relating to the electricity commodity (e.g. the Regulated Price Plan).

EFFECTIVE DATES

DISTRIBUTION RATES - May 1, 2008 for all consumption or deemed consumption services used on or after that date.

MISCELLANEOUS CHARGES - May 1, 2008 for all charges billed to customers on or after that date.
RETAIL TRANSMISSION RATES - May 1, 2008 for all consumption or deemed consumption services used on or after that date.
LOSS FACTOR ADJUSTMENT – for all consumption or deemed consumption services billed following May 1, 2008 or later

SERVICE CLASSIFICATIONS

Residential
This classification refers to all service supplied to single-family dwelling units for domestic or household purpose. Multi-unit residential establishments such as apartment buildings supplied through one service (bulk metered) will normally be classified as General Service, but, at Hydro One's discretion, up to four residential units may be classified as residential. Where electricity service is provided to combined residential and business (including agricultural usage) and the wiring does not provide for separate metering, the classification shall be at the discretion of Hydro One based on such considerations as the estimated predominant consumption.
Further servicing details are available in the utility's Conditions of Service.

General Service
This classification refers to all service supplied to premises other than those classified as Residential or Lighting. Some General Service accounts are energy(kWh)-billed, and some are demand(kW)-billed. Further servicing details are available in the utility's Conditions of Service.

Unmetered Scattered Load
This classification refers to certain instances where connections can be provided without metering. These loads are generally small in size and consistent in magnitude of load. Hydro One reserves the right to review all cases and may require that a meter be installed at its sole discretion. Services that can be unmetered include cable TV amplifiers, telephone switching devices, phone booths, bus shelters, rail way crossing signals, traffic signals, and other small fixed loads.
Further servicing details are available in the utility's Conditions of Service (including in the "Unmetered Connections" section).

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
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Schreiber Hydro-Electric Commission
Effective Date: May 1, 2008

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Street Lighting

This classification refers to accounts for the distribution and supply of electrical energy for street lighting. Street lights are devices owned by or operated for the road authority and/or the municipal corporation. These street lights in fact belong to the Street Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Sentinel Lighting

This classification refers to accounts for a separate service to a sentinel light. These sentinel lights in fact belong to the Sentinel Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Urban Density Classification

Customers who meet the Urban Density Criteria of being in an area containing 3,000 or more customers with a line density of at least 60 customers per kilometre, will be mapped to an Urban customer classification.

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
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Effective Date: May 1, 2008

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MONTHLY RATES AND CHARGES

Residential - R1 Schreiber

Service Charge	$	16.68
Distribution Volumetric Rate	$ / kWh	0.0271
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0044
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0004)
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0047
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0046
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service Less Than 50 kW (Energy-Billed) - GSe Schreiber

Service Charge	$	22.92
Distribution Volumetric Rate	$ / kWh	0.0321
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0040
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0006)
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0035
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0032
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service 50 kW or Greater (Demand-Billed) - GSd Schreiber

Service Charge	$	26.51
Distribution Volumetric Rate	$ / kW	9.22
Regulatory Asset Recovery - Rider #2	$ / kW	1.17
Regulatory Asset Recovery - Rider #3	$ / kW	(0.22)
Retail Transmission Rate - Network Service Rate (4)	$ / kW	1.11
Retail Transmission Rate - Line and Transformation Connection Service Rate (4)	$ / kW	1.00
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

Hydro One Networks Inc.
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Effective Date: May 1, 2008

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Unmetered, Scattered Load

Service Charge	$	12.91
Distribution Volumetric Rate	$ / kWh	0.0200
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0040
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0006)
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0035
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0032
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

(3) For energy-only metered customers, the billing determinant is the customer's metered energy consumption adjusted by the total loss factor as approved by the Board for Acquired LDC customers.
(4) For demand billed customers, appropriate loss factors must be applied to the applicable tariffs. Also the billing determinant for the Line and Transformation Connection Services rate is the customer's peak demand in the billing period. The billing determinant for the Network Services rate is: for non-interval-metered customers, the peak demand in the billing period, and for interval-metered customers, the peak demand between 7 AM and 7 PM local time on IESO business days

Customer-Supplied Transformation Allowance

Applicable to customers providing their own transformers

Demand-billed	$ / kW	0.60
Energy-billed	$ / kWh	0.0014

Hydro One Networks Inc.
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Loss Factors

Residential	1.085
General Service Less Than 50 kW (Energy-Billed)	1.092
General Service 50 kW or Greater (Demand-Billed)	1.061
Unmetered Scattered Load	1.092

Transformer Loss Allowance

Applicable to customers requiring a billing adjustment for transformer losses as the result of being metered on the primary side of a transformer. The following uniform values shall be applied to measured demand and energy to calculate transformer losses for voltages up to and including 50 kV (as metered on the primary side):

(a) 1.5% for transformer installations up to an individual bank capacity of 400 kVA,
(b) 1.0% for bank capacities over 400 kVA.

Alternatively, transformer losses may be determined from transformer test data, and measured demand and energy adjusted accordingly

For services which are not demand metered, an assumed demand of 50% of the transformer capacity will be used to calculate the loss allowance. Where several transformers are involved, the bank capacity is assumed to be the arithmetic sum of all transformer capacities

Hydro One Networks Inc.
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MISCELLANEOUS CHARGES

Specific Service Charges: Standard Amounts

Rate Code	Specific Service Charge - Standard Name	Calculation Method			
		2006 Rate Handbook	Standard Formula	Other Formula	Time and Materials
1	Temporary Service	$500			
2	Dispute Meter Test	$30 plus Measurement Canada fees			
3	Collection of account – no disconnection/load limiter	$30			
4	Collection/Disconnect/load limiter/reconnect (at meter) trip – regular hours	$65			
5	Collection/Disconnect/load limiter/reconnect (at meter) trip – after regular hours	$185			
6	Collection/Disconnect/load limiter/reconnect (at pole) trip – regular hours	$185			
7	Collection/Disconnect/load limiter/reconnect (at pole) trip – after regular hours	$415			
8	Account Set-up Charge	$30			
9	Arrears Certificate	$15			
10	NSF Cheque Charge	$15 + bank charges			
11	Easement Charge for Unregistered Rights	$15			
12	Late Payment Charge	1.5%/month			
13a	Retailer Services – Establishing Service Agreements (refer to Handbook for all charges)	$100/agreement/Retailer +$20/month/Retailer +$0.50/month/customer + other			
13b	Retailer Services – Other (includes Bill Ready for Retailers and Service Transactions Requests) as per the Handbook, Chapter 12	$0.30/month/customer + $0.25/request for request fee + $0.50/request for process fee			
14	Special Meter Reads	$30			
15	Service Layout Fee – Basic		$495		
16	Service Layout Fee – Complex		$690		
17	Crossing Application – Pipeline		$2,445		
18	Crossing Application – Water		$3,045		
19	Crossing Application – Railroad		$2,945		
20	Line Staking – per meter		$3.70		
21	Central Metering – New service < 45 kW		$115		
22	Conversion to Central Metering < 45 kW		$915		
23	Conversion to Central Metering > 45 kW		$800		
24	Tingle Voltage Test – In Excess of 4 Hours (per hour – average 2 additional hours)		$125		
25	Standby Administration Charge per month		$440		
26	Sentinel Lights Rental Rate per month			$7.10	
27	Sentinel Pole Rental Rate per month			$4.15	
28	Joint Use for Cable and Telecom companies per pole			$22.35	
29	Joint Use for LDCs per pole			$28.61	

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APPLICATION

The application of these rates and charges shall be in accordance with The Licence of The Distributor and any Codes, Guidelines or Orders of The Board, and amendments thereto as approved by The Board, which may be applicable to the administration of this schedule.
No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code, Guideline or Order of the Board, and amendments thereto as approved by the Board, or as specified herein
This schedule does not contain any rates and charges relating to the electricity commodity (e.g. the Regulated Price Plan).

EFFECTIVE DATES

DISTRIBUTION RATES - May 1, 2007 for all consumption or deemed consumption services used on or after that date.

MISCELLANEOUS CHARGES - May 1, 2007 for all charges billed to customers on or after that date.
RETAIL TRANSMISSION RATES - May 1, 2007 for all consumption or deemed consumption services used on or after that date.
LOSS FACTOR ADJUSTMENT – May 1, 2007

SERVICE CLASSIFICATIONS

Residential
This classification (note 1) refers to all service supplied to single-family dwelling units for domestic or household purpose. Multi-unit residential establishments such as apartment buildings supplied through one service (bulk metered) will normally be classified as General Service, but, at Hydro One's discretion, up to four residential units may be classified as residential. Where electricity service is provided to combined residential and business (including agricultural usage) and the wiring does not provide for separate metering, the classification shall be at the discretion of Hydro One based on such considerations as the estimated predominant consumption.
Further servicing details are available in the utility's Conditions of Service.

General Service
This classification (note 1) refers to all service supplied to premises other than those classified as Residential or Lighting. Some General Service accounts are energy(kWh)-billed, and some are demand(kW)-billed. Further servicing details are available in the utility's Conditions of Service. Also, see note 2.

Unmetered Scattered Load
This classification refers to certain instances where connections can be provided without metering. These loads are generally small in size and consistent in magnitude of load. Hydro One reserves the right to review all cases and may require that a meter be installed at its sole discretion. Services that can be unmetered include cable TV amplifiers, telephone switching devices, phone booths, bus shelters, rail way crossing signals, traffic signals, and other small fixed loads.
Further servicing details are available in the utility's Conditions of Service (including in the "Unmetered Connections" section).

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Schreiber Hydro-Electric Commission
Effective Date: May 1, 2007

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

Street Lighting

This classification refers to accounts for the distribution and supply of electrical energy for street lighting. Street lights are devices owned by or operated for the road authority and/or the municipal corporation. These street lights in fact belong to the Street Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Sentinel Lighting

This classification refers to accounts for a separate service to a sentinel light. These sentinel lights in fact belong to the Sentinel Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Interim Demand-Side Management Time-of-Use

This is potentially applicable to Demand-billed General Service accounts. See Note 2 below.

Note (1): Classification descriptions are paraphrases from the document "Hydro One Networks Inc. - Distribution Customers Conditions of Service - August 2004"

Note (2):

Interim Demand-Side Management Time-of-Use Rates: demand charges will be based on demand during the on-peak periods.

Criteria: Customers' electricity consumption (kW) in the off-peak period is at least twice the electricity consumption (kW) during the on-peak period.

Definition of Time Periods: The on-peak hours will be between 0700 hours to 1900 hours Eastern Standard Time during the winter (standard time) on IESO business days and 0600 hours to 1800 hours Eastern Standard Time during the summer (daylight savings time) on IESO business days. The off-peak period constitutes all of the remaining hours.

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
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Schreiber Hydro-Electric Commission
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MONTHLY RATES AND CHARGES

Residential

Service Charge	$	16.32
Distribution Volumetric Rate	$ / kWh	0.0184
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0068
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0044
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0055
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0047
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service - Energy Billed (less than 50 kW)

Service Charge	$	20.70
Distribution Volumetric Rate	$ / kWh	0.0251
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0050
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0040
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0050
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0043
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service - Demand Billed (50 kW or greater)

Service Charge	$	20.70
Distribution Volumetric Rate	$ / kW	7.36
Regulatory Asset Recovery - Rider #1	$ / kW	1.57
Regulatory Asset Recovery - Rider #2	$ / kW	1.17
Retail Transmission Rate - Network Service Rate (4)	$ / kW	1.94
Retail Transmission Rate - Line and Transformation Connection Service Rate (4)	$ / kW	1.61
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

Hydro One Networks Inc.
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Unmetered, Scattered Load

Service Charge	$	9.88
Distribution Volumetric Rate	$ / kWh	0.0251
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0050
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0040
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0050
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0043
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

(3) For energy-only metered customers, the billing determinant is the customer's metered energy consumption adjusted by the total loss factor as approved by the Board for Acquired LDC customers.
(4) For demand billed customers, appropriate loss factors must be applied to the applicable tariffs. Also the billing determinant for the Line and Transformation Connection Services rate is the customer's peak demand in the billing period. The billing determinant for the Network Services rate is: for non-interval-metered customers, the peak demand in the billing period, and for interval-metered customers, the peak demand between 7 AM and 7 PM local time on IESO business days

Interim Demand-Side Management Time-of-Use

See the "Service Classifications" section of this schedule.

Customer-Supplied Transformation Allowance

Applicable to demand-billed customers providing their own transformers
Primary Voltage under 50 kV (per kW)

Single Phase	$ / kW	0.20
Three Phase	$ / kW	0.60

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Loss Factors

Supply Facilities Loss Factor	1.0045
Distribution Loss Factors	
Customer less than 5,000 kW	1.0500
Customer greater than or equal to 5,000 kW	1.0100
Total Loss Factors	
Customer less than 5,000 kW	1.0545
Customer greater than or equal to 5,000 kW	1.0145

Transformer Loss Allowance

Applicable to customers requiring a billing adjustment for transformer losses as the result of being metered on the primary side of a transformer. The following uniform values shall be applied to measured demand and energy to calculate transformer losses for voltages up to and including 50 kV (as metered on the primary side):

(a) 1.5% for transformer installations up to an individual bank capacity of 400 kVA,
(b) 1.0% for bank capacities over 400 kVA.

Alternatively, transformer losses may be determined from transformer test data, and measured demand and energy adjusted accordingly

For services which are not demand metered, an assumed demand of 50% of the transformer capacity will be used to calculate the loss allowance. Where several transformers are involved, the bank capacity is assumed to be the arithmetic sum of all transformer capacities

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
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MISCELLANEOUS CHARGES

Specific Service Charges: Standard Amounts

Rate Code	Specific Service Charge - Standard Name	Calculation Method			
		2006 Rate Handbook	Standard Formula	Other Formula	Time and Materials
1	Temporary Service	$500			
2	Dispute Meter Test	$30 plus Measurement Canada fees			
3	Collection of account – no disconnection/load limiter	$30			
4	Collection/Disconnect/load limiter/reconnect (at meter) trip – regular hours	$65			
5	Collection/Disconnect/load limiter/reconnect (at meter) trip – after regular hours	$185			
6	Collection/Disconnect/load limiter/reconnect (at pole) trip – regular hours	$185			
7	Collection/Disconnect/load limiter/reconnect (at pole) trip – after regular hours	$415			
8	Account Set-up Charge	$30			
9	Arrears Certificate	$15			
10	NSF Cheque Charge	$15 + bank charges			
11	Easement Charge for Unregistered Rights	$15			
12	Late Payment Charge	1.5%/month			
13a	Retailer Services – Establishing Service Agreements (refer to Handbook for all charges)	$100/agreement/Retailer +$20/month/Retailer +$0.50/month/customer + other			
13b	Retailer Services – Other (includes Bill Ready for Retailers and Service Transactions Requests) as per the Handbook, Chapter 12	$0.30/month/customer + $0.25/request for request fee + $0.50/request for process fee			
14	Special Meter Reads	$30			
15	Billing Suspension and Terminations in Trailer Parks		$130		
16	Service Layout Fee – Basic		$405		
17	Service Layout Fee – Complex		$580		

Hydro One Networks Inc.
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18	Crossing Application – Pipeline		$2,065		
19	Crossing Application – Water		$2,525		
20	Crossing Application – Railroad		$2,565		
21	Line Staking – per meter		$3.10		
22	Central Metering – New service < 45 kW		$115		
23	Conversion to Central Metering < 45 kW		$795		
24	Conversion to Central Metering > 45 kW		$680		
25	Tingle Voltage Test – In Excess of 4 Hours (per hour – average 2 additional hours)		$105		
26	Standby Administration Charge per month (interim)		$375		
27	Sentinel Lights Rental Rate per month – Mercury Vapor			$7.00	
28	Guaranteed Units from Jan 01/91 to Aug 01/91			$26.50 / month	
29	Guaranteed Units from Jan 01/87 to Dec 31/90			$23.50 / month	
30	Joint Use for Cable and Telecom companies per pole			$22.35	
31	Joint Use for LDCs per pole			$28.61	

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Severn Hydro-Electric System
Effective Date: May 1, 2008

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

APPLICATION

The application of these rates and charges shall be in accordance with The Licence of The Distributor and any Codes, Guidelines or Orders of The Board, and amendments thereto as approved by The Board, which may be applicable to the administration of this schedule.
No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code, Guideline or Order of the Board, and amendments thereto as approved by the Board, or as specified herein
This schedule does not contain any rates and charges relating to the electricity commodity (e.g. the Regulated Price Plan).

EFFECTIVE DATES

DISTRIBUTION RATES - May 1, 2008 for all consumption or deemed consumption services used on or after that date.

MISCELLANEOUS CHARGES - May 1, 2008 for all charges billed to customers on or after that date.
RETAIL TRANSMISSION RATES - May 1, 2008 for all consumption or deemed consumption services used on or after that date.
LOSS FACTOR ADJUSTMENT – for all consumption or deemed consumption services billed following May 1, 2008 or later

SERVICE CLASSIFICATIONS

Residential
This classification refers to all service supplied to single-family dwelling units for domestic or household purpose. Multi-unit residential establishments such as apartment buildings supplied through one service (bulk metered) will normally be classified as General Service, but, at Hydro One's discretion, up to four residential units may be classified as residential. Where electricity service is provided to combined residential and business (including agricultural usage) and the wiring does not provide for separate metering, the classification shall be at the discretion of Hydro One based on such considerations as the estimated predominant consumption.
Further servicing details are available in the utility's Conditions of Service.

General Service
This classification refers to all service supplied to premises other than those classified as Residential or Lighting. Some General Service accounts are energy(kWh)-billed, and some are demand(kW)-billed. Further servicing details are available in the utility's Conditions of Service.

Unmetered Scattered Load
This classification refers to certain instances where connections can be provided without metering. These loads are generally small in size and consistent in magnitude of load. Hydro One reserves the right to review all cases and may require that a meter be installed at its sole discretion. Services that can be unmetered include cable TV amplifiers, telephone switching devices, phone booths, bus shelters, rail way crossing signals, traffic signals, and other small fixed loads.
Further servicing details are available in the utility's Conditions of Service (including in the "Unmetered Connections" section).

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Severn Hydro-Electric System
Effective Date: May 1, 2008

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Street Lighting

This classification refers to accounts for the distribution and supply of electrical energy for street lighting. Street lights are devices owned by or operated for the road authority and/or the municipal corporation. These street lights in fact belong to the Street Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Sentinel Lighting

This classification refers to accounts for a separate service to a sentinel light. These sentinel lights in fact belong to the Sentinel Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Urban Density Classification

Customers who meet the Urban Density Criteria of being in an area containing 3,000 or more customers with a line density of at least 60 customers per kilometre, will be mapped to an Urban customer classification.

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
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Effective Date: May 1, 2008

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

MONTHLY RATES AND CHARGES

Residential - R1 Severn

Service Charge	$	12.11
Distribution Volumetric Rate	$ / kWh	0.0225
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0032
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0004)
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0047
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0046
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service Less Than 50 kW (Energy-Billed) - GSe Severn

Service Charge	$	24.55
Distribution Volumetric Rate	$ / kWh	0.0230
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0022
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0006)
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0035
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0032
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service 50 kW or Greater (Demand-Billed) - GSd Severn

Service Charge	$	28.15
Distribution Volumetric Rate	$ / kW	8.70
Regulatory Asset Recovery - Rider #2	$ / kW	0.69
Regulatory Asset Recovery - Rider #3	$ / kW	(0.22)
Retail Transmission Rate - Network Service Rate (4)	$ / kW	1.11
Retail Transmission Rate - Line and Transformation Connection Service Rate (4)	$ / kW	1.00
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
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Effective Date: May 1, 2008

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Unmetered, Scattered Load

Service Charge	$	13.72
Distribution Volumetric Rate	$ / kWh	0.0200
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0022
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0006)
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0035
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0032
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

(3) For energy-only metered customers, the billing determinant is the customer's metered energy consumption adjusted by the total loss factor as approved by the Board for Acquired LDC customers.
(4) For demand billed customers, appropriate loss factors must be applied to the applicable tariffs. Also the billing determinant for the Line and Transformation Connection Services rate is the customer's peak demand in the billing period. The billing determinant for the Network Services rate is: for non-interval-metered customers, the peak demand in the billing period, and for interval-metered customers, the peak demand between 7 AM and 7 PM local time on IESO business days

Customer-Supplied Transformation Allowance

Applicable to customers providing their own transformers

Demand-billed	$ / kW	0.60
Energy-billed	$ / kWh	0.0014

Hydro One Networks Inc.
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Loss Factors

Residential	1.085
General Service Less Than 50 kW (Energy-Billed)	1.092
General Service 50 kW or Greater (Demand-Billed)	1.061
Unmetered Scattered Load	1.092

Transformer Loss Allowance

Applicable to customers requiring a billing adjustment for transformer losses as the result of being metered on the primary side of a transformer. The following uniform values shall be applied to measured demand and energy to calculate transformer losses for voltages up to and including 50 kV (as metered on the primary side):

(a) 1.5% for transformer installations up to an individual bank capacity of 400 kVA,
(b) 1.0% for bank capacities over 400 kVA.

Alternatively, transformer losses may be determined from transformer test data, and measured demand and energy adjusted accordingly

For services which are not demand metered, an assumed demand of 50% of the transformer capacity will be used to calculate the loss allowance. Where several transformers are involved, the bank capacity is assumed to be the arithmetic sum of all transformer capacities

Hydro One Networks Inc.
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MISCELLANEOUS CHARGES

Specific Service Charges: Standard Amounts

Rate Code	Specific Service Charge - Standard Name	Calculation Method			
		2006 Rate Handbook	Standard Formula	Other Formula	Time and Materials
1	Temporary Service	$500			
2	Dispute Meter Test	$30 plus Measurement Canada fees			
3	Collection of account – no disconnection/load limiter	$30			
4	Collection/Disconnect/load limiter/reconnect (at meter) trip – regular hours	$65			
5	Collection/Disconnect/load limiter/reconnect (at meter) trip – after regular hours	$185			
6	Collection/Disconnect/load limiter/reconnect (at pole) trip – regular hours	$185			
7	Collection/Disconnect/load limiter/reconnect (at pole) trip – after regular hours	$415			
8	Account Set-up Charge	$30			
9	Arrears Certificate	$15			
10	NSF Cheque Charge	$15 + bank charges			
11	Easement Charge for Unregistered Rights	$15			
12	Late Payment Charge	1.5%/month			
13a	Retailer Services – Establishing Service Agreements (refer to Handbook for all charges)	$100/agreement/Retailer +$20/month/Retailer +$0.50/month/customer + other			
13b	Retailer Services – Other (includes Bill Ready for Retailers and Service Transactions Requests) as per the Handbook, Chapter 12	$0.30/month/customer + $0.25/request for request fee + $0.50/request for process fee			
14	Special Meter Reads	$30			
15	Service Layout Fee – Basic		$495		
16	Service Layout Fee – Complex		$690		
17	Crossing Application – Pipeline		$2,445		
18	Crossing Application – Water		$3,045		
19	Crossing Application – Railroad		$2,945		
20	Line Staking – per meter		$3.70		
21	Central Metering – New service < 45 kW		$115		
22	Conversion to Central Metering < 45 kW		$915		
23	Conversion to Central Metering > 45 kW		$800		
24	Tingle Voltage Test – In Excess of 4 Hours (per hour – average 2 additional hours)		$125		
25	Standby Administration Charge per month		$440		
26	Sentinel Lights Rental Rate per month			$7.10	
27	Sentinel Pole Rental Rate per month			$4.15	
28	Joint Use for Cable and Telecom companies per pole			$22.35	
29	Joint Use for LDCs per pole			$28.61	

Hydro One Networks Inc.
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APPLICATION

The application of these rates and charges shall be in accordance with The Licence of The Distributor and any Codes, Guidelines or Orders of The Board, and amendments thereto as approved by The Board, which may be applicable to the administration of this schedule.
No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code, Guideline or Order of the Board, and amendments thereto as approved by the Board, or as specified herein
This schedule does not contain any rates and charges relating to the electricity commodity (e.g. the Regulated Price Plan).

EFFECTIVE DATES

DISTRIBUTION RATES - May 1, 2007 for all consumption or deemed consumption services used on or after that date.

MISCELLANEOUS CHARGES - May 1, 2007 for all charges billed to customers on or after that date.
RETAIL TRANSMISSION RATES - May 1, 2007 for all consumption or deemed consumption services used on or after that date.
LOSS FACTOR ADJUSTMENT – May 1, 2007

SERVICE CLASSIFICATIONS

Residential
This classification (note 1) refers to all service supplied to single-family dwelling units for domestic or household purpose. Multi-unit residential establishments such as apartment buildings supplied through one service (bulk metered) will normally be classified as General Service, but, at Hydro One’s discretion, up to four residential units may be classified as residential. Where electricity service is provided to combined residential and business (including agricultural usage) and the wiring does not provide for separate metering, the classification shall be at the discretion of Hydro One based on such considerations as the estimated predominant consumption.
Further servicing details are available in the utility’s Conditions of Service.

General Service
This classification (note 1) refers to all service supplied to premises other than those classified as Residential or Lighting. Some General Service accounts are energy(kWh)-billed, and some are demand(kW)-billed. Further servicing details are available in the utility’s Conditions of Service. Also, see note 2.

Unmetered Scattered Load
This classification refers to certain instances where connections can be provided without metering. These loads are generally small in size and consistent in magnitude of load. Hydro One reserves the right to review all cases and may require that a meter be installed at its sole discretion. Services that can be unmetered include cable TV amplifiers, telephone switching devices, phone booths, bus shelters, rail way crossing signals, traffic signals, and other small fixed loads.
Further servicing details are available in the utility’s Conditions of Service (including in the "Unmetered Connections" section).

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Street Lighting

This classification refers to accounts for the distribution and supply of electrical energy for street lighting. Street lights are devices owned by or operated for the road authority and/or the municipal corporation. These street lights in fact belong to the Street Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Sentinel Lighting

This classification refers to accounts for a separate service to a sentinel light. These sentinel lights in fact belong to the Sentinel Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Interim Demand-Side Management Time-of-Use

This is potentially applicable to Demand-billed General Service accounts. See Note 2 below.

Note (1): Classification descriptions are paraphrases from the document "Hydro One Networks Inc. - Distribution Customers Conditions of Service - August 2004"

Note (2):

Interim Demand-Side Management Time-of-Use Rates: demand charges will be based on demand during the on-peak periods.

Criteria: Customers' electricity consumption (kW) in the off-peak period is at least twice the electricity consumption (kW) during the on-peak period.

Definition of Time Periods: The on-peak hours will be between 0700 hours to 1900 hours Eastern Standard Time during the winter (standard time) on IESO business days and 0600 hours to 1800 hours Eastern Standard Time during the summer (daylight savings time) on IESO business days. The off-peak period constitutes all of the remaining hours.

Hydro One Networks Inc.
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MONTHLY RATES AND CHARGES

Residential

Service Charge	$	10.60
Distribution Volumetric Rate	$ / kWh	0.0090
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0059
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0032
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0055
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0047
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service - Energy Billed (less than 50 kW)

Service Charge	$	22.17
Distribution Volumetric Rate	$ / kWh	0.0106
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0031
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0022
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0050
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0043
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service - Demand Billed (50 kW or greater)

Service Charge	$	22.17
Distribution Volumetric Rate	$ / kW	3.35
Regulatory Asset Recovery - Rider #1	$ / kW	0.98
Regulatory Asset Recovery - Rider #2	$ / kW	0.69
Retail Transmission Rate - Network Service Rate (4)	$ / kW	1.94
Retail Transmission Rate - Line and Transformation Connection Service Rate (4)	$ / kW	1.61
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

Hydro One Networks Inc.
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Effective Date: May 1, 2007

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

Unmetered, Scattered Load

Service Charge	$	10.62
Distribution Volumetric Rate	$ / kWh	0.0106
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0031
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0022
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0050
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0043
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

(3) For energy-only metered customers, the billing determinant is the customer's metered energy consumption adjusted by the total loss factor as approved by the Board for Acquired LDC customers.
(4) For demand billed customers, appropriate loss factors must be applied to the applicable tariffs. Also the billing determinant for the Line and Transformation Connection Services rate is the customer's peak demand in the billing period. The billing determinant for the Network Services rate is: for non-interval-metered customers, the peak demand in the billing period, and for interval-metered customers, the peak demand between 7 AM and 7 PM local time on IESO business days

Interim Demand-Side Management Time-of-Use

See the "Service Classifications" section of this schedule.

Customer-Supplied Transformation Allowance

Applicable to demand-billed customers providing their own transformers
Primary Voltage under 50 kV (per kW)

Single Phase	$ / kW	0.20
Three Phase	$ / kW	0.60

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Severn Hydro-Electric System
Effective Date: May 1, 2007

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

Loss Factors

Supply Facilities Loss Factor	1.0045
Distribution Loss Factors	
Customer less than 5,000 kW	1.0500
Customer greater than or equal to 5,000 kW	1.0100
Total Loss Factors	
Customer less than 5,000 kW	1.0545
Customer greater than or equal to 5,000 kW	1.0145

Transformer Loss Allowance

Applicable to customers requiring a billing adjustment for transformer losses as the result of being metered on the primary side of a transformer. The following uniform values shall be applied to measured demand and energy to calculate transformer losses for voltages up to and including 50 kV (as metered on the primary side):

(a) 1.5% for transformer installations up to an individual bank capacity of 400 kVA,
(b) 1.0% for bank capacities over 400 kVA.

Alternatively, transformer losses may be determined from transformer test data, and measured demand and energy adjusted accordingly

For services which are not demand metered, an assumed demand of 50% of the transformer capacity will be used to calculate the loss allowance. Where several transformers are involved, the bank capacity is assumed to be the arithmetic sum of all transformer capacities

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Severn Hydro-Electric System
Effective Date: May 1, 2007

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

MISCELLANEOUS CHARGES

Specific Service Charges: Standard Amounts

Rate Code	Specific Service Charge - Standard Name	Calculation Method			
		2006 Rate Handbook	Standard Formula	Other Formula	Time and Materials
1	Temporary Service	$500			
2	Dispute Meter Test	$30 plus Measurement Canada fees			
3	Collection of account – no disconnection/load limiter	$30			
4	Collection/Disconnect/load limiter/reconnect (at meter) trip – regular hours	$65			
5	Collection/Disconnect/load limiter/reconnect (at meter) trip – after regular hours	$185			
6	Collection/Disconnect/load limiter/reconnect (at pole) trip – regular hours	$185			
7	Collection/Disconnect/load limiter/reconnect (at pole) trip – after regular hours	$415			
8	Account Set-up Charge	$30			
9	Arrears Certificate	$15			
10	NSF Cheque Charge	$15 + bank charges			
11	Easement Charge for Unregistered Rights	$15			
12	Late Payment Charge	1.5%/month			
13a	Retailer Services – Establishing Service Agreements (refer to Handbook for all charges)	$100/agreement/Retailer +$20/month/Retailer +$0.50/month/customer + other			
13b	Retailer Services – Other (includes Bill Ready for Retailers and Service Transactions Requests) as per the Handbook, Chapter 12	$0.30/month/customer + $0.25/request for request fee + $0.50/request for process fee			
14	Special Meter Reads	$30			
15	Billing Suspension and Terminations in Trailer Parks		$130		
16	Service Layout Fee – Basic		$405		
17	Service Layout Fee – Complex		$580		

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Severn Hydro-Electric System
Effective Date: May 1, 2007

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

18	Crossing Application – Pipeline		$2,065		
19	Crossing Application – Water		$2,525		
20	Crossing Application – Railroad		$2,565		
21	Line Staking – per meter		$3.10		
22	Central Metering – New service < 45 kW		$115		
23	Conversion to Central Metering < 45 kW		$795		
24	Conversion to Central Metering > 45 kW		$680		
25	Tingle Voltage Test – In Excess of 4 Hours (per hour – average 2 additional hours)		$105		
26	Standby Administration Charge per month (interim)		$375		
27	Sentinel Lights Rental Rate per month – Mercury Vapor			$7.00	
28	Guaranteed Units from Jan 01/91 to Aug 01/91			$26.50 / month	
29	Guaranteed Units from Jan 01/87 to Dec 31/90			$23.50 / month	
30	Joint Use for Cable and Telecom companies per pole			$22.35	
31	Joint Use for LDCs per pole			$28.61	

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Hydro-Electric Commission of the Town of Shelburne
Effective Date: May 1, 2008

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

APPLICATION

The application of these rates and charges shall be in accordance with The Licence of The Distributor and any Codes, Guidelines or Orders of The Board, and amendments thereto as approved by The Board, which may be applicable to the administration of this schedule.
No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code, Guideline or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.
This schedule does not contain any rates and charges relating to the electricity commodity (e.g. the Regulated Price Plan).

EFFECTIVE DATES

DISTRIBUTION RATES - May 1, 2008 for all consumption or deemed consumption services used on or after that date.

MISCELLANEOUS CHARGES - May 1, 2008 for all charges billed to customers on or after that date.
RETAIL TRANSMISSION RATES - May 1, 2008 for all consumption or deemed consumption services used on or after that date.
LOSS FACTOR ADJUSTMENT – for all consumption or deemed consumption services billed following May 1, 2008 or later

SERVICE CLASSIFICATIONS

Residential
This classification refers to all service supplied to single-family dwelling units for domestic or household purpose. Multi-unit residential establishments such as apartment buildings supplied through one service (bulk metered) will normally be classified as General Service, but, at Hydro One’s discretion, up to four residential units may be classified as residential. Where electricity service is provided to combined residential and business (including agricultural usage) and the wiring does not provide for separate metering, the classification shall be at the discretion of Hydro One based on such considerations as the estimated predominant consumption.
Further servicing details are available in the utility’s Conditions of Service.

General Service
This classification refers to all service supplied to premises other than those classified as Residential or Lighting. Some General Service accounts are energy(kWh)-billed, and some are demand(kW)-billed. Further servicing details are available in the utility’s Conditions of Service.

Unmetered Scattered Load
This classification refers to certain instances where connections can be provided without metering. These loads are generally small in size and consistent in magnitude of load. Hydro One reserves the right to review all cases and may require that a meter be installed at its sole discretion. Services that can be unmetered include cable TV amplifiers, telephone switching devices, phone booths, bus shelters, rail way crossing signals, traffic signals, and other small fixed loads.
Further servicing details are available in the utility’s Conditions of Service (including in the "Unmetered Connections" section).

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Hydro-Electric Commission of the Town of Shelburne
Effective Date: May 1, 2008

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

Street Lighting

This classification refers to accounts for the distribution and supply of electrical energy for street lighting. Street lights are devices owned by or operated for the road authority and/or the municipal corporation. These street lights in fact belong to the Street Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Sentinel Lighting

This classification refers to accounts for a separate service to a sentinel light. These sentinel lights in fact belong to the Sentinel Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Urban Density Classification

Customers who meet the Urban Density Criteria of being in an area containing 3,000 or more customers with a line density of at least 60 customers per kilometre, will be mapped to an Urban customer classification.

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Hydro-Electric Commission of the Town of Shelburne
Effective Date: May 1, 2008

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

MONTHLY RATES AND CHARGES

Residential - R1 Shelburne

Service Charge	$	15.23
Distribution Volumetric Rate	$ / kWh	0.0255
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0014
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0004)
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0047
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0046
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service Less Than 50 kW (Energy-Billed) - GSe Shelburne

Service Charge	$	23.09
Distribution Volumetric Rate	$ / kWh	0.0179
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0002
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0006)
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0035
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0032
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service 50 kW or Greater (Demand-Billed) - GSd Shelburne

Service Charge	$	26.69
Distribution Volumetric Rate	$ / kW	7.25
Regulatory Asset Recovery - Rider #2	$ / kW	0.08
Regulatory Asset Recovery - Rider #3	$ / kW	(0.22)
Retail Transmission Rate - Network Service Rate (4)	$ / kW	1.11
Retail Transmission Rate - Line and Transformation Connection Service Rate (4)	$ / kW	1.00
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Hydro-Electric Commission of the Town of Shelburne
Effective Date: May 1, 2008

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

Unmetered, Scattered Load

Service Charge	$	13.00
Distribution Volumetric Rate	$ / kWh	0.0200
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0002
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0006)
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0035
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0032
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

(3) For energy-only metered customers, the billing determinant is the customer's metered energy consumption adjusted by the total loss factor as approved by the Board for Acquired LDC customers.

(4) For demand billed customers, appropriate loss factors must be applied to the applicable tariffs. Also the billing determinant for the Line and Transformation Connection Services rate is the customer's peak demand in the billing period. The billing determinant for the Network Services rate is: for non-interval-metered customers, the peak demand in the billing period, and for interval-metered customers, the peak demand between 7 AM and 7 PM local time on IESO business days

Customer-Supplied Transformation Allowance

Applicable to customers providing their own transformers		
Demand-billed	$ / kW	0.60
Energy-billed	$ / kWh	0.0014

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
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Hydro-Electric Commission of the Town of Shelburne
Effective Date: May 1, 2008

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

Loss Factors

Residential	1.085
General Service Less Than 50 kW (Energy-Billed)	1.092
General Service 50 kW or Greater (Demand-Billed)	1.061
Unmetered Scattered Load	1.092

Transformer Loss Allowance

Applicable to customers requiring a billing adjustment for transformer losses as the result of being metered on the primary side of a transformer. The following uniform values shall be applied to measured demand and energy to calculate transformer losses for voltages up to and including 50 kV (as metered on the primary side):

(a) 1.5% for transformer installations up to an individual bank capacity of 400 kVA,
(b) 1.0% for bank capacities over 400 kVA.

Alternatively, transformer losses may be determined from transformer test data, and measured demand and energy adjusted accordingly
For services which are not demand metered, an assumed demand of 50% of the transformer capacity will be used to calculate the loss allowance. Where several transformers are involved, the bank capacity is assumed to be the arithmetic sum of all transformer capacities

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Hydro-Electric Commission of the Town of Shelburne
Effective Date: May 1, 2008

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

MISCELLANEOUS CHARGES

Specific Service Charges: Standard Amounts

Rate Code	Specific Service Charge - Standard Name	Calculation Method			
		2006 Rate Handbook	Standard Formula	Other Formula	Time and Materials
1	Temporary Service	$500			
2	Dispute Meter Test	$30 plus Measurement Canada fees			
3	Collection of account – no disconnection/load limiter	$30			
4	Collection/Disconnect/load limiter/reconnect (at meter) trip – regular hours	$65			
5	Collection/Disconnect/load limiter/reconnect (at meter) trip – after regular hours	$185			
6	Collection/Disconnect/load limiter/reconnect (at pole) trip – regular hours	$185			
7	Collection/Disconnect/load limiter/reconnect (at pole) trip – after regular hours	$415			
8	Account Set-up Charge	$30			
9	Arrears Certificate	$15			
10	NSF Cheque Charge	$15 + bank charges			
11	Easement Charge for Unregistered Rights	$15			
12	Late Payment Charge	1.5%/month			
13a	Retailer Services – Establishing Service Agreements (refer to Handbook for all charges)	$100/agreement/Retailer +$20/month/Retailer +$0.50/month/customer + other			
13b	Retailer Services – Other (includes Bill Ready for Retailers and Service Transactions Requests) as per the Handbook, Chapter 12	$0.30/month/customer + $0.25/request for request fee + $0.50/request for process fee			
14	Special Meter Reads	$30			
15	Service Layout Fee – Basic		$495		
16	Service Layout Fee – Complex		$690		
17	Crossing Application – Pipeline		$2,445		
18	Crossing Application – Water		$3,045		
19	Crossing Application – Railroad		$2,945		
20	Line Staking – per meter		$3.70		
21	Central Metering – New service < 45 kW		$115		
22	Conversion to Central Metering < 45 kW		$915		
23	Conversion to Central Metering > 45 kW		$800		
24	Tingle Voltage Test – In Excess of 4 Hours (per hour – average 2 additional hours)		$125		
25	Standby Administration Charge per month		$440		
26	Sentinel Lights Rental Rate per month			$7.10	
27	Sentinel Pole Rental Rate per month			$4.15	
28	Joint Use for Cable and Telecom companies per pole			$22.35	
29	Joint Use for LDCs per pole			$28.61	

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Hydro-Electric Commission of the Town of Shelburne
Effective Date: May 1, 2007

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

APPLICATION

The application of these rates and charges shall be in accordance with The Licence of The Distributor and any Codes, Guidelines or Orders of The Board, and amendments thereto as approved by The Board, which may be applicable to the administration of this schedule.
No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code, Guideline or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.
This schedule does not contain any rates and charges relating to the electricity commodity (e.g. the Regulated Price Plan).

EFFECTIVE DATES

DISTRIBUTION RATES - May 1, 2007 for all consumption or deemed consumption services used on or after that date.

MISCELLANEOUS CHARGES - May 1, 2007 for all charges billed to customers on or after that date.
RETAIL TRANSMISSION RATES - May 1, 2007 for all consumption or deemed consumption services used on or after that date.
LOSS FACTOR ADJUSTMENT – May 1, 2007

SERVICE CLASSIFICATIONS

Residential
This classification (note 1) refers to all service supplied to single-family dwelling units for domestic or household purpose. Multi-unit residential establishments such as apartment buildings supplied through one service (bulk metered) will normally be classified as General Service, but, at Hydro One’s discretion, up to four residential units may be classified as residential. Where electricity service is provided to combined residential and business (including agricultural usage) and the wiring does not provide for separate metering, the classification shall be at the discretion of Hydro One based on such considerations as the estimated predominant consumption.
Further servicing details are available in the utility’s Conditions of Service.

General Service
This classification (note 1) refers to all service supplied to premises other than those classified as Residential or Lighting. Some General Service accounts are energy(kWh)-billed, and some are demand(kW)-billed. Further servicing details are available in the utility’s Conditions of Service. Also, see note 2.

Unmetered Scattered Load
This classification refers to certain instances where connections can be provided without metering. These loads are generally small in size and consistent in magnitude of load. Hydro One reserves the right to review all cases and may require that a meter be installed at its sole discretion. Services that can be unmetered include cable TV amplifiers, telephone switching devices, phone booths, bus shelters, rail way crossing signals, traffic signals, and other small fixed loads.
Further servicing details are available in the utility’s Conditions of Service (including in the "Unmetered Connections" section).

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Hydro-Electric Commission of the Town of Shelburne
Effective Date: May 1, 2007

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

Street Lighting

This classification refers to accounts for the distribution and supply of electrical energy for street lighting. Street lights are devices owned by or operated for the road authority and/or the municipal corporation. These street lights in fact belong to the Street Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Sentinel Lighting

This classification refers to accounts for a separate service to a sentinel light. These sentinel lights in fact belong to the Sentinel Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Interim Demand-Side Management Time-of-Use

This is potentially applicable to Demand-billed General Service accounts. See Note 2 below.

Note (1): Classification descriptions are paraphrases from the document "Hydro One Networks Inc. - Distribution Customers Conditions of Service - August 2004"

Note (2):

Interim Demand-Side Management Time-of-Use Rates: demand charges will be based on demand during the on-peak periods.

Criteria: Customers' electricity consumption (kW) in the off-peak period is at least twice the electricity consumption (kW) during the on-peak period.

Definition of Time Periods: The on-peak hours will be between 0700 hours to 1900 hours Eastern Standard Time during the winter (standard time) on IESO business days and 0600 hours to 1800 hours Eastern Standard Time during the summer (daylight savings time) on IESO business days. The off-peak period constitutes all of the remaining hours.

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Hydro-Electric Commission of the Town of Shelburne
Effective Date: May 1, 2007

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

MONTHLY RATES AND CHARGES

Residential

Service Charge	$	14.14
Distribution Volumetric Rate	$ / kWh	0.0133
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0039
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0014
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0055
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0047
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service - Energy Billed (less than 50 kW)

Service Charge	$	20.01
Distribution Volumetric Rate	$ / kWh	0.0087
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0010
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0002
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0050
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0043
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service - Demand Billed (50 kW or greater)

Service Charge	$	20.01
Distribution Volumetric Rate	$ / kW	2.78
Regulatory Asset Recovery - Rider #1	$ / kW	0.32
Regulatory Asset Recovery - Rider #2	$ / kW	0.08
Retail Transmission Rate - Network Service Rate (4)	$ / kW	1.94
Retail Transmission Rate - Line and Transformation Connection Service Rate (4)	$ / kW	1.61
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Hydro-Electric Commission of the Town of Shelburne
Effective Date: May 1, 2007

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

Unmetered, Scattered Load

Service Charge	$	9.53
Distribution Volumetric Rate	$ / kWh	0.0087
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0010
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0002
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0050
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0043
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

(3) For energy-only metered customers, the billing determinant is the customer’s metered energy consumption adjusted by the total loss factor as approved by the Board for Acquired LDC customers.
(4) For demand billed customers, appropriate loss factors must be applied to the applicable tariffs. Also the billing determinant for the Line and Transformation Connection Services rate is the customer’s peak demand in the billing period. The billing determinant for the Network Services rate is: for non-interval-metered customers, the peak demand in the billing period, and for interval-metered customers, the peak demand between 7 AM and 7 PM local time on IESO business days

Interim Demand-Side Management Time-of-Use

See the "Service Classifications" section of this schedule.

Customer-Supplied Transformation Allowance

Applicable to demand-billed customers providing their own transformers
Primary Voltage under 50 kV (per kW)

Single Phase	$ / kW	0.20
Three Phase	$ / kW	0.60

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Hydro-Electric Commission of the Town of Shelburne
Effective Date: May 1, 2007

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

Loss Factors

Supply Facilities Loss Factor	1.0045
Distribution Loss Factors	
Customer less than 5,000 kW	1.0500
Customer greater than or equal to 5,000 kW	1.0100
Total Loss Factors	
Customer less than 5,000 kW	1.0545
Customer greater than or equal to 5,000 kW	1.0145

Transformer Loss Allowance

Applicable to customers requiring a billing adjustment for transformer losses as the result of being metered on the primary side of a transformer. The following uniform values shall be applied to measured demand and energy to calculate transformer losses for voltages up to and including 50 kV (as metered on the primary side):

(a) 1.5% for transformer installations up to an individual bank capacity of 400 kVA,
(b) 1.0% for bank capacities over 400 kVA.

Alternatively, transformer losses may be determined from transformer test data, and measured demand and energy adjusted accordingly

For services which are not demand metered, an assumed demand of 50% of the transformer capacity will be used to calculate the loss allowance. Where several transformers are involved, the bank capacity is assumed to be the arithmetic sum of all transformer capacities

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Hydro-Electric Commission of the Town of Shelburne
Effective Date: May 1, 2007

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

MISCELLANEOUS CHARGES

Specific Service Charges: Standard Amounts

Rate Code	Specific Service Charge - Standard Name	Calculation Method			
		2006 Rate Handbook	Standard Formula	Other Formula	Time and Materials
1	Temporary Service	$500			
2	Dispute Meter Test	$30 plus Measurement Canada fees			
3	Collection of account – no disconnection/load limiter	$30			
4	Collection/Disconnect/load limiter/reconnect (at meter) trip – regular hours	$65			
5	Collection/Disconnect/load limiter/reconnect (at meter) trip – after regular hours	$185			
6	Collection/Disconnect/load limiter/reconnect (at pole) trip – regular hours	$185			
7	Collection/Disconnect/load limiter/reconnect (at pole) trip – after regular hours	$415			
8	Account Set-up Charge	$30			
9	Arrears Certificate	$15			
10	NSF Cheque Charge	$15 + bank charges			
11	Easement Charge for Unregistered Rights	$15			
12	Late Payment Charge	1.5%/month			
13a	Retailer Services – Establishing Service Agreements (refer to Handbook for all charges)	$100/agreement/Retailer +$20/month/Retailer +$0.50/month/customer + other			
13b	Retailer Services – Other (includes Bill Ready for Retailers and Service Transactions Requests) as per the Handbook, Chapter 12	$0.30/month/customer + $0.25/request for request fee + $0.50/request for process fee			
14	Special Meter Reads	$30			
15	Billing Suspension and Terminations in Trailer Parks		$130		
16	Service Layout Fee – Basic		$405		
17	Service Layout Fee – Complex		$580		

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Hydro-Electric Commission of the Town of Shelburne
Effective Date: May 1, 2007

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

18	Crossing Application – Pipeline		$2,065		
19	Crossing Application – Water		$2,525		
20	Crossing Application – Railroad		$2,565		
21	Line Staking – per meter		$3.10		
22	Central Metering – New service < 45 kW		$115		
23	Conversion to Central Metering < 45 kW		$795		
24	Conversion to Central Metering > 45 kW		$680		
25	Tingle Voltage Test – In Excess of 4 Hours (per hour – average 2 additional hours)		$105		
26	Standby Administration Charge per month (interim)		$375		
27	Sentinel Lights Rental Rate per month – Mercury Vapor			$7.00	
28	Guaranteed Units from Jan 01/91 to Aug 01/91			$26.50 / month	
29	Guaranteed Units from Jan 01/87 to Dec 31/90			$23.50 / month	
30	Joint Use for Cable and Telecom companies per pole			$22.35	
31	Joint Use for LDCs per pole			$28.61	

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Smiths Falls Hydro Electric Commission
Effective Date: May 1, 2008

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

APPLICATION

The application of these rates and charges shall be in accordance with The Licence of The Distributor and any Codes, Guidelines or Orders of The Board, and amendments thereto as approved by The Board, which may be applicable to the administration of this schedule.
No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code, Guideline or Order of the Board, and amendments thereto as approved by the Board, or as specified herein
This schedule does not contain any rates and charges relating to the electricity commodity (e.g. the Regulated Price Plan).

EFFECTIVE DATES

DISTRIBUTION RATES - May 1, 2008 for all consumption or deemed consumption services used on or after that date.

MISCELLANEOUS CHARGES - May 1, 2008 for all charges billed to customers on or after that date.
RETAIL TRANSMISSION RATES - May 1, 2008 for all consumption or deemed consumption services used on or after that date.
LOSS FACTOR ADJUSTMENT – for all consumption or deemed consumption services billed following May 1, 2008 or later

SERVICE CLASSIFICATIONS

Residential
This classification refers to all service supplied to single-family dwelling units for domestic or household purpose. Multi-unit residential establishments such as apartment buildings supplied through one service (bulk metered) will normally be classified as General Service, but, at Hydro One’s discretion, up to four residential units may be classified as residential. Where electricity service is provided to combined residential and business (including agricultural usage) and the wiring does not provide for separate metering, the classification shall be at the discretion of Hydro One based on such considerations as the estimated predominant consumption.
Further servicing details are available in the utility’s Conditions of Service.

General Service
This classification refers to all service supplied to premises other than those classified as Residential or Lighting. Some General Service accounts are energy(kWh)-billed, and some are demand(kW)-billed. Further servicing details are available in the utility’s Conditions of Service.

Unmetered Scattered Load
This classification refers to certain instances where connections can be provided without metering. These loads are generally small in size and consistent in magnitude of load. Hydro One reserves the right to review all cases and may require that a meter be installed at its sole discretion. Services that can be unmetered include cable TV amplifiers, telephone switching devices, phone booths, bus shelters, rail way crossing signals, traffic signals, and other small fixed loads.
Further servicing details are available in the utility’s Conditions of Service (including in the "Unmetered Connections" section).

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
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Smiths Falls Hydro Electric Commission
Effective Date: May 1, 2008

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Street Lighting

This classification refers to accounts for the distribution and supply of electrical energy for street lighting. Street lights are devices owned by or operated for the road authority and/or the municipal corporation. These street lights in fact belong to the Street Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Sentinel Lighting

This classification refers to accounts for a separate service to a sentinel light. These sentinel lights in fact belong to the Sentinel Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Urban Density Classification

Customers who meet the Urban Density Criteria of being in an area containing 3,000 or more customers with a line density of at least 60 customers per kilometre, will be mapped to an Urban customer classification.

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
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Effective Date: May 1, 2008

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MONTHLY RATES AND CHARGES

Residential - UR/R1 Smiths Falls

Service Charge	$	12.42
Distribution Volumetric Rate	$ / kWh	0.0240
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0017
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0002)
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0047
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0045
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service Less Than 50 kW (Energy-Billed) - UGe/GSe Smiths Falls

Service Charge	$	9.62
Distribution Volumetric Rate	$ / kWh	0.0200
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0004
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0006)
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0036
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0033
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service 50 kW or Greater (Demand-Billed) - UGd/GSd Smiths Falls

Service Charge	$	13.84
Distribution Volumetric Rate	$ / kW	7.33
Regulatory Asset Recovery - Rider #2	$ / kW	0.13
Regulatory Asset Recovery - Rider #3	$ / kW	(0.27)
Retail Transmission Rate - Network Service Rate (4)	$ / kW	1.41
Retail Transmission Rate - Line and Transformation Connection Service Rate (4)	$ / kW	1.27
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

Hydro One Networks Inc.
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Smiths Falls Hydro Electric Commission
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Unmetered, Scattered Load

Service Charge	$	9.26
Distribution Volumetric Rate	$ / kWh	0.0200
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0004
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0006)
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0035
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0032
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

(3) For energy-only metered customers, the billing determinant is the customer's metered energy consumption adjusted by the total loss factor as approved by the Board for Acquired LDC customers.
(4) For demand billed customers, appropriate loss factors must be applied to the applicable tariffs. Also the billing determinant for the Line and Transformation Connection Services rate is the customer's peak demand in the billing period. The billing determinant for the Network Services rate is: for non-interval-metered customers, the peak demand in the billing period, and for interval-metered customers, the peak demand between 7 AM and 7 PM local time on IESO business days

Customer-Supplied Transformation Allowance

Applicable to customers providing their own transformers

Demand-billed	$ / kW	0.60
Energy-billed	$ / kWh	0.0014

Hydro One Networks Inc.
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Loss Factors

Residential	1.078
General Service Less Than 50 kW (Energy-Billed)	1.092
General Service 50 kW or Greater (Demand-Billed)	1.061
Unmetered Scattered Load	1.092

Transformer Loss Allowance

Applicable to customers requiring a billing adjustment for transformer losses as the result of being metered on the primary side of a transformer. The following uniform values shall be applied to measured demand and energy to calculate transformer losses for voltages up to and including 50 kV (as metered on the primary side):

(a) 1.5% for transformer installations up to an individual bank capacity of 400 kVA,
(b) 1.0% for bank capacities over 400 kVA.

Alternatively, transformer losses may be determined from transformer test data, and measured demand and energy adjusted accordingly

For services which are not demand metered, an assumed demand of 50% of the transformer capacity will be used to calculate the loss allowance. Where several transformers are involved, the bank capacity is assumed to be the arithmetic sum of all transformer capacities

Hydro One Networks Inc.
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Effective Date: May 1, 2008

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

MISCELLANEOUS CHARGES

Specific Service Charges: Standard Amounts

Rate Code	Specific Service Charge - Standard Name	Calculation Method			
		2006 Rate Handbook	Standard Formula	Other Formula	Time and Materials
1	Temporary Service	$500			
2	Dispute Meter Test	$30 plus Measurement Canada fees			
3	Collection of account – no disconnection/load limiter	$30			
4	Collection/Disconnect/load limiter/reconnect (at meter) trip – regular hours	$65			
5	Collection/Disconnect/load limiter/reconnect (at meter) trip – after regular hours	$185			
6	Collection/Disconnect/load limiter/reconnect (at pole) trip – regular hours	$185			
7	Collection/Disconnect/load limiter/reconnect (at pole) trip – after regular hours	$415			
8	Account Set-up Charge	$30			
9	Arrears Certificate	$15			
10	NSF Cheque Charge	$15 + bank charges			
11	Easement Charge for Unregistered Rights	$15			
12	Late Payment Charge	1.5%/month			
13a	Retailer Services – Establishing Service Agreements (refer to Handbook for all charges)	$100/agreement/Retailer +$20/month/Retailer +$0.50/month/customer + other			
13b	Retailer Services – Other (includes Bill Ready for Retailers and Service Transactions Requests) as per the Handbook, Chapter 12	$0.30/month/customer + $0.25/request for request fee + $0.50/request for process fee			
14	Special Meter Reads	$30			
15	Service Layout Fee – Basic		$495		
16	Service Layout Fee – Complex		$690		
17	Crossing Application – Pipeline		$2,445		
18	Crossing Application – Water		$3,045		
19	Crossing Application – Railroad		$2,945		
20	Line Staking – per meter		$3.70		
21	Central Metering – New service < 45 kW		$115		
22	Conversion to Central Metering < 45 kW		$915		
23	Conversion to Central Metering > 45 kW		$800		
24	Tingle Voltage Test – In Excess of 4 Hours (per hour – average 2 additional hours)		$125		
25	Standby Administration Charge per month		$440		
26	Sentinel Lights Rental Rate per month			$7.10	
27	Sentinel Pole Rental Rate per month			$4.15	
28	Joint Use for Cable and Telecom companies per pole			$22.35	
29	Joint Use for LDCs per pole			$28.61	

Hydro One Networks Inc.
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APPLICATION

The application of these rates and charges shall be in accordance with The Licence of The Distributor and any Codes, Guidelines or Orders of The Board, and amendments thereto as approved by The Board, which may be applicable to the administration of this schedule.
No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code, Guideline or Order of the Board, and amendments thereto as approved by the Board, or as specified herein
This schedule does not contain any rates and charges relating to the electricity commodity (e.g. the Regulated Price Plan).

EFFECTIVE DATES

DISTRIBUTION RATES - May 1, 2007 for all consumption or deemed consumption services used on or after that date.

MISCELLANEOUS CHARGES - May 1, 2007 for all charges billed to customers on or after that date.
RETAIL TRANSMISSION RATES - May 1, 2007 for all consumption or deemed consumption services used on or after that date.
LOSS FACTOR ADJUSTMENT – May 1, 2007

SERVICE CLASSIFICATIONS

Residential
This classification (note 1) refers to all service supplied to single-family dwelling units for domestic or household purpose. Multi-unit residential establishments such as apartment buildings supplied through one service (bulk metered) will normally be classified as General Service, but, at Hydro One's discretion, up to four residential units may be classified as residential. Where electricity service is provided to combined residential and business (including agricultural usage) and the wiring does not provide for separate metering, the classification shall be at the discretion of Hydro One based on such considerations as the estimated predominant consumption.
Further servicing details are available in the utility's Conditions of Service.

General Service
This classification (note 1) refers to all service supplied to premises other than those classified as Residential or Lighting. Some General Service accounts are energy(kWh)-billed, and some are demand(kW)-billed. Further servicing details are available in the utility's Conditions of Service. Also, see note 2.

Unmetered Scattered Load
This classification refers to certain instances where connections can be provided without metering. These loads are generally small in size and consistent in magnitude of load. Hydro One reserves the right to review all cases and may require that a meter be installed at its sole discretion. Services that can be unmetered include cable TV amplifiers, telephone switching devices, phone booths, bus shelters, rail way crossing signals, traffic signals, and other small fixed loads.
Further servicing details are available in the utility's Conditions of Service (including in the "Unmetered Connections" section).

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
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Smiths Falls Hydro Electric Commission
Effective Date: May 1, 2007

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Street Lighting

This classification refers to accounts for the distribution and supply of electrical energy for street lighting. Street lights are devices owned by or operated for the road authority and/or the municipal corporation. These street lights in fact belong to the Street Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Sentinel Lighting

This classification refers to accounts for a separate service to a sentinel light. These sentinel lights in fact belong to the Sentinel Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Interim Demand-Side Management Time-of-Use

This is potentially applicable to Demand-billed General Service accounts. See Note 2 below.

Note (1): Classification descriptions are paraphrases from the document "Hydro One Networks Inc. - Distribution Customers Conditions of Service - August 2004"

Note (2):

Interim Demand-Side Management Time-of-Use Rates: demand charges will be based on demand during the on-peak periods.

Criteria: Customers' electricity consumption (kW) in the off-peak period is at least twice the electricity consumption (kW) during the on-peak period.

Definition of Time Periods: The on-peak hours will be between 0700 hours to 1900 hours Eastern Standard Time during the winter (standard time) on IESO business days and 0600 hours to 1800 hours Eastern Standard Time during the summer (daylight savings time) on IESO business days. The off-peak period constitutes all of the remaining hours.

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MONTHLY RATES AND CHARGES

Residential

Service Charge	$	12.63
Distribution Volumetric Rate	$ / kWh	0.0142
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0046
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0017
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0055
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0047
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service - Energy Billed (less than 50 kW)

Service Charge	$	9.84
Distribution Volumetric Rate	$ / kWh	0.0105
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0012
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0004
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0050
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0043
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service - Demand Billed (50 kW or greater)

Service Charge	$	9.84
Distribution Volumetric Rate	$ / kW	3.33
Regulatory Asset Recovery - Rider #1	$ / kW	0.39
Regulatory Asset Recovery - Rider #2	$ / kW	0.13
Retail Transmission Rate - Network Service Rate (4)	$ / kW	1.94
Retail Transmission Rate - Line and Transformation Connection Service Rate (4)	$ / kW	1.61
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

Hydro One Networks Inc.
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Unmetered, Scattered Load

Service Charge	$	4.46
Distribution Volumetric Rate	$ / kWh	0.0105
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0012
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0004
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0050
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0043
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

(3) For energy-only metered customers, the billing determinant is the customer’s metered energy consumption adjusted by the total loss factor as approved by the Board for Acquired LDC customers.
(4) For demand billed customers, appropriate loss factors must be applied to the applicable tariffs. Also the billing determinant for the Line and Transformation Connection Services rate is the customer’s peak demand in the billing period. The billing determinant for the Network Services rate is: for non-interval-metered customers, the peak demand in the billing period, and for interval-metered customers, the peak demand between 7 AM and 7 PM local time on IESO business days

Interim Demand-Side Management Time-of-Use

See the "Service Classifications" section of this schedule.

Customer-Supplied Transformation Allowance

Applicable to demand-billed customers providing their own transformers
Primary Voltage under 50 kV (per kW)

Single Phase	$ / kW	0.20
Three Phase	$ / kW	0.60

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Loss Factors

Supply Facilities Loss Factor	1.0045
Distribution Loss Factors	
Customer less than 5,000 kW	1.0500
Customer greater than or equal to 5,000 kW	1.0100
Total Loss Factors	
Customer less than 5,000 kW	1.0545
Customer greater than or equal to 5,000 kW	1.0145

Transformer Loss Allowance

Applicable to customers requiring a billing adjustment for transformer losses as the result of being metered on the primary side of a transformer. The following uniform values shall be applied to measured demand and energy to calculate transformer losses for voltages up to and including 50 kV (as metered on the primary side):

(a) 1.5% for transformer installations up to an individual bank capacity of 400 kVA,
(b) 1.0% for bank capacities over 400 kVA.

Alternatively, transformer losses may be determined from transformer test data, and measured demand and energy adjusted accordingly

For services which are not demand metered, an assumed demand of 50% of the transformer capacity will be used to calculate the loss allowance. Where several transformers are involved, the bank capacity is assumed to be the arithmetic sum of all transformer capacities

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MISCELLANEOUS CHARGES

Specific Service Charges: Standard Amounts

Rate Code	Specific Service Charge - Standard Name	Calculation Method			
		2006 Rate Handbook	Standard Formula	Other Formula	Time and Materials
1	Temporary Service	$500			
2	Dispute Meter Test	$30 plus Measurement Canada fees			
3	Collection of account – no disconnection/load limiter	$30			
4	Collection/Disconnect/load limiter/reconnect (at meter) trip – regular hours	$65			
5	Collection/Disconnect/load limiter/reconnect (at meter) trip – after regular hours	$185			
6	Collection/Disconnect/load limiter/reconnect (at pole) trip – regular hours	$185			
7	Collection/Disconnect/load limiter/reconnect (at pole) trip – after regular hours	$415			
8	Account Set-up Charge	$30			
9	Arrears Certificate	$15			
10	NSF Cheque Charge	$15 + bank charges			
11	Easement Charge for Unregistered Rights	$15			
12	Late Payment Charge	1.5%/month			
13a	Retailer Services – Establishing Service Agreements (refer to Handbook for all charges)	$100/agreement/Retailer +$20/month/Retailer +$0.50/month/customer + other			
13b	Retailer Services – Other (includes Bill Ready for Retailers and Service Transactions Requests) as per the Handbook, Chapter 12	$0.30/month/customer + $0.25/request for request fee + $0.50/request for process fee			
14	Special Meter Reads	$30			
15	Billing Suspension and Terminations in Trailer Parks		$130		
16	Service Layout Fee – Basic		$405		
17	Service Layout Fee – Complex		$580		

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18	Crossing Application – Pipeline		$2,065		
19	Crossing Application – Water		$2,525		
20	Crossing Application – Railroad		$2,565		
21	Line Staking – per meter		$3.10		
22	Central Metering – New service < 45 kW		$115		
23	Conversion to Central Metering < 45 kW		$795		
24	Conversion to Central Metering > 45 kW		$680		
25	Tingle Voltage Test – In Excess of 4 Hours (per hour – average 2 additional hours)		$105		
26	Standby Administration Charge per month (interim)		$375		
27	Sentinel Lights Rental Rate per month – Mercury Vapor			$7.00	
28	Guaranteed Units from Jan 01/91 to Aug 01/91			$26.50 / month	
29	Guaranteed Units from Jan 01/87 to Dec 31/90			$23.50 / month	
30	Joint Use for Cable and Telecom companies per pole			$22.35	
31	Joint Use for LDCs per pole			$28.61	

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
South Bruce Peninsula Energy Inc.
Effective Date: May 1, 2008

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

APPLICATION

The application of these rates and charges shall be in accordance with The Licence of The Distributor and any Codes, Guidelines or Orders of The Board, and amendments thereto as approved by The Board, which may be applicable to the administration of this schedule.
No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code, Guideline or Order of the Board, and amendments thereto as approved by the Board, or as specified herein
This schedule does not contain any rates and charges relating to the electricity commodity (e.g. the Regulated Price Plan).

EFFECTIVE DATES

DISTRIBUTION RATES - May 1, 2008 for all consumption or deemed consumption services used on or after that date.

MISCELLANEOUS CHARGES - May 1, 2008 for all charges billed to customers on or after that date.
RETAIL TRANSMISSION RATES - May 1, 2008 for all consumption or deemed consumption services used on or after that date.
LOSS FACTOR ADJUSTMENT – for all consumption or deemed consumption services billed following May 1, 2008 or later

SERVICE CLASSIFICATIONS

Residential
This classification refers to all service supplied to single-family dwelling units for domestic or household purpose. Multi-unit residential establishments such as apartment buildings supplied through one service (bulk metered) will normally be classified as General Service, but, at Hydro One's discretion, up to four residential units may be classified as residential. Where electricity service is provided to combined residential and business (including agricultural usage) and the wiring does not provide for separate metering, the classification shall be at the discretion of Hydro One based on such considerations as the estimated predominant consumption.
Further servicing details are available in the utility's Conditions of Service.

General Service
This classification refers to all service supplied to premises other than those classified as Residential or Lighting. Some General Service accounts are energy(kWh)-billed, and some are demand(kW)-billed. Further servicing details are available in the utility's Conditions of Service.

Unmetered Scattered Load
This classification refers to certain instances where connections can be provided without metering. These loads are generally small in size and consistent in magnitude of load. Hydro One reserves the right to review all cases and may require that a meter be installed at its sole discretion. Services that can be unmetered include cable TV amplifiers, telephone switching devices, phone booths, bus shelters, rail way crossing signals, traffic signals, and other small fixed loads.
Further servicing details are available in the utility's Conditions of Service (including in the "Unmetered Connections" section).

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
South Bruce Peninsula Energy Inc.
Effective Date: May 1, 2008

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

Street Lighting

This classification refers to accounts for the distribution and supply of electrical energy for street lighting. Street lights are devices owned by or operated for the road authority and/or the municipal corporation. These street lights in fact belong to the Street Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Sentinel Lighting

This classification refers to accounts for a separate service to a sentinel light. These sentinel lights in fact belong to the Sentinel Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Urban Density Classification

Customers who meet the Urban Density Criteria of being in an area containing 3,000 or more customers with a line density of at least 60 customers per kilometre, will be mapped to an Urban customer classification.

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
South Bruce Peninsula Energy Inc.
Effective Date: May 1, 2008

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

MONTHLY RATES AND CHARGES

Residential - R1 Wiarton

Service Charge	$	15.80
Distribution Volumetric Rate	$ / kWh	0.0271
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0014
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0004)
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0047
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0046
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service Less Than 50 kW (Energy-Billed) - GSe Wiarton

Service Charge	$	25.15
Distribution Volumetric Rate	$ / kWh	0.0310
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0009
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0006)
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0035
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0032
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service 50 kW or Greater (Demand-Billed) - GSd Wiarton

Service Charge	$	28.74
Distribution Volumetric Rate	$ / kW	9.22
Regulatory Asset Recovery - Rider #2	$ / kW	0.29
Regulatory Asset Recovery - Rider #3	$ / kW	(0.22)
Retail Transmission Rate - Network Service Rate (4)	$ / kW	1.11
Retail Transmission Rate - Line and Transformation Connection Service Rate (4)	$ / kW	1.00
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
South Bruce Peninsula Energy Inc.
Effective Date: May 1, 2008

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

Unmetered, Scattered Load

Service Charge	$	14.52
Distribution Volumetric Rate	$ / kWh	0.0200
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0009
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0006)
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0035
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0032
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

(3) For energy-only metered customers, the billing determinant is the customer's metered energy consumption adjusted by the total loss factor as approved by the Board for Acquired LDC customers.
(4) For demand billed customers, appropriate loss factors must be applied to the applicable tariffs. Also the billing determinant for the Line and Transformation Connection Services rate is the customer's peak demand in the billing period. The billing determinant for the Network Services rate is: for non-interval-metered customers, the peak demand in the billing period, and for interval-metered customers, the peak demand between 7 AM and 7 PM local time on IESO business days

Customer-Supplied Transformation Allowance

Applicable to customers providing their own transformers

Demand-billed	$ / kW	0.60
Energy-billed	$ / kWh	0.0014

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
South Bruce Peninsula Energy Inc.
Effective Date: May 1, 2008

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

Loss Factors

Residential	1.085
General Service Less Than 50 kW (Energy-Billed)	1.092
General Service 50 kW or Greater (Demand-Billed)	1.061
Unmetered Scattered Load	1.092

Transformer Loss Allowance

Applicable to customers requiring a billing adjustment for transformer losses as the result of being metered on the primary side of a transformer. The following uniform values shall be applied to measured demand and energy to calculate transformer losses for voltages up to and including 50 kV (as metered on the primary side):

(a) 1.5% for transformer installations up to an individual bank capacity of 400 kVA,
(b) 1.0% for bank capacities over 400 kVA.

Alternatively, transformer losses may be determined from transformer test data, and measured demand and energy adjusted accordingly

For services which are not demand metered, an assumed demand of 50% of the transformer capacity will be used to calculate the loss allowance. Where several transformers are involved, the bank capacity is assumed to be the arithmetic sum of all transformer capacities

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
South Bruce Peninsula Energy Inc.
Effective Date: May 1, 2008

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

MISCELLANEOUS CHARGES

Specific Service Charges: Standard Amounts

Rate Code	Specific Service Charge - Standard Name	Calculation Method			
		2006 Rate Handbook	Standard Formula	Other Formula	Time and Materials
1	Temporary Service	$500			
2	Dispute Meter Test	$30 plus Measurement Canada fees			
3	Collection of account – no disconnection/load limiter	$30			
4	Collection/Disconnect/load limiter/reconnect (at meter) trip – regular hours	$65			
5	Collection/Disconnect/load limiter/reconnect (at meter) trip – after regular hours	$185			
6	Collection/Disconnect/load limiter/reconnect (at pole) trip – regular hours	$185			
7	Collection/Disconnect/load limiter/reconnect (at pole) trip – after regular hours	$415			
8	Account Set-up Charge	$30			
9	Arrears Certificate	$15			
10	NSF Cheque Charge	$15 + bank charges			
11	Easement Charge for Unregistered Rights	$15			
12	Late Payment Charge	1.5%/month			
13a	Retailer Services – Establishing Service Agreements (refer to Handbook for all charges)	$100/agreement/Retailer +$20/month/Retailer +$0.50/month/customer + other			
13b	Retailer Services – Other (includes Bill Ready for Retailers and Service Transactions Requests) as per the Handbook, Chapter 12	$0.30/month/customer + $0.25/request for request fee + $0.50/request for process fee			
14	Special Meter Reads	$30			
15	Service Layout Fee – Basic		$495		
16	Service Layout Fee – Complex		$690		
17	Crossing Application – Pipeline		$2,445		
18	Crossing Application – Water		$3,045		
19	Crossing Application – Railroad		$2,945		
20	Line Staking – per meter		$3.70		
21	Central Metering – New service < 45 kW		$115		
22	Conversion to Central Metering < 45 kW		$915		
23	Conversion to Central Metering > 45 kW		$800		
24	Tingle Voltage Test – In Excess of 4 Hours (per hour – average 2 additional hours)		$125		
25	Standby Administration Charge per month		$440		
26	Sentinel Lights Rental Rate per month			$7.10	
27	Sentinel Pole Rental Rate per month			$4.15	
28	Joint Use for Cable and Telecom companies per pole			$22.35	
29	Joint Use for LDCs per pole			$28.61	

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
South Bruce Peninsula Energy Inc.
Effective Date: May 1, 2007

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

APPLICATION

The application of these rates and charges shall be in accordance with The Licence of The Distributor and any Codes, Guidelines or Orders of The Board, and amendments thereto as approved by The Board, which may be applicable to the administration of this schedule.
No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code, Guideline or Order of the Board, and amendments thereto as approved by the Board, or as specified herein
This schedule does not contain any rates and charges relating to the electricity commodity (e.g. the Regulated Price Plan).

EFFECTIVE DATES

DISTRIBUTION RATES - May 1, 2007 for all consumption or deemed consumption services used on or after that date.

MISCELLANEOUS CHARGES - May 1, 2007 for all charges billed to customers on or after that date.
RETAIL TRANSMISSION RATES - May 1, 2007 for all consumption or deemed consumption services used on or after that date.
LOSS FACTOR ADJUSTMENT – May 1, 2007

SERVICE CLASSIFICATIONS

Residential
This classification (note 1) refers to all service supplied to single-family dwelling units for domestic or household purpose. Multi-unit residential establishments such as apartment buildings supplied through one service (bulk metered) will normally be classified as General Service, but, at Hydro One’s discretion, up to four residential units may be classified as residential. Where electricity service is provided to combined residential and business (including agricultural usage) and the wiring does not provide for separate metering, the classification shall be at the discretion of Hydro One based on such considerations as the estimated predominant consumption.
Further servicing details are available in the utility’s Conditions of Service.

General Service
This classification (note 1) refers to all service supplied to premises other than those classified as Residential or Lighting. Some General Service accounts are energy(kWh)-billed, and some are demand(kW)-billed. Further servicing details are available in the utility’s Conditions of Service. Also, see note 2.

Unmetered Scattered Load
This classification refers to certain instances where connections can be provided without metering. These loads are generally small in size and consistent in magnitude of load. Hydro One reserves the right to review all cases and may require that a meter be installed at its sole discretion. Services that can be unmetered include cable TV amplifiers, telephone switching devices, phone booths, bus shelters, rail way crossing signals, traffic signals, and other small fixed loads.
Further servicing details are available in the utility’s Conditions of Service (including in the "Unmetered Connections" section).

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
South Bruce Peninsula Energy Inc.
Effective Date: May 1, 2007

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

Street Lighting

This classification refers to accounts for the distribution and supply of electrical energy for street lighting. Street lights are devices owned by or operated for the road authority and/or the municipal corporation. These street lights in fact belong to the Street Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Sentinel Lighting

This classification refers to accounts for a separate service to a sentinel light. These sentinel lights in fact belong to the Sentinel Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Interim Demand-Side Management Time-of-Use

This is potentially applicable to Demand-billed General Service accounts. See Note 2 below.

Note (1): Classification descriptions are paraphrases from the document "Hydro One Networks Inc. - Distribution Customers Conditions of Service - August 2004"

Note (2):

Interim Demand-Side Management Time-of-Use Rates: demand charges will be based on demand during the on-peak periods.

Criteria: Customers' electricity consumption (kW) in the off-peak period is at least twice the electricity consumption (kW) during the on-peak period.

Definition of Time Periods: The on-peak hours will be between 0700 hours to 1900 hours Eastern Standard Time during the winter (standard time) on IESO business days and 0600 hours to 1800 hours Eastern Standard Time during the summer (daylight savings time) on IESO business days. The off-peak period constitutes all of the remaining hours.

Hydro One Networks Inc.
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MONTHLY RATES AND CHARGES

Residential

Service Charge	$	15.83
Distribution Volumetric Rate	$ / kWh	0.0155
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0037
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0014
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0055
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0047
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service - Energy Billed (less than 50 kW)

Service Charge	$	23.78
Distribution Volumetric Rate	$ / kWh	0.0189
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0019
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0009
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0050
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0043
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service - Demand Billed (50 kW or greater)

Service Charge	$	23.78
Distribution Volumetric Rate	$ / kW	5.99
Regulatory Asset Recovery - Rider #1	$ / kW	0.59
Regulatory Asset Recovery - Rider #2	$ / kW	0.29
Retail Transmission Rate - Network Service Rate (4)	$ / kW	1.94
Retail Transmission Rate - Line and Transformation Connection Service Rate (4)	$ / kW	1.61
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

Hydro One Networks Inc.
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Unmetered, Scattered Load

Service Charge	$	11.42
Distribution Volumetric Rate	$ / kWh	0.0189
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0019
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0009
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0050
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0043
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

(3) For energy-only metered customers, the billing determinant is the customer's metered energy consumption adjusted by the total loss factor as approved by the Board for Acquired LDC customers.
(4) For demand billed customers, appropriate loss factors must be applied to the applicable tariffs. Also the billing determinant for the Line and Transformation Connection Services rate is the customer's peak demand in the billing period. The billing determinant for the Network Services rate is: for non-interval-metered customers, the peak demand in the billing period, and for interval-metered customers, the peak demand between 7 AM and 7 PM local time on IESO business days

Interim Demand-Side Management Time-of-Use

See the "Service Classifications" section of this schedule.

Customer-Supplied Transformation Allowance

Applicable to demand-billed customers providing their own transformers
Primary Voltage under 50 kV (per kW)

Single Phase	$ / kW	0.20
Three Phase	$ / kW	0.60

Hydro One Networks Inc.
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Loss Factors

Supply Facilities Loss Factor	1.0045
Distribution Loss Factors	
Customer less than 5,000 kW	1.0500
Customer greater than or equal to 5,000 kW	1.0100
Total Loss Factors	
Customer less than 5,000 kW	1.0545
Customer greater than or equal to 5,000 kW	1.0145

Transformer Loss Allowance

Applicable to customers requiring a billing adjustment for transformer losses as the result of being metered on the primary side of a transformer. The following uniform values shall be applied to measured demand and energy to calculate transformer losses for voltages up to and including 50 kV (as metered on the primary side):

(a) 1.5% for transformer installations up to an individual bank capacity of 400 kVA,
(b) 1.0% for bank capacities over 400 kVA.

Alternatively, transformer losses may be determined from transformer test data, and measured demand and energy adjusted accordingly

For services which are not demand metered, an assumed demand of 50% of the transformer capacity will be used to calculate the loss allowance. Where several transformers are involved, the bank capacity is assumed to be the arithmetic sum of all transformer capacities

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
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South Bruce Peninsula Energy Inc.
Effective Date: May 1, 2007

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

MISCELLANEOUS CHARGES

Specific Service Charges: Standard Amounts

Rate Code	Specific Service Charge - Standard Name	Calculation Method			
		2006 Rate Handbook	Standard Formula	Other Formula	Time and Materials
1	Temporary Service	$500			
2	Dispute Meter Test	$30 plus Measurement Canada fees			
3	Collection of account – no disconnection/load limiter	$30			
4	Collection/Disconnect/load limiter/reconnect (at meter) trip – regular hours	$65			
5	Collection/Disconnect/load limiter/reconnect (at meter) trip – after regular hours	$185			
6	Collection/Disconnect/load limiter/reconnect (at pole) trip – regular hours	$185			
7	Collection/Disconnect/load limiter/reconnect (at pole) trip – after regular hours	$415			
8	Account Set-up Charge	$30			
9	Arrears Certificate	$15			
10	NSF Cheque Charge	$15 + bank charges			
11	Easement Charge for Unregistered Rights	$15			
12	Late Payment Charge	1.5%/month			
13a	Retailer Services – Establishing Service Agreements (refer to Handbook for all charges)	$100/agreement/Retailer +$20/month/Retailer +$0.50/month/customer + other			
13b	Retailer Services – Other (includes Bill Ready for Retailers and Service Transactions Requests) as per the Handbook, Chapter 12	$0.30/month/customer + $0.25/request for request fee + $0.50/request for process fee			
14	Special Meter Reads	$30			
15	Billing Suspension and Terminations in Trailer Parks		$130		
16	Service Layout Fee – Basic		$405		
17	Service Layout Fee – Complex		$580		

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
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18	Crossing Application – Pipeline		$2,065		
19	Crossing Application – Water		$2,525		
20	Crossing Application – Railroad		$2,565		
21	Line Staking – per meter		$3.10		
22	Central Metering – New service < 45 kW		$115		
23	Conversion to Central Metering < 45 kW		$795		
24	Conversion to Central Metering > 45 kW		$680		
25	Tingle Voltage Test – In Excess of 4 Hours (per hour – average 2 additional hours)		$105		
26	Standby Administration Charge per month (interim)		$375		
27	Sentinel Lights Rental Rate per month – Mercury Vapor			$7.00	
28	Guaranteed Units from Jan 01/91 to Aug 01/91			$26.50 / month	
29	Guaranteed Units from Jan 01/87 to Dec 31/90			$23.50 / month	
30	Joint Use for Cable and Telecom companies per pole			$22.35	
31	Joint Use for LDCs per pole			$28.61	

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Public Utilities Commission of the Township of South Glengarry
Effective Date: May 1, 2008

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

APPLICATION

The application of these rates and charges shall be in accordance with The Licence of The Distributor and any Codes, Guidelines or Orders of The Board, and amendments thereto as approved by The Board, which may be applicable to the administration of this schedule.
No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code, Guideline or Order of the Board, and amendments thereto as approved by the Board, or as specified herein
This schedule does not contain any rates and charges relating to the electricity commodity (e.g. the Regulated Price Plan).

EFFECTIVE DATES

DISTRIBUTION RATES - May 1, 2008 for all consumption or deemed consumption services used on or after that date.

MISCELLANEOUS CHARGES - May 1, 2008 for all charges billed to customers on or after that date.
RETAIL TRANSMISSION RATES - May 1, 2008 for all consumption or deemed consumption services used on or after that date.
LOSS FACTOR ADJUSTMENT – for all consumption or deemed consumption services billed following May 1, 2008 or later

SERVICE CLASSIFICATIONS

Residential
This classification refers to all service supplied to single-family dwelling units for domestic or household purpose. Multi-unit residential establishments such as apartment buildings supplied through one service (bulk metered) will normally be classified as General Service, but, at Hydro One’s discretion, up to four residential units may be classified as residential. Where electricity service is provided to combined residential and business (including agricultural usage) and the wiring does not provide for separate metering, the classification shall be at the discretion of Hydro One based on such considerations as the estimated predominant consumption.
Further servicing details are available in the utility’s Conditions of Service.

General Service
This classification refers to all service supplied to premises other than those classified as Residential or Lighting. Some General Service accounts are energy(kWh)-billed, and some are demand(kW)-billed. Further servicing details are available in the utility’s Conditions of Service.

Unmetered Scattered Load
This classification refers to certain instances where connections can be provided without metering. These loads are generally small in size and consistent in magnitude of load. Hydro One reserves the right to review all cases and may require that a meter be installed at its sole discretion. Services that can be unmetered include cable TV amplifiers, telephone switching devices, phone booths, bus shelters, rail way crossing signals, traffic signals, and other small fixed loads.
Further servicing details are available in the utility’s Conditions of Service (including in the "Unmetered Connections" section).

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Public Utilities Commission of the Township of South Glengarry
Effective Date: May 1, 2008

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Street Lighting

This classification refers to accounts for the distribution and supply of electrical energy for street lighting. Street lights are devices owned by or operated for the road authority and/or the municipal corporation. These street lights in fact belong to the Street Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Sentinel Lighting

This classification refers to accounts for a separate service to a sentinel light. These sentinel lights in fact belong to the Sentinel Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Urban Density Classification

Customers who meet the Urban Density Criteria of being in an area containing 3,000 or more customers with a line density of at least 60 customers per kilometre, will be mapped to an Urban customer classification.

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
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Effective Date: May 1, 2008

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MONTHLY RATES AND CHARGES

Residential - R1 South Glengarry

Service Charge	$	11.40
Distribution Volumetric Rate	$ / kWh	0.0195
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0036
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0004)
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0047
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0046
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service Less Than 50 kW (Energy-Billed) - GSe South Glengarry

Service Charge	$	20.74
Distribution Volumetric Rate	$ / kWh	0.0196
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0030
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0006)
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0035
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0032
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service 50 kW or Greater (Demand-Billed) - GSd South Glengarry

Service Charge	$	24.34
Distribution Volumetric Rate	$ / kW	7.75
Regulatory Asset Recovery - Rider #2	$ / kW	0.94
Regulatory Asset Recovery - Rider #3	$ / kW	(0.22)
Retail Transmission Rate - Network Service Rate (4)	$ / kW	1.11
Retail Transmission Rate - Line and Transformation Connection Service Rate (4)	$ / kW	1.00
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
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This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

Unmetered, Scattered Load

Service Charge	$	12.32
Distribution Volumetric Rate	$ / kWh	0.0200
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0030
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0006)
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0035
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0032
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

(3) For energy-only metered customers, the billing determinant is the customer's metered energy consumption adjusted by the total loss factor as approved by the Board for Acquired LDC customers.
(4) For demand billed customers, appropriate loss factors must be applied to the applicable tariffs. Also the billing determinant for the Line and Transformation Connection Services rate is the customer's peak demand in the billing period. The billing determinant for the Network Services rate is: for non-interval-metered customers, the peak demand in the billing period, and for interval-metered customers, the peak demand between 7 AM and 7 PM local time on IESO business days

Customer-Supplied Transformation Allowance

Applicable to customers providing their own transformers

Demand-billed	$ / kW	0.60
Energy-billed	$ / kWh	0.0014

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
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Public Utilities Commission of the Township of South Glengarry
Effective Date: May 1, 2008

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Loss Factors

Residential	1.085
General Service Less Than 50 kW (Energy-Billed)	1.092
General Service 50 kW or Greater (Demand-Billed)	1.061
Unmetered Scattered Load	1.092

Transformer Loss Allowance

Applicable to customers requiring a billing adjustment for transformer losses as the result of bein metered on the primary side of a transformer. The following uniform values shall be applied t measured demand and energy to calculate transformer losses for voltages up to and includin 50 kV (as metered on the primary side):

(a) 1.5% for transformer installations up to an individual bank capacity of 400 kVA,
(b) 1.0% for bank capacities over 400 kVA.

Alternatively, transformer losses may be determined from transformer test data, an measured demand and energy adjusted accordingly

For services which are not demand metered, an assumed demand of 50% of the transforme capacity will be used to calculate the loss allowance. Where several transformers are involved the bank capacity is assumed to be the arithmetic sum of all transformer capacities

Hydro One Networks Inc.
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MISCELLANEOUS CHARGES

Specific Service Charges: Standard Amounts

Rate Code	Specific Service Charge - Standard Name	Calculation Method			
		2006 Rate Handbook	Standard Formula	Other Formula	Time and Materials
1	Temporary Service	$500			
2	Dispute Meter Test	$30 plus Measurement Canada fees			
3	Collection of account – no disconnection/load limiter	$30			
4	Collection/Disconnect/load limiter/reconnect (at meter) trip – regular hours	$65			
5	Collection/Disconnect/load limiter/reconnect (at meter) trip – after regular hours	$185			
6	Collection/Disconnect/load limiter/reconnect (at pole) trip – regular hours	$185			
7	Collection/Disconnect/load limiter/reconnect (at pole) trip – after regular hours	$415			
8	Account Set-up Charge	$30			
9	Arrears Certificate	$15			
10	NSF Cheque Charge	$15 + bank charges			
11	Easement Charge for Unregistered Rights	$15			
12	Late Payment Charge	1.5%/month			
13a	Retailer Services – Establishing Service Agreements (refer to Handbook for all charges)	$100/agreement/Retailer +$20/month/Retailer +$0.50/month/customer + other			
13b	Retailer Services – Other (includes Bill Ready for Retailers and Service Transactions Requests) as per the Handbook, Chapter 12	$0.30/month/customer + $0.25/request for request fee + $0.50/request for process fee			
14	Special Meter Reads	$30			
15	Service Layout Fee – Basic		$495		
16	Service Layout Fee – Complex		$690		
17	Crossing Application – Pipeline		$2,445		
18	Crossing Application – Water		$3,045		
19	Crossing Application – Railroad		$2,945		
20	Line Staking – per meter		$3.70		
21	Central Metering – New service < 45 kW		$115		
22	Conversion to Central Metering < 45 kW		$915		
23	Conversion to Central Metering > 45 kW		$800		
24	Tingle Voltage Test – In Excess of 4 Hours (per hour – average 2 additional hours)		$125		
25	Standby Administration Charge per month		$440		
26	Sentinel Lights Rental Rate per month			$7.10	
27	Sentinel Pole Rental Rate per month			$4.15	
28	Joint Use for Cable and Telecom companies per pole			$22.35	
29	Joint Use for LDCs per pole			$28.61	

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Public Utilities Commission of the Township of South Glengarry
Effective Date: May 1, 2007

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

APPLICATION

The application of these rates and charges shall be in accordance with The Licence of The Distributor and any Codes, Guidelines or Orders of The Board, and amendments thereto as approved by The Board, which may be applicable to the administration of this schedule.
No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code, Guideline or Order of the Board, and amendments thereto as approved by the Board, or as specified herein
This schedule does not contain any rates and charges relating to the electricity commodity (e.g. the Regulated Price Plan).

EFFECTIVE DATES

DISTRIBUTION RATES - May 1, 2007 for all consumption or deemed consumption services used on or after that date.

MISCELLANEOUS CHARGES - May 1, 2007 for all charges billed to customers on or after that date.
RETAIL TRANSMISSION RATES - May 1, 2007 for all consumption or deemed consumption services used on or after that date.
LOSS FACTOR ADJUSTMENT – May 1, 2007

SERVICE CLASSIFICATIONS

Residential
This classification (note 1) refers to all service supplied to single-family dwelling units for domestic or household purpose. Multi-unit residential establishments such as apartment buildings supplied through one service (bulk metered) will normally be classified as General Service, but, at Hydro One's discretion, up to four residential units may be classified as residential. Where electricity service is provided to combined residential and business (including agricultural usage) and the wiring does not provide for separate metering, the classification shall be at the discretion of Hydro One based on such considerations as the estimated predominant consumption.
Further servicing details are available in the utility's Conditions of Service.

General Service
This classification (note 1) refers to all service supplied to premises other than those classified as Residential or Lighting. Some General Service accounts are energy(kWh)-billed, and some are demand(kW)-billed. Further servicing details are available in the utility's Conditions of Service. Also, see note 2.

Unmetered Scattered Load
This classification refers to certain instances where connections can be provided without metering. These loads are generally small in size and consistent in magnitude of load. Hydro One reserves the right to review all cases and may require that a meter be installed at its sole discretion. Services that can be unmetered include cable TV amplifiers, telephone switching devices, phone booths, bus shelters, rail way crossing signals, traffic signals, and other small fixed loads.
Further servicing details are available in the utility's Conditions of Service (including in the "Unmetered Connections" section).

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Public Utilities Commission of the Township of South Glengarry
Effective Date: May 1, 2007

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

Street Lighting

This classification refers to accounts for the distribution and supply of electrical energy for street lighting. Street lights are devices owned by or operated for the road authority and/or the municipal corporation. These street lights in fact belong to the Street Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Sentinel Lighting

This classification refers to accounts for a separate service to a sentinel light. These sentinel lights in fact belong to the Sentinel Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Interim Demand-Side Management Time-of-Use

This is potentially applicable to Demand-billed General Service accounts. See Note 2 below.

Note (1): Classification descriptions are paraphrases from the document "Hydro One Networks Inc. - Distribution Customers Conditions of Service - August 2004"
Note (2):

Interim Demand-Side Management Time-of-Use Rates: demand charges will be based on demand during the on-peak periods.
Criteria: Customers' electricity consumption (kW) in the off-peak period is at least twice the electricity consumption (kW) during the on-peak period.
Definition of Time Periods: The on-peak hours will be between 0700 hours to 1900 hours Eastern Standard Time during the winter (standard time) on IESO business days and 0600 hours to 1800 hours Eastern Standard Time during the summer (daylight savings time) on IESO business days. The off-peak period constitutes all of the remaining hours.

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
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Public Utilities Commission of the Township of South Glengarry
Effective Date: May 1, 2007

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MONTHLY RATES AND CHARGES

Residential

Service Charge	$	9.46
Distribution Volumetric Rate	$ / kWh	0.0075
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0052
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0036
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0055
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0047
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service - Energy Billed (less than 50 kW)

Service Charge	$	17.41
Distribution Volumetric Rate	$ / kWh	0.0075
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0037
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0030
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0050
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0043
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service - Demand Billed (50 kW or greater)

Service Charge	$	17.41
Distribution Volumetric Rate	$ / kW	2.37
Regulatory Asset Recovery - Rider #1	$ / kW	1.18
Regulatory Asset Recovery - Rider #2	$ / kW	0.94
Retail Transmission Rate - Network Service Rate (4)	$ / kW	1.94
Retail Transmission Rate - Line and Transformation Connection Service Rate (4)	$ / kW	1.61
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
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Public Utilities Commission of the Township of South Glengarry
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Unmetered, Scattered Load

Service Charge	$	8.25
Distribution Volumetric Rate	$ / kWh	0.0075
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0037
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0030
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0050
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0043
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

(3) For energy-only metered customers, the billing determinant is the customer's metered energy consumption adjusted by the total loss factor as approved by the Board for Acquired LDC customers.
(4) For demand billed customers, appropriate loss factors must be applied to the applicable tariffs. Also the billing determinant for the Line and Transformation Connection Services rate is the customer's peak demand in the billing period. The billing determinant for the Network Services rate is: for non-interval-metered customers, the peak demand in the billing period, and for interval-metered customers, the peak demand between 7 AM and 7 PM local time on IESO business days

Interim Demand-Side Management Time-of-Use

See the "Service Classifications" section of this schedule.

Customer-Supplied Transformation Allowance

Applicable to demand-billed customers providing their own transformers
Primary Voltage under 50 kV (per kW)

Single Phase	$ / kW	0.20
Three Phase	$ / kW	0.60

Hydro One Networks Inc.
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Loss Factors

Supply Facilities Loss Factor	1.0045
Distribution Loss Factors	
Customer less than 5,000 kW	1.0500
Customer greater than or equal to 5,000 kW	1.0100
Total Loss Factors	
Customer less than 5,000 kW	1.0545
Customer greater than or equal to 5,000 kW	1.0145

Transformer Loss Allowance

Applicable to customers requiring a billing adjustment for transformer losses as the result of being metered on the primary side of a transformer. The following uniform values shall be applied to measured demand and energy to calculate transformer losses for voltages up to and including 50 kV (as metered on the primary side):

(a) 1.5% for transformer installations up to an individual bank capacity of 400 kVA,
(b) 1.0% for bank capacities over 400 kVA.

Alternatively, transformer losses may be determined from transformer test data, and measured demand and energy adjusted accordingly

For services which are not demand metered, an assumed demand of 50% of the transformer capacity will be used to calculate the loss allowance. Where several transformers are involved, the bank capacity is assumed to be the arithmetic sum of all transformer capacities

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
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MISCELLANEOUS CHARGES

Specific Service Charges: Standard Amounts

Rate Code	Specific Service Charge - Standard Name	Calculation Method			
		2006 Rate Handbook	Standard Formula	Other Formula	Time and Materials
1	Temporary Service	$500			
2	Dispute Meter Test	$30 plus Measurement Canada fees			
3	Collection of account – no disconnection/load limiter	$30			
4	Collection/Disconnect/load limiter/reconnect (at meter) trip – regular hours	$65			
5	Collection/Disconnect/load limiter/reconnect (at meter) trip – after regular hours	$185			
6	Collection/Disconnect/load limiter/reconnect (at pole) trip – regular hours	$185			
7	Collection/Disconnect/load limiter/reconnect (at pole) trip – after regular hours	$415			
8	Account Set-up Charge	$30			
9	Arrears Certificate	$15			
10	NSF Cheque Charge	$15 + bank charges			
11	Easement Charge for Unregistered Rights	$15			
12	Late Payment Charge	1.5%/month			
13a	Retailer Services – Establishing Service Agreements (refer to Handbook for all charges)	$100/agreement/Retailer +$20/month/Retailer +$0.50/month/customer + other			
13b	Retailer Services – Other (includes Bill Ready for Retailers and Service Transactions Requests) as per the Handbook, Chapter 12	$0.30/month/customer + $0.25/request for request fee + $0.50/request for process fee			
14	Special Meter Reads	$30			
15	Billing Suspension and Terminations in Trailer Parks		$130		
16	Service Layout Fee – Basic		$405		
17	Service Layout Fee – Complex		$580		

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18	Crossing Application – Pipeline		$2,065		
19	Crossing Application – Water		$2,525		
20	Crossing Application – Railroad		$2,565		
21	Line Staking – per meter		$3.10		
22	Central Metering – New service < 45 kW		$115		
23	Conversion to Central Metering < 45 kW		$795		
24	Conversion to Central Metering > 45 kW		$680		
25	Tingle Voltage Test – In Excess of 4 Hours (per hour – average 2 additional hours)		$105		
26	Standby Administration Charge per month (interim)		$375		
27	Sentinel Lights Rental Rate per month – Mercury Vapor			$7.00	
28	Guaranteed Units from Jan 01/91 to Aug 01/91			$26.50 / month	
29	Guaranteed Units from Jan 01/87 to Dec 31/90			$23.50 / month	
30	Joint Use for Cable and Telecom companies per pole			$22.35	
31	Joint Use for LDCs per pole			$28.61	

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
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Village of South River Public Utilities Commission
Effective Date: May 1, 2008

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APPLICATION

The application of these rates and charges shall be in accordance with The Licence of The Distributor and any Codes, Guidelines or Orders of The Board, and amendments thereto as approved by The Board, which may be applicable to the administration of this schedule.
No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code, Guideline or Order of the Board, and amendments thereto as approved by the Board, or as specified herein
This schedule does not contain any rates and charges relating to the electricity commodity (e.g. the Regulated Price Plan).

EFFECTIVE DATES

DISTRIBUTION RATES - May 1, 2008 for all consumption or deemed consumption services used on or after that date.

MISCELLANEOUS CHARGES - May 1, 2008 for all charges billed to customers on or after that date.
RETAIL TRANSMISSION RATES - May 1, 2008 for all consumption or deemed consumption services used on or after that date.
LOSS FACTOR ADJUSTMENT – for all consumption or deemed consumption services billed following May 1, 2008 or later

SERVICE CLASSIFICATIONS

Residential
This classification refers to all service supplied to single-family dwelling units for domestic or household purpose. Multi-unit residential establishments such as apartment buildings supplied through one service (bulk metered) will normally be classified as General Service, but, at Hydro One's discretion, up to four residential units may be classified as residential. Where electricity service is provided to combined residential and business (including agricultural usage) and the wiring does not provide for separate metering, the classification shall be at the discretion of Hydro One based on such considerations as the estimated predominant consumption.
Further servicing details are available in the utility's Conditions of Service.

General Service
This classification refers to all service supplied to premises other than those classified as Residential or Lighting. Some General Service accounts are energy(kWh)-billed, and some are demand(kW)-billed. Further servicing details are available in the utility's Conditions of Service.

Unmetered Scattered Load
This classification refers to certain instances where connections can be provided without metering. These loads are generally small in size and consistent in magnitude of load. Hydro One reserves the right to review all cases and may require that a meter be installed at its sole discretion. Services that can be unmetered include cable TV amplifiers, telephone switching devices, phone booths, bus shelters, rail way crossing signals, traffic signals, and other small fixed loads.
Further servicing details are available in the utility's Conditions of Service (including in the "Unmetered Connections" section).

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
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Village of South River Public Utilities Commission
Effective Date: May 1, 2008

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Street Lighting

This classification refers to accounts for the distribution and supply of electrical energy for street lighting. Street lights are devices owned by or operated for the road authority and/or the municipal corporation. These street lights in fact belong to the Street Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Sentinel Lighting

This classification refers to accounts for a separate service to a sentinel light. These sentinel lights in fact belong to the Sentinel Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Urban Density Classification

Customers who meet the Urban Density Criteria of being in an area containing 3,000 or more customers with a line density of at least 60 customers per kilometre, will be mapped to an Urban customer classification.

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
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Village of South River Public Utilities Commission
Effective Date: May 1, 2008

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MONTHLY RATES AND CHARGES

Residential - R1 South River

Service Charge	$	15.21
Distribution Volumetric Rate	$ / kWh	0.0271
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0041
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0004)
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0047
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0046
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service Less Than 50 kW (Energy-Billed) - GSe South River

Service Charge	$	24.56
Distribution Volumetric Rate	$ / kWh	0.0295
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0030
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0006)
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0035
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0032
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service 50 kW or Greater (Demand-Billed) - GSd South River

Service Charge	$	28.16
Distribution Volumetric Rate	$ / kW	9.22
Regulatory Asset Recovery - Rider #2	$ / kW	0.92
Regulatory Asset Recovery - Rider #3	$ / kW	(0.22)
Retail Transmission Rate - Network Service Rate (4)	$ / kW	1.11
Retail Transmission Rate - Line and Transformation Connection Service Rate (4)	$ / kW	1.00
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

Hydro One Networks Inc.
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Village of South River Public Utilities Commission
Effective Date: May 1, 2008

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Unmetered, Scattered Load

Service Charge	$	13.73
Distribution Volumetric Rate	$ / kWh	0.0200
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0030
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0006)
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0035
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0032
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

(3) For energy-only metered customers, the billing determinant is the customer's metered energy consumption adjusted by the total loss factor as approved by the Board for Acquired LDC customers.
(4) For demand billed customers, appropriate loss factors must be applied to the applicable tariffs. Also the billing determinant for the Line and Transformation Connection Services rate is the customer's peak demand in the billing period. The billing determinant for the Network Services rate is: for non-interval-metered customers, the peak demand in the billing period, and for interval-metered customers, the peak demand between 7 AM and 7 PM local time on IESO business days

Customer-Supplied Transformation Allowance

Applicable to customers providing their own transformers

Demand-billed	$ / kW	0.60
Energy-billed	$ / kWh	0.0014

Hydro One Networks Inc.
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Loss Factors

Residential	1.085
General Service Less Than 50 kW (Energy-Billed)	1.092
General Service 50 kW or Greater (Demand-Billed)	1.061
Unmetered Scattered Load	1.092

Transformer Loss Allowance

Applicable to customers requiring a billing adjustment for transformer losses as the result of being metered on the primary side of a transformer. The following uniform values shall be applied to measured demand and energy to calculate transformer losses for voltages up to and including 50 kV (as metered on the primary side):

(a) 1.5% for transformer installations up to an individual bank capacity of 400 kVA,
(b) 1.0% for bank capacities over 400 kVA.

Alternatively, transformer losses may be determined from transformer test data, and measured demand and energy adjusted accordingly

For services which are not demand metered, an assumed demand of 50% of the transformer capacity will be used to calculate the loss allowance. Where several transformers are involved, the bank capacity is assumed to be the arithmetic sum of all transformer capacities

Hydro One Networks Inc.
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MISCELLANEOUS CHARGES

Specific Service Charges: Standard Amounts

Rate Code	Specific Service Charge - Standard Name	Calculation Method			
		2006 Rate Handbook	Standard Formula	Other Formula	Time and Materials
1	Temporary Service	$500			
2	Dispute Meter Test	$30 plus Measurement Canada fees			
3	Collection of account – no disconnection/load limiter	$30			
4	Collection/Disconnect/load limiter/reconnect (at meter) trip – regular hours	$65			
5	Collection/Disconnect/load limiter/reconnect (at meter) trip – after regular hours	$185			
6	Collection/Disconnect/load limiter/reconnect (at pole) trip – regular hours	$185			
7	Collection/Disconnect/load limiter/reconnect (at pole) trip – after regular hours	$415			
8	Account Set-up Charge	$30			
9	Arrears Certificate	$15			
10	NSF Cheque Charge	$15 + bank charges			
11	Easement Charge for Unregistered Rights	$15			
12	Late Payment Charge	1.5%/month			
13a	Retailer Services – Establishing Service Agreements (refer to Handbook for all charges)	$100/agreement/Retailer +$20/month/Retailer +$0.50/month/customer + other			
13b	Retailer Services – Other (includes Bill Ready for Retailers and Service Transactions Requests) as per the Handbook, Chapter 12	$0.30/month/customer + $0.25/request for request fee + $0.50/request for process fee			
14	Special Meter Reads	$30			
15	Service Layout Fee – Basic		$495		
16	Service Layout Fee – Complex		$690		
17	Crossing Application – Pipeline		$2,445		
18	Crossing Application – Water		$3,045		
19	Crossing Application – Railroad		$2,945		
20	Line Staking – per meter		$3.70		
21	Central Metering – New service < 45 kW		$115		
22	Conversion to Central Metering < 45 kW		$915		
23	Conversion to Central Metering > 45 kW		$800		
24	Tingle Voltage Test – In Excess of 4 Hours (per hour – average 2 additional hours)		$125		
25	Standby Administration Charge per month		$440		
26	Sentinel Lights Rental Rate per month			$7.10	
27	Sentinel Pole Rental Rate per month			$4.15	
28	Joint Use for Cable and Telecom companies per pole			$22.35	
29	Joint Use for LDCs per pole			$28.61	

Hydro One Networks Inc.
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APPLICATION

The application of these rates and charges shall be in accordance with The Licence of The Distributor and any Codes, Guidelines or Orders of The Board, and amendments thereto as approved by The Board, which may be applicable to the administration of this schedule.
No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code, Guideline or Order of the Board, and amendments thereto as approved by the Board, or as specified herein
This schedule does not contain any rates and charges relating to the electricity commodity (e.g. the Regulated Price Plan).

EFFECTIVE DATES

DISTRIBUTION RATES - May 1, 2007 for all consumption or deemed consumption services used on or after that date.

MISCELLANEOUS CHARGES - May 1, 2007 for all charges billed to customers on or after that date.
RETAIL TRANSMISSION RATES - May 1, 2007 for all consumption or deemed consumption services used on or after that date.
LOSS FACTOR ADJUSTMENT – May 1, 2007

SERVICE CLASSIFICATIONS

Residential
This classification (note 1) refers to all service supplied to single-family dwelling units for domestic or household purpose. Multi-unit residential establishments such as apartment buildings supplied through one service (bulk metered) will normally be classified as General Service, but, at Hydro One's discretion, up to four residential units may be classified as residential. Where electricity service is provided to combined residential and business (including agricultural usage) and the wiring does not provide for separate metering, the classification shall be at the discretion of Hydro One based on such considerations as the estimated predominant consumption.
Further servicing details are available in the utility's Conditions of Service.

General Service
This classification (note 1) refers to all service supplied to premises other than those classified as Residential or Lighting. Some General Service accounts are energy(kWh)-billed, and some are demand(kW)-billed. Further servicing details are available in the utility's Conditions of Service. Also, see note 2.

Unmetered Scattered Load
This classification refers to certain instances where connections can be provided without metering. These loads are generally small in size and consistent in magnitude of load. Hydro One reserves the right to review all cases and may require that a meter be installed at its sole discretion. Services that can be unmetered include cable TV amplifiers, telephone switching devices, phone booths, bus shelters, rail way crossing signals, traffic signals, and other small fixed loads.
Further servicing details are available in the utility's Conditions of Service (including in the "Unmetered Connections" section).

Hydro One Networks Inc.
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Street Lighting

This classification refers to accounts for the distribution and supply of electrical energy for street lighting. Street lights are devices owned by or operated for the road authority and/or the municipal corporation. These street lights in fact belong to the Street Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Sentinel Lighting

This classification refers to accounts for a separate service to a sentinel light. These sentinel lights in fact belong to the Sentinel Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Interim Demand-Side Management Time-of-Use

This is potentially applicable to Demand-billed General Service accounts. See Note 2 below.

Note (1): Classification descriptions are paraphrases from the document "Hydro One Networks Inc. - Distribution Customers Conditions of Service - August 2004"

Note (2):

Interim Demand-Side Management Time-of-Use Rates: demand charges will be based on demand during the on-peak periods.

Criteria: Customers' electricity consumption (kW) in the off-peak period is at least twice the electricity consumption (kW) during the on-peak period.

Definition of Time Periods: The on-peak hours will be between 0700 hours to 1900 hours Eastern Standard Time during the winter (standard time) on IESO business days and 0600 hours to 1800 hours Eastern Standard Time during the summer (daylight savings time) on IESO business days. The off-peak period constitutes all of the remaining hours.

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Village of South River Public Utilities Commission
Effective Date: May 1, 2007

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

MONTHLY RATES AND CHARGES

Residential

Service Charge	$	14.22
Distribution Volumetric Rate	$ / kWh	0.0125
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0063
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0041
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0055
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0047
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service - Energy Billed (less than 50 kW)

Service Charge	$	22.11
Distribution Volumetric Rate	$ / kWh	0.0158
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0039
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0030
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0050
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0043
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service - Demand Billed (50 kW or greater)

Service Charge	$	22.11
Distribution Volumetric Rate	$ / kW	4.87
Regulatory Asset Recovery - Rider #1	$ / kW	1.22
Regulatory Asset Recovery - Rider #2	$ / kW	0.92
Retail Transmission Rate - Network Service Rate (4)	$ / kW	1.94
Retail Transmission Rate - Line and Transformation Connection Service Rate (4)	$ / kW	1.61
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
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Village of South River Public Utilities Commission
Effective Date: May 1, 2007

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Unmetered, Scattered Load

Service Charge	$	10.59
Distribution Volumetric Rate	$ / kWh	0.0158
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0039
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0030
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0050
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0043
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

(3) For energy-only metered customers, the billing determinant is the customer's metered energy consumption adjusted by the total loss factor as approved by the Board for Acquired LDC customers.
(4) For demand billed customers, appropriate loss factors must be applied to the applicable tariffs. Also the billing determinant for the Line and Transformation Connection Services rate is the customer's peak demand in the billing period. The billing determinant for the Network Services rate is: for non-interval-metered customers, the peak demand in the billing period, and for interval-metered customers, the peak demand between 7 AM and 7 PM local time on IESO business days

Interim Demand-Side Management Time-of-Use

See the "Service Classifications" section of this schedule.

Customer-Supplied Transformation Allowance

Applicable to demand-billed customers providing their own transformers
Primary Voltage under 50 kV (per kW)

Single Phase	$ / kW	0.20
Three Phase	$ / kW	0.60

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
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Village of South River Public Utilities Commission
Effective Date: May 1, 2007

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Loss Factors

Supply Facilities Loss Factor	1.0045
Distribution Loss Factors	
Customer less than 5,000 kW	1.0500
Customer greater than or equal to 5,000 kW	1.0100
Total Loss Factors	
Customer less than 5,000 kW	1.0545
Customer greater than or equal to 5,000 kW	1.0145

Transformer Loss Allowance

Applicable to customers requiring a billing adjustment for transformer losses as the result of being metered on the primary side of a transformer. The following uniform values shall be applied to measured demand and energy to calculate transformer losses for voltages up to and including 50 kV (as metered on the primary side):

(a) 1.5% for transformer installations up to an individual bank capacity of 400 kVA,
(b) 1.0% for bank capacities over 400 kVA.

Alternatively, transformer losses may be determined from transformer test data, and measured demand and energy adjusted accordingly
For services which are not demand metered, an assumed demand of 50% of the transformer capacity will be used to calculate the loss allowance. Where several transformers are involved, the bank capacity is assumed to be the arithmetic sum of all transformer capacities

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
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Village of South River Public Utilities Commission
Effective Date: May 1, 2007

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

MISCELLANEOUS CHARGES

Specific Service Charges: Standard Amounts

Rate Code	Specific Service Charge - Standard Name	Calculation Method			
		2006 Rate Handbook	Standard Formula	Other Formula	Time and Materials
1	Temporary Service	$500			
2	Dispute Meter Test	$30 plus Measurement Canada fees			
3	Collection of account – no disconnection/load limiter	$30			
4	Collection/Disconnect/load limiter/reconnect (at meter) trip – regular hours	$65			
5	Collection/Disconnect/load limiter/reconnect (at meter) trip – after regular hours	$185			
6	Collection/Disconnect/load limiter/reconnect (at pole) trip – regular hours	$185			
7	Collection/Disconnect/load limiter/reconnect (at pole) trip – after regular hours	$415			
8	Account Set-up Charge	$30			
9	Arrears Certificate	$15			
10	NSF Cheque Charge	$15 + bank charges			
11	Easement Charge for Unregistered Rights	$15			
12	Late Payment Charge	1.5%/month			
13a	Retailer Services – Establishing Service Agreements (refer to Handbook for all charges)	$100/agreement/Retailer +$20/month/Retailer +$0.50/month/customer + other			
13b	Retailer Services – Other (includes Bill Ready for Retailers and Service Transactions Requests) as per the Handbook, Chapter 12	$0.30/month/customer + $0.25/request for request fee + $0.50/request for process fee			
14	Special Meter Reads	$30			
15	Billing Suspension and Terminations in Trailer Parks		$130		
16	Service Layout Fee – Basic		$405		
17	Service Layout Fee – Complex		$580		

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
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Village of South River Public Utilities Commission
Effective Date: May 1, 2007

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18	Crossing Application – Pipeline		$2,065		
19	Crossing Application – Water		$2,525		
20	Crossing Application – Railroad		$2,565		
21	Line Staking – per meter		$3.10		
22	Central Metering – New service < 45 kW		$115		
23	Conversion to Central Metering < 45 kW		$795		
24	Conversion to Central Metering > 45 kW		$680		
25	Tingle Voltage Test – In Excess of 4 Hours (per hour – average 2 additional hours)		$105		
26	Standby Administration Charge per month (interim)		$375		
27	Sentinel Lights Rental Rate per month – Mercury Vapor			$7.00	
28	Guaranteed Units from Jan 01/91 to Aug 01/91			$26.50 / month	
29	Guaranteed Units from Jan 01/87 to Dec 31/90			$23.50 / month	
30	Joint Use for Cable and Telecom companies per pole			$22.35	
31	Joint Use for LDCs per pole			$28.61	

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Hydro-Electric Commission of the Township of Springwater
Effective Date: May 1, 2008

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

APPLICATION

The application of these rates and charges shall be in accordance with The Licence of The Distributor and any Codes, Guidelines or Orders of The Board, and amendments thereto as approved by The Board, which may be applicable to the administration of this schedule.
No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code, Guideline or Order of the Board, and amendments thereto as approved by the Board, or as specified herein
This schedule does not contain any rates and charges relating to the electricity commodity (e.g. the Regulated Price Plan).

EFFECTIVE DATES

DISTRIBUTION RATES - May 1, 2008 for all consumption or deemed consumption services used on or after that date.

MISCELLANEOUS CHARGES - May 1, 2008 for all charges billed to customers on or after that date.
RETAIL TRANSMISSION RATES - May 1, 2008 for all consumption or deemed consumption services used on or after that date.
LOSS FACTOR ADJUSTMENT – for all consumption or deemed consumption services billed following May 1, 2008 or later

SERVICE CLASSIFICATIONS

Residential
This classification refers to all service supplied to single-family dwelling units for domestic or household purpose. Multi-unit residential establishments such as apartment buildings supplied through one service (bulk metered) will normally be classified as General Service, but, at Hydro One's discretion, up to four residential units may be classified as residential. Where electricity service is provided to combined residential and business (including agricultural usage) and the wiring does not provide for separate metering, the classification shall be at the discretion of Hydro One based on such considerations as the estimated predominant consumption.
Further servicing details are available in the utility's Conditions of Service.

General Service
This classification refers to all service supplied to premises other than those classified as Residential or Lighting. Some General Service accounts are energy(kWh)-billed, and some are demand(kW)-billed. Further servicing details are available in the utility's Conditions of Service.

Unmetered Scattered Load
This classification refers to certain instances where connections can be provided without metering. These loads are generally small in size and consistent in magnitude of load. Hydro One reserves the right to review all cases and may require that a meter be installed at its sole discretion. Services that can be unmetered include cable TV amplifiers, telephone switching devices, phone booths, bus shelters, rail way crossing signals, traffic signals, and other small fixed loads.
Further servicing details are available in the utility's Conditions of Service (including in the "Unmetered Connections" section).

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Hydro-Electric Commission of the Township of Springwater
Effective Date: May 1, 2008

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

Street Lighting

This classification refers to accounts for the distribution and supply of electrical energy for street lighting. Street lights are devices owned by or operated for the road authority and/or the municipal corporation. These street lights in fact belong to the Street Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Sentinel Lighting

This classification refers to accounts for a separate service to a sentinel light. These sentinel lights in fact belong to the Sentinel Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Urban Density Classification

Customers who meet the Urban Density Criteria of being in an area containing 3,000 or more customers with a line density of at least 60 customers per kilometre, will be mapped to an Urban customer classification.

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
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Effective Date: May 1, 2008

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MONTHLY RATES AND CHARGES

Residential - R1 Springwater

Service Charge	$	12.81
Distribution Volumetric Rate	$ / kWh	0.0225
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0031
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0004)
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0047
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0046
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service Less Than 50 kW (Energy-Billed) - GSe Springwater

Service Charge	$	22.96
Distribution Volumetric Rate	$ / kWh	0.0225
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0017
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0006)
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0035
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0032
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service 50 kW or Greater (Demand-Billed) - GSd Springwater

Service Charge	$	26.56
Distribution Volumetric Rate	$ / kW	8.60
Regulatory Asset Recovery - Rider #2	$ / kW	0.53
Regulatory Asset Recovery - Rider #3	$ / kW	(0.22)
Retail Transmission Rate - Network Service Rate (4)	$ / kW	1.11
Retail Transmission Rate - Line and Transformation Connection Service Rate (4)	$ / kW	1.00
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Hydro-Electric Commission of the Township of Springwater
Effective Date: May 1, 2008

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

Unmetered, Scattered Load

Service Charge	$	12.93
Distribution Volumetric Rate	$ / kWh	0.0200
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0017
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0006)
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0035
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0032
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

(3) For energy-only metered customers, the billing determinant is the customer's metered energy consumption adjusted by the total loss factor as approved by the Board for Acquired LDC customers.

(4) For demand billed customers, appropriate loss factors must be applied to the applicable tariffs. Also the billing determinant for the Line and Transformation Connection Services rate is the customer's peak demand in the billing period. The billing determinant for the Network Services rate is: for non-interval-metered customers, the peak demand in the billing period, and for interval-metered customers, the peak demand between 7 AM and 7 PM local time on IESO business days

Customer-Supplied Transformation Allowance

Applicable to customers providing their own transformers		
Demand-billed	$ / kW	0.60
Energy-billed	$ / kWh	0.0014

Hydro One Networks Inc.
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Hydro-Electric Commission of the Township of Springwater
Effective Date: May 1, 2008

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Loss Factors

Residential	1.085
General Service Less Than 50 kW (Energy-Billed)	1.092
General Service 50 kW or Greater (Demand-Billed)	1.061
Unmetered Scattered Load	1.092

Transformer Loss Allowance

Applicable to customers requiring a billing adjustment for transformer losses as the result of being metered on the primary side of a transformer. The following uniform values shall be applied to measured demand and energy to calculate transformer losses for voltages up to and including 50 kV (as metered on the primary side):

(a) 1.5% for transformer installations up to an individual bank capacity of 400 kVA,
(b) 1.0% for bank capacities over 400 kVA.

Alternatively, transformer losses may be determined from transformer test data, and measured demand and energy adjusted accordingly

For services which are not demand metered, an assumed demand of 50% of the transformer capacity will be used to calculate the loss allowance. Where several transformers are involved, the bank capacity is assumed to be the arithmetic sum of all transformer capacities

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Hydro-Electric Commission of the Township of Springwater
Effective Date: May 1, 2008

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

MISCELLANEOUS CHARGES

Specific Service Charges: Standard Amounts

Rate Code	Specific Service Charge - Standard Name	Calculation Method			
		2006 Rate Handbook	Standard Formula	Other Formula	Time and Materials
1	Temporary Service	$500			
2	Dispute Meter Test	$30 plus Measurement Canada fees			
3	Collection of account – no disconnection/load limiter	$30			
4	Collection/Disconnect/load limiter/reconnect (at meter) trip – regular hours	$65			
5	Collection/Disconnect/load limiter/reconnect (at meter) trip – after regular hours	$185			
6	Collection/Disconnect/load limiter/reconnect (at pole) trip – regular hours	$185			
7	Collection/Disconnect/load limiter/reconnect (at pole) trip – after regular hours	$415			
8	Account Set-up Charge	$30			
9	Arrears Certificate	$15			
10	NSF Cheque Charge	$15 + bank charges			
11	Easement Charge for Unregistered Rights	$15			
12	Late Payment Charge	1.5%/month			
13a	Retailer Services – Establishing Service Agreements (refer to Handbook for all charges)	$100/agreement/Retailer +$20/month/Retailer +$0.50/month/customer + other			
13b	Retailer Services – Other (includes Bill Ready for Retailers and Service Transactions Requests) as per the Handbook, Chapter 12	$0.30/month/customer + $0.25/request for request fee + $0.50/request for process fee			
14	Special Meter Reads	$30			
15	Service Layout Fee – Basic		$495		
16	Service Layout Fee – Complex		$690		
17	Crossing Application – Pipeline		$2,445		
18	Crossing Application – Water		$3,045		
19	Crossing Application – Railroad		$2,945		
20	Line Staking – per meter		$3.70		
21	Central Metering – New service < 45 kW		$115		
22	Conversion to Central Metering < 45 kW		$915		
23	Conversion to Central Metering > 45 kW		$800		
24	Tingle Voltage Test – In Excess of 4 Hours (per hour – average 2 additional hours)		$125		
25	Standby Administration Charge per month		$440		
26	Sentinel Lights Rental Rate per month			$7.10	
27	Sentinel Pole Rental Rate per month			$4.15	
28	Joint Use for Cable and Telecom companies per pole			$22.35	
29	Joint Use for LDCs per pole			$28.61	

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Hydro-Electric Commission of the Township of Springwater
Effective Date: May 1, 2007

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

APPLICATION

The application of these rates and charges shall be in accordance with The Licence of The Distributor and any Codes, Guidelines or Orders of The Board, and amendments thereto as approved by The Board, which may be applicable to the administration of this schedule.
No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code, Guideline or Order of the Board, and amendments thereto as approved by the Board, or as specified herein
This schedule does not contain any rates and charges relating to the electricity commodity (e.g. the Regulated Price Plan).

EFFECTIVE DATES

DISTRIBUTION RATES - May 1, 2007 for all consumption or deemed consumption services used on or after that date.

MISCELLANEOUS CHARGES - May 1, 2007 for all charges billed to customers on or after that date.
RETAIL TRANSMISSION RATES - May 1, 2007 for all consumption or deemed consumption services used on or after that date.
LOSS FACTOR ADJUSTMENT – May 1, 2007

SERVICE CLASSIFICATIONS

Residential
This classification (note 1) refers to all service supplied to single-family dwelling units for domestic or household purpose. Multi-unit residential establishments such as apartment buildings supplied through one service (bulk metered) will normally be classified as General Service, but, at Hydro One's discretion, up to four residential units may be classified as residential. Where electricity service is provided to combined residential and business (including agricultural usage) and the wiring does not provide for separate metering, the classification shall be at the discretion of Hydro One based on such considerations as the estimated predominant consumption.
Further servicing details are available in the utility's Conditions of Service.

General Service
This classification (note 1) refers to all service supplied to premises other than those classified as Residential or Lighting. Some General Service accounts are energy(kWh)-billed, and some are demand(kW)-billed. Further servicing details are available in the utility's Conditions of Service. Also, see note 2.

Unmetered Scattered Load
This classification refers to certain instances where connections can be provided without metering. These loads are generally small in size and consistent in magnitude of load. Hydro One reserves the right to review all cases and may require that a meter be installed at its sole discretion. Services that can be unmetered include cable TV amplifiers, telephone switching devices, phone booths, bus shelters, rail way crossing signals, traffic signals, and other small fixed loads.
Further servicing details are available in the utility's Conditions of Service (including in the "Unmetered Connections" section).

Hydro One Networks Inc.
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Effective Date: May 1, 2007

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Street Lighting

This classification refers to accounts for the distribution and supply of electrical energy for street lighting. Street lights are devices owned by or operated for the road authority and/or the municipal corporation. These street lights in fact belong to the Street Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Sentinel Lighting

This classification refers to accounts for a separate service to a sentinel light. These sentinel lights in fact belong to the Sentinel Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Interim Demand-Side Management Time-of-Use

This is potentially applicable to Demand-billed General Service accounts. See Note 2 below.

Note (1): Classification descriptions are paraphrases from the document "Hydro One Networks Inc. - Distribution Customers Conditions of Service - August 2004"

Note (2):

Interim Demand-Side Management Time-of-Use Rates: demand charges will be based on demand during the on-peak periods.

Criteria: Customers' electricity consumption (kW) in the off-peak period is at least twice the electricity consumption (kW) during the on-peak period.

Definition of Time Periods: The on-peak hours will be between 0700 hours to 1900 hours Eastern Standard Time during the winter (standard time) on IESO business days and 0600 hours to 1800 hours Eastern Standard Time during the summer (daylight savings time) on IESO business days. The off-peak period constitutes all of the remaining hours.

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Hydro-Electric Commission of the Township of Springwater
Effective Date: May 1, 2007

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

MONTHLY RATES AND CHARGES

Residential

Service Charge	$	11.79
Distribution Volumetric Rate	$ / kWh	0.0082
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0061
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0031
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0055
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0047
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service - Energy Billed (less than 50 kW)

Service Charge	$	20.53
Distribution Volumetric Rate	$ / kWh	0.0107
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0027
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0017
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0050
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0043
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service - Demand Billed (50 kW or greater)

Service Charge	$	20.53
Distribution Volumetric Rate	$ / kW	3.42
Regulatory Asset Recovery - Rider #1	$ / kW	0.85
Regulatory Asset Recovery - Rider #2	$ / kW	0.53
Retail Transmission Rate - Network Service Rate (4)	$ / kW	1.94
Retail Transmission Rate - Line and Transformation Connection Service Rate (4)	$ / kW	1.61
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
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Hydro-Electric Commission of the Township of Springwater
Effective Date: May 1, 2007

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

Unmetered, Scattered Load

Service Charge	$	9.80
Distribution Volumetric Rate	$ / kWh	0.0107
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0027
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0017
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0050
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0043
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

(3) For energy-only metered customers, the billing determinant is the customer’s metered energy consumption adjusted by the total loss factor as approved by the Board for Acquired LDC customers.
(4) For demand billed customers, appropriate loss factors must be applied to the applicable tariffs. Also the billing determinant for the Line and Transformation Connection Services rate is the customer’s peak demand in the billing period. The billing determinant for the Network Services rate is: for non-interval-metered customers, the peak demand in the billing period, and for interval-metered customers, the peak demand between 7 AM and 7 PM local time on IESO business days

Interim Demand-Side Management Time-of-Use

See the "Service Classifications" section of this schedule.

Customer-Supplied Transformation Allowance

Applicable to demand-billed customers providing their own transformers
Primary Voltage under 50 kV (per kW)

Single Phase	$ / kW	0.20
Three Phase	$ / kW	0.60

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Hydro-Electric Commission of the Township of Springwater
Effective Date: May 1, 2007

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

Loss Factors

Supply Facilities Loss Factor	1.0045
Distribution Loss Factors	
Customer less than 5,000 kW	1.0500
Customer greater than or equal to 5,000 kW	1.0100
Total Loss Factors	
Customer less than 5,000 kW	1.0545
Customer greater than or equal to 5,000 kW	1.0145

Transformer Loss Allowance

Applicable to customers requiring a billing adjustment for transformer losses as the result of being metered on the primary side of a transformer. The following uniform values shall be applied to measured demand and energy to calculate transformer losses for voltages up to and including 50 kV (as metered on the primary side):

(a) 1.5% for transformer installations up to an individual bank capacity of 400 kVA,
(b) 1.0% for bank capacities over 400 kVA.

Alternatively, transformer losses may be determined from transformer test data, and measured demand and energy adjusted accordingly

For services which are not demand metered, an assumed demand of 50% of the transformer capacity will be used to calculate the loss allowance. Where several transformers are involved, the bank capacity is assumed to be the arithmetic sum of all transformer capacities

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Hydro-Electric Commission of the Township of Springwater
Effective Date: May 1, 2007

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

MISCELLANEOUS CHARGES

Specific Service Charges: Standard Amounts

Rate Code	Specific Service Charge - Standard Name	Calculation Method			
		2006 Rate Handbook	Standard Formula	Other Formula	Time and Materials
1	Temporary Service	$500			
2	Dispute Meter Test	$30 plus Measurement Canada fees			
3	Collection of account – no disconnection/load limiter	$30			
4	Collection/Disconnect/load limiter/reconnect (at meter) trip – regular hours	$65			
5	Collection/Disconnect/load limiter/reconnect (at meter) trip – after regular hours	$185			
6	Collection/Disconnect/load limiter/reconnect (at pole) trip – regular hours	$185			
7	Collection/Disconnect/load limiter/reconnect (at pole) trip – after regular hours	$415			
8	Account Set-up Charge	$30			
9	Arrears Certificate	$15			
10	NSF Cheque Charge	$15 + bank charges			
11	Easement Charge for Unregistered Rights	$15			
12	Late Payment Charge	1.5%/month			
13a	Retailer Services – Establishing Service Agreements (refer to Handbook for all charges)	$100/agreement/Retailer +$20/month/Retailer +$0.50/month/customer + other			
13b	Retailer Services – Other (includes Bill Ready for Retailers and Service Transactions Requests) as per the Handbook, Chapter 12	$0.30/month/customer + $0.25/request for request fee + $0.50/request for process fee			
14	Special Meter Reads	$30			
15	Billing Suspension and Terminations in Trailer Parks		$130		
16	Service Layout Fee – Basic		$405		
17	Service Layout Fee – Complex		$580		

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Hydro-Electric Commission of the Township of Springwater
Effective Date: May 1, 2007

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

18	Crossing Application – Pipeline		$2,065		
19	Crossing Application – Water		$2,525		
20	Crossing Application – Railroad		$2,565		
21	Line Staking – per meter		$3.10		
22	Central Metering – New service < 45 kW		$115		
23	Conversion to Central Metering < 45 kW		$795		
24	Conversion to Central Metering > 45 kW		$680		
25	Tingle Voltage Test – In Excess of 4 Hours (per hour – average 2 additional hours)		$105		
26	Standby Administration Charge per month (interim)		$375		
27	Sentinel Lights Rental Rate per month – Mercury Vapor			$7.00	
28	Guaranteed Units from Jan 01/91 to Aug 01/91			$26.50 / month	
29	Guaranteed Units from Jan 01/87 to Dec 31/90			$23.50 / month	
30	Joint Use for Cable and Telecom companies per pole			$22.35	
31	Joint Use for LDCs per pole			$28.61	

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Stirling-Rawdon Public Utilities Commission
Effective Date: May 1, 2008

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

APPLICATION

The application of these rates and charges shall be in accordance with The Licence of The Distributor and any Codes, Guidelines or Orders of The Board, and amendments thereto as approved by The Board, which may be applicable to the administration of this schedule.
No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code, Guideline or Order of the Board, and amendments thereto as approved by the Board, or as specified herein
This schedule does not contain any rates and charges relating to the electricity commodity (e.g. the Regulated Price Plan).

EFFECTIVE DATES

DISTRIBUTION RATES - May 1, 2008 for all consumption or deemed consumption services used on or after that date.

MISCELLANEOUS CHARGES - May 1, 2008 for all charges billed to customers on or after that date.
RETAIL TRANSMISSION RATES - May 1, 2008 for all consumption or deemed consumption services used on or after that date.
LOSS FACTOR ADJUSTMENT – for all consumption or deemed consumption services billed following May 1, 2008 or later

SERVICE CLASSIFICATIONS

Residential
This classification refers to all service supplied to single-family dwelling units for domestic or household purpose. Multi-unit residential establishments such as apartment buildings supplied through one service (bulk metered) will normally be classified as General Service, but, at Hydro One's discretion, up to four residential units may be classified as residential. Where electricity service is provided to combined residential and business (including agricultural usage) and the wiring does not provide for separate metering, the classification shall be at the discretion of Hydro One based on such considerations as the estimated predominant consumption.
Further servicing details are available in the utility's Conditions of Service.

General Service
This classification refers to all service supplied to premises other than those classified as Residential or Lighting. Some General Service accounts are energy(kWh)-billed, and some are demand(kW)-billed. Further servicing details are available in the utility's Conditions of Service.

Unmetered Scattered Load
This classification refers to certain instances where connections can be provided without metering. These loads are generally small in size and consistent in magnitude of load. Hydro One reserves the right to review all cases and may require that a meter be installed at its sole discretion. Services that can be unmetered include cable TV amplifiers, telephone switching devices, phone booths, bus shelters, rail way crossing signals, traffic signals, and other small fixed loads.
Further servicing details are available in the utility's Conditions of Service (including in the "Unmetered Connections" section).

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Stirling-Rawdon Public Utilities Commission
Effective Date: May 1, 2008

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

Street Lighting

This classification refers to accounts for the distribution and supply of electrical energy for street lighting. Street lights are devices owned by or operated for the road authority and/or the municipal corporation. These street lights in fact belong to the Street Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Sentinel Lighting

This classification refers to accounts for a separate service to a sentinel light. These sentinel lights in fact belong to the Sentinel Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Urban Density Classification

Customers who meet the Urban Density Criteria of being in an area containing 3,000 or more customers with a line density of at least 60 customers per kilometre, will be mapped to an Urban customer classification.

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Stirling-Rawdon Public Utilities Commission
Effective Date: May 1, 2008

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

MONTHLY RATES AND CHARGES

Residential - R1 Stirling-Rawdon

Service Charge	$	13.62
Distribution Volumetric Rate	$ / kWh	0.0220
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0012
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0004)
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0047
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0046
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service Less Than 50 kW (Energy-Billed) - GSe Stirling-Rawdon

Service Charge	$	26.06
Distribution Volumetric Rate	$ / kWh	0.0247
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0009
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0006)
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0035
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0032
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service 50 kW or Greater (Demand-Billed) - GSd Stirling-Rawdon

Service Charge	$	29.66
Distribution Volumetric Rate	$ / kW	9.22
Regulatory Asset Recovery - Rider #2	$ / kW	0.30
Regulatory Asset Recovery - Rider #3	$ / kW	(0.22)
Retail Transmission Rate - Network Service Rate (4)	$ / kW	1.11
Retail Transmission Rate - Line and Transformation Connection Service Rate (4)	$ / kW	1.00
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Stirling-Rawdon Public Utilities Commission
Effective Date: May 1, 2008

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

Unmetered, Scattered Load

Service Charge	$	14.48
Distribution Volumetric Rate	$ / kWh	0.0200
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0009
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0006)
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0035
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0032
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

(3) For energy-only metered customers, the billing determinant is the customer’s metered energy consumption adjusted by the total loss factor as approved by the Board for Acquired LDC customers.
(4) For demand billed customers, appropriate loss factors must be applied to the applicable tariffs. Also the billing determinant for the Line and Transformation Connection Services rate is the customer’s peak demand in the billing period. The billing determinant for the Network Services rate is: for non-interval-metered customers, the peak demand in the billing period, and for interval-metered customers, the peak demand between 7 AM and 7 PM local time on IESO business days

Customer-Supplied Transformation Allowance

Applicable to customers providing their own transformers

Demand-billed	$ / kW	0.60
Energy-billed	$ / kWh	0.0014

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Stirling-Rawdon Public Utilities Commission
Effective Date: May 1, 2008

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

Loss Factors

Residential	1.085
General Service Less Than 50 kW (Energy-Billed)	1.092
General Service 50 kW or Greater (Demand-Billed)	1.061
Unmetered Scattered Load	1.092

Transformer Loss Allowance

Applicable to customers requiring a billing adjustment for transformer losses as the result of being metered on the primary side of a transformer. The following uniform values shall be applied to measured demand and energy to calculate transformer losses for voltages up to and including 50 kV (as metered on the primary side):

(a) 1.5% for transformer installations up to an individual bank capacity of 400 kVA,
(b) 1.0% for bank capacities over 400 kVA.

Alternatively, transformer losses may be determined from transformer test data, and measured demand and energy adjusted accordingly
For services which are not demand metered, an assumed demand of 50% of the transformer capacity will be used to calculate the loss allowance. Where several transformers are involved, the bank capacity is assumed to be the arithmetic sum of all transformer capacities

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Stirling-Rawdon Public Utilities Commission
Effective Date: May 1, 2008

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

MISCELLANEOUS CHARGES

Specific Service Charges: Standard Amounts

Rate Code	Specific Service Charge - Standard Name	Calculation Method			
		2006 Rate Handbook	Standard Formula	Other Formula	Time and Materials
1	Temporary Service	$500			
2	Dispute Meter Test	$30 plus Measurement Canada fees			
3	Collection of account – no disconnection/load limiter	$30			
4	Collection/Disconnect/load limiter/reconnect (at meter) trip – regular hours	$65			
5	Collection/Disconnect/load limiter/reconnect (at meter) trip – after regular hours	$185			
6	Collection/Disconnect/load limiter/reconnect (at pole) trip – regular hours	$185			
7	Collection/Disconnect/load limiter/reconnect (at pole) trip – after regular hours	$415			
8	Account Set-up Charge	$30			
9	Arrears Certificate	$15			
10	NSF Cheque Charge	$15 + bank charges			
11	Easement Charge for Unregistered Rights	$15			
12	Late Payment Charge	1.5%/month			
13a	Retailer Services – Establishing Service Agreements (refer to Handbook for all charges)	$100/agreement/Retailer +$20/month/Retailer +$0.50/month/customer + other			
13b	Retailer Services – Other (includes Bill Ready for Retailers and Service Transactions Requests) as per the Handbook, Chapter 12	$0.30/month/customer + $0.25/request for request fee + $0.50/request for process fee			
14	Special Meter Reads	$30			
15	Service Layout Fee – Basic		$495		
16	Service Layout Fee – Complex		$690		
17	Crossing Application – Pipeline		$2,445		
18	Crossing Application – Water		$3,045		
19	Crossing Application – Railroad		$2,945		
20	Line Staking – per meter		$3.70		
21	Central Metering – New service < 45 kW		$115		
22	Conversion to Central Metering < 45 kW		$915		
23	Conversion to Central Metering > 45 kW		$800		
24	Tingle Voltage Test – In Excess of 4 Hours (per hour – average 2 additional hours)		$125		
25	Standby Administration Charge per month		$440		
26	Sentinel Lights Rental Rate per month			$7.10	
27	Sentinel Pole Rental Rate per month			$4.15	
28	Joint Use for Cable and Telecom companies per pole			$22.35	
29	Joint Use for LDCs per pole			$28.61	

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Stirling-Rawdon Public Utilities Commission
Effective Date: May 1, 2007

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

APPLICATION

The application of these rates and charges shall be in accordance with The Licence of The Distributor and any Codes, Guidelines or Orders of The Board, and amendments thereto as approved by The Board, which may be applicable to the administration of this schedule.
No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code, Guideline or Order of the Board, and amendments thereto as approved by the Board, or as specified herein
This schedule does not contain any rates and charges relating to the electricity commodity (e.g. the Regulated Price Plan).

EFFECTIVE DATES

DISTRIBUTION RATES - May 1, 2007 for all consumption or deemed consumption services used on or after that date.

MISCELLANEOUS CHARGES - May 1, 2007 for all charges billed to customers on or after that date.
RETAIL TRANSMISSION RATES - May 1, 2007 for all consumption or deemed consumption services used on or after that date.
LOSS FACTOR ADJUSTMENT – May 1, 2007

SERVICE CLASSIFICATIONS

Residential
This classification (note 1) refers to all service supplied to single-family dwelling units for domestic or household purpose. Multi-unit residential establishments such as apartment buildings supplied through one service (bulk metered) will normally be classified as General Service, but, at Hydro One's discretion, up to four residential units may be classified as residential. Where electricity service is provided to combined residential and business (including agricultural usage) and the wiring does not provide for separate metering, the classification shall be at the discretion of Hydro One based on such considerations as the estimated predominant consumption.
Further servicing details are available in the utility's Conditions of Service.

General Service
This classification (note 1) refers to all service supplied to premises other than those classified as Residential or Lighting. Some General Service accounts are energy(kWh)-billed, and some are demand(kW)-billed. Further servicing details are available in the utility's Conditions of Service. Also, see note 2.

Unmetered Scattered Load
This classification refers to certain instances where connections can be provided without metering. These loads are generally small in size and consistent in magnitude of load. Hydro One reserves the right to review all cases and may require that a meter be installed at its sole discretion. Services that can be unmetered include cable TV amplifiers, telephone switching devices, phone booths, bus shelters, rail way crossing signals, traffic signals, and other small fixed loads.
Further servicing details are available in the utility's Conditions of Service (including in the "Unmetered Connections" section).

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Stirling-Rawdon Public Utilities Commission
Effective Date: May 1, 2007

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

Street Lighting

This classification refers to accounts for the distribution and supply of electrical energy for street lighting. Street lights are devices owned by or operated for the road authority and/or the municipal corporation. These street lights in fact belong to the Street Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Sentinel Lighting

This classification refers to accounts for a separate service to a sentinel light. These sentinel lights in fact belong to the Sentinel Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Interim Demand-Side Management Time-of-Use

This is potentially applicable to Demand-billed General Service accounts. See Note 2 below.

Note (1): Classification descriptions are paraphrases from the document "Hydro One Networks Inc. - Distribution Customers Conditions of Service - August 2004"

Note (2):

Interim Demand-Side Management Time-of-Use Rates: demand charges will be based on demand during the on-peak periods.

Criteria: Customers' electricity consumption (kW) in the off-peak period is at least twice the electricity consumption (kW) during the on-peak period.

Definition of Time Periods: The on-peak hours will be between 0700 hours to 1900 hours Eastern Standard Time during the winter (standard time) on IESO business days and 0600 hours to 1800 hours Eastern Standard Time during the summer (daylight savings time) on IESO business days. The off-peak period constitutes all of the remaining hours.

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Stirling-Rawdon Public Utilities Commission
Effective Date: May 1, 2007

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

MONTHLY RATES AND CHARGES

Residential

Service Charge	$	12.55
Distribution Volumetric Rate	$ / kWh	0.0103
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0038
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0012
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0055
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0047
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service - Energy Billed (less than 50 kW)

Service Charge	$	24.12
Distribution Volumetric Rate	$ / kWh	0.0130
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0021
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0009
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0050
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0043
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service - Demand Billed (50 kW or greater)

Service Charge	$	24.12
Distribution Volumetric Rate	$ / kW	4.11
Regulatory Asset Recovery - Rider #1	$ / kW	0.67
Regulatory Asset Recovery - Rider #2	$ / kW	0.30
Retail Transmission Rate - Network Service Rate (4)	$ / kW	1.94
Retail Transmission Rate - Line and Transformation Connection Service Rate (4)	$ / kW	1.61
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Stirling-Rawdon Public Utilities Commission
Effective Date: May 1, 2007

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

Unmetered, Scattered Load

Service Charge	$	11.59
Distribution Volumetric Rate	$ / kWh	0.0130
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0021
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0009
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0050
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0043
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

(3) For energy-only metered customers, the billing determinant is the customer’s metered energy consumption adjusted by the total loss factor as approved by the Board for Acquired LDC customers.
(4) For demand billed customers, appropriate loss factors must be applied to the applicable tariffs. Also the billing determinant for the Line and Transformation Connection Services rate is the customer’s peak demand in the billing period. The billing determinant for the Network Services rate is: for non-interval-metered customers, the peak demand in the billing period, and for interval-metered customers, the peak demand between 7 AM and 7 PM local time on IESO business days

Interim Demand-Side Management Time-of-Use

See the "Service Classifications" section of this schedule.

Customer-Supplied Transformation Allowance

Applicable to demand-billed customers providing their own transformers
Primary Voltage under 50 kV (per kW)

Single Phase	$ / kW	0.20
Three Phase	$ / kW	0.60

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Stirling-Rawdon Public Utilities Commission
Effective Date: May 1, 2007

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

Loss Factors

Supply Facilities Loss Factor	1.0045
Distribution Loss Factors	
Customer less than 5,000 kW	1.0500
Customer greater than or equal to 5,000 kW	1.0100
Total Loss Factors	
Customer less than 5,000 kW	1.0545
Customer greater than or equal to 5,000 kW	1.0145

Transformer Loss Allowance

Applicable to customers requiring a billing adjustment for transformer losses as the result of being metered on the primary side of a transformer. The following uniform values shall be applied to measured demand and energy to calculate transformer losses for voltages up to and including 50 kV (as metered on the primary side):

(a) 1.5% for transformer installations up to an individual bank capacity of 400 kVA,
(b) 1.0% for bank capacities over 400 kVA.

Alternatively, transformer losses may be determined from transformer test data, and measured demand and energy adjusted accordingly

For services which are not demand metered, an assumed demand of 50% of the transformer capacity will be used to calculate the loss allowance. Where several transformers are involved, the bank capacity is assumed to be the arithmetic sum of all transformer capacities

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Stirling-Rawdon Public Utilities Commission
Effective Date: May 1, 2007

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

MISCELLANEOUS CHARGES

Specific Service Charges: Standard Amounts

Rate Code	Specific Service Charge - Standard Name	Calculation Method			
		2006 Rate Handbook	Standard Formula	Other Formula	Time and Materials
1	Temporary Service	$500			
2	Dispute Meter Test	$30 plus Measurement Canada fees			
3	Collection of account – no disconnection/load limiter	$30			
4	Collection/Disconnect/load limiter/reconnect (at meter) trip – regular hours	$65			
5	Collection/Disconnect/load limiter/reconnect (at meter) trip – after regular hours	$185			
6	Collection/Disconnect/load limiter/reconnect (at pole) trip – regular hours	$185			
7	Collection/Disconnect/load limiter/reconnect (at pole) trip – after regular hours	$415			
8	Account Set-up Charge	$30			
9	Arrears Certificate	$15			
10	NSF Cheque Charge	$15 + bank charges			
11	Easement Charge for Unregistered Rights	$15			
12	Late Payment Charge	1.5%/month			
13a	Retailer Services – Establishing Service Agreements (refer to Handbook for all charges)	$100/agreement/Retailer +$20/month/Retailer +$0.50/month/customer + other			
13b	Retailer Services – Other (includes Bill Ready for Retailers and Service Transactions Requests) as per the Handbook, Chapter 12	$0.30/month/customer + $0.25/request for request fee + $0.50/request for process fee			
14	Special Meter Reads	$30			
15	Billing Suspension and Terminations in Trailer Parks		$130		
16	Service Layout Fee – Basic		$405		
17	Service Layout Fee – Complex		$580		

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Stirling-Rawdon Public Utilities Commission
Effective Date: May 1, 2007

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

18	Crossing Application – Pipeline		$2,065		
19	Crossing Application – Water		$2,525		
20	Crossing Application – Railroad		$2,565		
21	Line Staking – per meter		$3.10		
22	Central Metering – New service < 45 kW		$115		
23	Conversion to Central Metering < 45 kW		$795		
24	Conversion to Central Metering > 45 kW		$680		
25	Tingle Voltage Test – In Excess of 4 Hours (per hour – average 2 additional hours)		$105		
26	Standby Administration Charge per month (interim)		$375		
27	Sentinel Lights Rental Rate per month – Mercury Vapor			$7.00	
28	Guaranteed Units from Jan 01/91 to Aug 01/91			$26.50 / month	
29	Guaranteed Units from Jan 01/87 to Dec 31/90			$23.50 / month	
30	Joint Use for Cable and Telecom companies per pole			$22.35	
31	Joint Use for LDCs per pole			$28.61	

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Terrace Bay Superior Wires Inc.
Effective Date: May 1, 2008

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

APPLICATION

The application of these rates and charges shall be in accordance with The Licence of The Distributor and any Codes, Guidelines or Orders of The Board, and amendments thereto as approved by The Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code, Guideline or Order of the Board, and amendments thereto as approved by the Board, or as specified herein

This schedule does not contain any rates and charges relating to the electricity commodity (e.g. the Regulated Price Plan).

EFFECTIVE DATES

DISTRIBUTION RATES - May 1, 2008 for all consumption or deemed consumption services used on or after that date.

MISCELLANEOUS CHARGES - May 1, 2008 for all charges billed to customers on or after that date.

RETAIL TRANSMISSION RATES - May 1, 2008 for all consumption or deemed consumption services used on or after that date.

LOSS FACTOR ADJUSTMENT – for all consumption or deemed consumption services billed following May 1, 2008 or later

SERVICE CLASSIFICATIONS

Residential

This classification refers to all service supplied to single-family dwelling units for domestic or household purpose. Multi-unit residential establishments such as apartment buildings supplied through one service (bulk metered) will normally be classified as General Service, but, at Hydro One's discretion, up to four residential units may be classified as residential. Where electricity service is provided to combined residential and business (including agricultural usage) and the wiring does not provide for separate metering, the classification shall be at the discretion of Hydro One based on such considerations as the estimated predominant consumption.

Further servicing details are available in the utility's Conditions of Service.

General Service

This classification refers to all service supplied to premises other than those classified as Residential or Lighting. Some General Service accounts are energy(kWh)-billed, and some are demand(kW)-billed. Further servicing details are available in the utility's Conditions of Service.

Unmetered Scattered Load

This classification refers to certain instances where connections can be provided without metering. These loads are generally small in size and consistent in magnitude of load. Hydro One reserves the right to review all cases and may require that a meter be installed at its sole discretion. Services that can be unmetered include cable TV amplifiers, telephone switching devices, phone booths, bus shelters, rail way crossing signals, traffic signals, and other small fixed loads.

Further servicing details are available in the utility's Conditions of Service (including in the "Unmetered Connections" section).

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Terrace Bay Superior Wires Inc.
Effective Date: May 1, 2008

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

Large Use - see Note 1

Street Lighting

This classification refers to accounts for the distribution and supply of electrical energy for street lighting. Street lights are devices owned by or operated for the road authority and/or the municipal corporation. These street lights in fact belong to the Street Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Sentinel Lighting

This classification refers to accounts for a separate service to a sentinel light. These sentinel lights in fact belong to the Sentinel Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Urban Density Classification

Customers who meet the Urban Density Criteria of being in an area containing 3,000 or more customers with a line density of at least 60 customers per kilometre, will be mapped to an Urban customer classification.

Note (1) The former Large Use class is now part of the ST class, which is separate from the classes for customers of acquired distribution companies.
This former class refered to individual Customers whose monthly measured maximum demand (kW) averaged over the most recent 12 consecutive months is equal to or greater than 5,000 kW.

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
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Terrace Bay Superior Wires Inc.
Effective Date: May 1, 2008

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MONTHLY RATES AND CHARGES

Residential - R1 Terrace Bay

Service Charge	$	19.56
Distribution Volumetric Rate	$ / kWh	0.0271
Regulatory Asset Recovery - Rider #2	$ / kWh	-
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0004)
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0047
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0046
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service Less Than 50 kW (Energy-Billed) - GSe Terrace Bay

Service Charge	$	38.76
Distribution Volumetric Rate	$ / kWh	0.0267
Regulatory Asset Recovery - Rider #2	$ / kWh	-
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0006)
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0035
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0032
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service 50 kW or Greater (Demand-Billed) - GSd Terrace Bay

Service Charge	$	231.38
Distribution Volumetric Rate	$ / kW	9.22
Regulatory Asset Recovery - Rider #2	$ / kW	-
Regulatory Asset Recovery - Rider #3	$ / kW	(0.22)
Retail Transmission Rate - Network Service Rate (4)	$ / kW	1.11
Retail Transmission Rate - Line and Transformation Connection Service Rate (4)	$ / kW	1.00
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
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Terrace Bay Superior Wires Inc.
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Unmetered, Scattered Load

Service Charge	$	21.25
Distribution Volumetric Rate	$ / kWh	0.0200
Regulatory Asset Recovery - Rider #2	$ / kWh	-
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0006)
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0035
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0032
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

(3) For energy-only metered customers, the billing determinant is the customer’s metered energy consumption adjusted by the total loss factor as approved by the Board for Acquired LDC customers.
(4) For demand billed customers, appropriate loss factors must be applied to the applicable tariffs. Also the billing determinant for the Line and Transformation Connection Services rate is the customer’s peak demand in the billing period. The billing determinant for the Network Services rate is: for non-interval-metered customers, the peak demand in the billing period, and for interval-metered customers, the peak demand between 7 AM and 7 PM local time on IESO business days

Customer-Supplied Transformation Allowance

Applicable to customers providing their own transformers

Demand-billed	$ / kW	0.60
Energy-billed	$ / kWh	0.0014

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
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Terrace Bay Superior Wires Inc.
Effective Date: May 1, 2008

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Loss Factors

Residential	1.085
General Service Less Than 50 kW (Energy-Billed)	1.092
General Service 50 kW or Greater (Demand-Billed)	1.061
Unmetered Scattered Load	1.092

Transformer Loss Allowance

Applicable to customers requiring a billing adjustment for transformer losses as the result of being metered on the primary side of a transformer. The following uniform values shall be applied to measured demand and energy to calculate transformer losses for voltages up to and including 50 kV (as metered on the primary side):

(a) 1.5% for transformer installations up to an individual bank capacity of 400 kVA,
(b) 1.0% for bank capacities over 400 kVA.

Alternatively, transformer losses may be determined from transformer test data, and measured demand and energy adjusted accordingly

For services which are not demand metered, an assumed demand of 50% of the transformer capacity will be used to calculate the loss allowance. Where several transformers are involved, the bank capacity is assumed to be the arithmetic sum of all transformer capacities

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Terrace Bay Superior Wires Inc.
Effective Date: May 1, 2008

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

MISCELLANEOUS CHARGES

Specific Service Charges: Standard Amounts

Rate Code	Specific Service Charge - Standard Name	Calculation Method			
		2006 Rate Handbook	Standard Formula	Other Formula	Time and Materials
1	Temporary Service	$500			
2	Dispute Meter Test	$30 plus Measurement Canada fees			
3	Collection of account – no disconnection/load limiter	$30			
4	Collection/Disconnect/load limiter/reconnect (at meter) trip – regular hours	$65			
5	Collection/Disconnect/load limiter/reconnect (at meter) trip – after regular hours	$185			
6	Collection/Disconnect/load limiter/reconnect (at pole) trip – regular hours	$185			
7	Collection/Disconnect/load limiter/reconnect (at pole) trip – after regular hours	$415			
8	Account Set-up Charge	$30			
9	Arrears Certificate	$15			
10	NSF Cheque Charge	$15 + bank charges			
11	Easement Charge for Unregistered Rights	$15			
12	Late Payment Charge	1.5%/month			
13a	Retailer Services – Establishing Service Agreements (refer to Handbook for all charges)	$100/agreement/Retailer +$20/month/Retailer +$0.50/month/customer + other			
13b	Retailer Services – Other (includes Bill Ready for Retailers and Service Transactions Requests) as per the Handbook, Chapter 12	$0.30/month/customer + $0.25/request for request fee + $0.50/request for process fee			
14	Special Meter Reads	$30			
15	Service Layout Fee – Basic		$495		
16	Service Layout Fee – Complex		$690		
17	Crossing Application – Pipeline		$2,445		
18	Crossing Application – Water		$3,045		
19	Crossing Application – Railroad		$2,945		
20	Line Staking – per meter		$3.70		
21	Central Metering – New service < 45 kW		$115		
22	Conversion to Central Metering < 45 kW		$915		
23	Conversion to Central Metering > 45 kW		$800		
24	Tingle Voltage Test – In Excess of 4 Hours (per hour – average 2 additional hours)		$125		
25	Standby Administration Charge per month		$440		
26	Sentinel Lights Rental Rate per month			$7.10	
27	Sentinel Pole Rental Rate per month			$4.15	
28	Joint Use for Cable and Telecom companies per pole			$22.35	
29	Joint Use for LDCs per pole			$28.61	

Hydro One Networks Inc.

For the Service Area formerly served by Terrace Bay Superior Wires Inc.

TARIFF OF RATES AND CHARGES

Effective October 25, 2007

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

APPLICATION

- The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Codes, Guidelines or Orders of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.
- No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code, Guideline or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.
- This schedule does not contain any rates and charges relating to the electricity commodity (e.g. the Regulated Price Plan).

EFFECTIVE DATES

DISTRIBUTION RATES – October 25, 2007 for all consumption or deemed consumption services used on or after that date.
SPECIFIC SERVICE CHARGES – October 25, 2007 for all charges incurred by customers on or after that date.
LOSS FACTOR ADJUSTMENT – October 25, 2007 unless the distributor is not capable of prorating changed loss factors jointly with distribution rates. In that case, the revised loss factors will be implemented upon the first subsequent billing for each billing cycle.

SERVICE CLASSIFICATIONS

Residential
This classification applies to an account taking electricity at 750 volts or less where the electricity is used exclusively in a separate metered living accommodation. Customers shall be residing in single-dwelling units that consist of a detached house or one unit of a semi-detached, duplex, triplex or quadruplex house, with a residential zoning. Separately metered dwellings within a town house complex or apartment building also qualify as residential customers. All customers are single-phase.

General Service Less Than 50 kW
This classification applies to a non residential account taking electricity at 750 volts or less whose average monthly maximum demand is less than, or is forecast to be less than, 50 kW.

General Service 50 to 4,999 kW
This classification applies to a non residential account whose average monthly maximum demand used for billing purposes is equal to or greater than, or is forecast to be equal to or greater than, 50 kW but less than 5,000 kW.

Unmetered Scattered Load
This classification applies to an account taking electricity at 750 volts or less whose average monthly maximum demand is less than, or is forecast to be less than, 50 kW and the consumption is unmetered. Such connections include cable TV power packs, bus shelters, telephone booths, traffic lights, railway crossings, etc. The level of the consumption will be agreed to by the distributor and the customer, based on detailed manufacturer information/documentation with regard to electrical consumption of the unmetered load or periodic monitoring of actual consumption.

Street Lighting
This classification applies to an account for roadway lighting with a Municipality, Regional Municipality, Ministry of Transportation and private roadway lighting, controlled by photo cells. The consumption for these customers will be based on the calculated connected load times the required lighting times established in the approved OEB street lighting load shape template.

Hydro One Networks Inc.
For the Service Area formerly served by Terrace Bay Superior Wires Inc.
TARIFF OF RATES AND CHARGES
Effective October 25, 2007

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

MONTHLY RATES AND CHARGES

Residential

Service Charge	$	20.81
Distribution Volumetric Rate	$/kWh	0.0145
Regulatory Asset Recovery	$/kWh	0.0097
Retail Transmission Rate – Network Service Rate	$/kWh	0.0051
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0000
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

General Service Less Than 50 kW

Service Charge	$	41.34
Distribution Volumetric Rate	$/kWh	0.0118
Regulatory Asset Recovery	$/kWh	0.0082
Retail Transmission Rate – Network Service Rate	$/kWh	0.0047
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0000
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

General Service 50 to 4,999 kW

Service Charge	$	293.24
Distribution Volumetric Rate	$/kW	4.0020
Regulatory Asset Recovery	$/kW	2.2726
Retail Transmission Rate – Network Service Rate	$/kW	1.9115
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	0.0000
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Unmetered Scattered Load

Service Charge (per connection)	$	20.53
Distribution Volumetric Rate	$/kWh	0.0129
Regulatory Asset Recovery	$/kWh	0.0082
Retail Transmission Rate – Network Service Rate	$/kWh	0.0047
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0000
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Street Lighting

Service Charge (per connection)	$	1.36
Distribution Volumetric Rate	$/kW	4.2190
Regulatory Asset Recovery	$/kW	2.9480
Retail Transmission Rate – Network Service Rate	$/kW	1.4416
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	0.0000

Hydro One Networks Inc.

For the Service Area formerly served by Terrace Bay Superior Wires Inc.

TARIFF OF RATES AND CHARGES

Effective October 25, 2007

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Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Specific Service Charges

Customer Administration		
Arrears Certificate	$	15.00
Statement of Account	$	15.00
Pulling post-dated cheques	$	15.00
Duplicate invoices for previous billing	$	15.00
Request for other billing information	$	15.00
Easement Letter	$	15.00
Income tax letter	$	15.00
Notification Charge	$	15.00
Account history	$	15.00
Credit reference/credit check (plus credit agency costs)	$	15.00
Returned Cheque charge (plus bank charges)	$	15.00
Charge to certify cheque	$	15.00
Legal letter charge	$	15.00
Account set up charge / change of occupancy charge (plus credit agency costs if applicable)	$	30.00
Special Meter reads	$	30.00
Meter dispute charge plus Measurement Canada fees (if meter found correct)	$	30.00
Non-Payment of Account		
Late Payment - per month	%	1.50
Late Payment - per annum	%	19.56
Collection of account charge – no disconnection	$	30.00
Collection of account charge – no disconnection – after regular hours	$	165.00
Disconnect/Reconnect at meter – during regular hours	$	65.00
Disconnect/Reconnect at meter – after regular hours	$	185.00
Disconnect/Reconnect at pole – during regular hours	$	185.00
Disconnect/Reconnect at pole – after regular hours	$	415.00
Install / remove load control device – during regular hours	$	65.00
Install / remove load control device – after regular hours	$	185.00
Service call – customer-owned equipment	$	30.00
Service call – after regular hours	$	165.00
Temporary service install and remove – overhead – no transformer	$	500.00
Temporary service install and remove – underground – no transformer	$	300.00
Temporary service install and remove – overhead – with transformer	$	1,000.00
Specific Charge for Access to the Power Poles – per pole/year	$	22.35
Allowances		
Transformer Allowance for Ownership - per kW of billing demand/month	$/kW	(0.60)
Primary Metering Allowance for transformer losses – applied to measured demand and energy	%	(1.00)

LOSS FACTORS

Total Loss Factor – Secondary Metered Customer < 5,000 kW	1.0426
Total Loss Factor – Secondary Metered Customer > 5,000 kW	1.0145
Total Loss Factor – Primary Metered Customer < 5,000 kW	1.0321
Total Loss Factor – Primary Metered Customer > 5,000 kW	1.0045

Hydro One Networks Inc.
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Effective Date: May 1, 2008

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APPLICATION

The application of these rates and charges shall be in accordance with The Licence of The Distributor and any Codes, Guidelines or Orders of The Board, and amendments thereto as approved by The Board, which may be applicable to the administration of this schedule.
No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code, Guideline or Order of the Board, and amendments thereto as approved by the Board, or as specified herein
This schedule does not contain any rates and charges relating to the electricity commodity (e.g. the Regulated Price Plan).

EFFECTIVE DATES

DISTRIBUTION RATES - May 1, 2008 for all consumption or deemed consumption services used on or after that date.

MISCELLANEOUS CHARGES - May 1, 2008 for all charges billed to customers on or after that date.
RETAIL TRANSMISSION RATES - May 1, 2008 for all consumption or deemed consumption services used on or after that date.
LOSS FACTOR ADJUSTMENT – for all consumption or deemed consumption services billed following May 1, 2008 or later

SERVICE CLASSIFICATIONS

Residential
This classification refers to all service supplied to single-family dwelling units for domestic or household purpose. Multi-unit residential establishments such as apartment buildings supplied through one service (bulk metered) will normally be classified as General Service, but, at Hydro One's discretion, up to four residential units may be classified as residential. Where electricity service is provided to combined residential and business (including agricultural usage) and the wiring does not provide for separate metering, the classification shall be at the discretion of Hydro One based on such considerations as the estimated predominant consumption.
Further servicing details are available in the utility's Conditions of Service.

General Service
This classification refers to all service supplied to premises other than those classified as Residential or Lighting. Some General Service accounts are energy(kWh)-billed, and some are demand(kW)-billed. Further servicing details are available in the utility's Conditions of Service.

Unmetered Scattered Load
This classification refers to certain instances where connections can be provided without metering. These loads are generally small in size and consistent in magnitude of load. Hydro One reserves the right to review all cases and may require that a meter be installed at its sole discretion. Services that can be unmetered include cable TV amplifiers, telephone switching devices, phone booths, bus shelters, rail way crossing signals, traffic signals, and other small fixed loads.
Further servicing details are available in the utility's Conditions of Service (including in the "Unmetered Connections" section).

Hydro One Networks Inc.
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Street Lighting

This classification refers to accounts for the distribution and supply of electrical energy for street lighting. Street lights are devices owned by or operated for the road authority and/or the municipal corporation. These street lights in fact belong to the Street Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Sentinel Lighting

This classification refers to accounts for a separate service to a sentinel light. These sentinel lights in fact belong to the Sentinel Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Urban Density Classification

Customers who meet the Urban Density Criteria of being in an area containing 3,000 or more customers with a line density of at least 60 customers per kilometre, will be mapped to an Urban customer classification.

Hydro One Networks Inc.
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MONTHLY RATES AND CHARGES

Residential - R1 Thedford

Service Charge	$	13.57
Distribution Volumetric Rate	$ / kWh	0.0250
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0052
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0004)
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0047
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0046
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service Less Than 50 kW (Energy-Billed) - GSe Thedford

Service Charge	$	20.63
Distribution Volumetric Rate	$ / kWh	0.0230
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0031
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0006)
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0035
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0032
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service 50 kW or Greater (Demand-Billed) - GSd Thedford

Service Charge	$	24.23
Distribution Volumetric Rate	$ / kW	8.95
Regulatory Asset Recovery - Rider #2	$ / kW	1.00
Regulatory Asset Recovery - Rider #3	$ / kW	(0.22)
Retail Transmission Rate - Network Service Rate (4)	$ / kW	1.11
Retail Transmission Rate - Line and Transformation Connection Service Rate (4)	$ / kW	1.00
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

Hydro One Networks Inc.
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Unmetered, Scattered Load

Service Charge	$	12.27
Distribution Volumetric Rate	$ / kWh	0.0200
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0031
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0006)
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0035
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0032
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

(3) For energy-only metered customers, the billing determinant is the customer's metered energy consumption adjusted by the total loss factor as approved by the Board for Acquired LDC customers.
(4) For demand billed customers, appropriate loss factors must be applied to the applicable tariffs. Also the billing determinant for the Line and Transformation Connection Services rate is the customer's peak demand in the billing period. The billing determinant for the Network Services rate is: for non-interval-metered customers, the peak demand in the billing period, and for interval-metered customers, the peak demand between 7 AM and 7 PM local time on IESO business days

Customer-Supplied Transformation Allowance

Applicable to customers providing their own transformers		
Demand-billed	$ / kW	0.60
Energy-billed	$ / kWh	0.0014

Hydro One Networks Inc.
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Loss Factors

Residential	1.085
General Service Less Than 50 kW (Energy-Billed)	1.092
General Service 50 kW or Greater (Demand-Billed)	1.061
Unmetered Scattered Load	1.092

Transformer Loss Allowance

Applicable to customers requiring a billing adjustment for transformer losses as the result of being metered on the primary side of a transformer. The following uniform values shall be applied to measured demand and energy to calculate transformer losses for voltages up to and including 50 kV (as metered on the primary side):

(a) 1.5% for transformer installations up to an individual bank capacity of 400 kVA,
(b) 1.0% for bank capacities over 400 kVA.

Alternatively, transformer losses may be determined from transformer test data, and measured demand and energy adjusted accordingly

For services which are not demand metered, an assumed demand of 50% of the transformer capacity will be used to calculate the loss allowance. Where several transformers are involved, the bank capacity is assumed to be the arithmetic sum of all transformer capacities

Hydro One Networks Inc.
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MISCELLANEOUS CHARGES

Specific Service Charges: Standard Amounts

Rate Code	Specific Service Charge - Standard Name	Calculation Method			
		2006 Rate Handbook	Standard Formula	Other Formula	Time and Materials
1	Temporary Service	$500			
2	Dispute Meter Test	$30 plus Measurement Canada fees			
3	Collection of account – no disconnection/load limiter	$30			
4	Collection/Disconnect/load limiter/reconnect (at meter) trip – regular hours	$65			
5	Collection/Disconnect/load limiter/reconnect (at meter) trip – after regular hours	$185			
6	Collection/Disconnect/load limiter/reconnect (at pole) trip – regular hours	$185			
7	Collection/Disconnect/load limiter/reconnect (at pole) trip – after regular hours	$415			
8	Account Set-up Charge	$30			
9	Arrears Certificate	$15			
10	NSF Cheque Charge	$15 + bank charges			
11	Easement Charge for Unregistered Rights	$15			
12	Late Payment Charge	1.5%/month			
13a	Retailer Services – Establishing Service Agreements (refer to Handbook for all charges)	$100/agreement/Retailer +$20/month/Retailer +$0.50/month/customer + other			
13b	Retailer Services – Other (includes Bill Ready for Retailers and Service Transactions Requests) as per the Handbook, Chapter 12	$0.30/month/customer + $0.25/request for request fee + $0.50/request for process fee			
14	Special Meter Reads	$30			
15	Service Layout Fee – Basic		$495		
16	Service Layout Fee – Complex		$690		
17	Crossing Application – Pipeline		$2,445		
18	Crossing Application – Water		$3,045		
19	Crossing Application – Railroad		$2,945		
20	Line Staking – per meter		$3.70		
21	Central Metering – New service < 45 kW		$115		
22	Conversion to Central Metering < 45 kW		$915		
23	Conversion to Central Metering > 45 kW		$800		
24	Tingle Voltage Test – In Excess of 4 Hours (per hour – average 2 additional hours)		$125		
25	Standby Administration Charge per month		$440		
26	Sentinel Lights Rental Rate per month			$7.10	
27	Sentinel Pole Rental Rate per month			$4.15	
28	Joint Use for Cable and Telecom companies per pole			$22.35	
29	Joint Use for LDCs per pole			$28.61	

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Public Utilities Commission of the Village of Thedford
Effective Date: May 1, 2007

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

APPLICATION

The application of these rates and charges shall be in accordance with The Licence of The Distributor and any Codes, Guidelines or Orders of The Board, and amendments thereto as approved by The Board, which may be applicable to the administration of this schedule.
No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code, Guideline or Order of the Board, and amendments thereto as approved by the Board, or as specified herein
This schedule does not contain any rates and charges relating to the electricity commodity (e.g. the Regulated Price Plan).

EFFECTIVE DATES

DISTRIBUTION RATES - May 1, 2007 for all consumption or deemed consumption services used on or after that date.

MISCELLANEOUS CHARGES - May 1, 2007 for all charges billed to customers on or after that date.
RETAIL TRANSMISSION RATES - May 1, 2007 for all consumption or deemed consumption services used on or after that date.
LOSS FACTOR ADJUSTMENT – May 1, 2007

SERVICE CLASSIFICATIONS

Residential
This classification (note 1) refers to all service supplied to single-family dwelling units for domestic or household purpose. Multi-unit residential establishments such as apartment buildings supplied through one service (bulk metered) will normally be classified as General Service, but, at Hydro One’s discretion, up to four residential units may be classified as residential. Where electricity service is provided to combined residential and business (including agricultural usage) and the wiring does not provide for separate metering, the classification shall be at the discretion of Hydro One based on such considerations as the estimated predominant consumption.
Further servicing details are available in the utility’s Conditions of Service.

General Service
This classification (note 1) refers to all service supplied to premises other than those classified as Residential or Lighting. Some General Service accounts are energy(kWh)-billed, and some are demand(kW)-billed. Further servicing details are available in the utility’s Conditions of Service. Also, see note 2.

Unmetered Scattered Load
This classification refers to certain instances where connections can be provided without metering. These loads are generally small in size and consistent in magnitude of load. Hydro One reserves the right to review all cases and may require that a meter be installed at its sole discretion. Services that can be unmetered include cable TV amplifiers, telephone switching devices, phone booths, bus shelters, rail way crossing signals, traffic signals, and other small fixed loads.
Further servicing details are available in the utility’s Conditions of Service (including in the "Unmetered Connections" section).

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Public Utilities Commission of the Village of Thedford
Effective Date: May 1, 2007

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

Street Lighting

This classification refers to accounts for the distribution and supply of electrical energy for street lighting. Street lights are devices owned by or operated for the road authority and/or the municipal corporation. These street lights in fact belong to the Street Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Sentinel Lighting

This classification refers to accounts for a separate service to a sentinel light. These sentinel lights in fact belong to the Sentinel Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Interim Demand-Side Management Time-of-Use

This is potentially applicable to Demand-billed General Service accounts. See Note 2 below.

Note (1): Classification descriptions are paraphrases from the document "Hydro One Networks Inc. - Distribution Customers Conditions of Service - August 2004"

Note (2):

Interim Demand-Side Management Time-of-Use Rates: demand charges will be based on demand during the on-peak periods.

Criteria: Customers' electricity consumption (kW) in the off-peak period is at least twice the electricity consumption (kW) during the on-peak period.

Definition of Time Periods: The on-peak hours will be between 0700 hours to 1900 hours Eastern Standard Time during the winter (standard time) on IESO business days and 0600 hours to 1800 hours Eastern Standard Time during the summer (daylight savings time) on IESO business days. The off-peak period constitutes all of the remaining hours.

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Public Utilities Commission of the Village of Thedford
Effective Date: May 1, 2007

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

MONTHLY RATES AND CHARGES

Residential

Service Charge	$	12.75
Distribution Volumetric Rate	$ / kWh	0.0081
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0082
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0052
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0055
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0047
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service - Energy Billed (less than 50 kW)

Service Charge	$	17.83
Distribution Volumetric Rate	$ / kWh	0.0106
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0036
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0031
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0050
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0043
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service - Demand Billed (50 kW or greater)

Service Charge	$	17.83
Distribution Volumetric Rate	$ / kW	3.38
Regulatory Asset Recovery - Rider #1	$ / kW	1.14
Regulatory Asset Recovery - Rider #2	$ / kW	1.00
Retail Transmission Rate - Network Service Rate (4)	$ / kW	1.94
Retail Transmission Rate - Line and Transformation Connection Service Rate (4)	$ / kW	1.61
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Public Utilities Commission of the Village of Thedford
Effective Date: May 1, 2007

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

Unmetered, Scattered Load

Service Charge	$	8.45
Distribution Volumetric Rate	$ / kWh	0.0106
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0036
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0031
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0050
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0043
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

(3) For energy-only metered customers, the billing determinant is the customer’s metered energy consumption adjusted by the total loss factor as approved by the Board for Acquired LDC customers.

(4) For demand billed customers, appropriate loss factors must be applied to the applicable tariffs. Also the billing determinant for the Line and Transformation Connection Services rate is the customer’s peak demand in the billing period. The billing determinant for the Network Services rate is: for non-interval-metered customers, the peak demand in the billing period, and for interval-metered customers, the peak demand between 7 AM and 7 PM local time on IESO business days

Interim Demand-Side Management Time-of-Use

See the "Service Classifications" section of this schedule.

Customer-Supplied Transformation Allowance

Applicable to demand-billed customers providing their own transformers
Primary Voltage under 50 kV (per kW)

Single Phase	$ / kW	0.20
Three Phase	$ / kW	0.60

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
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Public Utilities Commission of the Village of Thedford
Effective Date: May 1, 2007

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

Loss Factors

Supply Facilities Loss Factor	1.0045
Distribution Loss Factors	
Customer less than 5,000 kW	1.0500
Customer greater than or equal to 5,000 kW	1.0100
Total Loss Factors	
Customer less than 5,000 kW	1.0545
Customer greater than or equal to 5,000 kW	1.0145

Transformer Loss Allowance

Applicable to customers requiring a billing adjustment for transformer losses as the result of being metered on the primary side of a transformer. The following uniform values shall be applied to measured demand and energy to calculate transformer losses for voltages up to and including 50 kV (as metered on the primary side):

(a) 1.5% for transformer installations up to an individual bank capacity of 400 kVA,
(b) 1.0% for bank capacities over 400 kVA.

Alternatively, transformer losses may be determined from transformer test data, and measured demand and energy adjusted accordingly

For services which are not demand metered, an assumed demand of 50% of the transformer capacity will be used to calculate the loss allowance. Where several transformers are involved, the bank capacity is assumed to be the arithmetic sum of all transformer capacities

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Public Utilities Commission of the Village of Thedford
Effective Date: May 1, 2007

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

MISCELLANEOUS CHARGES

Specific Service Charges: Standard Amounts

Rate Code	Specific Service Charge - Standard Name	Calculation Method			
		2006 Rate Handbook	Standard Formula	Other Formula	Time and Materials
1	Temporary Service	$500			
2	Dispute Meter Test	$30 plus Measurement Canada fees			
3	Collection of account – no disconnection/load limiter	$30			
4	Collection/Disconnect/load limiter/reconnect (at meter) trip – regular hours	$65			
5	Collection/Disconnect/load limiter/reconnect (at meter) trip – after regular hours	$185			
6	Collection/Disconnect/load limiter/reconnect (at pole) trip – regular hours	$185			
7	Collection/Disconnect/load limiter/reconnect (at pole) trip – after regular hours	$415			
8	Account Set-up Charge	$30			
9	Arrears Certificate	$15			
10	NSF Cheque Charge	$15 + bank charges			
11	Easement Charge for Unregistered Rights	$15			
12	Late Payment Charge	1.5%/month			
13a	Retailer Services – Establishing Service Agreements (refer to Handbook for all charges)	$100/agreement/Retailer +$20/month/Retailer +$0.50/month/customer + other			
13b	Retailer Services – Other (includes Bill Ready for Retailers and Service Transactions Requests) as per the Handbook, Chapter 12	$0.30/month/customer + $0.25/request for request fee + $0.50/request for process fee			
14	Special Meter Reads	$30			
15	Billing Suspension and Terminations in Trailer Parks		$130		
16	Service Layout Fee – Basic		$405		
17	Service Layout Fee – Complex		$580		

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
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Public Utilities Commission of the Village of Thedford
Effective Date: May 1, 2007

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

18	Crossing Application – Pipeline		$2,065		
19	Crossing Application – Water		$2,525		
20	Crossing Application – Railroad		$2,565		
21	Line Staking – per meter		$3.10		
22	Central Metering – New service < 45 kW		$115		
23	Conversion to Central Metering < 45 kW		$795		
24	Conversion to Central Metering > 45 kW		$680		
25	Tingle Voltage Test – In Excess of 4 Hours (per hour – average 2 additional hours)		$105		
26	Standby Administration Charge per month (interim)		$375		
27	Sentinel Lights Rental Rate per month – Mercury Vapor			$7.00	
28	Guaranteed Units from Jan 01/91 to Aug 01/91			$26.50 / month	
29	Guaranteed Units from Jan 01/87 to Dec 31/90			$23.50 / month	
30	Joint Use for Cable and Telecom companies per pole			$22.35	
31	Joint Use for LDCs per pole			$28.61	

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Thessalon Hydro Distribution Corporation
Effective Date: May 1, 2008

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

APPLICATION

The application of these rates and charges shall be in accordance with The Licence of The Distributor and any Codes, Guidelines or Orders of The Board, and amendments thereto as approved by The Board, which may be applicable to the administration of this schedule.
No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code, Guideline or Order of the Board, and amendments thereto as approved by the Board, or as specified herein
This schedule does not contain any rates and charges relating to the electricity commodity (e.g. the Regulated Price Plan).

EFFECTIVE DATES

DISTRIBUTION RATES - May 1, 2008 for all consumption or deemed consumption services used on or after that date.

MISCELLANEOUS CHARGES - May 1, 2008 for all charges billed to customers on or after that date.
RETAIL TRANSMISSION RATES - May 1, 2008 for all consumption or deemed consumption services used on or after that date.
LOSS FACTOR ADJUSTMENT – for all consumption or deemed consumption services billed following May 1, 2008 or later

SERVICE CLASSIFICATIONS

Residential
This classification refers to all service supplied to single-family dwelling units for domestic or household purpose. Multi-unit residential establishments such as apartment buildings supplied through one service (bulk metered) will normally be classified as General Service, but, at Hydro One's discretion, up to four residential units may be classified as residential. Where electricity service is provided to combined residential and business (including agricultural usage) and the wiring does not provide for separate metering, the classification shall be at the discretion of Hydro One based on such considerations as the estimated predominant consumption.
Further servicing details are available in the utility's Conditions of Service.

General Service
This classification refers to all service supplied to premises other than those classified as Residential or Lighting. Some General Service accounts are energy(kWh)-billed, and some are demand(kW)-billed. Further servicing details are available in the utility's Conditions of Service.

Unmetered Scattered Load
This classification refers to certain instances where connections can be provided without metering. These loads are generally small in size and consistent in magnitude of load. Hydro One reserves the right to review all cases and may require that a meter be installed at its sole discretion. Services that can be unmetered include cable TV amplifiers, telephone switching devices, phone booths, bus shelters, rail way crossing signals, traffic signals, and other small fixed loads.
Further servicing details are available in the utility's Conditions of Service (including in the "Unmetered Connections" section).

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Thessalon Hydro Distribution Corporation
Effective Date: May 1, 2008

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

Street Lighting

This classification refers to accounts for the distribution and supply of electrical energy for street lighting. Street lights are devices owned by or operated for the road authority and/or the municipal corporation. These street lights in fact belong to the Street Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Sentinel Lighting

This classification refers to accounts for a separate service to a sentinel light. These sentinel lights in fact belong to the Sentinel Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Urban Density Classification

Customers who meet the Urban Density Criteria of being in an area containing 3,000 or more customers with a line density of at least 60 customers per kilometre, will be mapped to an Urban customer classification.

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Thessalon Hydro Distribution Corporation
Effective Date: May 1, 2008

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

MONTHLY RATES AND CHARGES

Residential - R1 Thessalon

Service Charge	$	15.87
Distribution Volumetric Rate	$ / kWh	0.0220
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0012
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0004)
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0047
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0046
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service Less Than 50 kW (Energy-Billed) - GSe Thessalon

Service Charge	$	21.37
Distribution Volumetric Rate	$ / kWh	0.0256
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0008
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0006)
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0035
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0032
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service 50 kW or Greater (Demand-Billed) - GSd Thessalon

Service Charge	$	24.96
Distribution Volumetric Rate	$ / kW	7.60
Regulatory Asset Recovery - Rider #2	$ / kW	0.17
Regulatory Asset Recovery - Rider #3	$ / kW	(0.22)
Retail Transmission Rate - Network Service Rate (4)	$ / kW	1.11
Retail Transmission Rate - Line and Transformation Connection Service Rate (4)	$ / kW	1.00
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Thessalon Hydro Distribution Corporation
Effective Date: May 1, 2008

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

Unmetered, Scattered Load

Service Charge	$	12.13
Distribution Volumetric Rate	$ / kWh	0.0200
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0008
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0006)
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0035
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0032
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

(3) For energy-only metered customers, the billing determinant is the customer's metered energy consumption adjusted by the total loss factor as approved by the Board for Acquired LDC customers.
(4) For demand billed customers, appropriate loss factors must be applied to the applicable tariffs. Also the billing determinant for the Line and Transformation Connection Services rate is the customer's peak demand in the billing period. The billing determinant for the Network Services rate is: for non-interval-metered customers, the peak demand in the billing period, and for interval-metered customers, the peak demand between 7 AM and 7 PM local time on IESO business days

Customer-Supplied Transformation Allowance

Applicable to customers providing their own transformers

Demand-billed	$ / kW	0.60
Energy-billed	$ / kWh	0.0014

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
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Loss Factors

Residential	1.085
General Service Less Than 50 kW (Energy-Billed)	1.092
General Service 50 kW or Greater (Demand-Billed)	1.061
Unmetered Scattered Load	1.092

Transformer Loss Allowance

Applicable to customers requiring a billing adjustment for transformer losses as the result of being metered on the primary side of a transformer. The following uniform values shall be applied to measured demand and energy to calculate transformer losses for voltages up to and including 50 kV (as metered on the primary side):

(a) 1.5% for transformer installations up to an individual bank capacity of 400 kVA,
(b) 1.0% for bank capacities over 400 kVA.

Alternatively, transformer losses may be determined from transformer test data, and measured demand and energy adjusted accordingly

For services which are not demand metered, an assumed demand of 50% of the transformer capacity will be used to calculate the loss allowance. Where several transformers are involved, the bank capacity is assumed to be the arithmetic sum of all transformer capacities

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Thessalon Hydro Distribution Corporation
Effective Date: May 1, 2008

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

MISCELLANEOUS CHARGES

Specific Service Charges: Standard Amounts

Rate Code	Specific Service Charge - Standard Name	Calculation Method			
		2006 Rate Handbook	Standard Formula	Other Formula	Time and Materials
1	Temporary Service	$500			
2	Dispute Meter Test	$30 plus Measurement Canada fees			
3	Collection of account – no disconnection/load limiter	$30			
4	Collection/Disconnect/load limiter/reconnect (at meter) trip – regular hours	$65			
5	Collection/Disconnect/load limiter/reconnect (at meter) trip – after regular hours	$185			
6	Collection/Disconnect/load limiter/reconnect (at pole) trip – regular hours	$185			
7	Collection/Disconnect/load limiter/reconnect (at pole) trip – after regular hours	$415			
8	Account Set-up Charge	$30			
9	Arrears Certificate	$15			
10	NSF Cheque Charge	$15 + bank charges			
11	Easement Charge for Unregistered Rights	$15			
12	Late Payment Charge	1.5%/month			
13a	Retailer Services – Establishing Service Agreements (refer to Handbook for all charges)	$100/agreement/Retailer +$20/month/Retailer +$0.50/month/customer + other			
13b	Retailer Services – Other (includes Bill Ready for Retailers and Service Transactions Requests) as per the Handbook, Chapter 12	$0.30/month/customer + $0.25/request for request fee + $0.50/request for process fee			
14	Special Meter Reads	$30			
15	Service Layout Fee – Basic		$495		
16	Service Layout Fee – Complex		$690		
17	Crossing Application – Pipeline		$2,445		
18	Crossing Application – Water		$3,045		
19	Crossing Application – Railroad		$2,945		
20	Line Staking – per meter		$3.70		
21	Central Metering – New service < 45 kW		$115		
22	Conversion to Central Metering < 45 kW		$915		
23	Conversion to Central Metering > 45 kW		$800		
24	Tingle Voltage Test – In Excess of 4 Hours (per hour – average 2 additional hours)		$125		
25	Standby Administration Charge per month		$440		
26	Sentinel Lights Rental Rate per month			$7.10	
27	Sentinel Pole Rental Rate per month			$4.15	
28	Joint Use for Cable and Telecom companies per pole			$22.35	
29	Joint Use for LDCs per pole			$28.61	

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Thessalon Hydro Distribution Corporation
Effective Date: May 1, 2007

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APPLICATION

The application of these rates and charges shall be in accordance with The Licence of The Distributor and any Codes, Guidelines or Orders of The Board, and amendments thereto as approved by The Board, which may be applicable to the administration of this schedule.
No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code, Guideline or Order of the Board, and amendments thereto as approved by the Board, or as specified herein
This schedule does not contain any rates and charges relating to the electricity commodity (e.g. the Regulated Price Plan).

EFFECTIVE DATES

DISTRIBUTION RATES - May 1, 2007 for all consumption or deemed consumption services used on or after that date.

MISCELLANEOUS CHARGES - May 1, 2007 for all charges billed to customers on or after that date.
RETAIL TRANSMISSION RATES - May 1, 2007 for all consumption or deemed consumption services used on or after that date.
LOSS FACTOR ADJUSTMENT – May 1, 2007

SERVICE CLASSIFICATIONS

Residential
This classification (note 1) refers to all service supplied to single-family dwelling units for domestic or household purpose. Multi-unit residential establishments such as apartment buildings supplied through one service (bulk metered) will normally be classified as General Service, but, at Hydro One's discretion, up to four residential units may be classified as residential. Where electricity service is provided to combined residential and business (including agricultural usage) and the wiring does not provide for separate metering, the classification shall be at the discretion of Hydro One based on such considerations as the estimated predominant consumption.
Further servicing details are available in the utility's Conditions of Service.

General Service
This classification (note 1) refers to all service supplied to premises other than those classified as Residential or Lighting. Some General Service accounts are energy(kWh)-billed, and some are demand(kW)-billed. Further servicing details are available in the utility's Conditions of Service. Also, see note 2.

Unmetered Scattered Load
This classification refers to certain instances where connections can be provided without metering. These loads are generally small in size and consistent in magnitude of load. Hydro One reserves the right to review all cases and may require that a meter be installed at its sole discretion. Services that can be unmetered include cable TV amplifiers, telephone switching devices, phone booths, bus shelters, rail way crossing signals, traffic signals, and other small fixed loads.
Further servicing details are available in the utility's Conditions of Service (including in the "Unmetered Connections" section).

Hydro One Networks Inc.
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Effective Date: May 1, 2007

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Street Lighting

This classification refers to accounts for the distribution and supply of electrical energy for street lighting. Street lights are devices owned by or operated for the road authority and/or the municipal corporation. These street lights in fact belong to the Street Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Sentinel Lighting

This classification refers to accounts for a separate service to a sentinel light. These sentinel lights in fact belong to the Sentinel Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Interim Demand-Side Management Time-of-Use

This is potentially applicable to Demand-billed General Service accounts. See Note 2 below.

Note (1): Classification descriptions are paraphrases from the document "Hydro One Networks Inc. - Distribution Customers Conditions of Service - August 2004"

Note (2):

Interim Demand-Side Management Time-of-Use Rates: demand charges will be based on demand during the on-peak periods.

Criteria: Customers' electricity consumption (kW) in the off-peak period is at least twice the electricity consumption (kW) during the on-peak period.

Definition of Time Periods: The on-peak hours will be between 0700 hours to 1900 hours Eastern Standard Time during the winter (standard time) on IESO business days and 0600 hours to 1800 hours Eastern Standard Time during the summer (daylight savings time) on IESO business days. The off-peak period constitutes all of the remaining hours.

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Thessalon Hydro Distribution Corporation
Effective Date: May 1, 2007

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

MONTHLY RATES AND CHARGES

Residential

Service Charge	$	15.56
Distribution Volumetric Rate	$ / kWh	0.0105
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0028
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0012
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0055
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0047
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service - Energy Billed (less than 50 kW)

Service Charge	$	18.90
Distribution Volumetric Rate	$ / kWh	0.0155
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0010
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0008
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0050
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0043
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service - Demand Billed (50 kW or greater)

Service Charge	$	18.90
Distribution Volumetric Rate	$ / kW	3.22
Regulatory Asset Recovery - Rider #1	$ / kW	0.21
Regulatory Asset Recovery - Rider #2	$ / kW	0.17
Retail Transmission Rate - Network Service Rate (4)	$ / kW	1.94
Retail Transmission Rate - Line and Transformation Connection Service Rate (4)	$ / kW	1.61
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Thessalon Hydro Distribution Corporation
Effective Date: May 1, 2007

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

Unmetered, Scattered Load

Service Charge	$	8.99
Distribution Volumetric Rate	$ / kWh	0.0155
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0010
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0008
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0050
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0043
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

(3) For energy-only metered customers, the billing determinant is the customer’s metered energy consumption adjusted by the total loss factor as approved by the Board for Acquired LDC customers.
(4) For demand billed customers, appropriate loss factors must be applied to the applicable tariffs. Also the billing determinant for the Line and Transformation Connection Services rate is the customer’s peak demand in the billing period. The billing determinant for the Network Services rate is: for non-interval-metered customers, the peak demand in the billing period, and for interval-metered customers, the peak demand between 7 AM and 7 PM local time on IESO business days

Interim Demand-Side Management Time-of-Use

See the "Service Classifications" section of this schedule.

Customer-Supplied Transformation Allowance

Applicable to demand-billed customers providing their own transformers
Primary Voltage under 50 kV (per kW)

Single Phase	$ / kW	0.20
Three Phase	$ / kW	0.60

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
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Thessalon Hydro Distribution Corporation
Effective Date: May 1, 2007

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

Loss Factors

Supply Facilities Loss Factor	1.0045
Distribution Loss Factors	
Customer less than 5,000 kW	1.0615
Customer greater than or equal to 5,000 kW	1.0100
Total Loss Factors	
Customer less than 5,000 kW	1.0660
Customer greater than or equal to 5,000 kW	1.0145

Transformer Loss Allowance

Applicable to customers requiring a billing adjustment for transformer losses as the result of being metered on the primary side of a transformer. The following uniform values shall be applied to measured demand and energy to calculate transformer losses for voltages up to and including 50 kV (as metered on the primary side):

(a) 1.5% for transformer installations up to an individual bank capacity of 400 kVA,
(b) 1.0% for bank capacities over 400 kVA.

Alternatively, transformer losses may be determined from transformer test data, and measured demand and energy adjusted accordingly

For services which are not demand metered, an assumed demand of 50% of the transformer capacity will be used to calculate the loss allowance. Where several transformers are involved, the bank capacity is assumed to be the arithmetic sum of all transformer capacities

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
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This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

MISCELLANEOUS CHARGES

Specific Service Charges: Standard Amounts

Rate Code	Specific Service Charge - Standard Name	Calculation Method			
		2006 Rate Handbook	Standard Formula	Other Formula	Time and Materials
1	Temporary Service	$500			
2	Dispute Meter Test	$30 plus Measurement Canada fees			
3	Collection of account – no disconnection/load limiter	$30			
4	Collection/Disconnect/load limiter/reconnect (at meter) trip – regular hours	$65			
5	Collection/Disconnect/load limiter/reconnect (at meter) trip – after regular hours	$185			
6	Collection/Disconnect/load limiter/reconnect (at pole) trip – regular hours	$185			
7	Collection/Disconnect/load limiter/reconnect (at pole) trip – after regular hours	$415			
8	Account Set-up Charge	$30			
9	Arrears Certificate	$15			
10	NSF Cheque Charge	$15 + bank charges			
11	Easement Charge for Unregistered Rights	$15			
12	Late Payment Charge	1.5%/month			
13a	Retailer Services – Establishing Service Agreements (refer to Handbook for all charges)	$100/agreement/Retailer +$20/month/Retailer +$0.50/month/customer + other			
13b	Retailer Services – Other (includes Bill Ready for Retailers and Service Transactions Requests) as per the Handbook, Chapter 12	$0.30/month/customer + $0.25/request for request fee + $0.50/request for process fee			
14	Special Meter Reads	$30			
15	Billing Suspension and Terminations in Trailer Parks		$130		
16	Service Layout Fee – Basic		$405		
17	Service Layout Fee – Complex		$580		

Hydro One Networks Inc.
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18	Crossing Application – Pipeline		$2,065		
19	Crossing Application – Water		$2,525		
20	Crossing Application – Railroad		$2,565		
21	Line Staking – per meter		$3.10		
22	Central Metering – New service < 45 kW		$115		
23	Conversion to Central Metering < 45 kW		$795		
24	Conversion to Central Metering > 45 kW		$680		
25	Tingle Voltage Test – In Excess of 4 Hours (per hour – average 2 additional hours)		$105		
26	Standby Administration Charge per month (interim)		$375		
27	Sentinel Lights Rental Rate per month – Mercury Vapor			$7.00	
28	Guaranteed Units from Jan 01/91 to Aug 01/91			$26.50 / month	
29	Guaranteed Units from Jan 01/87 to Dec 31/90			$23.50 / month	
30	Joint Use for Cable and Telecom companies per pole			$22.35	
31	Joint Use for LDCs per pole			$28.61	

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Thorndale Hydro Electric Commission
Effective Date: May 1, 2008

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

APPLICATION

The application of these rates and charges shall be in accordance with The Licence of The Distributor and any Codes, Guidelines or Orders of The Board, and amendments thereto as approved by The Board, which may be applicable to the administration of this schedule.
No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code, Guideline or Order of the Board, and amendments thereto as approved by the Board, or as specified herein
This schedule does not contain any rates and charges relating to the electricity commodity (e.g. the Regulated Price Plan).

EFFECTIVE DATES

DISTRIBUTION RATES - May 1, 2008 for all consumption or deemed consumption services used on or after that date.

MISCELLANEOUS CHARGES - May 1, 2008 for all charges billed to customers on or after that date.
RETAIL TRANSMISSION RATES - May 1, 2008 for all consumption or deemed consumption services used on or after that date.
LOSS FACTOR ADJUSTMENT – for all consumption or deemed consumption services billed following May 1, 2008 or later

SERVICE CLASSIFICATIONS

Residential
This classification refers to all service supplied to single-family dwelling units for domestic or household purpose. Multi-unit residential establishments such as apartment buildings supplied through one service (bulk metered) will normally be classified as General Service, but, at Hydro One's discretion, up to four residential units may be classified as residential. Where electricity service is provided to combined residential and business (including agricultural usage) and the wiring does not provide for separate metering, the classification shall be at the discretion of Hydro One based on such considerations as the estimated predominant consumption.
Further servicing details are available in the utility's Conditions of Service.

General Service
This classification refers to all service supplied to premises other than those classified as Residential or Lighting. Some General Service accounts are energy(kWh)-billed, and some are demand(kW)-billed. Further servicing details are available in the utility's Conditions of Service.

Unmetered Scattered Load
This classification refers to certain instances where connections can be provided without metering. These loads are generally small in size and consistent in magnitude of load. Hydro One reserves the right to review all cases and may require that a meter be installed at its sole discretion. Services that can be unmetered include cable TV amplifiers, telephone switching devices, phone booths, bus shelters, rail way crossing signals, traffic signals, and other small fixed loads.
Further servicing details are available in the utility's Conditions of Service (including in the "Unmetered Connections" section).

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Thorndale Hydro Electric Commission
Effective Date: May 1, 2008

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

Street Lighting

This classification refers to accounts for the distribution and supply of electrical energy for street lighting. Street lights are devices owned by or operated for the road authority and/or the municipal corporation. These street lights in fact belong to the Street Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Sentinel Lighting

This classification refers to accounts for a separate service to a sentinel light. These sentinel lights in fact belong to the Sentinel Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Urban Density Classification

Customers who meet the Urban Density Criteria of being in an area containing 3,000 or more customers with a line density of at least 60 customers per kilometre, will be mapped to an Urban customer classification.

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
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Effective Date: May 1, 2008

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MONTHLY RATES AND CHARGES

Residential - R1 Thorndale

Service Charge	$	7.68
Distribution Volumetric Rate	$ / kWh	0.0200
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0032
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0004)
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0047
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0046
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service Less Than 50 kW (Energy-Billed) - GSe Thorndale

Service Charge	$	18.46
Distribution Volumetric Rate	$ / kWh	0.0238
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0032
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0006)
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0035
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0032
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service 50 kW or Greater (Demand-Billed) - GSd Thorndale

Service Charge	$	22.06
Distribution Volumetric Rate	$ / kW	9.22
Regulatory Asset Recovery - Rider #2	$ / kW	1.03
Regulatory Asset Recovery - Rider #3	$ / kW	(0.22)
Retail Transmission Rate - Network Service Rate (4)	$ / kW	1.11
Retail Transmission Rate - Line and Transformation Connection Service Rate (4)	$ / kW	1.00
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

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This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

Unmetered, Scattered Load

Service Charge	$	10.68
Distribution Volumetric Rate	$ / kWh	0.0200
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0032
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0006)
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0035
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0032
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

(3) For energy-only metered customers, the billing determinant is the customer's metered energy consumption adjusted by the total loss factor as approved by the Board for Acquired LDC customers.
(4) For demand billed customers, appropriate loss factors must be applied to the applicable tariffs. Also the billing determinant for the Line and Transformation Connection Services rate is the customer's peak demand in the billing period. The billing determinant for the Network Services rate is: for non-interval-metered customers, the peak demand in the billing period, and for interval-metered customers, the peak demand between 7 AM and 7 PM local time on IESO business days

Customer-Supplied Transformation Allowance

Applicable to customers providing their own transformers

Demand-billed	$ / kW	0.60
Energy-billed	$ / kWh	0.0014

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Loss Factors

Residential	1.085
General Service Less Than 50 kW (Energy-Billed)	1.092
General Service 50 kW or Greater (Demand-Billed)	1.061
Unmetered Scattered Load	1.092

Transformer Loss Allowance

Applicable to customers requiring a billing adjustment for transformer losses as the result of being metered on the primary side of a transformer. The following uniform values shall be applied to measured demand and energy to calculate transformer losses for voltages up to and including 50 kV (as metered on the primary side):

(a) 1.5% for transformer installations up to an individual bank capacity of 400 kVA,
(b) 1.0% for bank capacities over 400 kVA.

Alternatively, transformer losses may be determined from transformer test data, and measured demand and energy adjusted accordingly

For services which are not demand metered, an assumed demand of 50% of the transformer capacity will be used to calculate the loss allowance. Where several transformers are involved, the bank capacity is assumed to be the arithmetic sum of all transformer capacities

Hydro One Networks Inc.
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Thorndale Hydro Electric Commission
Effective Date: May 1, 2008

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

MISCELLANEOUS CHARGES

Specific Service Charges: Standard Amounts

Rate Code	Specific Service Charge - Standard Name	Calculation Method			
		2006 Rate Handbook	Standard Formula	Other Formula	Time and Materials
1	Temporary Service	$500			
2	Dispute Meter Test	$30 plus Measurement Canada fees			
3	Collection of account – no disconnection/load limiter	$30			
4	Collection/Disconnect/load limiter/reconnect (at meter) trip – regular hours	$65			
5	Collection/Disconnect/load limiter/reconnect (at meter) trip – after regular hours	$185			
6	Collection/Disconnect/load limiter/reconnect (at pole) trip – regular hours	$185			
7	Collection/Disconnect/load limiter/reconnect (at pole) trip – after regular hours	$415			
8	Account Set-up Charge	$30			
9	Arrears Certificate	$15			
10	NSF Cheque Charge	$15 + bank charges			
11	Easement Charge for Unregistered Rights	$15			
12	Late Payment Charge	1.5%/month			
13a	Retailer Services – Establishing Service Agreements (refer to Handbook for all charges)	$100/agreement/Retailer +$20/month/Retailer +$0.50/month/customer + other			
13b	Retailer Services – Other (includes Bill Ready for Retailers and Service Transactions Requests) as per the Handbook, Chapter 12	$0.30/month/customer + $0.25/request for request fee + $0.50/request for process fee			
14	Special Meter Reads	$30			
15	Service Layout Fee – Basic		$495		
16	Service Layout Fee – Complex		$690		
17	Crossing Application – Pipeline		$2,445		
18	Crossing Application – Water		$3,045		
19	Crossing Application – Railroad		$2,945		
20	Line Staking – per meter		$3.70		
21	Central Metering – New service < 45 kW		$115		
22	Conversion to Central Metering < 45 kW		$915		
23	Conversion to Central Metering > 45 kW		$800		
24	Tingle Voltage Test – In Excess of 4 Hours (per hour – average 2 additional hours)		$125		
25	Standby Administration Charge per month		$440		
26	Sentinel Lights Rental Rate per month			$7.10	
27	Sentinel Pole Rental Rate per month			$4.15	
28	Joint Use for Cable and Telecom companies per pole			$22.35	
29	Joint Use for LDCs per pole			$28.61	

Hydro One Networks Inc.
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This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

APPLICATION

The application of these rates and charges shall be in accordance with The Licence of The Distributor and any Codes, Guidelines or Orders of The Board, and amendments thereto as approved by The Board, which may be applicable to the administration of this schedule.
No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code, Guideline or Order of the Board, and amendments thereto as approved by the Board, or as specified herein
This schedule does not contain any rates and charges relating to the electricity commodity (e.g. the Regulated Price Plan).

EFFECTIVE DATES

DISTRIBUTION RATES - May 1, 2007 for all consumption or deemed consumption services used on or after that date.

MISCELLANEOUS CHARGES - May 1, 2007 for all charges billed to customers on or after that date.
RETAIL TRANSMISSION RATES - May 1, 2007 for all consumption or deemed consumption services used on or after that date.
LOSS FACTOR ADJUSTMENT – May 1, 2007

SERVICE CLASSIFICATIONS

Residential
This classification (note 1) refers to all service supplied to single-family dwelling units for domestic or household purpose. Multi-unit residential establishments such as apartment buildings supplied through one service (bulk metered) will normally be classified as General Service, but, at Hydro One's discretion, up to four residential units may be classified as residential. Where electricity service is provided to combined residential and business (including agricultural usage) and the wiring does not provide for separate metering, the classification shall be at the discretion of Hydro One based on such considerations as the estimated predominant consumption.
Further servicing details are available in the utility's Conditions of Service.

General Service
This classification (note 1) refers to all service supplied to premises other than those classified as Residential or Lighting. Some General Service accounts are energy(kWh)-billed, and some are demand(kW)-billed. Further servicing details are available in the utility's Conditions of Service. Also, see note 2.

Unmetered Scattered Load
This classification refers to certain instances where connections can be provided without metering. These loads are generally small in size and consistent in magnitude of load. Hydro One reserves the right to review all cases and may require that a meter be installed at its sole discretion. Services that can be unmetered include cable TV amplifiers, telephone switching devices, phone booths, bus shelters, rail way crossing signals, traffic signals, and other small fixed loads.
Further servicing details are available in the utility's Conditions of Service (including in the "Unmetered Connections" section).

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Street Lighting

This classification refers to accounts for the distribution and supply of electrical energy for street lighting. Street lights are devices owned by or operated for the road authority and/or the municipal corporation. These street lights in fact belong to the Street Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Sentinel Lighting

This classification refers to accounts for a separate service to a sentinel light. These sentinel lights in fact belong to the Sentinel Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Interim Demand-Side Management Time-of-Use

This is potentially applicable to Demand-billed General Service accounts. See Note 2 below.

Note (1): Classification descriptions are paraphrases from the document "Hydro One Networks Inc. - Distribution Customers Conditions of Service - August 2004"

Note (2):

Interim Demand-Side Management Time-of-Use Rates: demand charges will be based on demand during the on-peak periods.

Criteria: Customers' electricity consumption (kW) in the off-peak period is at least twice the electricity consumption (kW) during the on-peak period.

Definition of Time Periods: The on-peak hours will be between 0700 hours to 1900 hours Eastern Standard Time during the winter (standard time) on IESO business days and 0600 hours to 1800 hours Eastern Standard Time during the summer (daylight savings time) on IESO business days. The off-peak period constitutes all of the remaining hours.

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MONTHLY RATES AND CHARGES

Residential

Service Charge	$	4.32
Distribution Volumetric Rate	$ / kWh	0.0088
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0062
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0032
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0055
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0047
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service - Energy Billed (less than 50 kW)

Service Charge	$	14.52
Distribution Volumetric Rate	$ / kWh	0.0102
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0052
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0032
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0050
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0043
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service - Demand Billed (50 kW or greater)

Service Charge	$	14.52
Distribution Volumetric Rate	$ / kW	3.25
Regulatory Asset Recovery - Rider #1	$ / kW	1.67
Regulatory Asset Recovery - Rider #2	$ / kW	1.03
Retail Transmission Rate - Network Service Rate (4)	$ / kW	1.94
Retail Transmission Rate - Line and Transformation Connection Service Rate (4)	$ / kW	1.61
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

Hydro One Networks Inc.
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Unmetered, Scattered Load

Service Charge	$	6.79
Distribution Volumetric Rate	$ / kWh	0.0102
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0052
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0032
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0050
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0043
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

(3) For energy-only metered customers, the billing determinant is the customer’s metered energy consumption adjusted by the total loss factor as approved by the Board for Acquired LDC customers.

(4) For demand billed customers, appropriate loss factors must be applied to the applicable tariffs. Also the billing determinant for the Line and Transformation Connection Services rate is the customer’s peak demand in the billing period. The billing determinant for the Network Services rate is: for non-interval-metered customers, the peak demand in the billing period, and for interval-metered customers, the peak demand between 7 AM and 7 PM local time on IESO business days

Interim Demand-Side Management Time-of-Use

See the "Service Classifications" section of this schedule.

Customer-Supplied Transformation Allowance

Applicable to demand-billed customers providing their own transformers
Primary Voltage under 50 kV (per kW)

Single Phase	$ / kW	0.20
Three Phase	$ / kW	0.60

Hydro One Networks Inc.
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Loss Factors

Supply Facilities Loss Factor	1.0045
Distribution Loss Factors	
Customer less than 5,000 kW	1.0500
Customer greater than or equal to 5,000 kW	1.0100
Total Loss Factors	
Customer less than 5,000 kW	1.0545
Customer greater than or equal to 5,000 kW	1.0145

Transformer Loss Allowance

Applicable to customers requiring a billing adjustment for transformer losses as the result of being metered on the primary side of a transformer. The following uniform values shall be applied to measured demand and energy to calculate transformer losses for voltages up to and including 50 kV (as metered on the primary side):

(a) 1.5% for transformer installations up to an individual bank capacity of 400 kVA,
(b) 1.0% for bank capacities over 400 kVA.

Alternatively, transformer losses may be determined from transformer test data, and measured demand and energy adjusted accordingly

For services which are not demand metered, an assumed demand of 50% of the transformer capacity will be used to calculate the loss allowance. Where several transformers are involved, the bank capacity is assumed to be the arithmetic sum of all transformer capacities

Hydro One Networks Inc.
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Effective Date: May 1, 2007

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

MISCELLANEOUS CHARGES

Specific Service Charges: Standard Amounts

Rate Code	Specific Service Charge - Standard Name	Calculation Method			
		2006 Rate Handbook	Standard Formula	Other Formula	Time and Materials
1	Temporary Service	$500			
2	Dispute Meter Test	$30 plus Measurement Canada fees			
3	Collection of account – no disconnection/load limiter	$30			
4	Collection/Disconnect/load limiter/reconnect (at meter) trip – regular hours	$65			
5	Collection/Disconnect/load limiter/reconnect (at meter) trip – after regular hours	$185			
6	Collection/Disconnect/load limiter/reconnect (at pole) trip – regular hours	$185			
7	Collection/Disconnect/load limiter/reconnect (at pole) trip – after regular hours	$415			
8	Account Set-up Charge	$30			
9	Arrears Certificate	$15			
10	NSF Cheque Charge	$15 + bank charges			
11	Easement Charge for Unregistered Rights	$15			
12	Late Payment Charge	1.5%/month			
13a	Retailer Services – Establishing Service Agreements (refer to Handbook for all charges)	$100/agreement/Retailer +$20/month/Retailer +$0.50/month/customer + other			
13b	Retailer Services – Other (includes Bill Ready for Retailers and Service Transactions Requests) as per the Handbook, Chapter 12	$0.30/month/customer + $0.25/request for request fee + $0.50/request for process fee			
14	Special Meter Reads	$30			
15	Billing Suspension and Terminations in Trailer Parks		$130		
16	Service Layout Fee – Basic		$405		
17	Service Layout Fee – Complex		$580		

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Thorndale Hydro Electric Commission
Effective Date: May 1, 2007

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

18	Crossing Application – Pipeline		$2,065		
19	Crossing Application – Water		$2,525		
20	Crossing Application – Railroad		$2,565		
21	Line Staking – per meter		$3.10		
22	Central Metering – New service < 45 kW		$115		
23	Conversion to Central Metering < 45 kW		$795		
24	Conversion to Central Metering > 45 kW		$680		
25	Tingle Voltage Test – In Excess of 4 Hours (per hour – average 2 additional hours)		$105		
26	Standby Administration Charge per month (interim)		$375		
27	Sentinel Lights Rental Rate per month – Mercury Vapor			$7.00	
28	Guaranteed Units from Jan 01/91 to Aug 01/91			$26.50 / month	
29	Guaranteed Units from Jan 01/87 to Dec 31/90			$23.50 / month	
30	Joint Use for Cable and Telecom companies per pole			$22.35	
31	Joint Use for LDCs per pole			$28.61	

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Thorold Hydro Electric Commission
Effective Date: May 1, 2008

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

APPLICATION

The application of these rates and charges shall be in accordance with The Licence of The Distributor and any Codes, Guidelines or Orders of The Board, and amendments thereto as approved by The Board, which may be applicable to the administration of this schedule.
No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code, Guideline or Order of the Board, and amendments thereto as approved by the Board, or as specified herein
This schedule does not contain any rates and charges relating to the electricity commodity (e.g. the Regulated Price Plan).

EFFECTIVE DATES

DISTRIBUTION RATES - May 1, 2008 for all consumption or deemed consumption services used on or after that date.

MISCELLANEOUS CHARGES - May 1, 2008 for all charges billed to customers on or after that date.
RETAIL TRANSMISSION RATES - May 1, 2008 for all consumption or deemed consumption services used on or after that date.
LOSS FACTOR ADJUSTMENT – for all consumption or deemed consumption services billed following May 1, 2008 or later

SERVICE CLASSIFICATIONS

Residential
This classification refers to all service supplied to single-family dwelling units for domestic or household purpose. Multi-unit residential establishments such as apartment buildings supplied through one service (bulk metered) will normally be classified as General Service, but, at Hydro One's discretion, up to four residential units may be classified as residential. Where electricity service is provided to combined residential and business (including agricultural usage) and the wiring does not provide for separate metering, the classification shall be at the discretion of Hydro One based on such considerations as the estimated predominant consumption.
Further servicing details are available in the utility's Conditions of Service.

General Service
This classification refers to all service supplied to premises other than those classified as Residential or Lighting. Some General Service accounts are energy(kWh)-billed, and some are demand(kW)-billed. Further servicing details are available in the utility's Conditions of Service.

Unmetered Scattered Load
This classification refers to certain instances where connections can be provided without metering. These loads are generally small in size and consistent in magnitude of load. Hydro One reserves the right to review all cases and may require that a meter be installed at its sole discretion. Services that can be unmetered include cable TV amplifiers, telephone switching devices, phone booths, bus shelters, rail way crossing signals, traffic signals, and other small fixed loads.
Further servicing details are available in the utility's Conditions of Service (including in the "Unmetered Connections" section).

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Thorold Hydro Electric Commission
Effective Date: May 1, 2008

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

Street Lighting

This classification refers to accounts for the distribution and supply of electrical energy for street lighting. Street lights are devices owned by or operated for the road authority and/or the municipal corporation. These street lights in fact belong to the Street Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Sentinel Lighting

This classification refers to accounts for a separate service to a sentinel light. These sentinel lights in fact belong to the Sentinel Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Urban Density Classification

Customers who meet the Urban Density Criteria of being in an area containing 3,000 or more customers with a line density of at least 60 customers per kilometre, will be mapped to an Urban customer classification.

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Thorold Hydro Electric Commission
Effective Date: May 1, 2008

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

MONTHLY RATES AND CHARGES

Residential - UR/R1 Thorold

Service Charge	$	13.16
Distribution Volumetric Rate	$ / kWh	0.0240
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0014
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0002)
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0047
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0045
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service Less Than 50 kW (Energy-Billed) - UGe/GSe Thorold

Service Charge	$	19.43
Distribution Volumetric Rate	$ / kWh	0.0200
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0006
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0006)
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0036
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0033
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service 50 kW or Greater (Demand-Billed) - UGd/GSd Thorold

Service Charge	$	23.64
Distribution Volumetric Rate	$ / kW	7.33
Regulatory Asset Recovery - Rider #2	$ / kW	0.20
Regulatory Asset Recovery - Rider #3	$ / kW	(0.27)
Retail Transmission Rate - Network Service Rate (4)	$ / kW	1.41
Retail Transmission Rate - Line and Transformation Connection Service Rate (4)	$ / kW	1.27
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Thorold Hydro Electric Commission
Effective Date: May 1, 2008

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

Unmetered, Scattered Load

Service Charge	$	13.67
Distribution Volumetric Rate	$ / kWh	0.0200
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0006
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0006)
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0035
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0032
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

(3) For energy-only metered customers, the billing determinant is the customer's metered energy consumption adjusted by the total loss factor as approved by the Board for Acquired LDC customers.
(4) For demand billed customers, appropriate loss factors must be applied to the applicable tariffs. Also the billing determinant for the Line and Transformation Connection Services rate is the customer's peak demand in the billing period. The billing determinant for the Network Services rate is: for non-interval-metered customers, the peak demand in the billing period, and for interval-metered customers, the peak demand between 7 AM and 7 PM local time on IESO business days

Customer-Supplied Transformation Allowance

Applicable to customers providing their own transformers		
Demand-billed	$ / kW	0.60
Energy-billed	$ / kWh	0.0014

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Thorold Hydro Electric Commission
Effective Date: May 1, 2008

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

Loss Factors

Residential	1.078
General Service Less Than 50 kW (Energy-Billed)	1.092
General Service 50 kW or Greater (Demand-Billed)	1.061
Unmetered Scattered Load	1.092

Transformer Loss Allowance

Applicable to customers requiring a billing adjustment for transformer losses as the result of being metered on the primary side of a transformer. The following uniform values shall be applied to measured demand and energy to calculate transformer losses for voltages up to and including 50 kV (as metered on the primary side):

(a) 1.5% for transformer installations up to an individual bank capacity of 400 kVA,

(b) 1.0% for bank capacities over 400 kVA.

Alternatively, transformer losses may be determined from transformer test data, and measured demand and energy adjusted accordingly

For services which are not demand metered, an assumed demand of 50% of the transformer capacity will be used to calculate the loss allowance. Where several transformers are involved, the bank capacity is assumed to be the arithmetic sum of all transformer capacities

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Thorold Hydro Electric Commission
Effective Date: May 1, 2008

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

MISCELLANEOUS CHARGES

Specific Service Charges: Standard Amounts

Rate Code	Specific Service Charge - Standard Name	Calculation Method			
		2006 Rate Handbook	Standard Formula	Other Formula	Time and Materials
1	Temporary Service	$500			
2	Dispute Meter Test	$30 plus Measurement Canada fees			
3	Collection of account – no disconnection/load limiter	$30			
4	Collection/Disconnect/load limiter/reconnect (at meter) trip – regular hours	$65			
5	Collection/Disconnect/load limiter/reconnect (at meter) trip – after regular hours	$185			
6	Collection/Disconnect/load limiter/reconnect (at pole) trip – regular hours	$185			
7	Collection/Disconnect/load limiter/reconnect (at pole) trip – after regular hours	$415			
8	Account Set-up Charge	$30			
9	Arrears Certificate	$15			
10	NSF Cheque Charge	$15 + bank charges			
11	Easement Charge for Unregistered Rights	$15			
12	Late Payment Charge	1.5%/month			
13a	Retailer Services – Establishing Service Agreements (refer to Handbook for all charges)	$100/agreement/Retailer +$20/month/Retailer +$0.50/month/customer + other			
13b	Retailer Services – Other (includes Bill Ready for Retailers and Service Transactions Requests) as per the Handbook, Chapter 12	$0.30/month/customer + $0.25/request for request fee + $0.50/request for process fee			
14	Special Meter Reads	$30			
15	Service Layout Fee – Basic		$495		
16	Service Layout Fee – Complex		$690		
17	Crossing Application – Pipeline		$2,445		
18	Crossing Application – Water		$3,045		
19	Crossing Application – Railroad		$2,945		
20	Line Staking – per meter		$3.70		
21	Central Metering – New service < 45 kW		$115		
22	Conversion to Central Metering < 45 kW		$915		
23	Conversion to Central Metering > 45 kW		$800		
24	Tingle Voltage Test – In Excess of 4 Hours (per hour – average 2 additional hours)		$125		
25	Standby Administration Charge per month		$440		
26	Sentinel Lights Rental Rate per month			$7.10	
27	Sentinel Pole Rental Rate per month			$4.15	
28	Joint Use for Cable and Telecom companies per pole			$22.35	
29	Joint Use for LDCs per pole			$28.61	

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Thorold Hydro Electric Commission
Effective Date: May 1, 2007

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

APPLICATION

The application of these rates and charges shall be in accordance with The Licence of The Distributor and any Codes, Guidelines or Orders of The Board, and amendments thereto as approved by The Board, which may be applicable to the administration of this schedule.
No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code, Guideline or Order of the Board, and amendments thereto as approved by the Board, or as specified herein
This schedule does not contain any rates and charges relating to the electricity commodity (e.g. the Regulated Price Plan).

EFFECTIVE DATES

DISTRIBUTION RATES - May 1, 2007 for all consumption or deemed consumption services used on or after that date.

MISCELLANEOUS CHARGES - May 1, 2007 for all charges billed to customers on or after that date.
RETAIL TRANSMISSION RATES - May 1, 2007 for all consumption or deemed consumption services used on or after that date.
LOSS FACTOR ADJUSTMENT – May 1, 2007

SERVICE CLASSIFICATIONS

Residential
This classification (note 1) refers to all service supplied to single-family dwelling units for domestic or household purpose. Multi-unit residential establishments such as apartment buildings supplied through one service (bulk metered) will normally be classified as General Service, but, at Hydro One’s discretion, up to four residential units may be classified as residential. Where electricity service is provided to combined residential and business (including agricultural usage) and the wiring does not provide for separate metering, the classification shall be at the discretion of Hydro One based on such considerations as the estimated predominant consumption.
Further servicing details are available in the utility’s Conditions of Service.

General Service
This classification (note 1) refers to all service supplied to premises other than those classified as Residential or Lighting. Some General Service accounts are energy(kWh)-billed, and some are demand(kW)-billed. Further servicing details are available in the utility’s Conditions of Service. Also, see note 2.

Unmetered Scattered Load
This classification refers to certain instances where connections can be provided without metering. These loads are generally small in size and consistent in magnitude of load. Hydro One reserves the right to review all cases and may require that a meter be installed at its sole discretion. Services that can be unmetered include cable TV amplifiers, telephone switching devices, phone booths, bus shelters, rail way crossing signals, traffic signals, and other small fixed loads.
Further servicing details are available in the utility’s Conditions of Service (including in the "Unmetered Connections" section).

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Thorold Hydro Electric Commission
Effective Date: May 1, 2007

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

Street Lighting

This classification refers to accounts for the distribution and supply of electrical energy for street lighting. Street lights are devices owned by or operated for the road authority and/or the municipal corporation. These street lights in fact belong to the Street Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Sentinel Lighting

This classification refers to accounts for a separate service to a sentinel light. These sentinel lights in fact belong to the Sentinel Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Interim Demand-Side Management Time-of-Use

This is potentially applicable to Demand-billed General Service accounts. See Note 2 below.

Note (1): Classification descriptions are paraphrases from the document "Hydro One Networks Inc. - Distribution Customers Conditions of Service - August 2004"

Note (2):

Interim Demand-Side Management Time-of-Use Rates: demand charges will be based on demand during the on-peak periods.

Criteria: Customers' electricity consumption (kW) in the off-peak period is at least twice the electricity consumption (kW) during the on-peak period.

Definition of Time Periods: The on-peak hours will be between 0700 hours to 1900 hours Eastern Standard Time during the winter (standard time) on IESO business days and 0600 hours to 1800 hours Eastern Standard Time during the summer (daylight savings time) on IESO business days. The off-peak period constitutes all of the remaining hours.

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Thorold Hydro Electric Commission
Effective Date: May 1, 2007

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

MONTHLY RATES AND CHARGES

Residential

Service Charge	$	13.68
Distribution Volumetric Rate	$ / kWh	0.0147
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0041
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0014
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0055
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0047
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service - Energy Billed (less than 50 kW)

Service Charge	$	22.63
Distribution Volumetric Rate	$ / kWh	0.0150
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0015
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0006
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0050
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0043
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service - Demand Billed (50 kW or greater)

Service Charge	$	22.63
Distribution Volumetric Rate	$ / kW	4.76
Regulatory Asset Recovery - Rider #1	$ / kW	0.46
Regulatory Asset Recovery - Rider #2	$ / kW	0.20
Retail Transmission Rate - Network Service Rate (4)	$ / kW	1.94
Retail Transmission Rate - Line and Transformation Connection Service Rate (4)	$ / kW	1.61
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Thorold Hydro Electric Commission
Effective Date: May 1, 2007

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

Unmetered, Scattered Load

Service Charge	$	10.85
Distribution Volumetric Rate	$ / kWh	0.0150
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0015
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0006
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0050
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0043
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

(3) For energy-only metered customers, the billing determinant is the customer’s metered energy consumption adjusted by the total loss factor as approved by the Board for Acquired LDC customers.
(4) For demand billed customers, appropriate loss factors must be applied to the applicable tariffs. Also the billing determinant for the Line and Transformation Connection Services rate is the customer’s peak demand in the billing period. The billing determinant for the Network Services rate is: for non-interval-metered customers, the peak demand in the billing period, and for interval-metered customers, the peak demand between 7 AM and 7 PM local time on IESO business days

Interim Demand-Side Management Time-of-Use

See the "Service Classifications" section of this schedule.

Customer-Supplied Transformation Allowance

Applicable to demand-billed customers providing their own transformers
Primary Voltage under 50 kV (per kW)

Single Phase	$ / kW	0.20
Three Phase	$ / kW	0.60

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Thorold Hydro Electric Commission
Effective Date: May 1, 2007

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

Loss Factors

Supply Facilities Loss Factor	1.0045
Distribution Loss Factors	
Customer less than 5,000 kW	1.0500
Customer greater than or equal to 5,000 kW	1.0100
Total Loss Factors	
Customer less than 5,000 kW	1.0545
Customer greater than or equal to 5,000 kW	1.0145

Transformer Loss Allowance

Applicable to customers requiring a billing adjustment for transformer losses as the result of being metered on the primary side of a transformer. The following uniform values shall be applied to measured demand and energy to calculate transformer losses for voltages up to and including 50 kV (as metered on the primary side):

(a) 1.5% for transformer installations up to an individual bank capacity of 400 kVA,
(b) 1.0% for bank capacities over 400 kVA.

Alternatively, transformer losses may be determined from transformer test data, and measured demand and energy adjusted accordingly

For services which are not demand metered, an assumed demand of 50% of the transformer capacity will be used to calculate the loss allowance. Where several transformers are involved, the bank capacity is assumed to be the arithmetic sum of all transformer capacities

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Thorold Hydro Electric Commission
Effective Date: May 1, 2007

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

MISCELLANEOUS CHARGES

Specific Service Charges: Standard Amounts

Rate Code	Specific Service Charge - Standard Name	Calculation Method			
		2006 Rate Handbook	Standard Formula	Other Formula	Time and Materials
1	Temporary Service	$500			
2	Dispute Meter Test	$30 plus Measurement Canada fees			
3	Collection of account – no disconnection/load limiter	$30			
4	Collection/Disconnect/load limiter/reconnect (at meter) trip – regular hours	$65			
5	Collection/Disconnect/load limiter/reconnect (at meter) trip – after regular hours	$185			
6	Collection/Disconnect/load limiter/reconnect (at pole) trip – regular hours	$185			
7	Collection/Disconnect/load limiter/reconnect (at pole) trip – after regular hours	$415			
8	Account Set-up Charge	$30			
9	Arrears Certificate	$15			
10	NSF Cheque Charge	$15 + bank charges			
11	Easement Charge for Unregistered Rights	$15			
12	Late Payment Charge	1.5%/month			
13a	Retailer Services – Establishing Service Agreements (refer to Handbook for all charges)	$100/agreement/Retailer +$20/month/Retailer +$0.50/month/customer + other			
13b	Retailer Services – Other (includes Bill Ready for Retailers and Service Transactions Requests) as per the Handbook, Chapter 12	$0.30/month/customer + $0.25/request for request fee + $0.50/request for process fee			
14	Special Meter Reads	$30			
15	Billing Suspension and Terminations in Trailer Parks		$130		
16	Service Layout Fee – Basic		$405		
17	Service Layout Fee – Complex		$580		

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Thorold Hydro Electric Commission
Effective Date: May 1, 2007

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

18	Crossing Application – Pipeline		$2,065		
19	Crossing Application – Water		$2,525		
20	Crossing Application – Railroad		$2,565		
21	Line Staking – per meter		$3.10		
22	Central Metering – New service < 45 kW		$115		
23	Conversion to Central Metering < 45 kW		$795		
24	Conversion to Central Metering > 45 kW		$680		
25	Tingle Voltage Test – In Excess of 4 Hours (per hour – average 2 additional hours)		$105		
26	Standby Administration Charge per month (interim)		$375		
27	Sentinel Lights Rental Rate per month – Mercury Vapor			$7.00	
28	Guaranteed Units from Jan 01/91 to Aug 01/91			$26.50 / month	
29	Guaranteed Units from Jan 01/87 to Dec 31/90			$23.50 / month	
30	Joint Use for Cable and Telecom companies per pole			$22.35	
31	Joint Use for LDCs per pole			$28.61	

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Tweed Hydro Electric Commission
Effective Date: May 1, 2008

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

APPLICATION

The application of these rates and charges shall be in accordance with The Licence of The Distributor and any Codes, Guidelines or Orders of The Board, and amendments thereto as approved by The Board, which may be applicable to the administration of this schedule.
No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code, Guideline or Order of the Board, and amendments thereto as approved by the Board, or as specified herein
This schedule does not contain any rates and charges relating to the electricity commodity (e.g. the Regulated Price Plan).

EFFECTIVE DATES

DISTRIBUTION RATES - May 1, 2008 for all consumption or deemed consumption services used on or after that date.

MISCELLANEOUS CHARGES - May 1, 2008 for all charges billed to customers on or after that date.
RETAIL TRANSMISSION RATES - May 1, 2008 for all consumption or deemed consumption services used on or after that date.
LOSS FACTOR ADJUSTMENT – for all consumption or deemed consumption services billed following May 1, 2008 or later

SERVICE CLASSIFICATIONS

Residential
This classification refers to all service supplied to single-family dwelling units for domestic or household purpose. Multi-unit residential establishments such as apartment buildings supplied through one service (bulk metered) will normally be classified as General Service, but, at Hydro One's discretion, up to four residential units may be classified as residential. Where electricity service is provided to combined residential and business (including agricultural usage) and the wiring does not provide for separate metering, the classification shall be at the discretion of Hydro One based on such considerations as the estimated predominant consumption.
Further servicing details are available in the utility's Conditions of Service.

General Service
This classification refers to all service supplied to premises other than those classified as Residential or Lighting. Some General Service accounts are energy(kWh)-billed, and some are demand(kW)-billed. Further servicing details are available in the utility's Conditions of Service.

Unmetered Scattered Load
This classification refers to certain instances where connections can be provided without metering. These loads are generally small in size and consistent in magnitude of load. Hydro One reserves the right to review all cases and may require that a meter be installed at its sole discretion. Services that can be unmetered include cable TV amplifiers, telephone switching devices, phone booths, bus shelters, rail way crossing signals, traffic signals, and other small fixed loads.
Further servicing details are available in the utility's Conditions of Service (including in the "Unmetered Connections" section).

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Tweed Hydro Electric Commission
Effective Date: May 1, 2008

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

Street Lighting

This classification refers to accounts for the distribution and supply of electrical energy for street lighting. Street lights are devices owned by or operated for the road authority and/or the municipal corporation. These street lights in fact belong to the Street Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Sentinel Lighting

This classification refers to accounts for a separate service to a sentinel light. These sentinel lights in fact belong to the Sentinel Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Urban Density Classification

Customers who meet the Urban Density Criteria of being in an area containing 3,000 or more customers with a line density of at least 60 customers per kilometre, will be mapped to an Urban customer classification.

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Tweed Hydro Electric Commission
Effective Date: May 1, 2008

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MONTHLY RATES AND CHARGES

Residential - R1 Tweed

Service Charge	$	7.64
Distribution Volumetric Rate	$ / kWh	0.0210
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0037
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0004)
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0047
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0046
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service Less Than 50 kW (Energy-Billed) - GSe Tweed

Service Charge	$	14.03
Distribution Volumetric Rate	$ / kWh	0.0210
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0031
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0006)
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0035
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0032
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service 50 kW or Greater (Demand-Billed) - GSd Tweed

Service Charge	$	17.62
Distribution Volumetric Rate	$ / kW	8.80
Regulatory Asset Recovery - Rider #2	$ / kW	0.99
Regulatory Asset Recovery - Rider #3	$ / kW	(0.22)
Retail Transmission Rate - Network Service Rate (4)	$ / kW	1.11
Retail Transmission Rate - Line and Transformation Connection Service Rate (4)	$ / kW	1.00
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

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Unmetered, Scattered Load

Service Charge	$	8.46
Distribution Volumetric Rate	$ / kWh	0.0200
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0031
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0006)
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0035
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0032
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

(3) For energy-only metered customers, the billing determinant is the customer's metered energy consumption adjusted by the total loss factor as approved by the Board for Acquired LDC customers.
(4) For demand billed customers, appropriate loss factors must be applied to the applicable tariffs. Also the billing determinant for the Line and Transformation Connection Services rate is the customer's peak demand in the billing period. The billing determinant for the Network Services rate is: for non-interval-metered customers, the peak demand in the billing period, and for interval-metered customers, the peak demand between 7 AM and 7 PM local time on IESO business days

Customer-Supplied Transformation Allowance

Applicable to customers providing their own transformers

Demand-billed	$ / kW	0.60
Energy-billed	$ / kWh	0.0014

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Loss Factors

Residential	1.085
General Service Less Than 50 kW (Energy-Billed)	1.092
General Service 50 kW or Greater (Demand-Billed)	1.061
Unmetered Scattered Load	1.092

Transformer Loss Allowance

Applicable to customers requiring a billing adjustment for transformer losses as the result of being metered on the primary side of a transformer. The following uniform values shall be applied to measured demand and energy to calculate transformer losses for voltages up to and including 50 kV (as metered on the primary side):

(a) 1.5% for transformer installations up to an individual bank capacity of 400 kVA,
(b) 1.0% for bank capacities over 400 kVA.

Alternatively, transformer losses may be determined from transformer test data, and measured demand and energy adjusted accordingly

For services which are not demand metered, an assumed demand of 50% of the transformer capacity will be used to calculate the loss allowance. Where several transformers are involved, the bank capacity is assumed to be the arithmetic sum of all transformer capacities

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MISCELLANEOUS CHARGES

Specific Service Charges: Standard Amounts

Rate Code	Specific Service Charge - Standard Name	Calculation Method			
		2006 Rate Handbook	Standard Formula	Other Formula	Time and Materials
1	Temporary Service	$500			
2	Dispute Meter Test	$30 plus Measurement Canada fees			
3	Collection of account – no disconnection/load limiter	$30			
4	Collection/Disconnect/load limiter/reconnect (at meter) trip – regular hours	$65			
5	Collection/Disconnect/load limiter/reconnect (at meter) trip – after regular hours	$185			
6	Collection/Disconnect/load limiter/reconnect (at pole) trip – regular hours	$185			
7	Collection/Disconnect/load limiter/reconnect (at pole) trip – after regular hours	$415			
8	Account Set-up Charge	$30			
9	Arrears Certificate	$15			
10	NSF Cheque Charge	$15 + bank charges			
11	Easement Charge for Unregistered Rights	$15			
12	Late Payment Charge	1.5%/month			
13a	Retailer Services – Establishing Service Agreements (refer to Handbook for all charges)	$100/agreement/Retailer +$20/month/Retailer +$0.50/month/customer + other			
13b	Retailer Services – Other (includes Bill Ready for Retailers and Service Transactions Requests) as per the Handbook, Chapter 12	$0.30/month/customer + $0.25/request for request fee + $0.50/request for process fee			
14	Special Meter Reads	$30			
15	Service Layout Fee – Basic		$495		
16	Service Layout Fee – Complex		$690		
17	Crossing Application – Pipeline		$2,445		
18	Crossing Application – Water		$3,045		
19	Crossing Application – Railroad		$2,945		
20	Line Staking – per meter		$3.70		
21	Central Metering – New service < 45 kW		$115		
22	Conversion to Central Metering < 45 kW		$915		
23	Conversion to Central Metering > 45 kW		$800		
24	Tingle Voltage Test – In Excess of 4 Hours (per hour – average 2 additional hours)		$125		
25	Standby Administration Charge per month		$440		
26	Sentinel Lights Rental Rate per month			$7.10	
27	Sentinel Pole Rental Rate per month			$4.15	
28	Joint Use for Cable and Telecom companies per pole			$22.35	
29	Joint Use for LDCs per pole			$28.61	

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
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Tweed Hydro Electric Commission
Effective Date: May 1, 2007

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APPLICATION

The application of these rates and charges shall be in accordance with The Licence of The Distributor and any Codes, Guidelines or Orders of The Board, and amendments thereto as approved by The Board, which may be applicable to the administration of this schedule.
No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code, Guideline or Order of the Board, and amendments thereto as approved by the Board, or as specified herein
This schedule does not contain any rates and charges relating to the electricity commodity (e.g. the Regulated Price Plan).

EFFECTIVE DATES

DISTRIBUTION RATES - May 1, 2007 for all consumption or deemed consumption services used on or after that date.

MISCELLANEOUS CHARGES - May 1, 2007 for all charges billed to customers on or after that date.
RETAIL TRANSMISSION RATES - May 1, 2007 for all consumption or deemed consumption services used on or after that date.
LOSS FACTOR ADJUSTMENT – May 1, 2007

SERVICE CLASSIFICATIONS

Residential
This classification (note 1) refers to all service supplied to single-family dwelling units for domestic or household purpose. Multi-unit residential establishments such as apartment buildings supplied through one service (bulk metered) will normally be classified as General Service, but, at Hydro One’s discretion, up to four residential units may be classified as residential. Where electricity service is provided to combined residential and business (including agricultural usage) and the wiring does not provide for separate metering, the classification shall be at the discretion of Hydro One based on such considerations as the estimated predominant consumption.
Further servicing details are available in the utility’s Conditions of Service.

General Service
This classification (note 1) refers to all service supplied to premises other than those classified as Residential or Lighting. Some General Service accounts are energy(kWh)-billed, and some are demand(kW)-billed. Further servicing details are available in the utility’s Conditions of Service. Also, see note 2.

Unmetered Scattered Load
This classification refers to certain instances where connections can be provided without metering. These loads are generally small in size and consistent in magnitude of load. Hydro One reserves the right to review all cases and may require that a meter be installed at its sole discretion. Services that can be unmetered include cable TV amplifiers, telephone switching devices, phone booths, bus shelters, rail way crossing signals, traffic signals, and other small fixed loads.
Further servicing details are available in the utility’s Conditions of Service (including in the "Unmetered Connections" section).

Hydro One Networks Inc.
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Street Lighting

This classification refers to accounts for the distribution and supply of electrical energy for street lighting. Street lights are devices owned by or operated for the road authority and/or the municipal corporation. These street lights in fact belong to the Street Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Sentinel Lighting

This classification refers to accounts for a separate service to a sentinel light. These sentinel lights in fact belong to the Sentinel Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Interim Demand-Side Management Time-of-Use

This is potentially applicable to Demand-billed General Service accounts. See Note 2 below.

Note (1): Classification descriptions are paraphrases from the document "Hydro One Networks Inc. - Distribution Customers Conditions of Service - August 2004"

Note (2):

Interim Demand-Side Management Time-of-Use Rates: demand charges will be based on demand during the on-peak periods.

Criteria: Customers' electricity consumption (kW) in the off-peak period is at least twice the electricity consumption (kW) during the on-peak period.

Definition of Time Periods: The on-peak hours will be between 0700 hours to 1900 hours Eastern Standard Time during the winter (standard time) on IESO business days and 0600 hours to 1800 hours Eastern Standard Time during the summer (daylight savings time) on IESO business days. The off-peak period constitutes all of the remaining hours.

Hydro One Networks Inc.
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MONTHLY RATES AND CHARGES

Residential

Service Charge	$	4.48
Distribution Volumetric Rate	$ / kWh	0.0095
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0061
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0037
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0055
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0047
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service - Energy Billed (less than 50 kW)

Service Charge	$	8.26
Distribution Volumetric Rate	$ / kWh	0.0097
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0043
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0031
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0050
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0043
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service - Demand Billed (50 kW or greater)

Service Charge	$	8.26
Distribution Volumetric Rate	$ / kW	3.11
Regulatory Asset Recovery - Rider #1	$ / kW	1.35
Regulatory Asset Recovery - Rider #2	$ / kW	0.99
Retail Transmission Rate - Network Service Rate (4)	$ / kW	1.94
Retail Transmission Rate - Line and Transformation Connection Service Rate (4)	$ / kW	1.61
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

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Unmetered, Scattered Load

Service Charge	$	3.67
Distribution Volumetric Rate	$ / kWh	0.0097
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0043
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0031
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0050
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0043
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

(3) For energy-only metered customers, the billing determinant is the customer’s metered energy consumption adjusted by the total loss factor as approved by the Board for Acquired LDC customers.
(4) For demand billed customers, appropriate loss factors must be applied to the applicable tariffs. Also the billing determinant for the Line and Transformation Connection Services rate is the customer’s peak demand in the billing period. The billing determinant for the Network Services rate is: for non-interval-metered customers, the peak demand in the billing period, and for interval-metered customers, the peak demand between 7 AM and 7 PM local time on IESO business days

Interim Demand-Side Management Time-of-Use

See the "Service Classifications" section of this schedule.

Customer-Supplied Transformation Allowance

Applicable to demand-billed customers providing their own transformers
Primary Voltage under 50 kV (per kW)

Single Phase	$ / kW	0.20
Three Phase	$ / kW	0.60

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Loss Factors

Supply Facilities Loss Factor	1.0045
Distribution Loss Factors	
Customer less than 5,000 kW	1.0500
Customer greater than or equal to 5,000 kW	1.0100
Total Loss Factors	
Customer less than 5,000 kW	1.0545
Customer greater than or equal to 5,000 kW	1.0145

Transformer Loss Allowance

Applicable to customers requiring a billing adjustment for transformer losses as the result of being metered on the primary side of a transformer. The following uniform values shall be applied to measured demand and energy to calculate transformer losses for voltages up to and including 50 kV (as metered on the primary side):

(a) 1.5% for transformer installations up to an individual bank capacity of 400 kVA,

(b) 1.0% for bank capacities over 400 kVA.

Alternatively, transformer losses may be determined from transformer test data, and measured demand and energy adjusted accordingly

For services which are not demand metered, an assumed demand of 50% of the transformer capacity will be used to calculate the loss allowance. Where several transformers are involved, the bank capacity is assumed to be the arithmetic sum of all transformer capacities

Hydro One Networks Inc.
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MISCELLANEOUS CHARGES

Specific Service Charges: Standard Amounts

Rate Code	Specific Service Charge - Standard Name	Calculation Method			
		2006 Rate Handbook	Standard Formula	Other Formula	Time and Materials
1	Temporary Service	$500			
2	Dispute Meter Test	$30 plus Measurement Canada fees			
3	Collection of account – no disconnection/load limiter	$30			
4	Collection/Disconnect/load limiter/reconnect (at meter) trip – regular hours	$65			
5	Collection/Disconnect/load limiter/reconnect (at meter) trip – after regular hours	$185			
6	Collection/Disconnect/load limiter/reconnect (at pole) trip – regular hours	$185			
7	Collection/Disconnect/load limiter/reconnect (at pole) trip – after regular hours	$415			
8	Account Set-up Charge	$30			
9	Arrears Certificate	$15			
10	NSF Cheque Charge	$15 + bank charges			
11	Easement Charge for Unregistered Rights	$15			
12	Late Payment Charge	1.5%/month			
13a	Retailer Services – Establishing Service Agreements (refer to Handbook for all charges)	$100/agreement/Retailer +$20/month/Retailer +$0.50/month/customer + other			
13b	Retailer Services – Other (includes Bill Ready for Retailers and Service Transactions Requests) as per the Handbook, Chapter 12	$0.30/month/customer + $0.25/request for request fee + $0.50/request for process fee			
14	Special Meter Reads	$30			
15	Billing Suspension and Terminations in Trailer Parks		$130		
16	Service Layout Fee – Basic		$405		
17	Service Layout Fee – Complex		$580		

Hydro One Networks Inc.

TARIFF OF RATES AND CHARGES

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Tweed Hydro Electric Commission

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18	Crossing Application – Pipeline		$2,065		
19	Crossing Application – Water		$2,525		
20	Crossing Application – Railroad		$2,565		
21	Line Staking – per meter		$3.10		
22	Central Metering – New service < 45 kW		$115		
23	Conversion to Central Metering < 45 kW		$795		
24	Conversion to Central Metering > 45 kW		$680		
25	Tingle Voltage Test – In Excess of 4 Hours (per hour – average 2 additional hours)		$105		
26	Standby Administration Charge per month (interim)		$375		
27	Sentinel Lights Rental Rate per month – Mercury Vapor			$7.00	
28	Guaranteed Units from Jan 01/91 to Aug 01/91			$26.50 / month	
29	Guaranteed Units from Jan 01/87 to Dec 31/90			$23.50 / month	
30	Joint Use for Cable and Telecom companies per pole			$22.35	
31	Joint Use for LDCs per pole			$28.61	

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
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Effective Date: May 1, 2008

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

APPLICATION

The application of these rates and charges shall be in accordance with The Licence of The Distributor and any Codes, Guidelines or Orders of The Board, and amendments thereto as approved by The Board, which may be applicable to the administration of this schedule.
No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code, Guideline or Order of the Board, and amendments thereto as approved by the Board, or as specified herein
This schedule does not contain any rates and charges relating to the electricity commodity (e.g. the Regulated Price Plan).

EFFECTIVE DATES

DISTRIBUTION RATES - May 1, 2008 for all consumption or deemed consumption services used on or after that date.

MISCELLANEOUS CHARGES - May 1, 2008 for all charges billed to customers on or after that date.
RETAIL TRANSMISSION RATES - May 1, 2008 for all consumption or deemed consumption services used on or after that date.
LOSS FACTOR ADJUSTMENT – for all consumption or deemed consumption services billed following May 1, 2008 or later

SERVICE CLASSIFICATIONS

Residential
This classification refers to all service supplied to single-family dwelling units for domestic or household purpose. Multi-unit residential establishments such as apartment buildings supplied through one service (bulk metered) will normally be classified as General Service, but, at Hydro One’s discretion, up to four residential units may be classified as residential. Where electricity service is provided to combined residential and business (including agricultural usage) and the wiring does not provide for separate metering, the classification shall be at the discretion of Hydro One based on such considerations as the estimated predominant consumption.
Further servicing details are available in the utility’s Conditions of Service.

General Service
This classification refers to all service supplied to premises other than those classified as Residential or Lighting. Some General Service accounts are energy(kWh)-billed, and some are demand(kW)-billed. Further servicing details are available in the utility’s Conditions of Service.

Unmetered Scattered Load
This classification refers to certain instances where connections can be provided without metering. These loads are generally small in size and consistent in magnitude of load. Hydro One reserves the right to review all cases and may require that a meter be installed at its sole discretion. Services that can be unmetered include cable TV amplifiers, telephone switching devices, phone booths, bus shelters, rail way crossing signals, traffic signals, and other small fixed loads.
Further servicing details are available in the utility’s Conditions of Service (including in the "Unmetered Connections" section).

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Street Lighting

This classification refers to accounts for the distribution and supply of electrical energy for street lighting. Street lights are devices owned by or operated for the road authority and/or the municipal corporation. These street lights in fact belong to the Street Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Sentinel Lighting

This classification refers to accounts for a separate service to a sentinel light. These sentinel lights in fact belong to the Sentinel Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Urban Density Classification

Customers who meet the Urban Density Criteria of being in an area containing 3,000 or more customers with a line density of at least 60 customers per kilometre, will be mapped to an Urban customer classification.

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MONTHLY RATES AND CHARGES

Residential - R1 Wardsville

Service Charge	$	11.35
Distribution Volumetric Rate	$ / kWh	0.0200
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0010
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0004)
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0047
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0046
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service Less Than 50 kW (Energy-Billed) - GSe Wardsville

Service Charge	$	17.01
Distribution Volumetric Rate	$ / kWh	0.0199
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0008
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0006)
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0035
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0032
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service 50 kW or Greater (Demand-Billed) - GSd Wardsville

Service Charge	$	20.61
Distribution Volumetric Rate	$ / kW	8.20
Regulatory Asset Recovery - Rider #2	$ / kW	0.26
Regulatory Asset Recovery - Rider #3	$ / kW	(0.22)
Retail Transmission Rate - Network Service Rate (4)	$ / kW	1.11
Retail Transmission Rate - Line and Transformation Connection Service Rate (4)	$ / kW	1.00
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

Hydro One Networks Inc.
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Unmetered, Scattered Load

Service Charge	$	9.95
Distribution Volumetric Rate	$ / kWh	0.0200
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0008
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0006)
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0035
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0032
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

(3) For energy-only metered customers, the billing determinant is the customer's metered energy consumption adjusted by the total loss factor as approved by the Board for Acquired LDC customers.
(4) For demand billed customers, appropriate loss factors must be applied to the applicable tariffs. Also the billing determinant for the Line and Transformation Connection Services rate is the customer's peak demand in the billing period. The billing determinant for the Network Services rate is: for non-interval-metered customers, the peak demand in the billing period, and for interval-metered customers, the peak demand between 7 AM and 7 PM local time on IESO business days

Customer-Supplied Transformation Allowance

Applicable to customers providing their own transformers

Demand-billed	$ / kW	0.60
Energy-billed	$ / kWh	0.0014

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Loss Factors

Residential	1.085
General Service Less Than 50 kW (Energy-Billed)	1.092
General Service 50 kW or Greater (Demand-Billed)	1.061
Unmetered Scattered Load	1.092

Transformer Loss Allowance

Applicable to customers requiring a billing adjustment for transformer losses as the result of being metered on the primary side of a transformer. The following uniform values shall be applied to measured demand and energy to calculate transformer losses for voltages up to and including 50 kV (as metered on the primary side):

(a) 1.5% for transformer installations up to an individual bank capacity of 400 kVA,
(b) 1.0% for bank capacities over 400 kVA.

Alternatively, transformer losses may be determined from transformer test data, and measured demand and energy adjusted accordingly

For services which are not demand metered, an assumed demand of 50% of the transformer capacity will be used to calculate the loss allowance. Where several transformers are involved, the bank capacity is assumed to be the arithmetic sum of all transformer capacities

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Wardsville Hydro Electric Commission
Effective Date: May 1, 2008

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

MISCELLANEOUS CHARGES

Specific Service Charges: Standard Amounts

Rate Code	Specific Service Charge - Standard Name	Calculation Method			
		2006 Rate Handbook	Standard Formula	Other Formula	Time and Materials
1	Temporary Service	$500			
2	Dispute Meter Test	$30 plus Measurement Canada fees			
3	Collection of account – no disconnection/load limiter	$30			
4	Collection/Disconnect/load limiter/reconnect (at meter) trip – regular hours	$65			
5	Collection/Disconnect/load limiter/reconnect (at meter) trip – after regular hours	$185			
6	Collection/Disconnect/load limiter/reconnect (at pole) trip – regular hours	$185			
7	Collection/Disconnect/load limiter/reconnect (at pole) trip – after regular hours	$415			
8	Account Set-up Charge	$30			
9	Arrears Certificate	$15			
10	NSF Cheque Charge	$15 + bank charges			
11	Easement Charge for Unregistered Rights	$15			
12	Late Payment Charge	1.5%/month			
13a	Retailer Services – Establishing Service Agreements (refer to Handbook for all charges)	$100/agreement/Retailer +$20/month/Retailer +$0.50/month/customer + other			
13b	Retailer Services – Other (includes Bill Ready for Retailers and Service Transactions Requests) as per the Handbook, Chapter 12	$0.30/month/customer + $0.25/request for request fee + $0.50/request for process fee			
14	Special Meter Reads	$30			
15	Service Layout Fee – Basic		$495		
16	Service Layout Fee – Complex		$690		
17	Crossing Application – Pipeline		$2,445		
18	Crossing Application – Water		$3,045		
19	Crossing Application – Railroad		$2,945		
20	Line Staking – per meter		$3.70		
21	Central Metering – New service < 45 kW		$115		
22	Conversion to Central Metering < 45 kW		$915		
23	Conversion to Central Metering > 45 kW		$800		
24	Tingle Voltage Test – In Excess of 4 Hours (per hour – average 2 additional hours)		$125		
25	Standby Administration Charge per month		$440		
26	Sentinel Lights Rental Rate per month			$7.10	
27	Sentinel Pole Rental Rate per month			$4.15	
28	Joint Use for Cable and Telecom companies per pole			$22.35	
29	Joint Use for LDCs per pole			$28.61	

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
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Wardsville Hydro Electric Commission
Effective Date: May 1, 2007

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APPLICATION

The application of these rates and charges shall be in accordance with The Licence of The Distributor and any Codes, Guidelines or Orders of The Board, and amendments thereto as approved by The Board, which may be applicable to the administration of this schedule.
No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code, Guideline or Order of the Board, and amendments thereto as approved by the Board, or as specified herein
This schedule does not contain any rates and charges relating to the electricity commodity (e.g. the Regulated Price Plan).

EFFECTIVE DATES

DISTRIBUTION RATES - May 1, 2007 for all consumption or deemed consumption services used on or after that date.

MISCELLANEOUS CHARGES - May 1, 2007 for all charges billed to customers on or after that date.
RETAIL TRANSMISSION RATES - May 1, 2007 for all consumption or deemed consumption services used on or after that date.
LOSS FACTOR ADJUSTMENT – May 1, 2007

SERVICE CLASSIFICATIONS

Residential
This classification (note 1) refers to all service supplied to single-family dwelling units for domestic or household purpose. Multi-unit residential establishments such as apartment buildings supplied through one service (bulk metered) will normally be classified as General Service, but, at Hydro One’s discretion, up to four residential units may be classified as residential. Where electricity service is provided to combined residential and business (including agricultural usage) and the wiring does not provide for separate metering, the classification shall be at the discretion of Hydro One based on such considerations as the estimated predominant consumption.
Further servicing details are available in the utility’s Conditions of Service.

General Service
This classification (note 1) refers to all service supplied to premises other than those classified as Residential or Lighting. Some General Service accounts are energy(kWh)-billed, and some are demand(kW)-billed. Further servicing details are available in the utility’s Conditions of Service. Also, see note 2.

Unmetered Scattered Load
This classification refers to certain instances where connections can be provided without metering. These loads are generally small in size and consistent in magnitude of load. Hydro One reserves the right to review all cases and may require that a meter be installed at its sole discretion. Services that can be unmetered include cable TV amplifiers, telephone switching devices, phone booths, bus shelters, rail way crossing signals, traffic signals, and other small fixed loads.
Further servicing details are available in the utility’s Conditions of Service (including in the "Unmetered Connections" section).

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
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Wardsville Hydro Electric Commission
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Street Lighting

This classification refers to accounts for the distribution and supply of electrical energy for street lighting. Street lights are devices owned by or operated for the road authority and/or the municipal corporation. These street lights in fact belong to the Street Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Sentinel Lighting

This classification refers to accounts for a separate service to a sentinel light. These sentinel lights in fact belong to the Sentinel Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Interim Demand-Side Management Time-of-Use

This is potentially applicable to Demand-billed General Service accounts. See Note 2 below.

Note (1): Classification descriptions are paraphrases from the document "Hydro One Networks Inc. - Distribution Customers Conditions of Service - August 2004"

Note (2):

Interim Demand-Side Management Time-of-Use Rates: demand charges will be based on demand during the on-peak periods.

Criteria: Customers' electricity consumption (kW) in the off-peak period is at least twice the electricity consumption (kW) during the on-peak period.

Definition of Time Periods: The on-peak hours will be between 0700 hours to 1900 hours Eastern Standard Time during the winter (standard time) on IESO business days and 0600 hours to 1800 hours Eastern Standard Time during the summer (daylight savings time) on IESO business days. The off-peak period constitutes all of the remaining hours.

Hydro One Networks Inc.
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MONTHLY RATES AND CHARGES

Residential

Service Charge	$	9.64
Distribution Volumetric Rate	$ / kWh	0.0097
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0036
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0010
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0055
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0047
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service - Energy Billed (less than 50 kW)

Service Charge	$	12.32
Distribution Volumetric Rate	$ / kWh	0.0100
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0025
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0008
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0050
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0043
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service - Demand Billed (50 kW or greater)

Service Charge	$	12.32
Distribution Volumetric Rate	$ / kW	3.16
Regulatory Asset Recovery - Rider #1	$ / kW	0.81
Regulatory Asset Recovery - Rider #2	$ / kW	0.26
Retail Transmission Rate - Network Service Rate (4)	$ / kW	1.94
Retail Transmission Rate - Line and Transformation Connection Service Rate (4)	$ / kW	1.61
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

Hydro One Networks Inc.
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Unmetered, Scattered Load

Service Charge	$	5.70
Distribution Volumetric Rate	$ / kWh	0.0100
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0025
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0008
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0050
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0043
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

(3) For energy-only metered customers, the billing determinant is the customer’s metered energy consumption adjusted by the total loss factor as approved by the Board for Acquired LDC customers.
(4) For demand billed customers, appropriate loss factors must be applied to the applicable tariffs. Also the billing determinant for the Line and Transformation Connection Services rate is the customer’s peak demand in the billing period. The billing determinant for the Network Services rate is: for non-interval-metered customers, the peak demand in the billing period, and for interval-metered customers, the peak demand between 7 AM and 7 PM local time on IESO business days

Interim Demand-Side Management Time-of-Use

See the "Service Classifications" section of this schedule.

Customer-Supplied Transformation Allowance

Applicable to demand-billed customers providing their own transformers
Primary Voltage under 50 kV (per kW)

Single Phase	$ / kW	0.20
Three Phase	$ / kW	0.60

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Loss Factors

Supply Facilities Loss Factor	1.0045
Distribution Loss Factors	
Customer less than 5,000 kW	1.0500
Customer greater than or equal to 5,000 kW	1.0100
Total Loss Factors	
Customer less than 5,000 kW	1.0545
Customer greater than or equal to 5,000 kW	1.0145

Transformer Loss Allowance

Applicable to customers requiring a billing adjustment for transformer losses as the result of being metered on the primary side of a transformer. The following uniform values shall be applied to measured demand and energy to calculate transformer losses for voltages up to and including 50 kV (as metered on the primary side):

(a) 1.5% for transformer installations up to an individual bank capacity of 400 kVA,
(b) 1.0% for bank capacities over 400 kVA.

Alternatively, transformer losses may be determined from transformer test data, and measured demand and energy adjusted accordingly

For services which are not demand metered, an assumed demand of 50% of the transformer capacity will be used to calculate the loss allowance. Where several transformers are involved, the bank capacity is assumed to be the arithmetic sum of all transformer capacities

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
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MISCELLANEOUS CHARGES

Specific Service Charges: Standard Amounts

Rate Code	Specific Service Charge - Standard Name	Calculation Method			
		2006 Rate Handbook	Standard Formula	Other Formula	Time and Materials
1	Temporary Service	$500			
2	Dispute Meter Test	$30 plus Measurement Canada fees			
3	Collection of account – no disconnection/load limiter	$30			
4	Collection/Disconnect/load limiter/reconnect (at meter) trip – regular hours	$65			
5	Collection/Disconnect/load limiter/reconnect (at meter) trip – after regular hours	$185			
6	Collection/Disconnect/load limiter/reconnect (at pole) trip – regular hours	$185			
7	Collection/Disconnect/load limiter/reconnect (at pole) trip – after regular hours	$415			
8	Account Set-up Charge	$30			
9	Arrears Certificate	$15			
10	NSF Cheque Charge	$15 + bank charges			
11	Easement Charge for Unregistered Rights	$15			
12	Late Payment Charge	1.5%/month			
13a	Retailer Services – Establishing Service Agreements (refer to Handbook for all charges)	$100/agreement/Retailer +$20/month/Retailer +$0.50/month/customer + other			
13b	Retailer Services – Other (includes Bill Ready for Retailers and Service Transactions Requests) as per the Handbook, Chapter 12	$0.30/month/customer + $0.25/request for request fee + $0.50/request for process fee			
14	Special Meter Reads	$30			
15	Billing Suspension and Terminations in Trailer Parks		$130		
16	Service Layout Fee – Basic		$405		
17	Service Layout Fee – Complex		$580		

Hydro One Networks Inc.
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18	Crossing Application – Pipeline		$2,065		
19	Crossing Application – Water		$2,525		
20	Crossing Application – Railroad		$2,565		
21	Line Staking – per meter		$3.10		
22	Central Metering – New service < 45 kW		$115		
23	Conversion to Central Metering < 45 kW		$795		
24	Conversion to Central Metering > 45 kW		$680		
25	Tingle Voltage Test – In Excess of 4 Hours (per hour – average 2 additional hours)		$105		
26	Standby Administration Charge per month (interim)		$375		
27	Sentinel Lights Rental Rate per month – Mercury Vapor			$7.00	
28	Guaranteed Units from Jan 01/91 to Aug 01/91			$26.50 / month	
29	Guaranteed Units from Jan 01/87 to Dec 31/90			$23.50 / month	
30	Joint Use for Cable and Telecom companies per pole			$22.35	
31	Joint Use for LDCs per pole			$28.61	

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Hydro-Electric Commission of the Police Village of Warkworth
Effective Date: May 1, 2008

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

APPLICATION

The application of these rates and charges shall be in accordance with The Licence of The Distributor and any Codes, Guidelines or Orders of The Board, and amendments thereto as approved by The Board, which may be applicable to the administration of this schedule.
No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code, Guideline or Order of the Board, and amendments thereto as approved by the Board, or as specified herein
This schedule does not contain any rates and charges relating to the electricity commodity (e.g. the Regulated Price Plan).

EFFECTIVE DATES

DISTRIBUTION RATES - May 1, 2008 for all consumption or deemed consumption services used on or after that date.

MISCELLANEOUS CHARGES - May 1, 2008 for all charges billed to customers on or after that date.
RETAIL TRANSMISSION RATES - May 1, 2008 for all consumption or deemed consumption services used on or after that date.
LOSS FACTOR ADJUSTMENT – for all consumption or deemed consumption services billed following May 1, 2008 or later

SERVICE CLASSIFICATIONS

Residential
This classification refers to all service supplied to single-family dwelling units for domestic or household purpose. Multi-unit residential establishments such as apartment buildings supplied through one service (bulk metered) will normally be classified as General Service, but, at Hydro One's discretion, up to four residential units may be classified as residential. Where electricity service is provided to combined residential and business (including agricultural usage) and the wiring does not provide for separate metering, the classification shall be at the discretion of Hydro One based on such considerations as the estimated predominant consumption.
Further servicing details are available in the utility's Conditions of Service.

General Service
This classification refers to all service supplied to premises other than those classified as Residential or Lighting. Some General Service accounts are energy(kWh)-billed, and some are demand(kW)-billed. Further servicing details are available in the utility's Conditions of Service.

Unmetered Scattered Load
This classification refers to certain instances where connections can be provided without metering. These loads are generally small in size and consistent in magnitude of load. Hydro One reserves the right to review all cases and may require that a meter be installed at its sole discretion. Services that can be unmetered include cable TV amplifiers, telephone switching devices, phone booths, bus shelters, rail way crossing signals, traffic signals, and other small fixed loads.
Further servicing details are available in the utility's Conditions of Service (including in the "Unmetered Connections" section).

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Hydro-Electric Commission of the Police Village of Warkworth
Effective Date: May 1, 2008

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

Street Lighting

This classification refers to accounts for the distribution and supply of electrical energy for street lighting. Street lights are devices owned by or operated for the road authority and/or the municipal corporation. These street lights in fact belong to the Street Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Sentinel Lighting

This classification refers to accounts for a separate service to a sentinel light. These sentinel lights in fact belong to the Sentinel Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Urban Density Classification

Customers who meet the Urban Density Criteria of being in an area containing 3,000 or more customers with a line density of at least 60 customers per kilometre, will be mapped to an Urban customer classification.

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
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Hydro-Electric Commission of the Police Village of Warkworth
Effective Date: May 1, 2008

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MONTHLY RATES AND CHARGES

Residential - R1 Warkworth

Service Charge	$	15.95
Distribution Volumetric Rate	$ / kWh	0.0271
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0043
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0004)
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0047
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0046
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service Less Than 50 kW (Energy-Billed) - GSe Warkworth

Service Charge	$	23.76
Distribution Volumetric Rate	$ / kWh	0.0295
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0035
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0006)
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0035
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0032
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service 50 kW or Greater (Demand-Billed) - GSd Warkworth

Service Charge	$	27.36
Distribution Volumetric Rate	$ / kW	9.22
Regulatory Asset Recovery - Rider #2	$ / kW	1.03
Regulatory Asset Recovery - Rider #3	$ / kW	(0.22)
Retail Transmission Rate - Network Service Rate (4)	$ / kW	1.11
Retail Transmission Rate - Line and Transformation Connection Service Rate (4)	$ / kW	1.00
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
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Hydro-Electric Commission of the Police Village of Warkworth
Effective Date: May 1, 2008

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

Unmetered, Scattered Load

Service Charge	$	13.83
Distribution Volumetric Rate	$ / kWh	0.0200
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0035
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0006)
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0035
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0032
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

(3) For energy-only metered customers, the billing determinant is the customer’s metered energy consumption adjusted by the total loss factor as approved by the Board for Acquired LDC customers.
(4) For demand billed customers, appropriate loss factors must be applied to the applicable tariffs. Also the billing determinant for the Line and Transformation Connection Services rate is the customer’s peak demand in the billing period. The billing determinant for the Network Services rate is: for non-interval-metered customers, the peak demand in the billing period, and for interval-metered customers, the peak demand between 7 AM and 7 PM local time on IESO business days

Customer-Supplied Transformation Allowance

Applicable to customers providing their own transformers

Demand-billed	$ / kW	0.60
Energy-billed	$ / kWh	0.0014

Hydro One Networks Inc.
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Loss Factors

Residential	1.085
General Service Less Than 50 kW (Energy-Billed)	1.092
General Service 50 kW or Greater (Demand-Billed)	1.061
Unmetered Scattered Load	1.092

Transformer Loss Allowance

Applicable to customers requiring a billing adjustment for transformer losses as the result of being metered on the primary side of a transformer. The following uniform values shall be applied to measured demand and energy to calculate transformer losses for voltages up to and including 50 kV (as metered on the primary side):

(a) 1.5% for transformer installations up to an individual bank capacity of 400 kVA,
(b) 1.0% for bank capacities over 400 kVA.

Alternatively, transformer losses may be determined from transformer test data, and measured demand and energy adjusted accordingly

For services which are not demand metered, an assumed demand of 50% of the transformer capacity will be used to calculate the loss allowance. Where several transformers are involved, the bank capacity is assumed to be the arithmetic sum of all transformer capacities

Hydro One Networks Inc.
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MISCELLANEOUS CHARGES

Specific Service Charges: Standard Amounts

Rate Code	Specific Service Charge - Standard Name	Calculation Method			
		2006 Rate Handbook	Standard Formula	Other Formula	Time and Materials
1	Temporary Service	$500			
2	Dispute Meter Test	$30 plus Measurement Canada fees			
3	Collection of account – no disconnection/load limiter	$30			
4	Collection/Disconnect/load limiter/reconnect (at meter) trip – regular hours	$65			
5	Collection/Disconnect/load limiter/reconnect (at meter) trip – after regular hours	$185			
6	Collection/Disconnect/load limiter/reconnect (at pole) trip – regular hours	$185			
7	Collection/Disconnect/load limiter/reconnect (at pole) trip – after regular hours	$415			
8	Account Set-up Charge	$30			
9	Arrears Certificate	$15			
10	NSF Cheque Charge	$15 + bank charges			
11	Easement Charge for Unregistered Rights	$15			
12	Late Payment Charge	1.5%/month			
13a	Retailer Services – Establishing Service Agreements (refer to Handbook for all charges)	$100/agreement/Retailer +$20/month/Retailer +$0.50/month/customer + other			
13b	Retailer Services – Other (includes Bill Ready for Retailers and Service Transactions Requests) as per the Handbook, Chapter 12	$0.30/month/customer + $0.25/request for request fee + $0.50/request for process fee			
14	Special Meter Reads	$30			
15	Service Layout Fee – Basic		$495		
16	Service Layout Fee – Complex		$690		
17	Crossing Application – Pipeline		$2,445		
18	Crossing Application – Water		$3,045		
19	Crossing Application – Railroad		$2,945		
20	Line Staking – per meter		$3.70		
21	Central Metering – New service < 45 kW		$115		
22	Conversion to Central Metering < 45 kW		$915		
23	Conversion to Central Metering > 45 kW		$800		
24	Tingle Voltage Test – In Excess of 4 Hours (per hour – average 2 additional hours)		$125		
25	Standby Administration Charge per month		$440		
26	Sentinel Lights Rental Rate per month			$7.10	
27	Sentinel Pole Rental Rate per month			$4.15	
28	Joint Use for Cable and Telecom companies per pole			$22.35	
29	Joint Use for LDCs per pole			$28.61	

Hydro One Networks Inc.
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APPLICATION

The application of these rates and charges shall be in accordance with The Licence of The Distributor and any Codes, Guidelines or Orders of The Board, and amendments thereto as approved by The Board, which may be applicable to the administration of this schedule.
No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code, Guideline or Order of the Board, and amendments thereto as approved by the Board, or as specified herein
This schedule does not contain any rates and charges relating to the electricity commodity (e.g. the Regulated Price Plan).

EFFECTIVE DATES

DISTRIBUTION RATES - May 1, 2007 for all consumption or deemed consumption services used on or after that date.

MISCELLANEOUS CHARGES - May 1, 2007 for all charges billed to customers on or after that date.
RETAIL TRANSMISSION RATES - May 1, 2007 for all consumption or deemed consumption services used on or after that date.
LOSS FACTOR ADJUSTMENT – May 1, 2007

SERVICE CLASSIFICATIONS

Residential
This classification (note 1) refers to all service supplied to single-family dwelling units for domestic or household purpose. Multi-unit residential establishments such as apartment buildings supplied through one service (bulk metered) will normally be classified as General Service, but, at Hydro One's discretion, up to four residential units may be classified as residential. Where electricity service is provided to combined residential and business (including agricultural usage) and the wiring does not provide for separate metering, the classification shall be at the discretion of Hydro One based on such considerations as the estimated predominant consumption.
Further servicing details are available in the utility's Conditions of Service.

General Service
This classification (note 1) refers to all service supplied to premises other than those classified as Residential or Lighting. Some General Service accounts are energy(kWh)-billed, and some are demand(kW)-billed. Further servicing details are available in the utility's Conditions of Service. Also, see note 2.

Unmetered Scattered Load
This classification refers to certain instances where connections can be provided without metering. These loads are generally small in size and consistent in magnitude of load. Hydro One reserves the right to review all cases and may require that a meter be installed at its sole discretion. Services that can be unmetered include cable TV amplifiers, telephone switching devices, phone booths, bus shelters, rail way crossing signals, traffic signals, and other small fixed loads.
Further servicing details are available in the utility's Conditions of Service (including in the "Unmetered Connections" section).

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Hydro-Electric Commission of the Police Village of Warkworth
Effective Date: May 1, 2007

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

Street Lighting

This classification refers to accounts for the distribution and supply of electrical energy for street lighting. Street lights are devices owned by or operated for the road authority and/or the municipal corporation. These street lights in fact belong to the Street Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Sentinel Lighting

This classification refers to accounts for a separate service to a sentinel light. These sentinel lights in fact belong to the Sentinel Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Interim Demand-Side Management Time-of-Use

This is potentially applicable to Demand-billed General Service accounts. See Note 2 below.

Note (1): Classification descriptions are paraphrases from the document "Hydro One Networks Inc. - Distribution Customers Conditions of Service - August 2004"

Note (2):

Interim Demand-Side Management Time-of-Use Rates: demand charges will be based on demand during the on-peak periods.

Criteria: Customers' electricity consumption (kW) in the off-peak period is at least twice the electricity consumption (kW) during the on-peak period.

Definition of Time Periods: The on-peak hours will be between 0700 hours to 1900 hours Eastern Standard Time during the winter (standard time) on IESO business days and 0600 hours to 1800 hours Eastern Standard Time during the summer (daylight savings time) on IESO business days. The off-peak period constitutes all of the remaining hours.

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
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MONTHLY RATES AND CHARGES

Residential

Service Charge	$	15.25
Distribution Volumetric Rate	$ / kWh	0.0118
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0066
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0043
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0055
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0047
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service - Energy Billed (less than 50 kW)

Service Charge	$	21.31
Distribution Volumetric Rate	$ / kWh	0.0152
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0046
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0035
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0050
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0043
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service - Demand Billed (50 kW or greater)

Service Charge	$	21.31
Distribution Volumetric Rate	$ / kW	4.47
Regulatory Asset Recovery - Rider #1	$ / kW	1.44
Regulatory Asset Recovery - Rider #2	$ / kW	1.03
Retail Transmission Rate - Network Service Rate (4)	$ / kW	1.94
Retail Transmission Rate - Line and Transformation Connection Service Rate (4)	$ / kW	1.61
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
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Effective Date: May 1, 2007

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

Unmetered, Scattered Load

Service Charge	$	10.20
Distribution Volumetric Rate	$ / kWh	0.0152
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0046
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0035
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0050
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0043
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

(3) For energy-only metered customers, the billing determinant is the customer’s metered energy consumption adjusted by the total loss factor as approved by the Board for Acquired LDC customers.
(4) For demand billed customers, appropriate loss factors must be applied to the applicable tariffs. Also the billing determinant for the Line and Transformation Connection Services rate is the customer’s peak demand in the billing period. The billing determinant for the Network Services rate is: for non-interval-metered customers, the peak demand in the billing period, and for interval-metered customers, the peak demand between 7 AM and 7 PM local time on IESO business days

Interim Demand-Side Management Time-of-Use

See the "Service Classifications" section of this schedule.

Customer-Supplied Transformation Allowance

Applicable to demand-billed customers providing their own transformers
Primary Voltage under 50 kV (per kW)

Single Phase	$ / kW	0.20
Three Phase	$ / kW	0.60

Hydro One Networks Inc.
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Loss Factors

Supply Facilities Loss Factor	1.0045
Distribution Loss Factors	
Customer less than 5,000 kW	1.0500
Customer greater than or equal to 5,000 kW	1.0100
Total Loss Factors	
Customer less than 5,000 kW	1.0545
Customer greater than or equal to 5,000 kW	1.0145

Transformer Loss Allowance

Applicable to customers requiring a billing adjustment for transformer losses as the result of being metered on the primary side of a transformer. The following uniform values shall be applied to measured demand and energy to calculate transformer losses for voltages up to and including 50 kV (as metered on the primary side):

(a) 1.5% for transformer installations up to an individual bank capacity of 400 kVA,
(b) 1.0% for bank capacities over 400 kVA.

Alternatively, transformer losses may be determined from transformer test data, and measured demand and energy adjusted accordingly

For services which are not demand metered, an assumed demand of 50% of the transformer capacity will be used to calculate the loss allowance. Where several transformers are involved, the bank capacity is assumed to be the arithmetic sum of all transformer capacities

Hydro One Networks Inc.
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MISCELLANEOUS CHARGES

Specific Service Charges: Standard Amounts

Rate Code	Specific Service Charge - Standard Name	Calculation Method			
		2006 Rate Handbook	Standard Formula	Other Formula	Time and Materials
1	Temporary Service	$500			
2	Dispute Meter Test	$30 plus Measurement Canada fees			
3	Collection of account – no disconnection/load limiter	$30			
4	Collection/Disconnect/load limiter/reconnect (at meter) trip – regular hours	$65			
5	Collection/Disconnect/load limiter/reconnect (at meter) trip – after regular hours	$185			
6	Collection/Disconnect/load limiter/reconnect (at pole) trip – regular hours	$185			
7	Collection/Disconnect/load limiter/reconnect (at pole) trip – after regular hours	$415			
8	Account Set-up Charge	$30			
9	Arrears Certificate	$15			
10	NSF Cheque Charge	$15 + bank charges			
11	Easement Charge for Unregistered Rights	$15			
12	Late Payment Charge	1.5%/month			
13a	Retailer Services – Establishing Service Agreements (refer to Handbook for all charges)	$100/agreement/Retailer +$20/month/Retailer +$0.50/month/customer + other			
13b	Retailer Services – Other (includes Bill Ready for Retailers and Service Transactions Requests) as per the Handbook, Chapter 12	$0.30/month/customer + $0.25/request for request fee + $0.50/request for process fee			
14	Special Meter Reads	$30			
15	Billing Suspension and Terminations in Trailer Parks		$130		
16	Service Layout Fee – Basic		$405		
17	Service Layout Fee – Complex		$580		

Hydro One Networks Inc.
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18	Crossing Application – Pipeline		$2,065		
19	Crossing Application – Water		$2,525		
20	Crossing Application – Railroad		$2,565		
21	Line Staking – per meter		$3.10		
22	Central Metering – New service < 45 kW		$115		
23	Conversion to Central Metering < 45 kW		$795		
24	Conversion to Central Metering > 45 kW		$680		
25	Tingle Voltage Test – In Excess of 4 Hours (per hour – average 2 additional hours)		$105		
26	Standby Administration Charge per month (interim)		$375		
27	Sentinel Lights Rental Rate per month – Mercury Vapor			$7.00	
28	Guaranteed Units from Jan 01/91 to Aug 01/91			$26.50 / month	
29	Guaranteed Units from Jan 01/87 to Dec 31/90			$23.50 / month	
30	Joint Use for Cable and Telecom companies per pole			$22.35	
31	Joint Use for LDCs per pole			$28.61	

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
West Elgin Hydro Electric Commission
Effective Date: May 1, 2008

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

APPLICATION

The application of these rates and charges shall be in accordance with The Licence of The Distributor and any Codes, Guidelines or Orders of The Board, and amendments thereto as approved by The Board, which may be applicable to the administration of this schedule.
No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code, Guideline or Order of the Board, and amendments thereto as approved by the Board, or as specified herein
This schedule does not contain any rates and charges relating to the electricity commodity (e.g. the Regulated Price Plan).

EFFECTIVE DATES

DISTRIBUTION RATES - May 1, 2008 for all consumption or deemed consumption services used on or after that date.

MISCELLANEOUS CHARGES - May 1, 2008 for all charges billed to customers on or after that date.
RETAIL TRANSMISSION RATES - May 1, 2008 for all consumption or deemed consumption services used on or after that date.
LOSS FACTOR ADJUSTMENT – for all consumption or deemed consumption services billed following May 1, 2008 or later

SERVICE CLASSIFICATIONS

Residential
This classification refers to all service supplied to single-family dwelling units for domestic or household purpose. Multi-unit residential establishments such as apartment buildings supplied through one service (bulk metered) will normally be classified as General Service, but, at Hydro One's discretion, up to four residential units may be classified as residential. Where electricity service is provided to combined residential and business (including agricultural usage) and the wiring does not provide for separate metering, the classification shall be at the discretion of Hydro One based on such considerations as the estimated predominant consumption.
Further servicing details are available in the utility's Conditions of Service.

General Service
This classification refers to all service supplied to premises other than those classified as Residential or Lighting. Some General Service accounts are energy(kWh)-billed, and some are demand(kW)-billed. Further servicing details are available in the utility's Conditions of Service.

Unmetered Scattered Load
This classification refers to certain instances where connections can be provided without metering. These loads are generally small in size and consistent in magnitude of load. Hydro One reserves the right to review all cases and may require that a meter be installed at its sole discretion. Services that can be unmetered include cable TV amplifiers, telephone switching devices, phone booths, bus shelters, rail way crossing signals, traffic signals, and other small fixed loads.
Further servicing details are available in the utility's Conditions of Service (including in the "Unmetered Connections" section).

Hydro One Networks Inc.
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West Elgin Hydro Electric Commission
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This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

Street Lighting

This classification refers to accounts for the distribution and supply of electrical energy for street lighting. Street lights are devices owned by or operated for the road authority and/or the municipal corporation. These street lights in fact belong to the Street Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Sentinel Lighting

This classification refers to accounts for a separate service to a sentinel light. These sentinel lights in fact belong to the Sentinel Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Urban Density Classification

Customers who meet the Urban Density Criteria of being in an area containing 3,000 or more customers with a line density of at least 60 customers per kilometre, will be mapped to an Urban customer classification.

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
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MONTHLY RATES AND CHARGES

Residential - R1 West Elgin

Service Charge	$	14.44
Distribution Volumetric Rate	$ / kWh	0.0271
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0035
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0004)
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0047
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0046
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service Less Than 50 kW (Energy-Billed) - GSe West Elgin

Service Charge	$	19.24
Distribution Volumetric Rate	$ / kWh	0.0162
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0007
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0006)
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0035
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0032
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service 50 kW or Greater (Demand-Billed) - GSd West Elgin

Service Charge	$	22.84
Distribution Volumetric Rate	$ / kW	6.85
Regulatory Asset Recovery - Rider #2	$ / kW	0.21
Regulatory Asset Recovery - Rider #3	$ / kW	(0.22)
Retail Transmission Rate - Network Service Rate (4)	$ / kW	1.11
Retail Transmission Rate - Line and Transformation Connection Service Rate (4)	$ / kW	1.00
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

Hydro One Networks Inc.
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This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

Unmetered, Scattered Load

Service Charge	$	11.57
Distribution Volumetric Rate	$ / kWh	0.0200
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0007
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0006)
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0035
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0032
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

(3) For energy-only metered customers, the billing determinant is the customer's metered energy consumption adjusted by the total loss factor as approved by the Board for Acquired LDC customers.
(4) For demand billed customers, appropriate loss factors must be applied to the applicable tariffs. Also the billing determinant for the Line and Transformation Connection Services rate is the customer's peak demand in the billing period. The billing determinant for the Network Services rate is: for non-interval-metered customers, the peak demand in the billing period, and for interval-metered customers, the peak demand between 7 AM and 7 PM local time on IESO business days

Customer-Supplied Transformation Allowance

Applicable to customers providing their own transformers		
Demand-billed	$ / kW	0.60
Energy-billed	$ / kWh	0.0014

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Loss Factors

Residential	1.085
General Service Less Than 50 kW (Energy-Billed)	1.092
General Service 50 kW or Greater (Demand-Billed)	1.061
Unmetered Scattered Load	1.092

Transformer Loss Allowance

Applicable to customers requiring a billing adjustment for transformer losses as the result of being metered on the primary side of a transformer. The following uniform values shall be applied to measured demand and energy to calculate transformer losses for voltages up to and including 50 kV (as metered on the primary side):

(a) 1.5% for transformer installations up to an individual bank capacity of 400 kVA,
(b) 1.0% for bank capacities over 400 kVA.

Alternatively, transformer losses may be determined from transformer test data, and measured demand and energy adjusted accordingly

For services which are not demand metered, an assumed demand of 50% of the transformer capacity will be used to calculate the loss allowance. Where several transformers are involved, the bank capacity is assumed to be the arithmetic sum of all transformer capacities

Hydro One Networks Inc.
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MISCELLANEOUS CHARGES

Specific Service Charges: Standard Amounts

Rate Code	Specific Service Charge - Standard Name	Calculation Method			
		2006 Rate Handbook	Standard Formula	Other Formula	Time and Materials
1	Temporary Service	$500			
2	Dispute Meter Test	$30 plus Measurement Canada fees			
3	Collection of account – no disconnection/load limiter	$30			
4	Collection/Disconnect/load limiter/reconnect (at meter) trip – regular hours	$65			
5	Collection/Disconnect/load limiter/reconnect (at meter) trip – after regular hours	$185			
6	Collection/Disconnect/load limiter/reconnect (at pole) trip – regular hours	$185			
7	Collection/Disconnect/load limiter/reconnect (at pole) trip – after regular hours	$415			
8	Account Set-up Charge	$30			
9	Arrears Certificate	$15			
10	NSF Cheque Charge	$15 + bank charges			
11	Easement Charge for Unregistered Rights	$15			
12	Late Payment Charge	1.5%/month			
13a	Retailer Services – Establishing Service Agreements (refer to Handbook for all charges)	$100/agreement/Retailer +$20/month/Retailer +$0.50/month/customer + other			
13b	Retailer Services – Other (includes Bill Ready for Retailers and Service Transactions Requests) as per the Handbook, Chapter 12	$0.30/month/customer + $0.25/request for request fee + $0.50/request for process fee			
14	Special Meter Reads	$30			
15	Service Layout Fee – Basic		$495		
16	Service Layout Fee – Complex		$690		
17	Crossing Application – Pipeline		$2,445		
18	Crossing Application – Water		$3,045		
19	Crossing Application – Railroad		$2,945		
20	Line Staking – per meter		$3.70		
21	Central Metering – New service < 45 kW		$115		
22	Conversion to Central Metering < 45 kW		$915		
23	Conversion to Central Metering > 45 kW		$800		
24	Tingle Voltage Test – In Excess of 4 Hours (per hour – average 2 additional hours)		$125		
25	Standby Administration Charge per month		$440		
26	Sentinel Lights Rental Rate per month			$7.10	
27	Sentinel Pole Rental Rate per month			$4.15	
28	Joint Use for Cable and Telecom companies per pole			$22.35	
29	Joint Use for LDCs per pole			$28.61	

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APPLICATION

The application of these rates and charges shall be in accordance with The Licence of The Distributor and any Codes, Guidelines or Orders of The Board, and amendments thereto as approved by The Board, which may be applicable to the administration of this schedule.
No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code, Guideline or Order of the Board, and amendments thereto as approved by the Board, or as specified herein
This schedule does not contain any rates and charges relating to the electricity commodity (e.g. the Regulated Price Plan).

EFFECTIVE DATES

DISTRIBUTION RATES - May 1, 2007 for all consumption or deemed consumption services used on or after that date.

MISCELLANEOUS CHARGES - May 1, 2007 for all charges billed to customers on or after that date.
RETAIL TRANSMISSION RATES - May 1, 2007 for all consumption or deemed consumption services used on or after that date.
LOSS FACTOR ADJUSTMENT – May 1, 2007

SERVICE CLASSIFICATIONS

Residential
This classification (note 1) refers to all service supplied to single-family dwelling units for domestic or household purpose. Multi-unit residential establishments such as apartment buildings supplied through one service (bulk metered) will normally be classified as General Service, but, at Hydro One's discretion, up to four residential units may be classified as residential. Where electricity service is provided to combined residential and business (including agricultural usage) and the wiring does not provide for separate metering, the classification shall be at the discretion of Hydro One based on such considerations as the estimated predominant consumption.
Further servicing details are available in the utility's Conditions of Service.

General Service
This classification (note 1) refers to all service supplied to premises other than those classified as Residential or Lighting. Some General Service accounts are energy(kWh)-billed, and some are demand(kW)-billed. Further servicing details are available in the utility's Conditions of Service. Also, see note 2.

Unmetered Scattered Load
This classification refers to certain instances where connections can be provided without metering. These loads are generally small in size and consistent in magnitude of load. Hydro One reserves the right to review all cases and may require that a meter be installed at its sole discretion. Services that can be unmetered include cable TV amplifiers, telephone switching devices, phone booths, bus shelters, rail way crossing signals, traffic signals, and other small fixed loads.
Further servicing details are available in the utility's Conditions of Service (including in the "Unmetered Connections" section).

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Street Lighting

This classification refers to accounts for the distribution and supply of electrical energy for street lighting. Street lights are devices owned by or operated for the road authority and/or the municipal corporation. These street lights in fact belong to the Street Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Sentinel Lighting

This classification refers to accounts for a separate service to a sentinel light. These sentinel lights in fact belong to the Sentinel Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Interim Demand-Side Management Time-of-Use

This is potentially applicable to Demand-billed General Service accounts. See Note 2 below.

Note (1): Classification descriptions are paraphrases from the document "Hydro One Networks Inc. - Distribution Customers Conditions of Service - August 2004"

Note (2):

Interim Demand-Side Management Time-of-Use Rates: demand charges will be based on demand during the on-peak periods.

Criteria: Customers' electricity consumption (kW) in the off-peak period is at least twice the electricity consumption (kW) during the on-peak period.

Definition of Time Periods: The on-peak hours will be between 0700 hours to 1900 hours Eastern Standard Time during the winter (standard time) on IESO business days and 0600 hours to 1800 hours Eastern Standard Time during the summer (daylight savings time) on IESO business days. The off-peak period constitutes all of the remaining hours.

Hydro One Networks Inc.
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MONTHLY RATES AND CHARGES

Residential

Service Charge	$	13.30
Distribution Volumetric Rate	$ / kWh	0.0142
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0063
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0035
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0055
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0047
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service - Energy Billed (less than 50 kW)

Service Charge	$	15.40
Distribution Volumetric Rate	$ / kWh	0.0070
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0017
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0007
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0050
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0043
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service - Demand Billed (50 kW or greater)

Service Charge	$	15.40
Distribution Volumetric Rate	$ / kW	2.21
Regulatory Asset Recovery - Rider #1	$ / kW	0.54
Regulatory Asset Recovery - Rider #2	$ / kW	0.21
Retail Transmission Rate - Network Service Rate (4)	$ / kW	1.94
Retail Transmission Rate - Line and Transformation Connection Service Rate (4)	$ / kW	1.61
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

Hydro One Networks Inc.
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This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

Unmetered, Scattered Load

Service Charge	$	7.23
Distribution Volumetric Rate	$ / kWh	0.0070
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0017
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0007
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0050
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0043
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

(3) For energy-only metered customers, the billing determinant is the customer's metered energy consumption adjusted by the total loss factor as approved by the Board for Acquired LDC customers.

(4) For demand billed customers, appropriate loss factors must be applied to the applicable tariffs. Also the billing determinant for the Line and Transformation Connection Services rate is the customer's peak demand in the billing period. The billing determinant for the Network Services rate is: for non-interval-metered customers, the peak demand in the billing period, and for interval-metered customers, the peak demand between 7 AM and 7 PM local time on IESO business days

Interim Demand-Side Management Time-of-Use

See the "Service Classifications" section of this schedule.

Customer-Supplied Transformation Allowance

Applicable to demand-billed customers providing their own transformers

Primary Voltage under 50 kV (per kW)		
Single Phase	$ / kW	0.20
Three Phase	$ / kW	0.60

Hydro One Networks Inc.
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West Elgin Hydro Electric Commission
Effective Date: May 1, 2007

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

Loss Factors

Supply Facilities Loss Factor	1.0045
Distribution Loss Factors	
Customer less than 5,000 kW	1.0500
Customer greater than or equal to 5,000 kW	1.0100
Total Loss Factors	
Customer less than 5,000 kW	1.0545
Customer greater than or equal to 5,000 kW	1.0145

Transformer Loss Allowance

Applicable to customers requiring a billing adjustment for transformer losses as the result of being metered on the primary side of a transformer. The following uniform values shall be applied to measured demand and energy to calculate transformer losses for voltages up to and including 50 kV (as metered on the primary side):

(a) 1.5% for transformer installations up to an individual bank capacity of 400 kVA,
(b) 1.0% for bank capacities over 400 kVA.

Alternatively, transformer losses may be determined from transformer test data, and measured demand and energy adjusted accordingly

For services which are not demand metered, an assumed demand of 50% of the transformer capacity will be used to calculate the loss allowance. Where several transformers are involved, the bank capacity is assumed to be the arithmetic sum of all transformer capacities

Hydro One Networks Inc.
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MISCELLANEOUS CHARGES

Specific Service Charges: Standard Amounts

Rate Code	Specific Service Charge - Standard Name	Calculation Method			
		2006 Rate Handbook	Standard Formula	Other Formula	Time and Materials
1	Temporary Service	$500			
2	Dispute Meter Test	$30 plus Measurement Canada fees			
3	Collection of account – no disconnection/load limiter	$30			
4	Collection/Disconnect/load limiter/reconnect (at meter) trip – regular hours	$65			
5	Collection/Disconnect/load limiter/reconnect (at meter) trip – after regular hours	$185			
6	Collection/Disconnect/load limiter/reconnect (at pole) trip – regular hours	$185			
7	Collection/Disconnect/load limiter/reconnect (at pole) trip – after regular hours	$415			
8	Account Set-up Charge	$30			
9	Arrears Certificate	$15			
10	NSF Cheque Charge	$15 + bank charges			
11	Easement Charge for Unregistered Rights	$15			
12	Late Payment Charge	1.5%/month			
13a	Retailer Services – Establishing Service Agreements (refer to Handbook for all charges)	$100/agreement/Retailer +$20/month/Retailer +$0.50/month/customer + other			
13b	Retailer Services – Other (includes Bill Ready for Retailers and Service Transactions Requests) as per the Handbook, Chapter 12	$0.30/month/customer + $0.25/request for request fee + $0.50/request for process fee			
14	Special Meter Reads	$30			
15	Billing Suspension and Terminations in Trailer Parks		$130		
16	Service Layout Fee – Basic		$405		
17	Service Layout Fee – Complex		$580		

Hydro One Networks Inc.
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18	Crossing Application – Pipeline		$2,065		
19	Crossing Application – Water		$2,525		
20	Crossing Application – Railroad		$2,565		
21	Line Staking – per meter		$3.10		
22	Central Metering – New service < 45 kW		$115		
23	Conversion to Central Metering < 45 kW		$795		
24	Conversion to Central Metering > 45 kW		$680		
25	Tingle Voltage Test – In Excess of 4 Hours (per hour – average 2 additional hours)		$105		
26	Standby Administration Charge per month (interim)		$375		
27	Sentinel Lights Rental Rate per month – Mercury Vapor			$7.00	
28	Guaranteed Units from Jan 01/91 to Aug 01/91			$26.50 / month	
29	Guaranteed Units from Jan 01/87 to Dec 31/90			$23.50 / month	
30	Joint Use for Cable and Telecom companies per pole			$22.35	
31	Joint Use for LDCs per pole			$28.61	

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Whitchurch-Stouffville Hydro-Electric Commission
Effective Date: May 1, 2008

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

APPLICATION

The application of these rates and charges shall be in accordance with The Licence of The Distributor and any Codes, Guidelines or Orders of The Board, and amendments thereto as approved by The Board, which may be applicable to the administration of this schedule.
No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code, Guideline or Order of the Board, and amendments thereto as approved by the Board, or as specified herein
This schedule does not contain any rates and charges relating to the electricity commodity (e.g. the Regulated Price Plan).

EFFECTIVE DATES

DISTRIBUTION RATES - May 1, 2008 for all consumption or deemed consumption services used on or after that date.

MISCELLANEOUS CHARGES - May 1, 2008 for all charges billed to customers on or after that date.
RETAIL TRANSMISSION RATES - May 1, 2008 for all consumption or deemed consumption services used on or after that date.
LOSS FACTOR ADJUSTMENT – for all consumption or deemed consumption services billed following May 1, 2008 or later

SERVICE CLASSIFICATIONS

Residential
This classification refers to all service supplied to single-family dwelling units for domestic or household purpose. Multi-unit residential establishments such as apartment buildings supplied through one service (bulk metered) will normally be classified as General Service, but, at Hydro One's discretion, up to four residential units may be classified as residential. Where electricity service is provided to combined residential and business (including agricultural usage) and the wiring does not provide for separate metering, the classification shall be at the discretion of Hydro One based on such considerations as the estimated predominant consumption.
Further servicing details are available in the utility's Conditions of Service.

General Service
This classification refers to all service supplied to premises other than those classified as Residential or Lighting. Some General Service accounts are energy(kWh)-billed, and some are demand(kW)-billed. Further servicing details are available in the utility's Conditions of Service.

Unmetered Scattered Load
This classification refers to certain instances where connections can be provided without metering. These loads are generally small in size and consistent in magnitude of load. Hydro One reserves the right to review all cases and may require that a meter be installed at its sole discretion. Services that can be unmetered include cable TV amplifiers, telephone switching devices, phone booths, bus shelters, rail way crossing signals, traffic signals, and other small fixed loads.
Further servicing details are available in the utility's Conditions of Service (including in the "Unmetered Connections" section).

Hydro One Networks Inc.
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Street Lighting

This classification refers to accounts for the distribution and supply of electrical energy for street lighting. Street lights are devices owned by or operated for the road authority and/or the municipal corporation. These street lights in fact belong to the Street Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Sentinel Lighting

This classification refers to accounts for a separate service to a sentinel light. These sentinel lights in fact belong to the Sentinel Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Urban Density Classification

Customers who meet the Urban Density Criteria of being in an area containing 3,000 or more customers with a line density of at least 60 customers per kilometre, will be mapped to an Urban customer classification.

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MONTHLY RATES AND CHARGES

Residential - UR/R1 Whitchurch Stouffville

Service Charge	$	10.95
Distribution Volumetric Rate	$ / kWh	0.0230
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0012
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0002)
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0047
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0045
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service Less Than 50 kW (Energy-Billed) - UGe/GSe Whitchurch Stouffville

Service Charge	$	18.62
Distribution Volumetric Rate	$ / kWh	0.0200
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0004
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0006)
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0036
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0033
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service 50 kW or Greater (Demand-Billed) - UGd/GSd Whitchurch Stouffville

Service Charge	$	22.84
Distribution Volumetric Rate	$ / kW	7.15
Regulatory Asset Recovery - Rider #2	$ / kW	0.13
Regulatory Asset Recovery - Rider #3	$ / kW	(0.27)
Retail Transmission Rate - Network Service Rate (4)	$ / kW	1.41
Retail Transmission Rate - Line and Transformation Connection Service Rate (4)	$ / kW	1.27
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

Hydro One Networks Inc.

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Whitchurch-Stouffville Hydro-Electric Commission

Effective Date: May 1, 2008

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Unmetered, Scattered Load

Service Charge	$	13.76
Distribution Volumetric Rate	$ / kWh	0.0200
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0004
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0006)
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0035
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0032
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

(3) For energy-only metered customers, the billing determinant is the customer's metered energy consumption adjusted by the total loss factor as approved by the Board for Acquired LDC customers.
(4) For demand billed customers, appropriate loss factors must be applied to the applicable tariffs. Also the billing determinant for the Line and Transformation Connection Services rate is the customer's peak demand in the billing period. The billing determinant for the Network Services rate is: for non-interval-metered customers, the peak demand in the billing period, and for interval-metered customers, the peak demand between 7 AM and 7 PM local time on IESO business days

Customer-Supplied Transformation Allowance

Applicable to customers providing their own transformers

Demand-billed	$ / kW	0.60
Energy-billed	$ / kWh	0.0014

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Loss Factors

Residential	1.078
General Service Less Than 50 kW (Energy-Billed)	1.092
General Service 50 kW or Greater (Demand-Billed)	1.061
Unmetered Scattered Load	1.092

Transformer Loss Allowance

Applicable to customers requiring a billing adjustment for transformer losses as the result of being metered on the primary side of a transformer. The following uniform values shall be applied to measured demand and energy to calculate transformer losses for voltages up to and including 50 kV (as metered on the primary side):

(a) 1.5% for transformer installations up to an individual bank capacity of 400 kVA,
(b) 1.0% for bank capacities over 400 kVA.

Alternatively, transformer losses may be determined from transformer test data, and measured demand and energy adjusted accordingly

For services which are not demand metered, an assumed demand of 50% of the transformer capacity will be used to calculate the loss allowance. Where several transformers are involved, the bank capacity is assumed to be the arithmetic sum of all transformer capacities

Hydro One Networks Inc.
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This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

MISCELLANEOUS CHARGES

Specific Service Charges: Standard Amounts

Rate Code	Specific Service Charge - Standard Name	Calculation Method			
		2006 Rate Handbook	Standard Formula	Other Formula	Time and Materials
1	Temporary Service	$500			
2	Dispute Meter Test	$30 plus Measurement Canada fees			
3	Collection of account – no disconnection/load limiter	$30			
4	Collection/Disconnect/load limiter/reconnect (at meter) trip – regular hours	$65			
5	Collection/Disconnect/load limiter/reconnect (at meter) trip – after regular hours	$185			
6	Collection/Disconnect/load limiter/reconnect (at pole) trip – regular hours	$185			
7	Collection/Disconnect/load limiter/reconnect (at pole) trip – after regular hours	$415			
8	Account Set-up Charge	$30			
9	Arrears Certificate	$15			
10	NSF Cheque Charge	$15 + bank charges			
11	Easement Charge for Unregistered Rights	$15			
12	Late Payment Charge	1.5%/month			
13a	Retailer Services – Establishing Service Agreements (refer to Handbook for all charges)	$100/agreement/Retailer +$20/month/Retailer +$0.50/month/customer + other			
13b	Retailer Services – Other (includes Bill Ready for Retailers and Service Transactions Requests) as per the Handbook, Chapter 12	$0.30/month/customer + $0.25/request for request fee + $0.50/request for process fee			
14	Special Meter Reads	$30			
15	Service Layout Fee – Basic		$495		
16	Service Layout Fee – Complex		$690		
17	Crossing Application – Pipeline		$2,445		
18	Crossing Application – Water		$3,045		
19	Crossing Application – Railroad		$2,945		
20	Line Staking – per meter		$3.70		
21	Central Metering – New service < 45 kW		$115		
22	Conversion to Central Metering < 45 kW		$915		
23	Conversion to Central Metering > 45 kW		$800		
24	Tingle Voltage Test – In Excess of 4 Hours (per hour – average 2 additional hours)		$125		
25	Standby Administration Charge per month		$440		
26	Sentinel Lights Rental Rate per month			$7.10	
27	Sentinel Pole Rental Rate per month			$4.15	
28	Joint Use for Cable and Telecom companies per pole			$22.35	
29	Joint Use for LDCs per pole			$28.61	

Hydro One Networks Inc.
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This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

APPLICATION

The application of these rates and charges shall be in accordance with The Licence of The Distributor and any Codes, Guidelines or Orders of The Board, and amendments thereto as approved by The Board, which may be applicable to the administration of this schedule.
No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code, Guideline or Order of the Board, and amendments thereto as approved by the Board, or as specified herein
This schedule does not contain any rates and charges relating to the electricity commodity (e.g. the Regulated Price Plan).

EFFECTIVE DATES

DISTRIBUTION RATES - May 1, 2007 for all consumption or deemed consumption services used on or after that date.

MISCELLANEOUS CHARGES - May 1, 2007 for all charges billed to customers on or after that date.
RETAIL TRANSMISSION RATES - May 1, 2007 for all consumption or deemed consumption services used on or after that date.
LOSS FACTOR ADJUSTMENT – May 1, 2007

SERVICE CLASSIFICATIONS

Residential
This classification (note 1) refers to all service supplied to single-family dwelling units for domestic or household purpose. Multi-unit residential establishments such as apartment buildings supplied through one service (bulk metered) will normally be classified as General Service, but, at Hydro One's discretion, up to four residential units may be classified as residential. Where electricity service is provided to combined residential and business (including agricultural usage) and the wiring does not provide for separate metering, the classification shall be at the discretion of Hydro One based on such considerations as the estimated predominant consumption.
Further servicing details are available in the utility's Conditions of Service.

General Service
This classification (note 1) refers to all service supplied to premises other than those classified as Residential or Lighting. Some General Service accounts are energy(kWh)-billed, and some are demand(kW)-billed. Further servicing details are available in the utility's Conditions of Service. Also, see note 2.

Unmetered Scattered Load
This classification refers to certain instances where connections can be provided without metering. These loads are generally small in size and consistent in magnitude of load. Hydro One reserves the right to review all cases and may require that a meter be installed at its sole discretion. Services that can be unmetered include cable TV amplifiers, telephone switching devices, phone booths, bus shelters, rail way crossing signals, traffic signals, and other small fixed loads.
Further servicing details are available in the utility's Conditions of Service (including in the "Unmetered Connections" section).

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Street Lighting

This classification refers to accounts for the distribution and supply of electrical energy for street lighting. Street lights are devices owned by or operated for the road authority and/or the municipal corporation. These street lights in fact belong to the Street Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Sentinel Lighting

This classification refers to accounts for a separate service to a sentinel light. These sentinel lights in fact belong to the Sentinel Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Interim Demand-Side Management Time-of-Use

This is potentially applicable to Demand-billed General Service accounts. See Note 2 below.

Note (1): Classification descriptions are paraphrases from the document "Hydro One Networks Inc. - Distribution Customers Conditions of Service - August 2004"

Note (2):

Interim Demand-Side Management Time-of-Use Rates: demand charges will be based on demand during the on-peak periods.

Criteria: Customers' electricity consumption (kW) in the off-peak period is at least twice the electricity consumption (kW) during the on-peak period.

Definition of Time Periods: The on-peak hours will be between 0700 hours to 1900 hours Eastern Standard Time during the winter (standard time) on IESO business days and 0600 hours to 1800 hours Eastern Standard Time during the summer (daylight savings time) on IESO business days. The off-peak period constitutes all of the remaining hours.

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MONTHLY RATES AND CHARGES

Residential

Service Charge	$	10.54
Distribution Volumetric Rate	$ / kWh	0.0102
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0036
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0012
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0055
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0047
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service - Energy Billed (less than 50 kW)

Service Charge	$	21.85
Distribution Volumetric Rate	$ / kWh	0.0093
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0011
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0004
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0050
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0043
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service - Demand Billed (50 kW or greater)

Service Charge	$	21.85
Distribution Volumetric Rate	$ / kW	2.93
Regulatory Asset Recovery - Rider #1	$ / kW	0.35
Regulatory Asset Recovery - Rider #2	$ / kW	0.13
Retail Transmission Rate - Network Service Rate (4)	$ / kW	1.94
Retail Transmission Rate - Line and Transformation Connection Service Rate (4)	$ / kW	1.61
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

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Unmetered, Scattered Load

Service Charge	$	10.46
Distribution Volumetric Rate	$ / kWh	0.0093
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0011
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0004
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0050
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0043
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

(3) For energy-only metered customers, the billing determinant is the customer's metered energy consumption adjusted by the total loss factor as approved by the Board for Acquired LDC customers.
(4) For demand billed customers, appropriate loss factors must be applied to the applicable tariffs. Also the billing determinant for the Line and Transformation Connection Services rate is the customer's peak demand in the billing period. The billing determinant for the Network Services rate is: for non-interval-metered customers, the peak demand in the billing period, and for interval-metered customers, the peak demand between 7 AM and 7 PM local time on IESO business days

Interim Demand-Side Management Time-of-Use

See the "Service Classifications" section of this schedule.

Customer-Supplied Transformation Allowance

Applicable to demand-billed customers providing their own transformers
Primary Voltage under 50 kV (per kW)

Single Phase	$ / kW	0.20
Three Phase	$ / kW	0.60

Hydro One Networks Inc.
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Loss Factors

Supply Facilities Loss Factor	1.0045
Distribution Loss Factors	
Customer less than 5,000 kW	1.0500
Customer greater than or equal to 5,000 kW	1.0100
Total Loss Factors	
Customer less than 5,000 kW	1.0545
Customer greater than or equal to 5,000 kW	1.0145

Transformer Loss Allowance

Applicable to customers requiring a billing adjustment for transformer losses as the result of being metered on the primary side of a transformer. The following uniform values shall be applied to measured demand and energy to calculate transformer losses for voltages up to and including 50 kV (as metered on the primary side):

(a) 1.5% for transformer installations up to an individual bank capacity of 400 kVA,
(b) 1.0% for bank capacities over 400 kVA.

Alternatively, transformer losses may be determined from transformer test data, and measured demand and energy adjusted accordingly

For services which are not demand metered, an assumed demand of 50% of the transformer capacity will be used to calculate the loss allowance. Where several transformers are involved, the bank capacity is assumed to be the arithmetic sum of all transformer capacities

Hydro One Networks Inc.
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MISCELLANEOUS CHARGES

Specific Service Charges: Standard Amounts

Rate Code	Specific Service Charge - Standard Name	Calculation Method			
		2006 Rate Handbook	Standard Formula	Other Formula	Time and Materials
1	Temporary Service	$500			
2	Dispute Meter Test	$30 plus Measurement Canada fees			
3	Collection of account – no disconnection/load limiter	$30			
4	Collection/Disconnect/load limiter/reconnect (at meter) trip – regular hours	$65			
5	Collection/Disconnect/load limiter/reconnect (at meter) trip – after regular hours	$185			
6	Collection/Disconnect/load limiter/reconnect (at pole) trip – regular hours	$185			
7	Collection/Disconnect/load limiter/reconnect (at pole) trip – after regular hours	$415			
8	Account Set-up Charge	$30			
9	Arrears Certificate	$15			
10	NSF Cheque Charge	$15 + bank charges			
11	Easement Charge for Unregistered Rights	$15			
12	Late Payment Charge	1.5%/month			
13a	Retailer Services – Establishing Service Agreements (refer to Handbook for all charges)	$100/agreement/Retailer +$20/month/Retailer +$0.50/month/customer + other			
13b	Retailer Services – Other (includes Bill Ready for Retailers and Service Transactions Requests) as per the Handbook, Chapter 12	$0.30/month/customer + $0.25/request for request fee + $0.50/request for process fee			
14	Special Meter Reads	$30			
15	Billing Suspension and Terminations in Trailer Parks		$130		
16	Service Layout Fee – Basic		$405		
17	Service Layout Fee – Complex		$580		

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18	Crossing Application – Pipeline		$2,065		
19	Crossing Application – Water		$2,525		
20	Crossing Application – Railroad		$2,565		
21	Line Staking – per meter		$3.10		
22	Central Metering – New service < 45 kW		$115		
23	Conversion to Central Metering < 45 kW		$795		
24	Conversion to Central Metering > 45 kW		$680		
25	Tingle Voltage Test – In Excess of 4 Hours (per hour – average 2 additional hours)		$105		
26	Standby Administration Charge per month (interim)		$375		
27	Sentinel Lights Rental Rate per month – Mercury Vapor			$7.00	
28	Guaranteed Units from Jan 01/91 to Aug 01/91			$26.50 / month	
29	Guaranteed Units from Jan 01/87 to Dec 31/90			$23.50 / month	
30	Joint Use for Cable and Telecom companies per pole			$22.35	
31	Joint Use for LDCs per pole			$28.61	

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Woodville Hydro-Electric System
Effective Date: May 1, 2008

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

APPLICATION

The application of these rates and charges shall be in accordance with The Licence of The Distributor and any Codes, Guidelines or Orders of The Board, and amendments thereto as approved by The Board, which may be applicable to the administration of this schedule.
No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code, Guideline or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.
This schedule does not contain any rates and charges relating to the electricity commodity (e.g. the Regulated Price Plan).

EFFECTIVE DATES

DISTRIBUTION RATES - May 1, 2008 for all consumption or deemed consumption services used on or after that date.

MISCELLANEOUS CHARGES - May 1, 2008 for all charges billed to customers on or after that date.
RETAIL TRANSMISSION RATES - May 1, 2008 for all consumption or deemed consumption services used on or after that date.
LOSS FACTOR ADJUSTMENT – for all consumption or deemed consumption services billed following May 1, 2008 or later

SERVICE CLASSIFICATIONS

Residential
This classification refers to all service supplied to single-family dwelling units for domestic or household purpose. Multi-unit residential establishments such as apartment buildings supplied through one service (bulk metered) will normally be classified as General Service, but, at Hydro One's discretion, up to four residential units may be classified as residential. Where electricity service is provided to combined residential and business (including agricultural usage) and the wiring does not provide for separate metering, the classification shall be at the discretion of Hydro One based on such considerations as the estimated predominant consumption.
Further servicing details are available in the utility's Conditions of Service.

General Service
This classification refers to all service supplied to premises other than those classified as Residential or Lighting. Some General Service accounts are energy(kWh)-billed, and some are demand(kW)-billed. Further servicing details are available in the utility's Conditions of Service.

Unmetered Scattered Load
This classification refers to certain instances where connections can be provided without metering. These loads are generally small in size and consistent in magnitude of load. Hydro One reserves the right to review all cases and may require that a meter be installed at its sole discretion. Services that can be unmetered include cable TV amplifiers, telephone switching devices, phone booths, bus shelters, rail way crossing signals, traffic signals, and other small fixed loads.
Further servicing details are available in the utility's Conditions of Service (including in the "Unmetered Connections" section).

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Woodville Hydro-Electric System
Effective Date: May 1, 2008

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

Street Lighting

This classification refers to accounts for the distribution and supply of electrical energy for street lighting. Street lights are devices owned by or operated for the road authority and/or the municipal corporation. These street lights in fact belong to the Street Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Sentinel Lighting

This classification refers to accounts for a separate service to a sentinel light. These sentinel lights in fact belong to the Sentinel Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Urban Density Classification

Customers who meet the Urban Density Criteria of being in an area containing 3,000 or more customers with a line density of at least 60 customers per kilometre, will be mapped to an Urban customer classification.

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Woodville Hydro-Electric System
Effective Date: May 1, 2008

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

MONTHLY RATES AND CHARGES

Residential - R1 Woodville

Service Charge	$	6.82
Distribution Volumetric Rate	$ / kWh	0.0200
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0026
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0004)
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0047
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0046
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service Less Than 50 kW (Energy-Billed) - GSe Woodville

Service Charge	$	19.87
Distribution Volumetric Rate	$ / kWh	0.0321
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0048
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0006)
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0035
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0032
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service 50 kW or Greater (Demand-Billed) - GSd Woodville

Service Charge	$	23.47
Distribution Volumetric Rate	$ / kW	9.22
Regulatory Asset Recovery - Rider #2	$ / kW	1.35
Regulatory Asset Recovery - Rider #3	$ / kW	(0.22)
Retail Transmission Rate - Network Service Rate (4)	$ / kW	1.11
Retail Transmission Rate - Line and Transformation Connection Service Rate (4)	$ / kW	1.00
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Woodville Hydro-Electric System
Effective Date: May 1, 2008

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

Unmetered, Scattered Load

Service Charge	$	11.38
Distribution Volumetric Rate	$ / kWh	0.0200
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0048
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0006)
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0035
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0032
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

(3) For energy-only metered customers, the billing determinant is the customer's metered energy consumption adjusted by the total loss factor as approved by the Board for Acquired LDC customers.
(4) For demand billed customers, appropriate loss factors must be applied to the applicable tariffs. Also the billing determinant for the Line and Transformation Connection Services rate is the customer's peak demand in the billing period. The billing determinant for the Network Services rate is: for non-interval-metered customers, the peak demand in the billing period, and for interval-metered customers, the peak demand between 7 AM and 7 PM local time on IESO business days

Customer-Supplied Transformation Allowance

Applicable to customers providing their own transformers

Demand-billed	$ / kW	0.60
Energy-billed	$ / kWh	0.0014

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Woodville Hydro-Electric System
Effective Date: May 1, 2008

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Loss Factors

Residential	1.085
General Service Less Than 50 kW (Energy-Billed)	1.092
General Service 50 kW or Greater (Demand-Billed)	1.061
Unmetered Scattered Load	1.092

Transformer Loss Allowance

Applicable to customers requiring a billing adjustment for transformer losses as the result of being metered on the primary side of a transformer. The following uniform values shall be applied to measured demand and energy to calculate transformer losses for voltages up to and including 50 kV (as metered on the primary side):

(a) 1.5% for transformer installations up to an individual bank capacity of 400 kVA,
(b) 1.0% for bank capacities over 400 kVA.

Alternatively, transformer losses may be determined from transformer test data, and measured demand and energy adjusted accordingly

For services which are not demand metered, an assumed demand of 50% of the transformer capacity will be used to calculate the loss allowance. Where several transformers are involved, the bank capacity is assumed to be the arithmetic sum of all transformer capacities

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Woodville Hydro-Electric System
Effective Date: May 1, 2008

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

MISCELLANEOUS CHARGES

Specific Service Charges: Standard Amounts

Rate Code	Specific Service Charge - Standard Name	Calculation Method			
		2006 Rate Handbook	Standard Formula	Other Formula	Time and Materials
1	Temporary Service	$500			
2	Dispute Meter Test	$30 plus Measurement Canada fees			
3	Collection of account – no disconnection/load limiter	$30			
4	Collection/Disconnect/load limiter/reconnect (at meter) trip – regular hours	$65			
5	Collection/Disconnect/load limiter/reconnect (at meter) trip – after regular hours	$185			
6	Collection/Disconnect/load limiter/reconnect (at pole) trip – regular hours	$185			
7	Collection/Disconnect/load limiter/reconnect (at pole) trip – after regular hours	$415			
8	Account Set-up Charge	$30			
9	Arrears Certificate	$15			
10	NSF Cheque Charge	$15 + bank charges			
11	Easement Charge for Unregistered Rights	$15			
12	Late Payment Charge	1.5%/month			
13a	Retailer Services – Establishing Service Agreements (refer to Handbook for all charges)	$100/agreement/Retailer +$20/month/Retailer +$0.50/month/customer + other			
13b	Retailer Services – Other (includes Bill Ready for Retailers and Service Transactions Requests) as per the Handbook, Chapter 12	$0.30/month/customer + $0.25/request for request fee + $0.50/request for process fee			
14	Special Meter Reads	$30			
15	Service Layout Fee – Basic		$495		
16	Service Layout Fee – Complex		$690		
17	Crossing Application – Pipeline		$2,445		
18	Crossing Application – Water		$3,045		
19	Crossing Application – Railroad		$2,945		
20	Line Staking – per meter		$3.70		
21	Central Metering – New service < 45 kW		$115		
22	Conversion to Central Metering < 45 kW		$915		
23	Conversion to Central Metering > 45 kW		$800		
24	Tingle Voltage Test – In Excess of 4 Hours (per hour – average 2 additional hours)		$125		
25	Standby Administration Charge per month		$440		
26	Sentinel Lights Rental Rate per month			$7.10	
27	Sentinel Pole Rental Rate per month			$4.15	
28	Joint Use for Cable and Telecom companies per pole			$22.35	
29	Joint Use for LDCs per pole			$28.61	

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Woodville Hydro-Electric System
Effective Date: May 1, 2007

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APPLICATION

The application of these rates and charges shall be in accordance with The Licence of The Distributor and any Codes, Guidelines or Orders of The Board, and amendments thereto as approved by The Board, which may be applicable to the administration of this schedule.
No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code, Guideline or Order of the Board, and amendments thereto as approved by the Board, or as specified herein
This schedule does not contain any rates and charges relating to the electricity commodity (e.g. the Regulated Price Plan).

EFFECTIVE DATES

DISTRIBUTION RATES - May 1, 2007 for all consumption or deemed consumption services used on or after that date.

MISCELLANEOUS CHARGES - May 1, 2007 for all charges billed to customers on or after that date.
RETAIL TRANSMISSION RATES - May 1, 2007 for all consumption or deemed consumption services used on or after that date.
LOSS FACTOR ADJUSTMENT – May 1, 2007

SERVICE CLASSIFICATIONS

Residential
This classification (note 1) refers to all service supplied to single-family dwelling units for domestic or household purpose. Multi-unit residential establishments such as apartment buildings supplied through one service (bulk metered) will normally be classified as General Service, but, at Hydro One’s discretion, up to four residential units may be classified as residential. Where electricity service is provided to combined residential and business (including agricultural usage) and the wiring does not provide for separate metering, the classification shall be at the discretion of Hydro One based on such considerations as the estimated predominant consumption.
Further servicing details are available in the utility’s Conditions of Service.

General Service
This classification (note 1) refers to all service supplied to premises other than those classified as Residential or Lighting. Some General Service accounts are energy(kWh)-billed, and some are demand(kW)-billed. Further servicing details are available in the utility’s Conditions of Service. Also, see note 2.

Unmetered Scattered Load
This classification refers to certain instances where connections can be provided without metering. These loads are generally small in size and consistent in magnitude of load. Hydro One reserves the right to review all cases and may require that a meter be installed at its sole discretion. Services that can be unmetered include cable TV amplifiers, telephone switching devices, phone booths, bus shelters, rail way crossing signals, traffic signals, and other small fixed loads.
Further servicing details are available in the utility’s Conditions of Service (including in the "Unmetered Connections" section).

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Woodville Hydro-Electric System
Effective Date: May 1, 2007

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Street Lighting

This classification refers to accounts for the distribution and supply of electrical energy for street lighting. Street lights are devices owned by or operated for the road authority and/or the municipal corporation. These street lights in fact belong to the Street Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Sentinel Lighting

This classification refers to accounts for a separate service to a sentinel light. These sentinel lights in fact belong to the Sentinel Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Interim Demand-Side Management Time-of-Use

This is potentially applicable to Demand-billed General Service accounts. See Note 2 below.

Note (1): Classification descriptions are paraphrases from the document "Hydro One Networks Inc. - Distribution Customers Conditions of Service - August 2004"

Note (2):

Interim Demand-Side Management Time-of-Use Rates: demand charges will be based on demand during the on-peak periods.

Criteria: Customers' electricity consumption (kW) in the off-peak period is at least twice the electricity consumption (kW) during the on-peak period.

Definition of Time Periods: The on-peak hours will be between 0700 hours to 1900 hours Eastern Standard Time during the winter (standard time) on IESO business days and 0600 hours to 1800 hours Eastern Standard Time during the summer (daylight savings time) on IESO business days. The off-peak period constitutes all of the remaining hours.

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
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MONTHLY RATES AND CHARGES

Residential

Service Charge	$	3.78
Distribution Volumetric Rate	$ / kWh	0.0095
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0051
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0026
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0055
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0047
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service - Energy Billed (less than 50 kW)

Service Charge	$	16.89
Distribution Volumetric Rate	$ / kWh	0.0157
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0067
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0048
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0050
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0043
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service - Demand Billed (50 kW or greater)

Service Charge	$	16.89
Distribution Volumetric Rate	$ / kW	4.34
Regulatory Asset Recovery - Rider #1	$ / kW	2.12
Regulatory Asset Recovery - Rider #2	$ / kW	1.35
Retail Transmission Rate - Network Service Rate (4)	$ / kW	1.94
Retail Transmission Rate - Line and Transformation Connection Service Rate (4)	$ / kW	1.61
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Woodville Hydro-Electric System
Effective Date: May 1, 2007

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Unmetered, Scattered Load

Service Charge	$	7.98
Distribution Volumetric Rate	$ / kWh	0.0157
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0067
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0048
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0050
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0043
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

(3) For energy-only metered customers, the billing determinant is the customer’s metered energy consumption adjusted by the total loss factor as approved by the Board for Acquired LDC customers.
(4) For demand billed customers, appropriate loss factors must be applied to the applicable tariffs. Also the billing determinant for the Line and Transformation Connection Services rate is the customer’s peak demand in the billing period. The billing determinant for the Network Services rate is: for non-interval-metered customers, the peak demand in the billing period, and for interval-metered customers, the peak demand between 7 AM and 7 PM local time on IESO business days

Interim Demand-Side Management Time-of-Use

See the "Service Classifications" section of this schedule.

Customer-Supplied Transformation Allowance

Applicable to demand-billed customers providing their own transformers
Primary Voltage under 50 kV (per kW)

Single Phase	$ / kW	0.20
Three Phase	$ / kW	0.60

Hydro One Networks Inc.
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Woodville Hydro-Electric System
Effective Date: May 1, 2007

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Loss Factors

Supply Facilities Loss Factor	1.0045
Distribution Loss Factors	
Customer less than 5,000 kW	1.0500
Customer greater than or equal to 5,000 kW	1.0100
Total Loss Factors	
Customer less than 5,000 kW	1.0545
Customer greater than or equal to 5,000 kW	1.0145

Transformer Loss Allowance

Applicable to customers requiring a billing adjustment for transformer losses as the result of being metered on the primary side of a transformer. The following uniform values shall be applied to measured demand and energy to calculate transformer losses for voltages up to and including 50 kV (as metered on the primary side):

(a) 1.5% for transformer installations up to an individual bank capacity of 400 kVA,
(b) 1.0% for bank capacities over 400 kVA.

Alternatively, transformer losses may be determined from transformer test data, and measured demand and energy adjusted accordingly

For services which are not demand metered, an assumed demand of 50% of the transformer capacity will be used to calculate the loss allowance. Where several transformers are involved, the bank capacity is assumed to be the arithmetic sum of all transformer capacities

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Woodville Hydro-Electric System
Effective Date: May 1, 2007

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

MISCELLANEOUS CHARGES

Specific Service Charges: Standard Amounts

Rate Code	Specific Service Charge - Standard Name	Calculation Method			
		2006 Rate Handbook	Standard Formula	Other Formula	Time and Materials
1	Temporary Service	$500			
2	Dispute Meter Test	$30 plus Measurement Canada fees			
3	Collection of account – no disconnection/load limiter	$30			
4	Collection/Disconnect/load limiter/reconnect (at meter) trip – regular hours	$65			
5	Collection/Disconnect/load limiter/reconnect (at meter) trip – after regular hours	$185			
6	Collection/Disconnect/load limiter/reconnect (at pole) trip – regular hours	$185			
7	Collection/Disconnect/load limiter/reconnect (at pole) trip – after regular hours	$415			
8	Account Set-up Charge	$30			
9	Arrears Certificate	$15			
10	NSF Cheque Charge	$15 + bank charges			
11	Easement Charge for Unregistered Rights	$15			
12	Late Payment Charge	1.5%/month			
13a	Retailer Services – Establishing Service Agreements (refer to Handbook for all charges)	$100/agreement/Retailer +$20/month/Retailer +$0.50/month/customer + other			
13b	Retailer Services – Other (includes Bill Ready for Retailers and Service Transactions Requests) as per the Handbook, Chapter 12	$0.30/month/customer + $0.25/request for request fee + $0.50/request for process fee			
14	Special Meter Reads	$30			
15	Billing Suspension and Terminations in Trailer Parks		$130		
16	Service Layout Fee – Basic		$405		
17	Service Layout Fee – Complex		$580		

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Woodville Hydro-Electric System
Effective Date: May 1, 2007

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

18	Crossing Application – Pipeline		$2,065		
19	Crossing Application – Water		$2,525		
20	Crossing Application – Railroad		$2,565		
21	Line Staking – per meter		$3.10		
22	Central Metering – New service < 45 kW		$115		
23	Conversion to Central Metering < 45 kW		$795		
24	Conversion to Central Metering > 45 kW		$680		
25	Tingle Voltage Test – In Excess of 4 Hours (per hour – average 2 additional hours)		$105		
26	Standby Administration Charge per month (interim)		$375		
27	Sentinel Lights Rental Rate per month – Mercury Vapor			$7.00	
28	Guaranteed Units from Jan 01/91 to Aug 01/91			$26.50 / month	
29	Guaranteed Units from Jan 01/87 to Dec 31/90			$23.50 / month	
30	Joint Use for Cable and Telecom companies per pole			$22.35	
31	Joint Use for LDCs per pole			$28.61	

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Village of Wyoming Hydro Electric Commission
Effective Date: May 1, 2008

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

APPLICATION

The application of these rates and charges shall be in accordance with The Licence of The Distributor and any Codes, Guidelines or Orders of The Board, and amendments thereto as approved by The Board, which may be applicable to the administration of this schedule.
No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code, Guideline or Order of the Board, and amendments thereto as approved by the Board, or as specified herein
This schedule does not contain any rates and charges relating to the electricity commodity (e.g. the Regulated Price Plan).

EFFECTIVE DATES

DISTRIBUTION RATES - May 1, 2008 for all consumption or deemed consumption services used on or after that date.

MISCELLANEOUS CHARGES - May 1, 2008 for all charges billed to customers on or after that date.
RETAIL TRANSMISSION RATES - May 1, 2008 for all consumption or deemed consumption services used on or after that date.
LOSS FACTOR ADJUSTMENT – for all consumption or deemed consumption services billed following May 1, 2008 or later

SERVICE CLASSIFICATIONS

Residential
This classification refers to all service supplied to single-family dwelling units for domestic or household purpose. Multi-unit residential establishments such as apartment buildings supplied through one service (bulk metered) will normally be classified as General Service, but, at Hydro One's discretion, up to four residential units may be classified as residential. Where electricity service is provided to combined residential and business (including agricultural usage) and the wiring does not provide for separate metering, the classification shall be at the discretion of Hydro One based on such considerations as the estimated predominant consumption.
Further servicing details are available in the utility's Conditions of Service.

General Service
This classification refers to all service supplied to premises other than those classified as Residential or Lighting. Some General Service accounts are energy(kWh)-billed, and some are demand(kW)-billed. Further servicing details are available in the utility's Conditions of Service.

Unmetered Scattered Load
This classification refers to certain instances where connections can be provided without metering. These loads are generally small in size and consistent in magnitude of load. Hydro One reserves the right to review all cases and may require that a meter be installed at its sole discretion. Services that can be unmetered include cable TV amplifiers, telephone switching devices, phone booths, bus shelters, rail way crossing signals, traffic signals, and other small fixed loads.
Further servicing details are available in the utility's Conditions of Service (including in the "Unmetered Connections" section).

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Village of Wyoming Hydro Electric Commission
Effective Date: May 1, 2008

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

Street Lighting

This classification refers to accounts for the distribution and supply of electrical energy for street lighting. Street lights are devices owned by or operated for the road authority and/or the municipal corporation. These street lights in fact belong to the Street Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Sentinel Lighting

This classification refers to accounts for a separate service to a sentinel light. These sentinel lights in fact belong to the Sentinel Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Urban Density Classification

Customers who meet the Urban Density Criteria of being in an area containing 3,000 or more customers with a line density of at least 60 customers per kilometre, will be mapped to an Urban customer classification.

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Service Area Formerly Served by
Village of Wyoming Hydro Electric Commission
Effective Date: May 1, 2008

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

MONTHLY RATES AND CHARGES

Residential - R1 Wyoming

Service Charge	$	12.88
Distribution Volumetric Rate	$ / kWh	0.0190
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0011
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0004)
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0047
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0046
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service Less Than 50 kW (Energy-Billed) - GSe Wyoming

Service Charge	$	20.75
Distribution Volumetric Rate	$ / kWh	0.0246
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0007
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0006)
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0035
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0032
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service 50 kW or Greater (Demand-Billed) - GSd Wyoming

Service Charge	$	24.35
Distribution Volumetric Rate	$ / kW	9.22
Regulatory Asset Recovery - Rider #2	$ / kW	0.23
Regulatory Asset Recovery - Rider #3	$ / kW	(0.22)
Retail Transmission Rate - Network Service Rate (4)	$ / kW	1.11
Retail Transmission Rate - Line and Transformation Connection Service Rate (4)	$ / kW	1.00
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

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This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

Unmetered, Scattered Load

Service Charge	$	12.32
Distribution Volumetric Rate	$ / kWh	0.0200
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0007
Regulatory Asset Recovery - Rider #3	$ / kWh	(0.0006)
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0035
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0032
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

(3) For energy-only metered customers, the billing determinant is the customer’s metered energy consumption adjusted by the total loss factor as approved by the Board for Acquired LDC customers.
(4) For demand billed customers, appropriate loss factors must be applied to the applicable tariffs. Also the billing determinant for the Line and Transformation Connection Services rate is the customer’s peak demand in the billing period. The billing determinant for the Network Services rate is: for non-interval-metered customers, the peak demand in the billing period, and for interval-metered customers, the peak demand between 7 AM and 7 PM local time on IESO business days

Customer-Supplied Transformation Allowance

Applicable to customers providing their own transformers		
Demand-billed	$ / kW	0.60
Energy-billed	$ / kWh	0.0014

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Loss Factors

Residential	1.085
General Service Less Than 50 kW (Energy-Billed)	1.092
General Service 50 kW or Greater (Demand-Billed)	1.061
Unmetered Scattered Load	1.092

Transformer Loss Allowance

Applicable to customers requiring a billing adjustment for transformer losses as the result of being metered on the primary side of a transformer. The following uniform values shall be applied to measured demand and energy to calculate transformer losses for voltages up to and including 50 kV (as metered on the primary side):

(a) 1.5% for transformer installations up to an individual bank capacity of 400 kVA,
(b) 1.0% for bank capacities over 400 kVA.

Alternatively, transformer losses may be determined from transformer test data, and measured demand and energy adjusted accordingly

For services which are not demand metered, an assumed demand of 50% of the transformer capacity will be used to calculate the loss allowance. Where several transformers are involved, the bank capacity is assumed to be the arithmetic sum of all transformer capacities

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MISCELLANEOUS CHARGES

Specific Service Charges: Standard Amounts

Rate Code	Specific Service Charge - Standard Name	Calculation Method			
		2006 Rate Handbook	Standard Formula	Other Formula	Time and Materials
1	Temporary Service	$500			
2	Dispute Meter Test	$30 plus Measurement Canada fees			
3	Collection of account – no disconnection/load limiter	$30			
4	Collection/Disconnect/load limiter/reconnect (at meter) trip – regular hours	$65			
5	Collection/Disconnect/load limiter/reconnect (at meter) trip – after regular hours	$185			
6	Collection/Disconnect/load limiter/reconnect (at pole) trip – regular hours	$185			
7	Collection/Disconnect/load limiter/reconnect (at pole) trip – after regular hours	$415			
8	Account Set-up Charge	$30			
9	Arrears Certificate	$15			
10	NSF Cheque Charge	$15 + bank charges			
11	Easement Charge for Unregistered Rights	$15			
12	Late Payment Charge	1.5%/month			
13a	Retailer Services – Establishing Service Agreements (refer to Handbook for all charges)	$100/agreement/Retailer +$20/month/Retailer +$0.50/month/customer + other			
13b	Retailer Services – Other (includes Bill Ready for Retailers and Service Transactions Requests) as per the Handbook, Chapter 12	$0.30/month/customer + $0.25/request for request fee + $0.50/request for process fee			
14	Special Meter Reads	$30			
15	Service Layout Fee – Basic		$495		
16	Service Layout Fee – Complex		$690		
17	Crossing Application – Pipeline		$2,445		
18	Crossing Application – Water		$3,045		
19	Crossing Application – Railroad		$2,945		
20	Line Staking – per meter		$3.70		
21	Central Metering – New service < 45 kW		$115		
22	Conversion to Central Metering < 45 kW		$915		
23	Conversion to Central Metering > 45 kW		$800		
24	Tingle Voltage Test – In Excess of 4 Hours (per hour – average 2 additional hours)		$125		
25	Standby Administration Charge per month		$440		
26	Sentinel Lights Rental Rate per month			$7.10	
27	Sentinel Pole Rental Rate per month			$4.15	
28	Joint Use for Cable and Telecom companies per pole			$22.35	
29	Joint Use for LDCs per pole			$28.61	

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This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

APPLICATION

The application of these rates and charges shall be in accordance with The Licence of The Distributor and any Codes, Guidelines or Orders of The Board, and amendments thereto as approved by The Board, which may be applicable to the administration of this schedule.
No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code, Guideline or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.
This schedule does not contain any rates and charges relating to the electricity commodity (e.g. the Regulated Price Plan).

EFFECTIVE DATES

DISTRIBUTION RATES - May 1, 2007 for all consumption or deemed consumption services used on or after that date.

MISCELLANEOUS CHARGES - May 1, 2007 for all charges billed to customers on or after that date.
RETAIL TRANSMISSION RATES - May 1, 2007 for all consumption or deemed consumption services used on or after that date.
LOSS FACTOR ADJUSTMENT – May 1, 2007

SERVICE CLASSIFICATIONS

Residential
This classification (note 1) refers to all service supplied to single-family dwelling units for domestic or household purpose. Multi-unit residential establishments such as apartment buildings supplied through one service (bulk metered) will normally be classified as General Service, but, at Hydro One's discretion, up to four residential units may be classified as residential. Where electricity service is provided to combined residential and business (including agricultural usage) and the wiring does not provide for separate metering, the classification shall be at the discretion of Hydro One based on such considerations as the estimated predominant consumption.
Further servicing details are available in the utility's Conditions of Service.

General Service
This classification (note 1) refers to all service supplied to premises other than those classified as Residential or Lighting. Some General Service accounts are energy(kWh)-billed, and some are demand(kW)-billed. Further servicing details are available in the utility's Conditions of Service. Also, see note 2.

Unmetered Scattered Load
This classification refers to certain instances where connections can be provided without metering. These loads are generally small in size and consistent in magnitude of load. Hydro One reserves the right to review all cases and may require that a meter be installed at its sole discretion. Services that can be unmetered include cable TV amplifiers, telephone switching devices, phone booths, bus shelters, rail way crossing signals, traffic signals, and other small fixed loads.
Further servicing details are available in the utility's Conditions of Service (including in the "Unmetered Connections" section).

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Street Lighting

This classification refers to accounts for the distribution and supply of electrical energy for street lighting. Street lights are devices owned by or operated for the road authority and/or the municipal corporation. These street lights in fact belong to the Street Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Sentinel Lighting

This classification refers to accounts for a separate service to a sentinel light. These sentinel lights in fact belong to the Sentinel Lighting class of the Hydro One core Retail rates. For their rates, see the Hydro One core Retail rates. Further servicing details are available in the utility's Conditions of Service.

Interim Demand-Side Management Time-of-Use

This is potentially applicable to Demand-billed General Service accounts. See Note 2 below.

Note (1): Classification descriptions are paraphrases from the document "Hydro One Networks Inc. - Distribution Customers Conditions of Service - August 2004"

Note (2):

Interim Demand-Side Management Time-of-Use Rates: demand charges will be based on demand during the on-peak periods.

Criteria: Customers' electricity consumption (kW) in the off-peak period is at least twice the electricity consumption (kW) during the on-peak period.

Definition of Time Periods: The on-peak hours will be between 0700 hours to 1900 hours Eastern Standard Time during the winter (standard time) on IESO business days and 0600 hours to 1800 hours Eastern Standard Time during the summer (daylight savings time) on IESO business days. The off-peak period constitutes all of the remaining hours.

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MONTHLY RATES AND CHARGES

Residential

Service Charge	$	11.52
Distribution Volumetric Rate	$ / kWh	0.0081
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0036
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0011
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0055
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0047
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service - Energy Billed (less than 50 kW)

Service Charge	$	17.36
Distribution Volumetric Rate	$ / kWh	0.0145
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0016
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0007
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0050
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0043
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

General Service - Demand Billed (50 kW or greater)

Service Charge	$	17.36
Distribution Volumetric Rate	$ / kW	4.57
Regulatory Asset Recovery - Rider #1	$ / kW	0.52
Regulatory Asset Recovery - Rider #2	$ / kW	0.23
Retail Transmission Rate - Network Service Rate (4)	$ / kW	1.94
Retail Transmission Rate - Line and Transformation Connection Service Rate (4)	$ / kW	1.61
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

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Unmetered, Scattered Load

Service Charge	$	8.22
Distribution Volumetric Rate	$ / kWh	0.0145
Regulatory Asset Recovery - Rider #1	$ / kWh	0.0016
Regulatory Asset Recovery - Rider #2	$ / kWh	0.0007
Retail Transmission Rate - Network Service Rate (3)	$ / kWh	0.0050
Retail Transmission Rate - Line and Transformation Connection Service Rate (3)	$ / kWh	0.0043
Wholesale Market Service Rate (3)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (3)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

(3) For energy-only metered customers, the billing determinant is the customer’s metered energy consumption adjusted by the total loss factor as approved by the Board for Acquired LDC customers.
(4) For demand billed customers, appropriate loss factors must be applied to the applicable tariffs. Also the billing determinant for the Line and Transformation Connection Services rate is the customer’s peak demand in the billing period. The billing determinant for the Network Services rate is: for non-interval-metered customers, the peak demand in the billing period, and for interval-metered customers, the peak demand between 7 AM and 7 PM local time on IESO business days

Interim Demand-Side Management Time-of-Use

See the "Service Classifications" section of this schedule.

Customer-Supplied Transformation Allowance

Applicable to demand-billed customers providing their own transformers
Primary Voltage under 50 kV (per kW)

Single Phase	$ / kW	0.20
Three Phase	$ / kW	0.60

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This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

Loss Factors

Supply Facilities Loss Factor	1.0045
Distribution Loss Factors	
Customer less than 5,000 kW	1.0500
Customer greater than or equal to 5,000 kW	1.0100
Total Loss Factors	
Customer less than 5,000 kW	1.0545
Customer greater than or equal to 5,000 kW	1.0145

Transformer Loss Allowance

Applicable to customers requiring a billing adjustment for transformer losses as the result of being metered on the primary side of a transformer. The following uniform values shall be applied to measured demand and energy to calculate transformer losses for voltages up to and including 50 kV (as metered on the primary side):

(a) 1.5% for transformer installations up to an individual bank capacity of 400 kVA,

(b) 1.0% for bank capacities over 400 kVA.

Alternatively, transformer losses may be determined from transformer test data, and measured demand and energy adjusted accordingly

For services which are not demand metered, an assumed demand of 50% of the transformer capacity will be used to calculate the loss allowance. Where several transformers are involved, the bank capacity is assumed to be the arithmetic sum of all transformer capacities

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MISCELLANEOUS CHARGES

Specific Service Charges: Standard Amounts

Rate Code	Specific Service Charge - Standard Name	Calculation Method			
		2006 Rate Handbook	Standard Formula	Other Formula	Time and Materials
1	Temporary Service	$500			
2	Dispute Meter Test	$30 plus Measurement Canada fees			
3	Collection of account – no disconnection/load limiter	$30			
4	Collection/Disconnect/load limiter/reconnect (at meter) trip – regular hours	$65			
5	Collection/Disconnect/load limiter/reconnect (at meter) trip – after regular hours	$185			
6	Collection/Disconnect/load limiter/reconnect (at pole) trip – regular hours	$185			
7	Collection/Disconnect/load limiter/reconnect (at pole) trip – after regular hours	$415			
8	Account Set-up Charge	$30			
9	Arrears Certificate	$15			
10	NSF Cheque Charge	$15 + bank charges			
11	Easement Charge for Unregistered Rights	$15			
12	Late Payment Charge	1.5%/month			
13a	Retailer Services – Establishing Service Agreements (refer to Handbook for all charges)	$100/agreement/Retailer +$20/month/Retailer +$0.50/month/customer + other			
13b	Retailer Services – Other (includes Bill Ready for Retailers and Service Transactions Requests) as per the Handbook, Chapter 12	$0.30/month/customer + $0.25/request for request fee + $0.50/request for process fee			
14	Special Meter Reads	$30			
15	Billing Suspension and Terminations in Trailer Parks		$130		
16	Service Layout Fee – Basic		$405		
17	Service Layout Fee – Complex		$580		

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18	Crossing Application – Pipeline		$2,065		
19	Crossing Application – Water		$2,525		
20	Crossing Application – Railroad		$2,565		
21	Line Staking – per meter		$3.10		
22	Central Metering – New service < 45 kW		$115		
23	Conversion to Central Metering < 45 kW		$795		
24	Conversion to Central Metering > 45 kW		$680		
25	Tingle Voltage Test – In Excess of 4 Hours (per hour – average 2 additional hours)		$105		
26	Standby Administration Charge per month (interim)		$375		
27	Sentinel Lights Rental Rate per month – Mercury Vapor			$7.00	
28	Guaranteed Units from Jan 01/91 to Aug 01/91			$26.50 / month	
29	Guaranteed Units from Jan 01/87 to Dec 31/90			$23.50 / month	
30	Joint Use for Cable and Telecom companies per pole			$22.35	
31	Joint Use for LDCs per pole			$28.61	

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Sub-Transmission (ST) Class
Effective Date: May 1, 2008

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

APPLICATION

The application of these rates and charges shall be in accordance with The Licence of The Distributor and any Codes, Guidelines or Orders of The Board, and amendments thereto as approved by The Board, which may be applicable to the administration of this schedule.
No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code, Guideline or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.
This schedule does not contain any rates and charges relating to the electricity commodity (e.g. the Regulated Price Plan).

EFFECTIVE DATES

DISTRIBUTION RATES - May 1, 2008 for all consumption or deemed consumption services used on or after that date.

MISCELLANEOUS CHARGES - May 1, 2008 for all charges billed to customers on or after that date.
RETAIL TRANSMISSION RATES - May 1, 2008 for all consumption or deemed consumption services used on or after that date.
LOSS FACTOR ADJUSTMENT – for all consumption or deemed consumption services billed following May 1, 2008 or later

SERVICE CLASSIFICATIONS

Sub-Transmission (ST)
This classification refers to
a) Embedded supply to Local Distribution Companies (LDCs), "Embedded" meaning receiving supply via Hydro One Distribution assets, and where Hydro One is the Host distributor to the Embedded LDC. Situations where the LDC is supplied via Specific Facilities are included.
or
b) load which:
i) is three-phase; and
ii) is directly connected to and supplied from Hydro One Distribution assets between 44 kV and 13.8 kV inclusive; the meaning of "directly" includes HON not owning the local transformation; and
iii) is greater than 500 kW (monthly measured maximum demand averaged over the most recent calendar year or whose forecasted monthly average demand over twelve consecutive months is greater than 500 kW).
Any new customer satisfying the criteria for ST classification, will be classified as an ST account.
Further servicing details are available in the utility’s Conditions of Service.

Hydro One Networks Inc.
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MONTHLY RATES AND CHARGES

Service charge	$	188
Meter Charge (for Hydro One ownership)	$	553
Facility charge for connection to Common ST Lines (44 kV to 13.8 kV) (11)	$ / kW (1)	0.58
Facility charge for connection to Specific ST Lines (44 kV to 13.8 kV)	$ / km (2)	729
Facility charge for connection to Specific Primary Lines (12.5 kV to 4.16 kV)	$ / km (2)	565
Facility charge for connection to high-voltage (≥ 13.8 kV secondary) delivery High Voltage Distribution Station	$ / kW (1)	1.42
Facility charge for connection to low-voltage (< 13.8 kV secondary) delivery High Voltage Distribution Station	$ / kW (1)	2.66
Facility charge for connection to low voltage (< 13.8 kV secondary) Low Voltage Distribution Station	$ / kW (3)	1.24
Regulatory Asset Recovery - Rider #2, for source class:		note (4)
LDC and Direct	$	note (5)
Customers of Retail classes:		
T	$ / kW (4)	0.09
G3	$ / kW (4)	0.15
UG	$ / kW (4)	0.11
F3	$ / kW (4)	0.16
General Service customers of acquired LDCs:		
Arnprior	$ / kW (4)	0.20
Arran-Elderslie	$ / kW (4)	0.28
Blyth	$ / kW (4)	0.64
Brockville	$ / kW (4)	0.12
Caledon CH	$ / kW (4)	0.27
Caledon OH	$ / kW (4)	0.24
Campbellford-Seymour	$ / kW (4)	0.17
Durham	$ / kW (4)	0.18
Erin	$ / kW (4)	0.25
Forest	$ / kW (4)	0.20
Georgian Bay Energy	$ / kW (4)	0.19
Glencoe	$ / kW (4)	0.44
Lindsay	$ / kW (4)	0.19
Markdale	$ / kW (4)	0.13
Napanee	$ / kW (4)	0.20
North Dundas	$ / kW (4)	0.11
North Perth	$ / kW (4)	0.13
Perth	$ / kW (4)	0.12
Quinte West	$ / kW (4)	0.18
Shelburne	$ / kW (4)	0.08
Smiths Falls	$ / kW (4)	0.13

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Springwater	$ / kW (4)	0.53
Thorold	$ / kW (4)	0.20
West Elgin	$ / kW (4)	0.21
Whitchurch Stouffville	$ / kW (4)	0.13
Large User customers of acquired LDCs:		
Arnprior	$ / kW (4)	0.09
Brockville	$ / kW (4)	0.21
Caledon	$ / kW (4)	0.16
Georgian Bay Energy	$ / kW (4)	0.17
Quinte West	$ / kW (4)	0.11
Regulatory Asset Recovery - Rider #3		
Rider 3A - General (12)	$ / kW	0.02
Rider 3B - Wholesale Market Service Charge (13)	$ / kW	(0.29)
Retail Transmission Service Rates (8)(9)(10):		
Network Service Rate (6)	$ / kW	2.01
Line Connection Service Rate (7)	$ / kW	0.50
Transformation Connection Service Rate (7)	$ / kW	1.38
Both Line and Transformation Connection Service Rate (7)	$ / kW	1.88
Wholesale Market Service Rate (9)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (9)	$ / kWh	0.0010
Standard Supply Service (Regulated Price Plan) - Administration Charge	$	0.25

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
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Loss factors

Supply Facilities Loss Factor	1.006
Distribution Loss Factors	
Embedded Delivery Points (metering at station)	1.000
Embedded Delivery Points (metering away from station)	1.028
Total Loss Factors	
Embedded Delivery Points (metering at station)	1.006
Embedded Delivery Points (metering away from station)	1.034

Where the feeder delivers to solely one supply point, and the metering is located away from the supplying Transformer Station or High Voltage Distribution Station, the customer will calculate the applicable losses based on an engineering study. The study will identify a Site Specific Loss Adjustment (SSLA) and a radial line loss as appropriate, to which will be added non-technical losses consistent with the method inherent in the existing Distribution Loss Factor. This calculated value would replace the average Total Loss Factor.

Where the metering is at the supplying TS or HVDS (either inside the fence or immediately outside the fence), the DLF will not be applied, but solely the losses associated with the transformation at the station will be applied, ie. the approved Supply Facilities Loss Factor.

Where there is no metering at the customer supply point, causing quantities to be calculated by taking the differences between other metering, to avoid double-counting losses, the normal application of the DLF to the difference in metering quantities can be replaced by a calculation uplifting the meter quantities separately.

Transformer Loss Adjustment

Applicable to ST customers requiring a billing adjustment for transformer losses as the result of being metered on the secondary side of a transformer.
This uniform value shall be added to measured demand and energy (as metered on the secondary side) to adjust for transformer losses: 1.0%
Alternatively, transformer losses may be determined from transformer test data, and measured demand and energy adjusted accordingly.

Hydro One Networks Inc.
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Effective Date: May 1, 2008

NOTES:

Note (1): The basis of the charge is the customer's monthly maximum demand. For a customer with multiple delivery points served from the same Transformer Station or High Voltage Distribution Station, the aggregated demand will be the applicable billing determinant. Demand is not aggregated between stations.

Note (2): The basis of the charge is kilometres of line, within the supplied LDC's service area, supplying solely that LDC.

Note (3): These rates are based on the "non-coincident demand" at each delivery point of the customer supplied by the station. This is measured as the kW demand at the delivery point at the time in the month of maximum load on the delivery point. For a customer connected through two or more distribution stations, the total charge for the connection to the shared distribution stations is the sum of the relevant charges for each of the distribution stations.

Note (4): Regulatory Asset Recovery "Rate Rider #2" began in 2006 and will end in 2010. Each ST customer will maintain the same Rate Rider #2 as it had in its pre-ST class, even if not listed above.

Note (5): Regulatory Asset Recovery "Rate Rider #2" values are specific to each LDC and each Direct.

Note (6): The monthly billing determinant for the RTSR Network Service rate is:
- for interval-metered customers the peak demand from 7 AM to 7 PM (local time) on IESO business days
- for non-interval-metered customers the non-coincident peak demand

Note (7): The monthly billing determinant for the RTSR Line and Transformation Connection Service rates is the non-coincident peak demand.

Note (8): Delivery point with respect to Retail Transmission Rates is defined as the low side of the Transformer Station that steps down voltage from above 50 kV to below 50 kV. For a customer's multiple interval-metered delivery points served from the same Transformer Station, the aggregated demand at the said delivery points on the low side of the Transformer Station will be the applicable billing determinant.

Note (9): These rates pertain to the IESO's defined point of sale; consequently, appropriate loss factors as approved by the Board and set out in Hydro One Distribution's loss factors must be applied to the metered load of energy-metered customers. Similarly, appropriate loss factors as approved by the Board and set out as Hydro One Distribution's loss factors must be applied to the applicable tariffs of demand-billed customers.

Note (10): The loss factors, and which connection service rates are applied, are determined based on the point at which the distribution utility or customer is metered for its connection to Hydro One Distribution's system. Hydro One Distribution's connection agreements with these distribution utilities and customers will establish the appropriate loss factors and connection rates to apply from Hydro One Distribution's tariff schedules.

Note (11) : The Common ST Lines rate also applies to the small amount of supply to Distributors which uses lines in the 12.5 kV to 4.16 kV range from HVDSs or LVDSs.

Note (12) : "Rider 3A - General" applies to those customers who were charged Retail Transmission Service Network Charges.

Note (13) : "Rider 3B - Wholesale Market Service Charge" applies to those customers who were charged Wholesale Market Service Charges.

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Sub-Transmission (ST) Class
Effective Date: May 1, 2008

MISCELLANEOUS CHARGES

Specific Service Charges: Standard Amounts

Rate Code	Specific Service Charge - Standard Name	Calculation Method			
		2006 Rate Handbook	Standard Formula	Other Formula	Time and Materials
1	Temporary Service	$500			
2	Dispute Meter Test	$30 plus Measurement Canada fees			
3	Collection of account – no disconnection/load limiter	$30			
4	Collection/Disconnect/load limiter/reconnect (at meter) trip – regular hours	$65			
5	Collection/Disconnect/load limiter/reconnect (at meter) trip – after regular hours	$185			
6	Collection/Disconnect/load limiter/reconnect (at pole) trip – regular hours	$185			
7	Collection/Disconnect/load limiter/reconnect (at pole) trip – after regular hours	$415			
8	Account Set-up Charge	$30			
9	Arrears Certificate	$15			
10	NSF Cheque Charge	$15 + bank charges			
11	Easement Charge for Unregistered Rights	$15			
12	Late Payment Charge	1.5%/month			
13a	Retailer Services – Establishing Service Agreements (refer to Handbook for all charges)	$100/agreement/Retailer +$20/month/Retailer +$0.50/month/customer + other			
13b	Retailer Services – Other (includes Bill Ready for Retailers and Service Transactions Requests) as per the Handbook, Chapter 12	$0.30/month/customer + $0.25/request for request fee + $0.50/request for process fee			
14	Special Meter Reads	$30			
15	Service Layout Fee – Basic		$495		
16	Service Layout Fee – Complex		$690		
17	Crossing Application – Pipeline		$2,445		
18	Crossing Application – Water		$3,045		
19	Crossing Application – Railroad		$2,945		
20	Line Staking – per meter		$3.70		
21	Central Metering – New service < 45 kW		$115		

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TARIFF OF RATES AND CHARGES
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22	Conversion to Central Metering < 45 kW		$915		
23	Conversion to Central Metering > 45 kW		$800		
24	Tingle Voltage Test – In Excess of 4 Hours (per hour – average 2 additional hours)		$125		
25	Standby Administration Charge per month		$440		
26	Sentinel Lights Rental Rate per month			$7.10	
27	Sentinel Pole Rental Rate per month			$4.15	
28	Joint Use for Cable and Telecom companies per pole			$22.35	
29	Joint Use for LDCs per pole			$28.61	

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Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Direct and Embedded LDC Classes
Effective Date: May 1, 2007

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

APPLICATION

The application of these rates and charges shall be in accordance with The Licence of The Distributor and any Codes, Guidelines or Orders of The Board, and amendments thereto as approved by The Board, which may be applicable to the administration of this schedule.
No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code, Guideline or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.
This schedule does not contain any rates and charges relating to the electricity commodity (e.g. the Regulated Price Plan).

EFFECTIVE DATES

DISTRIBUTION RATES - May 1, 2007 for all consumption or deemed consumption services used on or after that date.

MISCELLANEOUS CHARGES - May 1, 2007 for all charges billed to customers on or after that date.
RETAIL TRANSMISSION RATES - May 1, 2007 for all consumption or deemed consumption services used on or after that date.
LOSS FACTOR ADJUSTMENT – May 1, 2007.

SERVICE CLASSIFICATIONS

Direct

This classification refers to industrial or commercial customers other than acquired Large Users or Sub-transmission (T class) Customers, whose monthly measured maximum demand averaged over the most recent calendar year or whose forecasted monthly average demand over twelve consecutive months is equal to or greater than 5000 kW and who are directly connected to Hydro One Distribution’s Low Voltage (LV) system. The meaning of "directly" includes HON not owning the local transformation.
Any new customer satisfying the criteria for Direct classification, will be classified as a Direct.
Further servicing details are available in the utility’s Conditions of Service.

Embedded Local Distribution Company (LDC)

This classification refers to Embedded supply to Local Distribution Companies (LDCs), "Embedded" meaning receiving supply via Hydro One Distribution's Low Voltage (LV) system and where Hydro One is the Host distributor to the Embedded LDC. Situations where the LDC is supplied via Specific Facilities are included. Further servicing details are available in the utility’s Conditions of Service.

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Direct and Embedded LDC Classes
Effective Date: May 1, 2007

MONTHLY RATES AND CHARGES

Direct

Facility charge for shared LV Lines	$ / kW (1)	0.633
Regulatory Asset Recovery - Rider #1	$	note (4)
Regulatory Asset Recovery - Rider #2	$	note (4)
Retail Transmission Service Rates (8)(9)(10):		
Network Service Rate (6)	$ / kW	2.42
Line Connection Service Rate (7)	$ / kW	0.73
Transformation Connection Service Rate (7)	$ / kW	1.34
Both Line and Transformation Connection Service Rate (7)	$ / kW	2.07
Wholesale Market Service Rate (9)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (9)	$ / kWh	0.0010

Embedded Local Distribution Company

Facility charge for Shared LV Lines	$ / kW (1)	0.633
Facility charge for connection to Specific LV Lines	$ / km (2)	526
Facility charge for connection to Specific Distribution Lines	$ / km (2)	358
Facility charge for connection to shared high-voltage (≥ 24.9 kV) delivery High Voltage Distribution Station	$ / kW (3)	1.678
Facility charge for connection to shared low-voltage (< 24.9 kV) delivery High Voltage Distribution Station	$ / kW (3)	3.797
Facility charge for connection to shared Low Voltage Distribution Station	$ / kW (3)	2.120
Regulatory Asset Recovery - Rider #1	$	note (5)
Regulatory Asset Recovery - Rider #2	$	note (5)
Retail Transmission Service Rates (8)(9)(10):		
Network Service Rate (6)	$ / kW	2.52
Line Connection Service Rate (7)	$ / kW	0.74
Transformation Connection Service Rate (7)	$ / kW	1.35
Both Line and Transformation Connection Service Rate (7)	$ / kW	2.09
Wholesale Market Service Rate (9)	$ / kWh	0.0052
Rural or Remote Rate Protection Rate (9)	$ / kWh	0.0010

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Direct and Embedded LDC Classes
Effective Date: May 1, 2007

Loss factors

Supply Facilities Loss Factor	1.006
Distribution Loss Factors	
Embedded Delivery Points on Express Feeders	1.000
Embedded Delivery Points on Non-Express Feeders	1.028
Total Loss Factors	
Embedded Delivery Points on Express Feeders	1.006
Embedded Delivery Points on Non-Express Feeders	1.034

For Direct and Embedded LDC customers that are supplied through Express feeders, as defined below, and whom Hydro One requires to move the meter location from inside a Transformer Station (TS) or High Voltage Distribution Station (HVDS) to outside the TS or HVDS, the applicable Supply Facility Loss Factor and the Distribution Loss Factor will be determined for such customers on the basis of an engineering study to arrive at a Site Specific Loss Adjustment (SSLA) for this circumstance, including radial line loss as appropriate, and this calculated value would replace the average Total Loss Factor shown above.
Express feeders are feeders that supply only one customer, either an Embedded Distributor or Embedded Direct, with the meter currently located at the Transformer Station or High Voltage Distribution Station.

Distribution utilities receiving power directly through their own facilities from one of two dedicated High Voltage Distribution Stations (HVDS) which perform a transformation function from 115 kV to 27.6 kV, specifically distribution utilities who receive power from Hydro One Distribution's Vineland HVDS and Hydro One Distribution's Fallow field HVDS, have a Total Loss Factor of: 1.006

NOTES:

Note (1): The basis of the charge is the customer's monthly maximum demand by delivery point embedded in Hydro One Distribution's service territory.

Note (2): The basis of the charge is kilometres of line, within the supplied LDC's service area, supplying solely that LDC.

Note (3): These rates are based on the "non-coincident demand" at each delivery point of the LDC supplied by the station. This is measured as the kW demand at the delivery point at the time in the month of maximum load on the delivery point. For an LDC connected through two or more shared distribution stations, the total charge for the connection to the shared distribution stations is the sum of the relevant charges for each of the distribution stations.

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Direct and Embedded LDC Classes
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Note (4): Regulatory Asset Recovery "Rate Riders" are specific to each Direct.

Note (5): Regulatory Asset Recovery "Rate Riders" are specific to each LDC.

Note (6): The monthly billing determinant for the network service rate is the peak demand from 7 AM to 7 PM (local time) on IESO business days.

Note (7): The monthly billing determinant for the line and transformation connection service rate is the non-coincident peak by delivery point

Note (8): Delivery point with respect to Retail Transmission Rates is defined as the low side of the Transformation Station that steps down voltage from above 50 kV to below 50 kV. For a customer with delivery points served from multiple feeders connected to the same Transformation Station, the aggregated demand at the said delivery points on the low side of the Transformation Station will be the applicable billing determinant.

Note (9): These rates pertain to the IESO's defined point of sale; consequently, appropriate loss factors as approved by the Board and set out in Hydro One Distribution's loss factors must be applied to the metered load of energy-metered customers. Similarly, appropriate loss factors as approved by the Board and set out in Hydro One Distribution's loss factors must be applied to the applicable tariffs of demand-metered customers.

Note (10): The loss factors, and which connection service rates are applied, are determined based on the point at which the distribution utility or customer is connected to Hydro One Distribution's system. Hydro One Distribution's connection agreements with these distribution utilities and customers will establish the appropriate loss factors and connection rates to apply from Hydro One Distribution's tariff schedules.

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Direct and Embedded LDC Classes
Effective Date: May 1, 2007

MISCELLANEOUS CHARGES

Specific Service Charges: Standard Amounts

Rate Code	Specific Service Charge - Standard Name	Calculation Method			
		2006 Rate Handbook	Standard Formula	Other Formula	Time and Materials
1	Temporary Service	$500			
2	Dispute Meter Test	$30 plus Measurement Canada fees			
3	Collection of account – no disconnection/load limiter	$30			
4	Collection/Disconnect/load limiter/reconnect (at meter) trip – regular hours	$65			
5	Collection/Disconnect/load limiter/reconnect (at meter) trip – after regular hours	$185			
6	Collection/Disconnect/load limiter/reconnect (at pole) trip – regular hours	$185			
7	Collection/Disconnect/load limiter/reconnect (at pole) trip – after regular hours	$415			
8	Account Set-up Charge	$30			
9	Arrears Certificate	$15			
10	NSF Cheque Charge	$15 + bank charges			
11	Easement Charge for Unregistered Rights	$15			
12	Late Payment Charge	1.5%/month			
13a	Retailer Services – Establishing Service Agreements (refer to Handbook for all charges)	$100/agreement/Retailer +$20/month/Retailer +$0.50/month/customer + other			
13b	Retailer Services – Other (includes Bill Ready for Retailers and Service Transactions Requests) as per the Handbook, Chapter 12	$0.30/month/customer + $0.25/request for request fee + $0.50/request for process fee			
14	Special Meter Reads	$30			
15	Billing Suspension and Terminations in Trailer Parks		$130		
16	Service Layout Fee – Basic		$405		
17	Service Layout Fee – Complex		$580		
18	Crossing Application – Pipeline		$2,065		
19	Crossing Application – Water		$2,525		

Hydro One Networks Inc.
TARIFF OF RATES AND CHARGES
for the Direct and Embedded LDC Classes
Effective Date: May 1, 2007

20	Crossing Application – Railroad		$2,565		
21	Line Staking – per meter		$3.10		
22	Central Metering – New service < 45 kW		$115		
23	Conversion to Central Metering < 45 kW		$795		
24	Conversion to Central Metering > 45 kW		$680		
25	Tingle Voltage Test – In Excess of 4 Hours (per hour – average 2 additional hours)		$105		
26	Standby Administration Charge per month (interim)		$375		
27	Sentinel Lights Rental Rate per month – Mercury Vapor			$7.00	
28	Guaranteed Units from Jan 01/91 to Aug 01/91			$26.50 / month	
29	Guaranteed Units from Jan 01/87 to Dec 31/90			$23.50 / month	
30	Joint Use for Cable and Telecom companies per pole			$22.35	
31	Joint Use for LDCs per pole			$28.61	

MISCELLANEOUS CHARGES RATES

1.0 INTRODUCTION

Miscellaneous Charges are charges for specific services over and above the standard level of service. Each service has an approved fixed rate charged to a customer for a specific activity, or as a penalty, as in the case of late payment charges.

A description of the current services and their proposed 2008 rates can be found in Schedule 11-1 below. The rates for any service not covered in Schedule 11-1 below, but included in the Schedule 11-1 that is part of the 2006 Electricity Distribution Rate Handbook (the Handbook), May 2005 version, have been reviewed and are acceptable to Hydro One Distribution. The description for all services listed in Schedule 11-1 below can be found in either the Handbook, in Exhibit E3, Tab 1, Schedule 1 or in Exhibit D1, Tab 3, Schedule 3.

As required by the Handbook, Schedule 11-1 identifies the basis for determining the proposed rates. Schedule 11-2 details the methodology used to determine the rates not specifically set by the Handbook. The rate of each service is based on average elapsed hours required to carry out the work, as well as burdened labour rates, vehicle costs, and material. Schedule 11-3 summarizes the rates, historical volumes, 2008 forecasted volumes, and 2008 projected revenues/capital contributions for each service.

Schedule 11-1: Specific Service Charges: Standard Amounts

Rate Code	Specific Service Charge - Standard Name	Calculation Method			
		2006 Rate Handbook	Standard Formula	Other Formula	Time and Materials
1	Temporary Service	$500			
2	Dispute Meter Test	$30 plus Measurement Canada fees			
3	Collection of account – no disconnection/load limiter	$30			
4	Collection/Disconnect/load limiter/reconnect (at meter) trip – regular hours	$65			
5	Collection/Disconnect/load limiter/reconnect (at meter) trip – after regular hours	$185			
6	Collection/Disconnect/load limiter/reconnect (at pole) trip – regular hours	$185			
7	Collection/Disconnect/load limiter/reconnect (at pole) trip – after regular hours	$415			
8	Account Set-up Charge	$30			
9	Arrears Certificate	$15			
10	NSF Cheque Charge	$15 + bank charges			
11	Easement Charge for Unregistered Rights	$15			
12	Late Payment Charge	1.5%/month			
13a	Retailer Services – Establishing Service Agreements (refer to Handbook for all charges)	$100/agreement/Retailer +$20/month/Retailer +$0.50/month/customer + other			
13b	Retailer Services – Other (includes Bill Ready for Retailers and Service Transactions Requests) as per the Handbook, Chapter 12	$0.30/month/customer + $0.25/request for request fee + $0.50/request for process fee			
14	Special Meter Reads	$30			
15	Service Layout Fee – Basic		$495		
16	Service Layout Fee – Complex		$690		
17	Crossing Application – Pipeline		$2445		
18	Crossing Application – Water		$3045		
19	Crossing Application – Railroad		$2945		
20	Line Staking – per meter		$3.70		
21	Central Metering – New service < 45 kW		$115		
22	Conversion to Central Metering < 45 kW		$915		
23	Conversion to Central Metering > 45 kW		$800		
24	Tingle Voltage Test – In Excess of 4 Hours (per hour – average 2 additional hours)		$125		
25	Standby Administration Charge per month		$440		
26	Sentinel Lights Rental Rate per month			$7.10	
27	Sentinel Lights Pole Rental Rate per month			$4.15	
28	Joint Use for Cable and Telecom companies per pole			$22.35	
29	Joint Use for LDCs per pole			$28.61	

Schedule 11-2a : Specific Service Charges: Standard Formula and Amounts

Specific Service Charge Description					
Used For:					
	Service layout Fee - Basic				
		Rate/Amount	Hours/Units	O/T Factor	Calculated Cost
L	Direct Labour (Area Distribution Engineering Technician) Straight Time	$64.31	4		$257.24
A					
B					
O					
U					
R	Payroll Burden %	72.60%			$186.76
	Total Labour Cost				$444.00
O	Small Vehicle Time	12	4		$48.00
T					
H					
E					
R					
	Total Other Cost				$48.00
Total Cost					$492.00
	Specific Service Charge Value Requested - Round to nearest $5				$495.00

Specific Service Charge Description					
Used For:					
	Service Layout Fee - Complex				
		Rate/Amount	Hours/Units	O/T Factor	Calculated Cost
L	Direct Labour (Area Distribution Engineering Technician) Straight Time	$64.31	5.6		$360.14
A					
B					
O					
U					
R	Payroll Burden %	72.60%			$261.59
	Total Labour Cost				$621.59
O	Small Vehicle Time	$12	5.6		$67.20
T					
H					
E					
R					
	Total Other Cost				$67.20
Total Cost					$688.79
	Specific Service Charge Value Requested - Round to nearest $5				$690.00

Specific Service Charge Description					
Used For:					
	Crossing Application - Pipeline				
		Rate/Amount	Hours/Units	O/T Factor	Calculated Cost
L	Direct Labour (Area Distribution Engineering Technician) Straight Time	$64.31	7.95		$511.26
A	Direct Labour (Drafting) Straight Time	$66.62	11		$732.82
B					
O					
U					
R	Payroll Burden %	72.60%			$903.21
	Total Labour Cost				$2,147.29
O	Small Vehicle Time	$12	7.95		$95.40
T	Materials				$200.00
H					
E					
R					
	Total Other Cost				$295.40
Total Cost					$2,442.69
	Specific Service Charge Value Requested - Round to nearest $5				$2,445.00

Specific Service Charge Description					
Used For:					
	Crossing Application - Water				
		Rate/Amount	Hours/Units	O/T Factor	Calculated Cost
L	Direct Labour (Area Distribution Engineering Technician) Straight Time	$64.31	9.54		$613.52
A	Direct Labour (Drafting) Straight Time	$66.62	11		$732.82
B					
O					
U					
R	Payroll Burden %	72.60%			$977.44
	Total Labour Cost				$2,323.78
O	Small Vehicle Time	$12	9.54		$114.28
T	Utility Boat	$55	5.54		$304.70
H	Material				$300.00
E					
R					
	Total Other Cost				$719.18
Total Cost					$3,042.96
	Specific Service Charge Value Requested - Round to nearest $5				$3,045.00

Specific Service Charge Description					
Used For:					
	Crossing Application - Railway				
		Rate/Amount	Hours/Units	O/T Factor	Calculated Cost
L	Direct Labour (Area Distribution Engineering Technician) Straight Time	$64.31	7.95		$511.26
A	Direct Labour (Drafting) Straight Time	$66.62	11		$732.82
B					
O					
U					
R	Payroll Burden %	72.60%			$903.21
	Total Labour Cost				$2,147.29
O	Small Vehicle Time	$12	7.95		$95.40
T	Materials				$700.00
H					
E					
R					
	Total Other Cost				$795.40
Total Cost					$2,942.69
	Specific Service Charge Value Requested - Round to nearest $5				$2,945.00

1

Specific Service Charge Description					
Used For:					
	Line Staking - per meter of line				
		Rate/Amount	Hours/Units	O/T Factor	Calculated Cost
L	Direct Labour (Area Distribution Engineering Technician) Straight Time	$64.31	0.03		$1.93
A					
B					
O					
U					
R	Payroll Burden %	72.60%			$1.40
	Total Labour Cost				$3.33
O	Small Vehicle Time	$12	0.03		$0.36
T					
H					
E					
R					
	Total Other Cost				$0.36
Total Cost					$3.69
	Specific Service Charge Value Requested - Round to nearest $5				$3.70

2

Specific Service Charge Description					
Used For:					
	Central Metering - New Service				
		Rate/Amount	Hours/Units	O/T Factor	Calculated Cost
L					
A					
B					
O					
U					
R	Payroll Burden %	72.60%			
	Total Labour Cost				$0.00
O	Material				$116.19
T					
H					
E					
R					
	Total Other Cost				$116.19
Total Cost					$116.19
	Specific Service Charge Value Requested - Round to nearest $5				$115.00

Specific Service Charge Description					
Used For:					
	Conversion to Central Metering - < 45 kW				
		Rate/Amount	Hours/Units	O/T Factor	Calculated Cost
L	Direct Labour (Clerical) Straight Time	$59.10	0.44		$26.00
A	Direct Labour (Power Line Maintainer) Straight Time	$64.31	3.18		$204.51
B	Direct Labour (Area Distribution Engineering Technician) Straight Time	$64.31	2.73		$175.57
O					
U					
R	Payroll Burden %	72.60%			$294.81
	Total Labour Cost				$700.89
O	Large Vehicle Time	40	1.59		$63.60
T	Small Vehicle	12	2.73		32.76
H	Material				116.19
E					
R					
	Total Other Cost				$212.55
Total Cost					$913.44
	Specific Service Charge Value Requested - Round to nearest $5				$915.00

Specific Service Charge Description					
Used For:					
	Conversion to Central Metering - > 45 kW				
		Rate/Amount	Hours/Units	O/T Factor	Calculated Cost
L	Direct Labour (Clerical) Straight Time	$59.10	0.44		$26.00
A	Direct Labour (Area Distribution Engineering Technician) Straight Time	$64.31	2.73		$175.57
B	Direct Labour (Power Line Maintainer) Straight Time	$64.31	3.18		$204.51
O					
U					
R	Payroll Burden %	72.60%			$294.81
	Total Labour Cost				$700.89
O	Large Vehicle Time	40	1.59		$63.60
T	Small Vehicle	12	2.73		32.76
H					
E					
R					
	Total Other Cost				$96.36
Total Cost					$797.25
	Specific Service Charge Value Requested - Round to nearest $5				$800.00

Specific Service Charge Description					
Used For:					
	Tingle Voltage - In excess of 4 hours				
		Rate/Amount	Hours/Units	O/T Factor	Calculated Cost
L	Direct Labour (Area Distribution Engineering Technician) Straight Time	$64.31	1		$64.31
A					
B					
O					
U					
R	Payroll Burden %	72.60%			$46.69
	Total Labour Cost				$111.00
O	Small Vehicle Time	12	1		$12.00
T					
H					
E					
R					
	Total Other Cost				$12.00
Total Cost					$123.00
	Specific Service Charge Value Requested - Round to nearest $5				$125.00

Specific Service Charge Description					
Used For:					
	Standby Administration Charge				
		Rate/Amount	Hours/Units	O/T Factor	Calculated Cost
L	Direct Labour (Clerical) Straight Time – Billing System	$59.10	0.3		$17.73
A	Direct Labour (MP2) Straight Time – Metering Dept.	$75.02	0.5		$37.51
B	Direct Labour (MP4) Straight Time – Operations	$84.88	1.0		$84.88
O	Direct Labour (MP4) Straight Time - Rates	$84.88	1.0		$84.88
U	Direct Labour (Clerical) Straight Time - Rates	$59.10	0.5		$29.55
R					
	Payroll Burden %	72.60%			$184.80
	Total Labour Cost				$439.35
O					
T					
H					
E					
R					
	Total Other Cost				
Total Cost					$439.35
	Specific Service Charge Value Requested - Round to nearest $5				$440.00

Schedule 11-2b : Specific Service Charges: Other Formula

(a) Sentinel Lights

The proposed rate for sentinel lights has been developed as follows:

Calculation of Revenue Requirement for Sentinel Lights		
Year Ending December 31, 2008		
($ 000's)		
Line No.	**Particulars**	**2008**
1	Mid-Year Rate Base	4,514
	Cost of Service	
2	Operating, maintenance & administrative	2,184
3	Depreciation & amortization	507
4	Capital taxes	13
5	Income taxes	160

Calculation of Revenue Requirement for Sentinel Lights		
Year Ending December 31, 2008		
($ 000's)		
Line No.	**Particulars**	**2008**
6	Cost of service excluding return	2,864
7	Return on capital	309
8	Total revenue requirement	3,173
9	Mid- Year Number of Sentinel Lights	37,341
10	Annual Revenue Requirement per Light	84.97
11	Monthly Charge Per Light	7.10

Calculation of Revenue Requirement for Sentinel Light Poles		
Year Ending December 31, 2008		
($ 000's)		
Line No.	**Particulars**	**2008**
1	Mid-Year Rate Base	932
	Cost of Service	
2	Operating, maintenance & administrative	0
3	Depreciation & amortization	34
4	Capital taxes	2
5	Income taxes	14
6	Cost of service excluding return	50
7	Return on capital	64
8	Total revenue requirement	114
9	Mid- Year Number of Sentinel Light Poles	2,290
10	Annual Revenue Requirement per Light Pole	49.87
11	Monthly Charge Per Light Pole	4.15

(b) Joint Use

The Methodology to determine the Joint Use rate for Telecommunications companies was the one provided by the Ontario Energy Board (OEB) in their March 7, 2005 order for Telecommunications pole rental calculations. In the calculations, a space allocation of 21.9% as directed by the OEB for Telecommunications was used.

Calculation of JU Costs	**OEB Order**
Net Embedded Cost	$ 478.00
Depreciation per Pole	31.11
Interest	54.59
Maintenance (L&F)	7.61
Total Capital Related Costs	$ 93.31
Allocated Capital Cost	$ 20.43
Loss of Productivity	1.23
Administration	0.69
Vegetation Mgmt	0
Total Licensee Cost	**$ 22.35**

No change to the rate is being sought at this time.

The Joint Use attachment rate for LDC’s is a negotiated rate. This rate was agreed upon with the EDA on behalf of the LDC’s and has been in effect for the last 4 years. The methodology used was the same as used for the Telecommunications companies however, the space allocation used was 28.1% given that LDC attachments require more space on a pole due to safety standards. No change is being sought at this time.

Refer to Exhibit E3, Tab 1, Schedule 1 for further information.

Schedule 11-3a: Specific Service Charges: Revenue

Rate Code	Description	Amount	2004 Volume	2005 Volume	2006 Volume	Forecasted 2007 Volume	Forecasted 2008 Volume	2008 Proposed Revenue from approved rates ($)
1	Dispute Meter Test	$30	135	140	193	182	184	$5,520
2	Collection of account – no disconnection/load limiter	$30	N/A	2,585	2,300	2,300	2,300	$69,000
3	Disconnect/load limiter/reconnect (at meter) trip – regular hours	$65	4,102	9,696	10,080	10,282	10,395	$675,655
4	Disconnect/load limiter/reconnect (at meter) trip – after regular hours	$185	442	541	281	287	290	$53,608
5	Disconnect/load limiter/reconnect (at pole) trip – regular hours	$185	N/A	N/A	143	146	147	$27,281
6	Disconnect/load limiter/reconnect (at pole) trip – after regular hours	$415	N/A	N/A	7	7	7	$2,996
7	Account Set-up Charge	$30	149,345	144,437	141,778	140,392	141,800	$4,256,400
8	Arrears Certificate	$15	N/A	N/A	N/A	N/A	N/A	N/A
9	NSF Cheque Charge	$15 + bank charges	11,159	9,781	9,240	9,330	9,429	$188,577
10	Easement Charge for Unregistered Rights	$15	N/A	N/A	N/A	N/A	N/A	N/A
11	Late Payment Charge	1.5% / month	$11,393,238	$13,133,672	$13,968,999	$14,339,451	$14,491,449	$14,491,449
12a	Retailer Services – Establishing Service Agreements (rates as per the Handbook)	$100/agreement/ Retailer +$20/month/Retailer +$0.50/month/ customer	$1,300,000	$1,200,000	$1,000,000	$1,000,000	$1,000,000	$1,000,000
12b	Retailer Services – Other (includes Bill Ready for Retailers and Service Transactions Requests) as per the Handbook	$0.30/month/ customer + $0.25/request for request fee + $0.50/request for process fee	$64,000	$64,000	$63,000	$63,000	$63,000	$63,000
13	Special Meter Reads	$30	N/A	N/A	N/A	N/A	N/A	N/A
14	Tingle Voltage Test – In Excess of 4 Hours (per hour)	$105	30	30	30	30	30	$3,150
15	Standby Administration Charge	$440.00/month	0	0	0	25	25	0
16	Sentinel Lights Rental Rate per month	$7.10/month	40,603	40,029	38,754	37,812	36,870	$3,173,000
17	Sentinel Lights Pole Rental Rate per month	$4.15/month	2,490	2,513	2,377	2,319	2,261	$114,000
18	Joint Use rate for Telecom Companies per pole	$22.35	234,734	237,623	265,399	272,415	280,588	$6,271,142
19	Joint Use for LDCs per pole	$28.61	7,244	7,295	7,236	9,615	9,903	$283,325

Note: Retail codes 13a and 13b are shown in schedule 11-3a as approved rates only. The revenue generated from these service charges is not included as external revenue but can be found in the RCVA variance account as identified in Exhibit F1, Tab1, Schedule 2.

Schedule 11-3b: Specific Service Charges: Capital Contributions

Rate Code	Description	Amount	2004 Volume	2005 Volume	2006 Volume	2007 Volume	2008 Volume	2008 Proposed Capital Contributions based on approved rates ($)
1	Temporary Service	$500	211	211	211	211	211	$105,500
2	Service Layout Fee – Basic	$495	232	264	264	260	260	$128,700
3	Service Layout Fee – Complex	$690	8	N/A	N/A	10	10	$6,900
4	Crossing Application – Pipeline	$2445	4	4	2	10	10	$24,450
5	Crossing Application – Water	$3045	135	111	81	100	100	$304,500
6	Crossing Application – Railroad	$2945	16	27	8	20	20	$58,900
7	Line Staking – per meter	$3.70	289	241	205	200	200	$740
8	Central Metering – New service < 45 kW	$115	1095	1095	1095	950	950	$109,250
9	Conversion to Central Metering < 45 kW	$915	792	792	792	800	800	$732,000
10	Conversion to Central Metering > 45 kW	$800	126	126	126	150	150	$120,000

Note: “N/A” in schedule 3 infers that the data is not tracked and hence not available.

TERMS AND CONDITIONS

1.0 INTRODUCTION

This exhibit will provide evidence with respect to Hydro One Distribution's terms and conditions of service for distribution-connected customers. As required under Section 2.4 of the Distribution System Code ("Code"), Hydro One Distribution has documented its Conditions of Service that describe its operating practices and connection policies. All of the components of the Conditions of Service as outlined in Section 2.4 are covered, as well as additional important information.

Our Conditions of Service is publicly available, and a brochure summarizing terms is sent to all new customers at the time of connection and to all existing customers annually.

This filed copy of our Conditions of Service is recently updated to incorporate relevant Code changes and new industry initiatives. Updates incorporate terms related to the Regulated Price Plan, connection of embedded Generators, and the Renewable Energy Standard Offer Program. Further updates to reflect the implementation of smart meters and time-of-use rates will be required at such time as those programs are finalized. In addition, sections of the document have been rewritten or consolidated for better clarity and ease of use, for example items related to the rights and obligations of Customers are grouped to one section, and a new section on tingle and stray voltage is included.

Hydro One is providing notice to customers of the changes to Hydro One's Conditions of Service, and these terms will then be effective March 1, 2008.

Appendix A is the updated Conditions of Service for Hydro One Distribution Customers.

Hydro One Networks Inc.
Distribution Customers

Conditions of Service

OCTOBER 2007

Table of Contents

SECTION 1 INTRODUCTION

These Conditions of Service describe Hydro One Networks Inc.'s ("Hydro One") operating practices and connection policies and set out the terms and conditions upon which Hydro One offers and the Customer accepts Distribution Services.

Terms contained in these Conditions of Service or in any contract for the supply of electricity by Hydro One shall not prejudice or affect any rights, privileges, or powers vested in Hydro One by law under any federal or Ontario statute or any regulations thereunder.

The definitions of terms used in these Conditions of Service appear in section 4.0. Capitalized expressions used in these Conditions of Service have the meaning ascribed in that section.

1.1. Identification of Distributor and Service Area

Hydro One is a corporation incorporated under Ontario's *Business Corporations Act* and an electricity Distributor licensed by the OEB to distribute electricity in the service area described in Hydro One's Distribution Licence, ED-2003-0043 (the "Licence"). Hydro One's service area may be changed from time to time by the OEB.

Details of the Licence may be viewed at www.HydroOneNetworks.com.

1.2. Related Codes and Governing Laws

Hydro One and the Customer shall comply with all Applicable Laws, including the provisions of the latest editions of the following documents:

(i) *Electricity Act;*
(ii) *Ontario Energy Board Act;*
(iii) the Licence;
(iv) Affiliate Relationships Code for Electricity Distributors and Transmitters;
(v) Distribution System Code;
(vi) Retail Settlement Code;
(vii) Standard Supply Service Code; and
(viii) Relevant Rate Orders.

If there is a conflict between these Conditions of Service and any of the above, the documents listed above shall govern in order of priority indicated above. If there is a conflict between these Conditions of Service and a Connection Agreement executed by the Customer and Hydro One; the Connection Agreement shall govern. The fact that a condition, right, obligation, or other term appears in these

Conditions of Service but not in any of the documents listed above or in a Connection Agreement shall not be interpreted as a conflict or be deemed grounds for finding a conflict.

Customers and their agents planning and designing for electricity service must refer to all applicable provincial and Canadian electrical codes and all applicable federal, provincial, and municipal laws, regulations, codes and by-laws to ensure compliance with their requirements. All work shall be conducted in accordance with the latest edition of Ontario's *Occupational Health and Safety Act* (OHSA) and, where applicable, the Regulations for Construction Projects and the harmonized Electrical and Utility Safety Association (E & USA) Rule Book.

1.3. Interpretations

In these Conditions of Service:

(i) the singular includes the plural and vice versa;
(ii) the use of one gender includes the other;
(iii) the word "person" includes not only a natural person but also a firm, a body corporate, an unincorporated association and an authority;
(iv) the word "its" may mean "his", "her" or "their";
(v) the words "including", "include(s)" and "included" shall be interpreted as being without limitation;
(vi) a reference to a person includes a reference to the person's heirs, executors, administrators, successors, substitutes (including, but not limited to, persons taking by novation) and assigns;
(vii) an agreement, representation or warranty on the part of or in favour of two or more persons binds or is for the benefit of them jointly and severally;
(viii) specified periods of time refer to business days, and the number of days from a given day or the day of an act or event is to be calculated exclusive of the given day or day of the act or event; and
(ix) a reference to a day is to be interpreted as the period of time commencing at midnight and ending 24 hours later and does not include weekends and Public Holidays.

1.4. Amendments and Changes

The provisions of these Conditions of Service and any amendments made from time to time form part of the contract between Hydro One and any connected Customer, Retailer, or Generator, and these Conditions of Service supersede all previous Conditions of Service, oral or written, of Hydro One and any of its predecessor municipal electric utilities as of the effective date (Section 1.7 J) of these Conditions of Service.

In the event of changes to these Conditions of Service, Hydro One will issue an advance public notice with the Customer's bill as per Section 2.4.8 of the Distribution System Code. Customers will have ten (10) days, from receipt of the notification, to provide comments through the contacts identified in the public notice.

The Customer is responsible for contacting Hydro One to obtain the current version of these Conditions of Service. Hydro One may charge a reasonable fee for providing the Customer with a copy of these Conditions of Service. The current version of the Conditions of Service is posted on the Hydro One Web site and may be downloaded from: www.HydroOneNetworks.com.

1.5. Contact Information

For general inquiries, Hydro One can be reached during its normal business hours: Monday to Friday from 7:30 am to 8 pm. E.T. at 1-888-664-9376, by e-mail at CustomerCommunications@HydroOneNetworks.com or by writing to:

Hydro One Networks Inc.
P.O. Box 5700
Markham, Ontario
L3R 1C8

For emergency purposes, Customers can call Hydro One at 1-800-434-1235, twenty four (24) hours per day, seven (7) days per week, or the number shown on the Customer's bill.

1.6. Customer Rights and Obligations

A. Accuracy of Information

Customers have the obligation to provide Hydro One with information that is true, complete, and correct. The information is used to provide Customer service, deliver and/or supply energy, manage Customer accounts and assess credit history regarding the need for a security deposit. Hydro One may verify the accuracy of all information provided and may obtain additional credit information from a credit-reporting agency as required. If Hydro One is unable to establish the identity of the Customer based upon the information provided by the Customer, Hydro One may disconnect the Customer in accordance with Section 2.2 of these Conditions of Service.

B. Space and Access

The Customer shall provide Hydro One, free of charge or rent, with a convenient and safe place for Hydro One's Facilities and Equipment, for example, a meter, on the Customer’s premises. Hydro One assumes no risk thereby and under no circumstances will Hydro One be liable for any damages resulting from, arising out of or related to the presence of the Hydro One Facilities and Equipment.

The Customer shall not allow anyone other than an employee, or authorized agent of Hydro One, or a person lawfully entitled to do so, to repair, remove, replace, alter, inspect or tamper with the Hydro One Facilities and Equipment on the Customer’s premises.

In addition to Hydro One’s rights under Section 40 of the *Electricity Act*, Hydro One employees and Hydro One’s authorized agents may enter the Customer’s property at any time for any of the following purposes:

(i) install, inspect, read, calibrate, maintain, repair, alter, remove, or replace a meter;

(ii) inspect, maintain, repair, alter, remove, replace, or disconnect wires or other facilities used to transmit or Distribute electricity;

(iii) inspect, maintain, repair, alter, remove, and replace Hydro One Facilities and Equipment, such as sentinel lights; and

(iv) perform switching operations or interrupt the Customer’s supply to maintain or improve the supply system or to provide new or upgraded services to other Customers.

Hydro One will use reasonable efforts to exercise this power of entry during normal business hours. The Hydro One employee or authorized agent exercising this power of entry will identify himself with proper identification upon request.

Where Hydro One has requested key access for meters or meter rooms inside the Customer’s premises, key access shall be provided to Hydro One. Any exceptions to this requirement are subject to Hydro One’s written approval. Hydro One may require that a Customer relocate an inaccessible meter to an accessible location at the Customer’s expense.

C. Customer Equipment

The Customer is responsible for installation and maintenance of Customer Equipment, including vegetation maintenance around the Customer’s power lines. Customer Equipment includes, but is not limited to, power lines, poles and the base of the meter.

The Customer is responsible for ensuring that all Customer Equipment complies with all Applicable Laws, including, but not limited to, the Electrical Safety Code and is properly identified and connected for metering and operation purposes. Where applicable, Customer Equipment shall be subject to the reasonable acceptance of Hydro One and the approval of the Electrical Safety Authority. Hydro One’s approval of any Customer Equipment is solely for the purposes of Hydro One’s protection of the Distribution System. The Customer is solely responsible for protecting its own property.

The Customer shall inspect the Customer Equipment at regular intervals. Clearances must conform to the Electrical Safety Code. The Customer shall repair or replace, in a timely fashion, any Customer Equipment, including, but not limited to, poles and transformer pads, that may affect the safety, integrity or reliability of the Distribution System. If the Customer does not take such action within the time specified by Hydro One, Hydro One may disconnect the supply of power to the Customer. Hydro One’s policies and procedures with respect to the disconnection process are further described in these Conditions of Service.

If the Customer does not carry out its repairs within a reasonable time, or the repairs are not considered adequate by Hydro One or an inspection authority, Hydro One may disconnect the supply of electricity to the Customer and/or carry out the repairs at the Customer's expense, and Hydro One shall not be liable to the Customer for any damages arising as a result thereof, other than physical damage to the Customer Equipment arising directly from entry on the Customer’s property.

D. Tree and Vegetation Management

Subject to any prior agreements, Customers are responsible for all initial and continuing tree trimming, tree and brush removal for all new and existing Secondary Services, Primary Services, and Sub-transmission Services on a Customer’s property. Clearances must conform to the Electrical Safety Code. For distribution or sub-transmission lines built by the Customer, and where ownership is to be transferred to Hydro One upon Connection, the clearances must conform to Distribution Standards. Hydro One strongly recommends that a certified utility arborist or a qualified electrical contractor be hired for this work. Refer to Section 2.1.2 E for sources.

E. No Charge Outage for Upgrade or Maintenance of Customer Equipment for Safety Reasons

Hydro One will, upon at least ten (10) days’ prior notice from the Customer, once each year during normal business hours, disconnect and reconnect the Customer’s service without charge, for the Customer to upgrade or maintain Customer Equipment for safety reasons, including, but not limited to, the safe clearance of trees and vegetation from Customer lines.

F. Responsibility for Damage to Hydro One Facilities and Equipment

Hydro One Facilities and Equipment located on the Customer’s premises are in the care of and at the risk of the Customer. If any of Hydro One’s Facilities and

Equipment are damaged or destroyed by fire or any other cause other than ordinary wear and tear, the Customer shall pay Hydro One either, at Hydro One's sole discretion, the value of said Hydro One Facilities and Equipment or the cost of repairing or replacing same.

The Customer shall not build, or cause to be built, plant or maintain any structure, tree, shrub or landscaping that would or could obstruct or endanger any Hydro One Facilities and Equipment, interfere with the proper and safe operation of the Distribution System or any part thereof or affect Hydro One's compliance with any Applicable Laws. If the Customer does not remove the structure, tree, shrub or landscaping that would or could obstruct or endanger any Hydro One Facilities and Equipment, interfere with the proper and safe operation of the Distribution System or any part thereof or affect Hydro One's compliance with any Applicable Laws, Hydro One may disconnect the supply of electricity to the Customer and/or carry out the removal at the Customer's expense, and Hydro One shall not be liable to the Customer for any damages arising as a result thereof, other than physical damage arising directly from entry on the Customer's property.

G. Indemnity for Generation Facilities

The Customer shall indemnify and hold harmless Hydro One, its directors, officers, employees and authorized agents from any claims made by any third parties, related to the construction, installation, or Connection of a Generation Facility by or on behalf of the Customer or located on the Customer's property.

H. Testing Customer's Load

The Customer shall allow Hydro One to install and use meters and other equipment to conduct tests to determine the electrical characteristics of the Customer's load.

I. Automatic Reclosing Facilities

In order to restore the Distribution System, Hydro One installs facilities for automatic reclosing of circuit breakers and reclosers, and from time to time may change the reclosing time of any such reclosing facilities. The Customer shall be responsible for providing at his own expense:

(a) adequate protective equipment for any electrical apparatus which might be adversely affected by reclosing facilities; and

(b) such equipment as may be required for the proper reconnection of any apparatus or equipment of the Customer, without adversely affecting the proper functioning of the reclosing facilities.

J. Registration/Deregistration as a Wholesale Market Participant

In order for Hydro One to make the necessary changes to its billing systems, Customers who wish to register or de-register with the Independent Electricity System Operator (IESO) as a Wholesale Market Participant shall notify Hydro One in writing at least sixty (60) days in advance and complete the necessary documentation.

K. Accounts with more than one Person

If an account is opened in more than one person's name, all such persons are Customers and are jointly and severally responsible for compliance with these Conditions of Service and to pay the Rates and charges in accordance with these Conditions of Service.

1.7. Hydro One's Distributor Rights

A. Access to Customer Property

Hydro One shall have access to Customer's property in accordance with section 40 of the *Electricity Act.*

B. Tree and Vegetation Management and Removal of Obstructions

To ensure public safety and the continued reliable operation of the Distribution System Hydro One maintains its rights of way on a continued and cyclical basis. The timing of this periodic re-clearing of existing rights of way is determined by system assessments, rights of way limitations, storm damage, diseased trees, and vegetation type. Re-clearing of rights of way typically affects trees and vegetation on private property. Hydro One will notify and discuss the planned re-clearing of existing rights of way with property owners prior to performing the work in order to mitigate the impacts to the environment and the property. However, in the event of emergencies, Hydro One may be unable to notify the property owner prior to performing the work.

In any event, pursuant to subsection 40(4) of the *Electricity Act*, Hydro One may enter any land for the purpose of cutting down or removing trees, branches or other obstructions, if in the opinion of Hydro One, it is necessary to do so to maintain the safe and reliable operation of the Distribution System.

1.8. Disputes

Initial contacts for Customer complaints should be made by calling Hydro One at 1-888-664-9376 during normal business hours, Monday to Friday from 7:30 a.m. to 8 p.m. E.T. Customer complaints that cannot be resolved by calling this number will be escalated to Hydro One's Customer Relations Centre (CRC), which will serve as the primary point of contact with Hydro One. A member of the CRC will make contact with the Customer, coordinate internal complaint activities, research, investigate, and follow up (when necessary) on the complaint to ensure resolution and closure.

In the event that issues cannot be resolved between Hydro One and the Customer, complaints can be escalated to a third party complaints resolution service provider approved by the OEB. Until such time as the OEB approves an independent third party, the OEB will assume this role.

1.9. Liability

Hydro One shall be liable to a Customer and a Customer shall be liable to Hydro One only for any damages that arise directly out of the willful misconduct or negligence of:

(i) Hydro One in providing Distribution Services to the Customer;
(ii) the Customer in being connected to the Distribution System; or
(iii) Hydro One or the Customer in meeting their respective obligations or exercising their respective rights under these Conditions of Service, their licences and any other Applicable Laws.

Notwithstanding the above, neither Hydro One nor the Customer shall be liable under any circumstances whatsoever for any loss of profits or revenues, business interruption losses, loss of contract or loss of goodwill, or for any indirect, consequential, incidental or special damages, including but not limited to punitive or exemplary damages, whether any of the said liability, loss or damages arise in contract, tort or otherwise.

1.10. Force Majeure

Other than for any amounts due and payable by the Customer to Hydro One or by Hydro One to the Customer, neither Hydro One nor the Customer shall be deemed to have committed an event of default in respect of any obligation under these Conditions of Service if prevented from performing that obligation, in whole or in part, because of a Force Majeure Event.

Hydro One shall not be liable for any delay or failure in the performance of any of its obligations under these Conditions of Service due to any Force Majeure Event.

If a Force Majeure Event prevents either party from performing any of its obligations under these Conditions of Service, that party shall:

(i) other than for Force Majeure Events related to Acts of God, promptly notify the other party of the Force Majeure Event and a good faith assessment of the effect that the event will have on the former party's ability to perform any of its obligations. If the immediate notice is not in writing, it shall be confirmed in writing as soon as reasonably practical;

(ii) not be entitled to suspend performance of any of its obligations under these Conditions of Service to any greater extent or for any longer time than the Force Majeure Event requires it to do;

(iii) use its best efforts to mitigate the effects of the Force Majeure Event, remedy its inability to perform, and resume full performance of its obligations;

(iv) keep the other party continually informed of its efforts; and

(v) other than for Force Majeure Events related to Acts of God, provide written notice to the other party when it resumes performance of any obligations affected by the Force Majeure Event; and

(vi) if the Force Majeure Event is a strike, lockout or other labour dispute involving Hydro One's employees or authorized agents, Hydro One shall be entitled to discharge its obligations to notify its Customers in writing by means of placing a notice in the local newspaper, and, notwithstanding (iii) above, the settlement of any strike, lockout or labour dispute involving Hydro One's employees or authorized agents shall be within the sole discretion of Hydro One or its authorized agents, none of whom shall be under any of the obligations in (iii) above.

1.11. Coming Into Force

These Conditions of Service are effective as of March 1, 2008.

SECTION 2 DISTRIBUTION ACTIVITIES – GENERAL

A. Cable Locates

Upon request, Hydro One will locate, if able, all secondary and primary underground cables without charge. Cables installed on private property will be located at no charge to the Customer up to the point where the Customer or the Customer's contractor can safely isolate the balance of the service. If Hydro One is unable to locate an underground cable, Hydro One will provide a service disconnection and reconnection during normal working hours without charge. Hydro One will charge for underground cable locates outside normal business hours, other than in an Emergency situation.

B. Fault Locates and Repairs

Hydro One will normally locate and repair faults on all Hydro One-owned service cables without charge. In the event that a fault and/or damage is caused by the Customer or third party, the costs of repair shall be paid by the party responsible.

In the event that structures, pavement, or landscaping make the cable inaccessible for repair, the Customer shall provide all civil work, supports, vegetation and landscaping associated with any repair or replacement of the failed cable.

C. Motors and Welders

The maximum acceptable rating for a motor or combination of motors that may be started simultaneously at full voltage across the line is:

Voltage Level	Maximum Rating
120 V	2 HP
240 V	4 HP
120/208 V	6 HP
347/600 V	8 HP

Where the simultaneous motor load is more than allowable for simultaneous starting at full voltage across the line, the Customer shall use reduced-voltage starters that are acceptable to Hydro One.

Motors and welders in excess of the following thresholds are subject to approval by Hydro One.

- Welder size exceeds 30 kVA
- Motor size exceeds the following levels:

Voltage Level	1-phase motor	3-phase motor
16/27.6 kV	> 20 hp	> 100 hp
Below 16/27.6 kV	> 10 hp	> 25 hp

2.1. Connections

A. Early Consultation

The Customer shall submit to Hydro One, well in advance of commencement of construction, the following information:

(i) required in-service date;
(ii) service entrance capacity and voltage rating of the service entrance equipment;
(iii) detailed information on heating equipment, air conditioners and any other appliances and/or equipment that demands a high consumption of electrical energy;
(iv) detailed information, as per application forms for the connection of a Generation Facility, for all generators being connected in parallel with the Distribution System;
(v) survey plan or site plan, at the request of Hydro One indicating the proposed location of the service entrance equipment with respect to public rights-of-way and property lot lines;
(vi) all information required to set up an account for billing purposes; and
(vii) additional information as noted on the Hydro One Web site at www.HydroOneNetworks.com or specified by Hydro One, in writing.

B. Common Service Taps

Standard Customers shall provide, at their expense and in compliance with the Electrical Safety Code, a secondary or primary pole or an underground primary voltage line, for common service taps. Hydro One will supply two neighbouring

Standard Customers from the same Customer-supplied facility (common service taps) only when the following conditions are met:

(i) the Standard Customers and Hydro One agree on the location of the portion of the Standard Customer's supplied and built facility to be owned by Hydro One ("Common Line");
(ii) the Common Line is located on property owned by one or both of the neighbouring Standard Customers;
(iii) the Common Line to be owned by Hydro One is built to Hydro One's Distribution Standards; and
(iv) the Common Line is transferred with easements and tree-clearing rights to Hydro One for a nominal fee.

If all the above conditions cannot be met, each Customer shall supply, install, and own a separate line on its own property.

C. Temporary Connections

If a Customer requires temporary service, the two types and applicable charges are as follows:

(i) temporary service that at a later date is to be relocated to a permanent service site: a standard temporary service fee is charged;
(ii) temporary service that has a finite Connection and cancellation time period, for example, service to construction sites: The material cost of the transformation and metering will be provided by Hydro One without charge. All other labour and material costs to install and remove the service will be paid by the Customer based on Hydro One's actual costs.

D. Sub-transmission Service – Exclusive of Embedded Distributor

Sub-transmission Service may be a Basic Connection or an Expansion. However, transformation, conductor or a credit for conductor is not provided by Hydro One. A MIST Meter is required for all new Sub-transmission Customers with an average estimated load exceeding 200 kilowatt ("kW") annually, and the Sub-transmission Customer shall contribute to the cost, such contribution to be determined by Hydro One using a discounted cash flow model in compliance with Appendix B of the Distribution System Code.

E. Large Users and Direct Customers

Transformation and conductor are not provided for Large Users and Direct Customers. A MIST Meter is required for all Connections and is provided either by the Large User and Direct Customer or by Hydro One, in which latter case the

Large User and Direct Customer shall contribute to the cost, such contribution to be determined by Hydro One using a discounted cash flow model in compliance with Appendix B of the Distribution System Code.

F. Embedded Distributor

Transformation and conductor are not provided for an Embedded Distributor. A MIST Meter is required for all Connections and is provided either by the Embedded Distributor or by Hydro One, in which latter case the Embedded Distributor shall contribute to the cost, such contribution to be determined by Hydro One using a discounted cash flow model in compliance with Appendix B of the Distribution System Code.

G. Central Metered Services

At the request of a Customer, Hydro One may, at its discretion, supply a Single-Phase Standard Customer with a central metering service to two or more buildings. The Standard Customer shall:

(i) pay the difference between the cost of the central metering and the meter that Hydro One would have provided to the Standard Customer under the Standard Supply Code;
(ii) comply strictly with the Electrical Safety Code and Hydro One's Distribution Standards;
(iii) have an appropriately sized main disconnect and equipment for each service connected to the central metering service; and
(iv) supply and install, at its own expense, all conductor, poles, and underground conductor, as required on its private property.

The maximum number of services to be connected at the central metering point is four. Additional services must be connected downstream of the central metering point.

Where Hydro One requires that a Customer install the central metering, the costs set out in Section 2.3.7 shall apply.

H. Primary Metered Services

When a Customer requests a Primary Metered Service (connected at the primary voltage level) or the design of the layout makes secondary metering impractical, the Customer shall install, own, and maintain, at its own expense, the entire distribution system required downstream from the metering point, including conductors, poles, and transformation. Customers requiring non-standard secondary voltages are responsible for the incremental cost of primary metering over the cost of the non-standard secondary metering.

Secondary metering is considered practical when the Customer's entire load can be metered on the secondary side of the transformation.

I. Travel Trailer Parks (Intermittent/Seasonal Use)

The park authority/owner will provide, own, and maintain all Distribution facilities, including transformers and individual metering as required, within the park boundary. Such facilities will be subject to the approval of the Electrical Safety Authority. All electricity supplied for park services will be combined and billed under one General Service account. If secondary metering is not practical, a Primary Metered Service will be required at or near the park property limit.

Notwithstanding the foregoing, for existing parks where Hydro One owns, as of the date of these Conditions of Service, the transformers on the Customer's Distribution line and the secondary metering within the park boundary, Hydro One will continue to own these facilities provided that no new services are added.

When the park owner requests an increase in the size of the services, additional services within the park or such additional services are required, the following conditions shall apply:

(i) the park owner will, subject to OEB approval, purchase the existing Distribution facilities owned by Hydro One within the park boundary ("Existing Park Facilities"). If the park owner does not purchase the Existing Park Facilities, the park owner may choose to replace the Existing Park Facilities at its own expense and will own the new facilities;

(ii) the park owner shall supply and install new Distribution facilities including transformers, etc., as required for the addition;

(iii) Hydro One shall remove existing secondary metering, install a primary metering unit at or near the Customer's property limit without charge, and consolidate existing contracts into one General Service account;

(iv) park owners of privately-owned systems shall meet all the requirements of the Electrical Safety Authority.

J. Trailer Parks Other than Travel Trailer Parks

Parks with mobile homes will be treated as a subdivision, with Hydro One taking ownership of the primary distribution system only under the following conditions:

i) there is a registered plan of subdivision;

ii) construction is to Hydro One's design standards; and

iii) easements and cutting rights are granted to Hydro One for all primary lines.

Ownership of the primary distribution system will be the park owner's responsibility in all other cases.

K. Service and Supply Locations

Hydro One reserves the right to determine the service supply and Connection locations. The Customer shall obtain Hydro One's approval prior to the construction of electrical facilities.

One service layout or estimate is normally provided without charge. The Customer shall pay a fee to Hydro One if the Customer changes any of its Connection requirements after the initial layout or estimate is provided or the Customer requests another estimate or layout for the same Connection.

L. Number of Delivery Points

Normally Hydro One permits only one Delivery Point per property. Where it is not technically or financially feasible to have only one Delivery Point, Hydro One may, in its sole discretion, connect additional Delivery Point(s) on the same property. Each Delivery Point must be separately metered and billed at the appropriate rate classification.

M. Delivery Point Capacity

The maximum size of Primary Service or Secondary Service at any Delivery Point is as follows:

(i) for a Single Phase Customer Connection: 167 kVA of transformation capacity, Customers that require service above 167 kVA must either install or convert to a three-phase service

(ii) for a Three Phase Customer Connection:

a) if the Distribution voltage is 13 kV or less: 501 kVA of transformation capacity

b) if the Distribution voltage is above 13 kV or a subtransmission system is not present (e.g. the Distribution Network is supplied from a Distribution Station that is directly connected to a high voltage Transmission Line), the maximum size is determined by Hydro One based on system configuration and capability.

N. Transformation - Overhead Transformers

The maximum overhead transformer sizes for standard secondary voltages provided by Hydro One are:

(i) for a Single Phase overhead Standard Customer Connection: 167 kVA;
(ii) for a Three Phase Standard Customer Connection: 501 kVA.

Customers requiring non-standard secondary voltages will be responsible for installing, owning, maintaining and operating their own transformer.

O. Transformation - Pad- Mounted Transformers (underground type)

Maximum transformer sizes supplied by Hydro One are:

(i) for Single Phase Standard Customer Connection: 150 kVA
(ii) for a Three Phase Standard Customer Connection: 500 kVA (Y-Y)

Standard Customers requesting underground pad-mounted type transformers will pay the difference in material and installation costs between the overhead installation and the underground installation, and will supply and install at the Standard Customer's expense an appropriate transformer pad. The Customer should contact Hydro One for further information on transformer pads.

Standard Customers may install their own pad-mounted transformer larger than 500 kVA and will be entitled to a Customer-owned transformation allowance. Customer-owned transformers shall be properly sized, acceptable to Hydro One and meet the energy efficiency standards in CSA C802.1.

At the Customer's request, Hydro One may install, own and maintain transformer installations of 750 kVA and 1000 kVA, 27.6 kV – 347/600 V, Y-Y and the Customer shall contribute 100 per cent of Hydro One's actual costs. The Customer will not receive a Customer-supplied transformation allowance.

Customers requiring non-standard secondary voltages will be responsible for installing, owning, maintaining and operating their own transformer.

P. Transformation - Station Transformers

Where Customers require transformation capacity in excess of the sizes noted above, the Customer shall supply the station site, pad, transformers, fencing, structure, and distribution line on Private Property in accordance with the Electrical Safety Code. Customer-owned transformers shall be properly sized, acceptable to Hydro One and meet the energy efficiency standards in CSA C802.1

The high voltage protection of a Customer supplied and owned transformer(s) shall co-ordinate with the Distribution System protection.

An appropriate transformation ownership allowance shall be applied, as approved by the OEB. Hydro One does not supply live bushing (station type) transformers for new Connections.

Existing Hydro One-owned station type transformers serving a Customer will be maintained to the end of their useful life. At the end of the useful life, the Customer will supply, install, own, and maintain the replacement unit.

Q. Transformation - Additional Station Transformers

In the event that additional transformation is required due to load growth, and Hydro One owns the original transformer, Customers have two options:

(i) purchase Hydro One's transformer and switchgear and add additional transformation; or
(ii) if mutually agreeable, pay Hydro One the actual costs of installing the additional transformation, in which case Hydro One would continue to own, maintain, and replace the transformer as needed.

The Customer will supply all other associated material and perform any other work required to accommodate the additional transformation, at its own expense.

R. Types of Connections

The two types of Connections to the Distribution System are:

(i) Basic Connection; and
(ii) an Expansion.

2.1.1. Basic Connection (Building that Lies Along)

The terms below may also apply to Customers requiring a service capacity increase.

Where a Customer makes a written request to Hydro One to connect a Building that Lies Along Hydro One's Distribution System, Hydro One shall provide a Connection. Hydro One provides a Basic Connection at no charge. The Basic Connection consists of:

(i) supply and installation of standard overhead transformation, according to the Customer's rate class, which includes secondary bus extensions or installations complete with conductor and anchoring;

(ii) supply and installation of standard metering;
(iii) an estimate and layout for the new service;
(iv) connection of the Secondary or Primary Service at the described Ownership Demarcation Point and the Operational Demarcation Point; and
(v) for year-round residential and seasonal residential classes only, the supply and installation of up to 30 metres overhead secondary conductor for up to a 200 amp service, or an equivalent credit toward underground conductor. Year-round residential and seasonal residential Customers with Primary Services will be credited for the 30 meters of secondary wire.

A Basic Connection does not include the following additional costs, for which the Customer shall pay Hydro One:

(a) for year-round residential and seasonal residential Customer classes – the cost difference between overhead and underground secondary wire;
(b) incremental costs associated with the supply and installation of underground transformation;
(c) the supply and installation of poles, anchors, all secondary conductor over 30 metres, hardware, and structures, as required on Customer's property; and
(d) the costs of all changes required to the Distribution System exclusive of the secondary bus installation. These costs include pole changes, anchoring or hardware changes.

Where applicable and at their own expense, Customers will also be responsible for:

(e) the supply of tree and vegetation management on the Customer's property;
(f) any easements or property agreements as required by Hydro One;
(g) the cost of any fees, permits, or other permissions required to connect the service; and
(h) the amount payable by the Customer to Hydro One if the Customer is being added to a Single or Three Phase line constructed on or after January 1, 1993.

2.1.2. Expansions / Offer to Connect

Where a Customer makes a written request to Hydro One to connect a building that is in Hydro One's service territory, Hydro One shall make an "Offer to Connect". For an Expansion, Hydro One will perform an economic evaluation using a discounted cash flow model in compliance with Appendix B of the Distribution System Code to determine the Customer's share, if any, of the equipment, labour, material and ongoing maintenance costs of the Expansion (the "Expansion Costs").

If the Present Value of the future revenue is not sufficient to recover the Expansion Costs, the Customer shall pay a capital contribution calculated in a manner consistent with the requirements of the Distribution System Code. The capital contribution shall not exceed the Customer's share of the difference between the Present Value of the Expansion Costs and the Present Value of the projected revenue.

When performing the economic evaluation, Hydro One will estimate the Customer's monthly consumption based on information provided by the Customer. Where available, Customer-supplied load forecasts acceptable to Hydro One will be used.

For Customers requesting a service capacity increase which requires an Expansion of the Distribution System, an economic evaluation will also be performed, using a discounted cash flow model in compliance with Appendix B of the Distribution System Code to determine the Customer's contribution amount.

A. Revenue Horizon

Hydro One uses a revenue horizon of up to twenty-five (25) years to project expected forecasted revenues based on the forecasted load from the Expansion. The load forecast and the revenue horizon used for the economic evaluation are in the sole discretion of Hydro One.

B. Connection and Cost Recovery Agreement/Revenue Guarantee

For an Expansion where Hydro One is making an investment of $75,000.00 or more in the Distribution System, the Customer may be required to execute a Connection and Cost Recovery Agreement, which includes a revenue guarantee. Key provisions of this agreement are described in Appendix "A" to these Conditions of Service.

C. Staking and Engineering Fees

Hydro One will provide staking and design at the Customer's expense. This payment will be recognized in the discounted cash flow calculation.

D. Offer to Connect

Hydro One will respond to requests for Connection within the following timeframes:

(i) from Standard Customers, Sub-transmission Customers, Large Users and Direct Customers, by no later than 15 calendar days after receipt of the request. At this time, Hydro One will specify any information that must be provided and any obligations that must be met, by the Customer in order for Hydro One to process the request. An offer to connect will be made by no later than 60 calendar days following Hydro One's receipt of all necessary information and the Customer's meeting of all its obligations.

(ii) from Embedded Distributors, by no later than 30 calendar days after receipt of a request. At this time, Hydro One will specify any information that must be provided and any obligations that must be met, by the Customer in order for Hydro One to process the request. An offer to connect will be made by no later than 90 calendar days following Hydro One's receipt of all necessary information and the Customer meeting all of its obligations.

Hydro One's initial "offer to connect" will include, at no cost to the Customer:

(a) a statement as to whether the offer is a firm offer or is an estimate of the costs that would be revised in the future to reflect actual costs incurred;
(b) a reference to these Conditions of Service and information on how the Customer requesting Connection may obtain a copy of them;
(c) a statement as to whether a capital contribution will be required from a Customer;
(d) a statement as to whether Hydro One will require an Expansion deposit from the Customer, and the amount of the Expansion deposit that the Customer will have to provide;
(e) a description of the Connection charges that would apply and a statement whether they will be charged separately from the capital contribution, and, if known, the amount of those connection charges;
(f) the amounts to be paid by the Customer to Hydro One if the Customer is being added to a Single or Three Phase line constructed on or after January 1, 1993; and
(g) any additional information pertinent to the offer.

If Hydro One will require a Customer to pay a capital contribution, Hydro One will, in addition to complying with the above, also include in its initial offer, at no cost to the Customer:

a) the amount of the capital contribution that the Customer will have to pay for the Expansion;
b) the calculation used to determine the amount of the capital contribution to be paid by the Customer, including all of the assumptions and inputs used to produce the economic evaluation as described in these Conditions of Service;
c) a statement as to whether the offer includes work for which the Customer may obtain an alternative bid and, if so, the process by which the Customer may obtain the alternative bid;

d) a description of, and costs for, the contestable work and the uncontestable work associated with the Expansion, broken down into the following categories:

   i) labour (including design, engineering and construction);
   ii) materials;
   iii) equipment; and
   iv) overhead (including administration);

e) an amount for any additional costs that will occur as a result of the alternative bid option being chosen (including, but not limited to, inspection costs);
f) if the offer is for a residential Customer, a description of, and the amount for, the cost of the basic connection that has been factored into the economic evaluation; and
g) if the offer is for a non-residential Customer and if Hydro One has chosen to recover the non-residential basic connection charge as part of its revenue requirement, a description of, and the amount for, the connection charges that have been factored into the economic evaluation.

E. Alternative Bids

Customers may seek alternative bids for the contestable portion of the Expansion from Qualified Contractors where the Expansion requires a capital contribution to be made by the Customer.

Information on electrical contractors is available from the following sources:

- Yellow Pages under Electric Contractors
- www.ECAO.org under Visitor area and Contractor Locator
- www.yellowpages.ca under Electric Contractors

E.1. Uncontestable work excluded from alternative bids include:

(i) the preliminary planning, design and engineering specifications of the work required for the Distribution System expansion and connection; and
(ii) the construction work on existing Hydro One Facilities and Equipment.

E.2. The Customer shall be responsible for:

(i) selecting, hiring, and paying the Qualified Contractor the costs for the work eligible for the alternative bid;
(ii) assuming full responsibility for the construction of that aspect of the Expansion;

(iii) administering the contract or paying Hydro One to perform this service, at time and material rates. Administering the contract includes acquisition of all required permissions, permits, and property rights as required;
(iv) constructing the Expansion (line extension) to meet Hydro One's design requirements;
(v) paying an inspection fee to Hydro One for inspection of the construction;
(vi) paying the cost of any easements or property agreements as required by Hydro One;
(vii) transferring ownership of the facilities built on public property or servicing more than one Customer to Hydro One for a nominal fee prior to connection;
(viii) paying costs for any additional design and engineering; and
(ix) paying all applicable Electrical Safety Authority inspection fees.

E.3. Hydro One shall be responsible for:

(i) providing the design specifications for the construction; and
(ii) inspecting and authorizing the line for Connection.

E.4. Private Ownership of Alternative Bid Construction

As a condition of Connection, the Customer-built line may be transferred to Hydro One's ownership only if constructed to Hydro One's design standards, the line resides on the road allowance and any required easements are provided to Hydro One. Normally, line constructed on private property shall be owned and maintained by the Customer. However, a Customer may privately construct and transfer ownership of the Expansion on private property to Hydro One if all of the following conditions are met:

(i) the line is constructed to Hydro One's design standards;
(ii) the line to be constructed is for the benefit of more than one Customer or there is a physical indication of a possible new connection; and
(iii) easements and cutting rights are granted to Hydro One for the line.

Submarine cable that has been constructed to Hydro One's design standards and that has the appropriate crossing approvals shall be transferred to Hydro One with any required easements, where such cable supplies more than one customer or where there is a physical indication of a possible new connection. Submarine cable supplying a single customer shall be owned and maintained by the Customer.

F. Rebates for Capital Contribution Customers

If a Customer is added, after November, 2000, and within 5 years of the original construction, to an Expansion that was constructed and paid for by another Customer, Hydro One shall, as per the DSC, calculate the rebate amount payable to the initial contributors, considering factors such as the relative load level and the relative line length. Hydro One shall collect the rebate amount from the unforecasted customers and shall pay the said amount to the initial contributors.

Before Hydro One makes the Connection, the new Customer will contribute its fair share of the original Expansion costs for the shared portion of the line; and the original contributor or present property owner, as the case may be, will be entitled to the rebate, without interest, based on the apportioned benefit for the remaining period. No rebates will occur after the 5-year Connection horizon has expired.

G. Rebates for Refund Administration Service

Rebates will normally be made to the present property owners unless a Refund Administration Service agreement is in place.

G.1. Single and Three Phase Lines constructed from January 1, 1993, to October 31, 2000

If a Customer is added to a Single or Three Phase line constructed during the period January 1, 1993 to October 31, 2000, and there is a Refund Administration Service agreement in effect for that line, Hydro One will rebate an amount equal to the new Customer's fair share of the original cost of the shared portion of the line. The original capital contribution is not depreciated.

G.2. Single and Three Phase Lines constructed prior to January 1, 1993 - Capital contribution collected or recorded was $20,000 or more

If a Customer is added to a Single or Three Phase line constructed prior to January 1, 1993, and the original contribution collected or recorded is $20,000 or more, Hydro One will rebate in accordance with the agreement with the original contributor(s), but will not collect from the new Customer an amount equal to the new Customer's fair share of the original cost of the shared portion of the line. The capital contribution is depreciated at 3 per cent per year in service. Prepaid maintenance charges are not depreciated. At the end of the 15th year of the line Connection date, Hydro One will refund all remaining capital and prepaid maintenance.

2.1.3. Connection Denial

Hydro One may deny Connection to any Customer for any of the following reasons:

(i) refusal by the Customer to sign and deliver any agreements required to be executed by the Customer under these Conditions of Service;
(ii) the Connection will represent a contravention of the laws of Canada or Ontario;
(iii) the Connection will cause Hydro One to be in violation of the conditions in the Licence;
(iv) the Connection will have an adverse effect on the reliability or the safety of the Distribution System;
(v) the Connection will cause a material decrease in the efficiency of the Distribution System;
(vi) the Connection will have a material adverse effect on the quality of the Distribution service received by an existing Customer, which effect could include voltage flicker, harmonics and power outages;
(vii) the Connection will result in the discriminatory access to Distribution Services by other Customers;
(viii) the person requesting the Connection is currently in arrears for Distribution Services, electricity supplied, or other services provided by Hydro One;
(ix) the Connection is not in compliance with these Conditions of Service;
(x) the Connection does not meet Hydro One's design requirements;
(xi) the Connection will impose an unsafe situation to workers or the public beyond the normal risks inherent in the operation of the Distribution System;
(xii) the Connection will result in the inability of Hydro One to perform planned inspections or maintenance;
(xiii) by order of the Electrical Safety Authority;
(xiv) the Customer does not have the requisite approval(s) of the Electrical Safety Authority for the Connection; or
(xv) the premises being connected are the subject of a stop work order under the Building Code Act (Ontario).

Hydro One shall notify the Customer of the Connection denial with reasons in writing. Remedies will be suggested to the Customer where Hydro One is able to do so. If it is not possible for Hydro One to resolve the issue, it is the responsibility of the Customer to do so before a Connection will be made.

2.1.4. Inspections Before Connections

All Customer electrical installations shall be inspected and approved by the Electrical Safety Authority before Connection to the Distribution System. Hydro One requires notification from the Electrical Safety Authority of this approval prior to Connection of a Customer.

Where Hydro One has required the Customer to perform specified work associated with the installation of connection assets on the Customer's premises, the Customer shall obtain acceptance by Hydro One of said work as a prerequisite to Connection to the Distribution System.

Before connecting to Hydro One's Distribution System, Hydro One will exercise its obligation to inspect all electrical connections and provisions for metering to ensure that they satisfy all technical requirements, unless a protective device that has been accepted by Hydro One separates the Connection.

Hydro One may at any time re-inspect any electrical connection or meter installation notwithstanding any previous inspection and acceptance of the installation.

Inspection requirements also apply to reconnections noted in Section 2.2.D.

2.1.5. Relocation of Hydro One Facilities and Equipment

A Customer requesting a relocation of all or any part of Hydro One Facilities and Equipment shall pay Hydro One all associated costs incurred by Hydro One in relocating the Hydro One Facilities and Equipment. Where there is applicable legislation or an agreement made with Ontario Hydro prior to April 1, 1999, the cost of such relocation will be as per the legislation or agreement.

If the relocation is from public to Private Property, Hydro One shall acquire easement rights at the expense of the Customer. This would include the actual cost to carry out the work and any costs resulting from having to obtain the new easement or authorization equivalent.

2.1.6. Easements

A. Unregistered Rights

Section 46 of the *Electricity Act* provides that all property that is subject to unregistered rights prior to April 1, 1999, will continue to be subject to the right until the right expires or until it is released by the holder of the right.

B. Registered Easements and Owner Agreement

For new or modified Connections, Hydro One shall have the right to require a Customer to provide Hydro One with a registered easement or an owner agreement with respect to Hydro One Facilities and Equipment located on the property of the Customer or the property of a third party and/or where Hydro One deems it necessary.

Hydro One requires registered easements for facilities under any of the following conditions:

(i) any single or multi-phase line, underground or submarine cables, poles, anchors, or aerial occupation where the line crosses Private Property, including any common service taps;

(ii) anchors on Private Property supporting 44 kV lines, 27.6 kV lines, Three Phase feeders, and any single or multi-phase structures supporting reclosers, voltage regulators or capacitor banks where the poles are located on road allowance; and

(iii) any new facilities and equipment being added to Hydro One Facilities and Equipment which are the subject of an existing unregistered easement that does not include replacement or maintenance of the existing Hydro One Facilities and Equipment.

Owner agreements are required for Hydro One Facilities and Equipment where Hydro One does not require registered easements.

2.1.7. Contracts

A. Implied Contracts

In all cases, notwithstanding the absence of a written contract, Hydro One has an implied contract with any Customer that is connected to the Distribution System and receives Distribution Services from Hydro One. The terms of the implied contract are embedded in these Conditions of Service, the Electricity Distribution Rate Handbook, Hydro One's Rate schedules, the Licence, the Distribution System Code, the Standard Supply Service Code and the Retail Settlement Code, all as amended from time to time.

Any person(s) who take or use electricity delivered and/or supplied by Hydro One shall be liable for payment for such electricity. Any implied contract for the supply of electricity by Hydro One shall be binding upon the heirs, administrators, executors, successors and assigns of the person(s) who took and/or used the electricity supplied by Hydro One.

In the absence of a contract for electricity with a tenant, or in the event the electricity is used by a person (s) unknown to Hydro One, the cost for electricity consumed by such person(s) is due and payable by the owner(s) of such property.

When a tenant contacts Hydro One to establish an account at the property, the contract is with that tenant. When a tenant advises Hydro One that he will no longer accept responsibility for that property, Hydro One will adhere to the date provided by the tenant, regardless of the terms of any lease or verbal agreement between that tenant and the landlord or owner.

Hydro One will not maintain availability of a meter and service without an active account and Customer. When tenants advise Hydro One they are no longer responsible for the account, a final bill will be issued for the account. At that time, a new account will be set up in the landlord/owner's name, unless:

(a) a new tenant has called to assume responsibility for the account**;** or
(b) the landlord/owner refuses responsibility and wishes to have the connection equipment removed.

If a new account is set up in landlord/owner's name, the following terms and conditions apply:

(i) Hydro One will, without any notice, open an account(s) for electrical service to the properties in the landlord/owner's name as soon as any vacating tenant's account has been closed;
(ii) the landlord/owner will be responsible for the new account(s) and will comply with these Conditions of Service; and
(iii) a new account set up charge will apply to the new account(s), which will appear on the first electricity bill for any new account(s). Even though the property may be vacant, monthly service charges and electricity used will be billed to this new account(s).

This arrangement will be in place unless Hydro One is advised in writing otherwise.

B. Customer Service Contract

All Customers wishing to connect to the Distribution System, other than a developer, must sign a Customer Service Contract as described in Appendix "A" to these Conditions of Service.

C. Connection and Cost Recovery Agreements

Where Hydro One is entitled under these Conditions of Service to recover all or a portion of the costs of a Connection and/or requires that a Customer provide a revenue guarantee, the Customer must execute a Connection and Cost Recovery Agreement or a Connection Cost Recovery Agreement ("CCRA"). The CCRA shall be executed before Hydro One commences any construction activities in respect of the Connection. The CCRA will describe the work to be performed by Hydro One in respect of the Connection and any other conditions set forth in Hydro One's offer to connect, together with the applicable payment terms (including revenue guarantees and/or capital contribution where applicable). Key provisions of the CCRA are described in Appendix "A" to these Conditions of Service.

D. Developers

Developers shall be required to execute a Subdivision Agreement. Key provisions of the Subdivision Agreement are described in Appendix "A" to these Conditions of Service.

E. Connection Agreements

(i) Embedded Distributor, Sub-transmission Customer, Large User, Direct Customer or Standard Customer

Hydro One shall have the right to require any Embedded Distributor, Sub-transmission Customer, Large User, Direct Customer or Standard Customer to execute a Connection Agreement. Key provisions of the Connection Agreement are described in Appendix "A" to these Conditions of Service.

(ii) Embedded Generation Facilities

Hydro One requires all Customers with Generation Facilities connected in parallel with the Distribution System and all Embedded Generators wishing to connect to the Distribution System to execute a Connection Agreement in the applicable form prescribed in Appendix "E" of the *Distribution System Code* and/or such other agreements as may be reasonably required by Hydro One in the circumstances as described in Appendix "E" of the *Distribution System Code* as "Other Potential Contracts". The Connection Agreement with an Embedded Generator who is not a Wholesale Market Participant will also contain the terms under which Hydro One purchases power from that Embedded Generator.

(iii) Timing of Execution

Hydro One, in its sole discretion, shall have the right to require Customers to execute a Connection Agreement on or after Connection.

F. Special Contracts

Special contracts that are customized in accordance with the service requested by the Customer normally include the following examples:

(a) construction sites;

(b) mobile facilities;

(c) non-permanent structures;

(d) special occasions, etc.; and

(e) house moves.

2.2. Disconnection

Hydro One reserves the right to physically Disconnect or limit the amount of electricity that a Customer can consume for any of the following reasons:

(i) failure to pay Hydro One any amounts due and payable for the Distribution of electricity or for supply of electricity under Section 29 of the *Electricity Act*;
(ii) failure to pay Hydro One any amounts due and payable on a distributor-consolidated bill;
(iii) failure to pay any Connection costs due and payable;
(iv) non-payment of security deposits identified as a condition of service or a condition of continuing service;
(v) contravention of the laws of Canada or Ontario;
(vi) imposition of an unsafe worker situation beyond normal risks inherent in the operation of the Distribution System;
(vii) adverse effect on the reliability and safety of the Distribution System;
(viii) a material decrease in the efficiency of the Distribution System;
(ix) a material adverse effect on the quality of Distribution Services received by an existing Connection;
(x) inability of Hydro One to perform meter reading, planned inspections, maintenance, repairs or replacement of a meter;
(xi) failure of the Customer to comply with a directive of Hydro One that Hydro One makes for the purposes of meeting its Licence obligations;
(xii) failure of the Customer to comply with any requirements in these Conditions of Service or a term of any agreement made between the Customer and Hydro One, including, but not limited to, a Connection Agreement or a Connection and Cost Recovery Agreement;
(xiii) failure of the Customer to enter into a Connection Agreement required by these Conditions of Service;
(xiv) in compliance with a court order;

(xv) by order of the Electrical Safety Authority;
(xvi) by order of the IESO; or
(xvii) for the reasons identified in Section 2.2.A of these Conditions of Service.

A. Disconnection/Load Limiter Process for Reasons of Non-payment

If a bill remains unpaid in whole or in part twenty-one (21) calendar days after the due date and at least seven (7) calendar days after a written notice has been provided to the Customer by personal service, prepaid mail or by posting notice on the property in a conspicuous place, Hydro One may fully interrupt or limit the distribution of electricity to the Customer.

In accordance with Section 4.2.1 of the Distribution System Code, Hydro One shall provide the Customer being disconnected for non-payment the Fire Safety Notice of the Office of the Fire Marshall and any other public safety notices or information bulletins issued by public safety authorities and provided to Hydro One, which provide information respecting dangers associated with the disconnection of electricity service.

B. Disconnection Process for Reasons Other than Non-Payment

Subject to Hydro One's rights in Section C below, Hydro One will provide notice of disconnection to the Customer for reasons other than non-payment by personal service, prepaid mail or by posting notice on the property in a conspicuous place. If the Customer does not remedy the situation that gave rise to Hydro One's right to disconnect the Customer from the Distribution System within the time period specified by Hydro One in the notice, Hydro One may disconnect the Customer from the Distribution System or interrupt the distribution of electricity to the Customer on or after the date specified in the notice.

C. Immediate Disconnection without Notice

Hydro One may immediately interrupt a Customer, without notice, in accordance with a court order, a request by a fire department or for emergency, public safety (including potential for loss of life or limb), system reliability reasons or in order to inspect, maintain, repair, alter, remove, replace or disconnect wires or other facilities used to distribute electricity or where there is an energy diversion, fraud or abuse on the part of the Customer.

D. Liability for Disconnection

Disconnection does not relieve the Customer of the liability for arrears or minimum bills for the balance of the term of the contract.

Under no circumstances will Hydro One be liable for any damage resulting from, associated with or related to the Disconnection or the limitation of distribution of electricity, including damage to the Customer or the Customer's premises and any business or other losses suffered by the Customer as a result of the disconnection.

E. Reconnection

Where the reason for the Disconnection has been remedied to Hydro One's satisfaction, Hydro One shall reconnect a Customer. All costs, including inspections, associated with the Disconnection and reconnection shall be paid for by the Customer prior to reconnection of the service.

Under any of the following circumstances, Hydro One requires that the Customer obtain the approval of the Electrical Safety Authority prior to Hydro One reconnecting the service:

- (i) where Hydro One has reason to believe that the wiring may have been damaged or altered;
- (ii) where service was disconnected for modification of Customer wiring;
- (iii) where service has been disconnected for a period of six months or longer;
- (iv) where the service was disconnected as a result of an adverse effect on the reliability and safety of the Distribution System; or
- (v) where it is a requirement of the Electrical Safety Code.

F. Disconnection and Reconnection Related Charges

Unless specified elsewhere in these Conditions of Service, a charge shall apply in cases where it is necessary for Hydro One to make a trip to the Customer's premises to collect payment for an overdue account, disconnect service, install a Load Limiter or reconnect service.

G. Unauthorized Energy Use

Hydro One reserves the right to disconnect the Distribution of electricity to a Customer, without notice, for causes including energy diversion, fraud or abuse on the part of the Customer. Such service shall not be reconnected until the Customer rectifies the condition and pays all uncollected charges and costs incurred by Hydro One arising from unauthorized energy use, including inspections and repair costs, and the cost of disconnection and reconnection.

H. Service Cancellation

Where a Customer requests service cancellation, Hydro One will remove certain delivery equipment, such as power lines, transformer and meter. If reconnection is requested, the Customer will incur a cost to reinstall appropriate delivery equipment and shall follow the steps and processes for new connections set out in these Conditions of Service.

2.3. Conveyance of Electricity

2.3.1. Limitations on the Guarantee of Supply

Hydro One will endeavour to use reasonable diligence in providing a regular and uninterrupted supply of electricity but does not guarantee a constant supply or the maintenance of unvaried voltage and will not be liable for damages to the Customer by reason of any failure in respect thereof.

Customers requiring a higher degree of security than that of normal supply are responsible to provide their own backup or standby facilities and/or pay all associated incremental costs. Customers may require, at their premises, special protective equipment which is subject to the approval of Hydro One, to minimize the effect of momentary power interruptions.

Customers requiring a three-phase supply should install protective apparatus to avoid damage to their equipment, which may be caused by the interruption of one phase, or non-simultaneous switching of phases of Hydro One’s supply. Damages resulting from the failure to install protective apparatus shall be at the Customer’s expense.

During an emergency, Hydro One may interrupt supply of electricity to a Customer in response to a shortage of supply or to effect repairs on the Distribution System, or while repairs are being made to Customer-owned equipment. In addition to Hydro One’s rights under Section 40 of the *Electricity Act*, Hydro One or its authorized agents may enter the Customer’s property in accordance with Section 1.6.B of these Conditions of Service.

2.3.2. Power Quality

A. Standards and Guidelines for Power Quality

Hydro One shall follow Good Utility Practice in terms of its guidelines and standards for power quality where applicable but does not guarantee an unvaried voltage or frequency.

B. Voltage and Current Harmonics

Large rectifiers, inverters, arc furnaces, static VAR systems and other non-linear loads generate harmonic voltages and currents. These harmonics may interfere with the operation of the Distribution System by conductive interference and/or may interfere with communication systems by inductive interference.

Hydro One will follow Good Utility Practice for establishing limits on harmonic current emissions and voltage distortions. The Customer shall ensure that the equipment at its facility does not generate harmonic currents that exceed acceptable industry practices.

C. Voltage Fluctuations and Flicker

Voltage fluctuations will normally be within the limits of the Hydro One voltage flicker curve, which is based on the GE Borderline of Irritability for incandescent lighting.

D. Frequency Fluctuations

In general, the frequency of AC power on the Distribution System is dictated by the supply frequency on the transmission system to which the Distribution System is connected.

E. Over-voltages

In general, Hydro One will follow Good Utility Practice to minimize the magnitude and extent of short-term over-voltages.

F. Stray or Tingle Voltage

Varying amounts of low-level voltage often exist between the earth and electrically grounded farm equipment such as metal stabling, feeders, milk pipelines or even wet concrete floors. Usually, these voltage levels present no harm to animals. However, if an animal touches two pieces of equipment that are at different voltage levels, a small electric current passes through the animal. This is known as stray voltage. Stray voltage can be produced by a wide variety of off-farm and on-farm sources.

Using dairy cows as an example, reported symptoms include:

- Reluctance to enter milking parlour
- Reduced water or feed intake
- Nervous or aggressive behaviour
- Uneven and incomplete milkout

- Increased mastitis
- Lowered milk production
- Reduced growth

These same symptoms can also be the result of other non-electrical farm factors. For example, disease, poor nutrition, unsanitary conditions, or milking machine problems can produce some of the same symptoms in farm animals as stray voltage. Farmers should consider and investigate all possibilities, including stray voltage, when attempting to resolve these symptoms.

Off-farm sources:
In a properly functioning electrical distribution system, some voltage will always exist between the neutral system (ground conductors) and the earth. The level of this NEV (neutral-to-earth voltage) can change on a daily or seasonal basis, depending on changes in electrical loading, environmental conditions and other factors. For safety reasons, Hydro One's neutral system is connected to a farm's grounding system. While this bond protects people and animals from shocks caused by faulty electrical equipment and lighting strikes, it also results in a stray voltage equal to a fraction of the NEV appearing on grounded farm equipment such as feeders, waterers, metal stabling, metal grates, milk pipelines and wet concrete floors.

On-the-farm sources:
Poor or faulty farm wiring, improper grounding, unbalanced farm system loading, defective equipment or voltages from telephone lines or gas pipelines are all possible sources.

For additional information on the effects of stray voltage on livestock see the Ontario Ministry of Agriculture, Food and Rural Affairs (OMAFRA) website, www.omafra.gov.on.ca/english/livestock/dairy/facts/strayvol.html.

If you think you have a stray voltage problem, call Hydro One at 1-888-664-9376 to set up an appointment for a visit from Hydro One staff, who will perform appropriate measurements to help determine if stray voltage is present on your farm. Hydro One provides up to 4 hours of stray voltage testing at the Customer's premises without charge.

G. Power Quality Inquiries

Hydro One maintains a 24-hour call answer service (Section 1.5) for the purpose of receiving inquiries from Customers regarding power interruptions, power quality incidents, and incidents related to the integrity or safety of its Distribution System.

In response to a Customer's power quality concern, where the utilization of electric power affects the performance of electrical equipment, Hydro One will work with the Customer to perform investigative analysis to identify the underlying cause. Depending on the circumstances, this may include review of relevant power interruption data, trend analysis, and/or use of diagnostic measurement tools.

If, after an initial investigation, the power quality issue remains unresolved, and it is determined that further detailed engineering study is required, Hydro One shall advise the Customer of an intended course of action. Upon determination of the cause resulting in the power quality concern, where it is deemed a system delivery issue and where industry standards are not met, Hydro One will recommend and/or take appropriate mitigation measures. Hydro One will not be obligated to correct a problem if correcting the problem would adversely affect other Hydro One Customers. Hydro One will use appropriate industry standards and Good Utility Practice as a guideline.

If, through an initial assessment or subsequent detailed investigation, it is determined that the source of a power quality complaint is the Customer's own equipment, then Hydro One may require reimbursement from the Customer for all or a portion of the costs incurred in carrying out the investigation.

H. Outage Notification Process

It is occasionally necessary to interrupt a Customer's supply to maintain or improve the Distribution System. For planned outages, Hydro One will endeavor to provide as much notice as possible, but at least two (2) business days' notice for minor interruptions and up to ten (10) business days' notice for larger interruptions. Hydro One will notify Customers by telephone, fax, mail or hand delivery. Additional notification through the media may also be provided.

In emergencies, Hydro One will not provide prior notification of an interruption.

2.3.3. Electrical Disturbances

Customer Responsibilities

Customers shall ensure that their electrical equipment does not cause any unacceptable voltage fluctuations, voltage unbalance, harmonics, or other disturbances that could negatively affect other Customers connected to the Distribution System, or Hydro One Facilities and Equipment. Examples of equipment capable of causing disturbances are large motors, welders, and variable speed drives. In planning the installation of such equipment, the Customer must consult with Hydro One.

The Customer's equipment shall comply with the limitations for permissible distortion caused by harmonic currents and voltages described in CAN/CSA-C61000-3-6 from the Canadian Standards Association.

If it is determined that unacceptable conditions are being caused by any Customer Equipment, the Customer shall take appropriate remedial action to correct the condition. Depending on the severity of the electrical disturbance, Hydro One may require that such equipment be disconnected from the Distribution System, in accordance with Section 2.2, until corrective measures are taken.

The characteristics of specific electrical disturbances should be referred to Hydro One for evaluation and interpretation against the Hydro One standards and guidelines for power quality. (See Section 2.3.2A)

Customers who may require an uninterrupted source of electricity, or a supply completely free from fluctuations and disturbance, must provide their own power conditioning equipment for these purposes.

2.3.4. Standard Voltage Offerings

Hydro One will supply a single stage of transformation to the Customer's utilization voltage at standard voltages only. These voltages will conform to Canadian Standards Association ("CSA") standards. The Customer will supply any additional transformation required below the utilization voltage if required. Where the Customer requires a secondary voltage other than those noted below, the Customer shall supply the transformers and associated equipment.

A. Standard Secondary Voltages

Single Phase – 120/240 volts 3 wire;

Three Phase – 120/208 volts 4 wire; and

Three Phase - 347/600 volts 4 wire.

B. Standard Primary Voltages

Hydro One has a variety of primary distribution and sub-transmission voltages across the province, but in general has only one primary voltage in each vicinity. Hydro One shall provide only the nominal primary voltage present in the vicinity to service a Connection or development, unless the development cannot be effectively fed from the existing supply. Customers requesting a Primary or Sub-transmission Service should contact Hydro One to determine the primary voltage available at their location.

Typical Primary Voltages

44,000 Volts – 3 Phase 3 Wire;
16,000/27,600 Volts – 3 Phase 4 Wire;
14,400/25,000 Volts – 3 Phase 4 Wire;

8,000/13,800 Volts – 3 Phase 4 Wire;
4,800/8,320 Volts – 3 Phase 4 Wire; or
2,140/4,160 Volts – 3 Phase 4 Wire

2.3.5. Voltage Guidelines

Standard operating conditions are:

CSA Standard CAN3-235-83 Table 3				
Nominal System Voltages	Recommended Voltage Variation Limits for Circuits up to 1000 volts, at the Service Entrance.			
	Extreme Operating Conditions	Normal Operating Conditions		Extreme Operating Conditions
Single Phase				
120/240	106/212	110/220	125/250	127/254
240	212	220	250	254
480	424	440	500	508
600	530	550	625	635
Three Phase 4 -Wire				
120/208Y	110/190	112/194	125/216	127/220
240/416Y	220/380	224/388	250/432	254/440
277/480Y	245/424	254/440	288/500	293/508
346/600Y	306/530	318/550	360/625	367/635
Three Phase 3 – Wire				
240	212	220	250	254
480	424	440	500	508
600	530	550	625	635

These voltage guidelines relate to long-term steady-state levels and do not include short term or transient disturbances.

For system voltages greater than 1,000 V and up to 50,000 V, the maximum voltage variation is ± 6% of the nominal voltage. Under emergency conditions voltages may drop below these thresholds.

Where voltages lie outside the indicated limits for Normal Operating Conditions but within the indicated limits for Extreme Operating Conditions, improvement or corrective action will be taken on a planned and programmed basis, but not necessarily on an emergency basis.

Where voltages lie outside the indicated limits for Extreme Operating Conditions, improvement or corrective action will be taken on an emergency basis. The urgency for such action will depend on many factors such as the location and nature of load or circuit involved, and the extent to which limits are exceeded with respect to voltage levels and duration, etc.

Hydro One practises reasonable diligence in maintaining supply voltage levels but is not responsible for variations in voltage from external forces such as operating contingencies, exceptionally high loads and low voltage supply from the transmitter.

2.3.6. Emergency Backup Generation Facilities & Load Displacement Generation Facilities

2.3.6.1. Portable or Permanently Connected Emergency Backup Generation Facilities

Customers with a portable or permanently connected Emergency Backup Generation Facilities shall comply with all the applicable criteria of the Electrical Safety Code and, in particular, shall ensure that the Customer's emergency generation does not back feed on the Distribution System. The Customer shall be responsible for proper interface protection between the portable or permanently connected Emergency Backup Generation Facility's electrical circuits and the Distribution System. Portable or permanently connected Emergency Backup Generation Facilities shall not be installed in a manner that would adversely affect the Distribution System. Portable or permanently connected Emergency Backup Generation Facilities must be operated in isolation from the Distribution System.

Customers with permanently connected Emergency Backup Generation Facilities shall notify Hydro One regarding the presence of such equipment. All applicable environmental requirements are the responsibility of the Customer. Customers shall consult with Hydro One during the planning and prior to the installation of any portable or permanently connected Emergency Backup Generation Facilities.

2.3.6.2 Load Displacement Generation Facilities

Customers intending to install generators for Load Displacement purposes shall consult with Hydro One during the planning of and prior to the installation of any Generation Facility for Load Displacement. Customers with a Load Displacement Generation Facility shall comply with all the applicable criteria of the Electrical Safety Code and, in particular, shall ensure that the Load Displacement generation does not back feed onto the Distribution System. The Customer shall be responsible for proper interface protection between the Customer's electrical circuits and the Distribution System. Any Load Displacement generation shall be installed in a manner that would not adversely affect the Distribution System. All Customers with Load Displacement generation must notify Hydro One regarding the presence of their Load Displacement Generation. Load Displacement generation must satisfy the general technical requirements and the Connection Impact Assessment (CIA) criteria set out in section 3.5 of these Conditions of Service.

2.3.7. Metering and Meter Reading

2.3.7.1. General

For Retail settlement and billing purposes, Hydro One shall provide, install, own and maintain a Meter Installation for all Customers except where the Customer or Embedded Distributor elects to be a Wholesale Market Participant or is an Embedded Generator.

The type of metering will be based on the Customer's Rate class, energy consumption and peak load. The security and accuracy of metering will be maintained under regulations and standards established by Measurement Canada and Hydro One.

When a Customer's power factor is known to be less than 90 per cent, a kVA meter or other equivalent electronic meter shall be used for measuring and billing.

If deemed appropriate by Hydro One, the Customer shall permit Hydro One to connect a revenue meter through the Customer's phone line for remote interrogation and data transfer. Hydro One will ensure that there are no material adverse impacts of the revenue meter connection on the Customer's use of the phone line.

The meter measuring the Customer's electricity consumption is owned and maintained by Hydro One. This ownership ends at the meter base, which then feeds into the premise's electrical panel. Any maintenance requirements for the meter base are the responsibility of the Customer.

A. Location of metering

The meter(s) shall be located on the exterior of the building as determined by the layout and approved by Hydro One based on standards established by the Electrical Safety Code and the Ontario Building Code. In general, the meter(s) may be located:

(i) on the front side of the building facing the street or roadway;
(ii) no more than 3 metres from the front facing the street or roadway;
(iii) on the wall of the building so that midpoint of the meter after installation will be 1.75 metres plus or minus 100mm from finished grade, or, where this is not possible, the meter may be installed on poles or on a separate support;

(iv) if the meter(s) are located on poles, the poles must be installed, owned and maintained by the Customer on the Customer's property; or

(v) in dedicated metering rooms for large general service class Customers (e.g. shopping centres, apartment and condominium buildings), provided that guaranteed continuous access, by key or other appropriate means, is provided to Hydro One or its authorized agent.

B. Single Phase – Secondary Metered

New Customers with Secondary Metered Service shall have metering based on estimated load. Existing Customers with Secondary Metered Service shall have metering based on the actual average monthly peak load for the previous year. Standard Customers with an average monthly peak load of 50 kW or less shall be metered and billed on kilowatt-hours ("kWh") only. Standard Customers with an average monthly peak load over 50 kW shall be metered and billed on monthly kW as well as kWh, except those in residential and seasonal residential rate classifications.

C. Three Phase – Secondary Metered

All Three Phase Standard Customers will be metered for energy usage in kWh and for peak monthly kW demand and/or monthly peak kVA, depending on the peak load and power factor at the Customer's utilization voltage.

D. Primary Metered

Where a Primary Metered Service is used, the Standard Customer shall own and maintain the entire Distribution System beyond the metering point, which will include poles, conductors and transformers.

E. Totalized Metering

When a Customer requests totalizing in order to consolidate two or more Delivery Points at separate locations on one contiguous property, the following conditions shall apply:

(i) the Customer must own the distribution facilities, including transformation beyond the effective metering point. The effective metering point is defined as the location where primary metering is installed;

(ii) totalizing will be accomplished by either primary or secondary metering, through the use of remote interrogation metering, or other similar units. The Customer shall pay the incremental costs of providing totalizing metering; and

(iii) the total capacity required is less than the Delivery Point capacity limits noted in Section 2.1M.

F. Metering for an Embedded Generation Facility

Net Metered Generation Facilities

Hydro One shall offer a net metering option for load Customers installing a generation facility that meet the criteria set out in subsection 7(1) of the Net Metering Regulation, Ontario Regulation 541/05.

Embedded Generation Facilities, including Renewable Energy Standard Offer Program (RESOP) Generation Facilities

Metering for Embedded Generation Facilities shall comply with the requirements of Hydro One's policy on Metering for Embedded Generators NOP-041, which can be found at www.HydroOneNetworks.com.

G. Central Metering

Hydro One may, at its discretion, require that a Standard Customer with two or more buildings be metered by means of a central metering service. The Standard Customer shall pay Hydro One the following labour and material charges:

(i) for existing service under 45 kW, the Standard Customer shall pay labour and material costs;
(ii) for existing service over 45 kW, the Standard Customer shall pay labour costs only;
(iii) for new service under 45 kW, the Standard Customer shall pay for instrument transformer costs; and
(iv) for new service over 45 kW, the Standard Customer shall not be required to pay for labour or material.

H. Metering Pulses

When Customers request metering pulses or signals for load management purposes, two options exist:

(i) The Customer provides his own instrument transformers and signal control equipment in a separate cabinet on the load side of Hydro One's metering; or

(ii) Hydro One will supply the pulses or signals on the following terms:

(a) the Standard Customer pays all costs to provide pulses and signals; and
(b) the control for pulse or signal will be brought to a Hydro One terminal block remote from the revenue metering. Consequently, the Customer will not have access to Hydro One's metering equipment. (Customers are not allowed to connect to Hydro One's instrument transformers).

I. Multiple Residential Properties

Where the owner of an existing bulk metered Multiple Residential Property chooses to convert to individual metered dwelling units, the costs of conversion will be the owner's responsibility. In such cases, the common facilities such as elevators, hall lights, exterior lighting, laundry equipment, central electric water heating, etc., shall be combined on a separate service and billed at the General Service rate with demand metering as appropriate.

2.3.7.2 Current Transformer Boxes

Standard Customers are responsible for supplying, owning, and maintaining meter bases, except for Three Phase services with Complex Metering Installations where Hydro One requires and supplies at no charge a "P" base enclosure. For services requiring additional metering components such as instrument transformers, the Standard Customer shall supply and install the following, all of which are subject to approval by the Electrical Safety Authority and Hydro One:

(i) instrument transformer enclosures with minimum dimensions of 90cm x 90cm x 30cm;
(ii) all required conduit as specified by Hydro One; and
(iii) where appropriate, a self-contained 400 amp meter base complete with a 400 amp current transformer. Hydro One will provide the Standard Customer with an allowance for the cost of the current transformer.

For central metering services, a current transformer enclosure is not required.

2.3.7.3 Interval Metering

A. Conditions for Supplying Interval Metering

Hydro One shall provide and install a Metering Inside the Settlement Timeframe (MIST) Meter for any existing Customer that has an average monthly peak demand greater than 1000 kW during a 12-month period.

Hydro One shall install a MIST Meter on any new installation that is forecasted by Hydro One to have an average monthly peak demand greater than 200 kW.

Hydro One may provide a MIST Meter to an existing Customer who upgrades his service size and as a result of the increased service size, the meter must be replaced.

Existing Customers who are below the 1000 kW threshold may request an Interval Meter, by submitting a written request. Hydro One shall, at its discretion, determine whether this is a MIST Meter or MOST Meter. A Customer who does not qualify for an Interval Meter, as noted above, shall pay Hydro One for the difference between the cost of a standard Meter Installation and the cost of the Interval Meter installation, including the cost of equipment, labour and telecommunications.

B. Interval-Metering Data

While the meter data belongs to the Customer, Hydro One requires the information to settle the Customer's electricity bill. Hydro One will maintain the usage profile of all Customers with Interval Meters and shall make this information available to Customers.

The Customer has the following three options to obtain Interval Meter data:

(i) direct access – The Customer can elect to access the MIST Meter data directly using Standard Customer purchased software. Hydro One will provide the information required to access and use the meter data provided that the Customer executes the Read Only Access Agreement. Key provisions of the Read Only Access Agreement are described in Appendix "A" to these Conditions of Service;

(ii) Web access provided by Hydro One – when available, Customers will have access to their own Interval Meter data on the Internet using their own account specific password; and

(iii) information provided by Hydro One – Customer may request interval data to be forwarded by Hydro One or its authorized agent, for a fee, levied in accordance with the Retail Settlement Code.

If a Customer requires real-time information from a MIST Meter, the Customer shall be responsible for installing and maintaining a telecommunications line at its own expense.

C. Smart Metering

Hydro One has begun replacing metering with Smart Meters, to meet Ontario Government targets to install smart meters in all Ontario households and small businesses by 2010. For an interim period, a smart meter is deemed to be a conventional meter, until Hydro One elects to implement time-of-use pricing.

2.3.7.4 Meter Reading

If unable to access the premises, Hydro One shall attempt to arrange access to the premises at a time convenient for both Hydro One and the Customer. At its discretion, Hydro One may require the Customer to read the meter and provide the results to Hydro One.

If the Customer does not accommodate Hydro One's request for meter reading or access, the Customer shall be informed in writing of its obligation to contact Hydro One and arrange appropriate access to the meters, or provide Hydro One with the required meter readings.

Hydro One reads meters on a monthly, bi-monthly, quarterly, or annual frequency, depending on Rate classification and service size, and meter readings are obtained either manually or remotely using electronic means. Where Hydro One is unable, for any reason, to obtain a meter reading the Customer may be required to provide a meter reading.

Hydro One reserves the right to use an estimated meter read for both energy and demand quantities when actual readings are not scheduled or available.

To ensure accurate billing and proper operation, it is necessary for Hydro One to read, and visually inspect the meter, at least annually. If Hydro One cannot access the meter for this purpose after the Customer has been contacted directly, Hydro One reserves the right to require a relocation of the meter at the Customer's expense. If the situation is not rectified, Hydro One may ultimately disconnect the Customer in accordance with Section 2.2 of these Conditions of Service.

2.3.7.5 Final Meter Reading

When a final meter reading is required for billing purposes, the Customer shall provide Hydro One with at least five (5) business days' notice of the date the billing is to be discontinued to allow Hydro One to obtain a final meter reading as close as reasonably possible to the required date. The Customer shall provide access to Hydro One for this purpose. If access is not obtained and a final meter reading is not possible, the Customer shall pay an amount based on estimated electrical demand and/or the electrical energy used since the last meter reading.

2.3.7.6 Faulty Registration of Meters

The security and accuracy of metering is governed by the federal *Electricity and Gas Inspection Act* and associated regulations, under the jurisdiction of

Measurement Canada. Hydro One's revenue meters shall comply with the accuracy specifications established by those regulations.

The entity billing a Customer, whether it is Hydro One or a Retailer, is responsible for advising the Customer of any meter error of which it becomes aware and its magnitude and of the Customer's rights and obligations under the *Electricity and Gas Inspection Act*. The billing entity is also responsible for subsequently settling actual payment differences with the Customer or Retailer.

In the event of incorrect electricity usage registration, the billing entity will rectify billing errors in the manner set out in Section 2.4.4 of these Conditions of Service.

2.3.7.7 Meter Dispute Testing

Measurement Canada has jurisdiction, under the *Electricity and Gas Inspection Act*, in a dispute between Hydro One and its Customer where the condition or registration of a meter or metering installation is in question. Hydro One will inform Customers of the assistance provided by Measurement Canada in dispute investigations.

Meter dispute testing is typically the last step in a multi-stage process between the Customer and Hydro One. The process typically begins with a Customer high bill inquiry, the object of which is to validate that the bill calculations, charges and bill determinants are accurate. The process may include any or all of the following steps, as required: collection of problem details from the Customer; analysis of billing details including calculation of charges and appropriateness of meter readings; comparison of estimated readings with past usage; obtaining a check meter reading; provision of information to assist the Customer understanding of and confidence in the bills; and field visit to the Customer premises to verify meter reading, meter data and test meter operation.

At any point in this process, if Hydro One staff determine suspect meter operation, a meter dispute test will be initiated. However, if Hydro One is satisfied with meter operation and accuracy of billing, and the Customer is not satisfied, the Customer will be referred to Measurement Canada.

If the services of Measurement Canada are requested by the Customer or Retailer to resolve the issue, Hydro One may charge the Customer for the costs of processing the application to Measurement Canada and removing and transporting the meter to a testing location. If the dispute is substantiated by Measurement Canada and the resolution is in the favour of the Customer, Hydro One shall bear such costs.

Measurement Canada will follow its dispute investigation process and issue a decision. Hydro One or the Customer who initiated the dispute investigation both have the option to appeal the decision and follow Measurement Canada's appeal process.

2.4. Tariffs and Charges

2.4.1. Service Connection

2.4.1.1 Rate Classifications

When assigning a Customer to the appropriate Rate classification, Hydro One considers the nature and use of the Customer's electricity service, as well as the density of the Customers connected to the Distribution line. The Distribution Services Rates for each classification are based on the cost of delivering electricity to that class of Customers and meeting their electricity supply needs.

The main Rate classifications are Residential-Year-Round, Seasonal Residential, Farm, Industrial Commercial, Industrial Commercial General Service, Industrial Commercial Sub Transmission, and Lighting (Street Light and Sentinel). The Rate classifications for Acquired Local Distribution Company Customers are Residential, General Service-Energy Billed, General Service-Demand Billed, Unmetered Scattered Load and Large Use. All Hydro One Rates charged for each Rate classification for Distribution Services, including charges for services provided to specific Customers where the costs are not recovered through the Distribution Service Rates ("Miscellaneous Distribution Charges") and pass-through charges, are subject to OEB approval. In addition, Hydro One is required to pass through the OEB-approved charges for Wholesale Market Services and Retail Transmission Services.

Hydro One also provides Distribution Services to Direct Customers and Embedded Distributors who may or may not be Wholesale Market Participants.

2.4.1.2 Components of Distribution Rates

Hydro One Distribution Service Rates include a monthly service charge component and a volume-based component. For Demand Billed Customers, the volume Rate is a per kW charge. The billing demand shall be taken as 90% of the kVA or 100% of the measured demand in kW, whichever is greater. For Energy Only Customers, the volume Rate is a per kWh charge. The monthly service charge component is designed to recover some common costs of Distribution Services that are independent of electricity use. All other Distribution Service costs are recovered through the volume Rate.

2.4.1.3 Rural or Remote Electricity Rate Protection, and Debt Retirement Charge

Hydro One is required to collect rural and remote rate protection in accordance with the Regulations made pursuant to Section 79 of the *Electricity Act* and Debt Retirement Charges set in accordance with Section 85 of the *Electricity Act*.

2.4.1.4 Rate Schedules and Notice of Rate Changes

The OEB-approved Rates and charges for Distribution Services are as set out in the Rate schedules available at www.HydroOneNetworks.com. Notice of Rate changes may be published in major local newspapers and shall be mailed to all Customers with the first bills issued using the revised Rates.

2.4.2. Energy Supply

A. Standard Supply Service

Hydro One shall provide Customers connected to the Distribution System with access to electricity through Standard Supply Service. All Customers are Standard Supply Service Customers until Hydro One is informed of and completes the Customer transfer to a competitive Retailer, all in accordance with Section 10 Service Transaction Requests of the Retail Settlement Code.

Hydro One may, at its discretion, refuse to process a Service Transfer Request for a Customer to switch to a Retailer if that Customer is in arrears to Hydro One for Distribution Services and/or Standard Supply Service.

Where a Service Transfer Request is made, a switch bill will be issued to the Customer. This bill will be based on an actual meter read unless the Customer, Hydro One and the Retailer agree in writing to an alternative. The effective date of the service transfer shall be the next scheduled meter reading date unless a request is made for a special meter reading and Hydro One can accommodate the request. The OEB-approved special meter read charge will apply.

All service transfers, except a return to Standard Supply Service, must be supported by the Customer's written authorization, a copy of which must be retained by the applicable competitive Retailer.

B. Pricing of Standard Supply Service, including Regulated Price Plan (RPP)

Pricing of Standard Supply Service is in accordance with applicable regulations made under the *Ontario Energy Board Act* and the Standard Supply Code, specifically section 3, Rates. Pricing of Standard Supply Service is dependent on Customer electricity usage and meter type as follows:

(i) Customers with conventional meters, and who are eligible for RPP as outlined in Ontario Regulation 95/05, shall be charged for Standard Supply Service at rates determined, approved or fixed by the Ontario Energy Board.

(ii) Non-RPP customers with conventional meters shall be billed for hourly electrical energy consumed based on the weighted average hourly spot market (WAHSP) for electricity for the period over which the customer is being billed. The WAHSP will be calculated according to the methodology prescribed in the Retail Settlement Code.

(iii) Non-RPP customers with Interval Meter or another eligible time-of-use metering infrastructure capable of providing data on at least an hourly basis shall be billed for hourly electrical energy consumed based on the respective Hourly Ontario Electricity Price (HOEP).

(iv) Electing Spot Consumers with Interval Meter or another eligible time-of-use metering infrastructure capable of providing data on at least an hourly basis shall be billed for hourly electrical energy consumed based on the respective Hourly Ontario Electricity Price (HOEP).

Hydro One will categorize a Customer as an Electing Spot Consumer only when notified by the Customer in writing, and where the Customer has an Interval Meter or another eligible time-of-use metering infrastructure capable of providing data on at least an hourly basis.

Hydro One will issue an RPP variance settlement amount when:

- advised by the Customer of a move out of Ontario;
- following receipt of a notice that the Customer will buy electricity from a Retailer;
- advised by the Customer of electing to Spot; or
- the Customer ceases to be eligible for RPP.

The variance amount will be a charge or credit, and will be calculated in accordance with the methodology established by the Ontario Energy Board.

Until Hydro One elects to implement time-of-use pricing or the classification is changed by the OEB, a smart meter is deemed to be a conventional meter, and pricing will be in accordance with the categories set out above.

C. Competitive Retailer Supplied Electricity

Hydro One does not provide Standard Supply Service to a Distribution System connected Customer that has contracted with a Retailer for electricity supply. Hydro One remains obligated to provide Distribution Services to such Customer in accordance with these Conditions of Service. The Retailer-supplied Customer will be billed either by Hydro One under Distributor Consolidated Billing or by the Customer's designated Retailer under Retailer Consolidated Billing, as prescribed in the Retail Settlement Code.

2.4.3. Deposits

For the purposes of this Section 2.4.3, residential Customers include Residential, Seasonal Residential, Energy Billed Farm Customers with a principal residence, and bulk metered residential condominiums.

For the purposes of this Section 2.4.3, non-residential Customers include Farm with no principal residence, Industrial Commercial General Service, Industrial Commercial Sub Transmission, General Service-Energy Billed, General Service-Demand Billed, Large Use, Directs, Unmetered Scattered Loads and Lighting (Street and Sentinel)

A. Requirements for Security Deposit

Hydro One may require a security deposit from a Customer unless the Customer has a good payment history of one year in the case of a residential Customer, five years in the case of a non-residential Customer in a less than 50 kW demand rate class, or seven years in the case of a non-residential Customer in any other rate class. The time period that makes up the good payment history must be the most recent period of time and some of the time period must have occurred in the previous 24 months.

Security deposits may be required at the time the Customer initially applies for service, or subsequently when a Customer has failed to maintain a good payment history. The security deposit amount will be applied to the Customer's electricity account and appear as a charge on the next electricity bill issued.

B. Acceptable Forms of Security

Hydro One will accept security deposits in either of the following forms, at the discretion of the Customer:

(i) cash or cheque; or
(ii) automatically renewing irrevocable letter of credit from a bank as defined in the *Bank Act*.

At the Customer's discretion, a security deposit required at the time of application for service may be paid in equal monthly installments over a period of up to six months. Customers wishing to pay in installments must contact Hydro One at 1-888-664-9376 to make such payment arrangements.

C. Calculation of Security Deposit Amounts

Billing Cycle Factors shall be 2.5 for monthly-billed Customers, 1.75 for bi-monthly billed Customers and 1.5 for quarterly-billed Customers.

Security deposit levels for new Customers shall be determined in the following manner:

Billing Cycle Factor X estimated bill based on Customer's average monthly load during most recent 12 consecutive months within the past two years.

Where 12 consecutive months of relevant usage information within the past two years is not available, the Customer's average monthly load shall be based on a reasonable estimate made by Hydro One.

D. Limits on amount of security required

All rate classes:

The maximum amount of a security deposit shall be calculated based on the Billing Cycle Factor multiplied by the estimated bill based on the Customer's average monthly load during the most recent 12 consecutive months within the past two years (or Hydro One's reasonable estimate of monthly load where there is insufficient history).

Where a Customer has a payment history which discloses more than one disconnection notice in a relevant 12-month period, Hydro One will use that Customer's highest actual or estimated monthly load to calculate the security deposit amount.

Non-residential Demand Billed (> 50 kW) rate class:

Despite the above, where the Customer provides Hydro One with a credit rating from a recognized credit rating agency, the maximum amount of security deposit shall be reduced in accordance with the following table. The table below uses Standard & Poor's ratings, but equivalent ratings from Moody's and Dominion Bond Rating Services will be accepted.

Credit Rating (using Standard & Poor's Ratings)	Allowable Reduction
AAA- and above or equivalent	100 per cent
AA-, AA, AA+ or equivalent	95 per cent
A-, From A, A+ to below AA or equivalent	85 per cent
BBB-, From BBB, BBB+ to below A or equivalent	75 per cent
Below BBB- or equivalent	0 per cent

Exception:

Despite the above, for a non-residential > 5000 kW Customer who has established a good payment history for the relevant seven year period, Hydro One will return only 50 per cent of the security deposit held.

E. Review and Updating of Security Deposits

Hydro One will review and update security deposits at least once each calendar year to determine whether the entire amount is to be returned to the Customer due to establishment of a good payment history for the relevant period of time, or whether the amount is to be adjusted based on recalculation of the maximum amount of the security deposit under 2.4.3 C or 2.4.3 D above. Where some or all of the security is to be returned to the Customer, Hydro One will promptly credit the Customer's account including applicable interest.

Customers receiving more than one disconnection notice in a relevant 12-month period shall provide a security deposit or increase the amount of the existing security deposit.

F. Interest on Security Deposits

Interest is payable on cash/cheque security deposits and shall accrue monthly commencing on receipt of the total deposit required. The interest rate shall be at the Prime Business Rate as published on the Bank of Canada Web site, less two (2) per cent, updated quarterly, to a minimum of zero per cent.

Interest due will be paid out quarterly, or on return of the security deposit or closure of the account, whichever comes first. Interest will be paid out as a credit to the account.

G. Waiver/return of security deposit for Good Payment History

At Hydro One's discretion, residential Customers who do not have a payment history with Hydro One for the relevant time period, may be exempted from providing security at application for service. In these cases, security shall be required if the Customer fails to maintain a good payment history.

Security deposits shall be waived or returned for all other Customers demonstrating good payment history with Hydro One for the relevant time period. The relevant time period is based on the date the deposit was paid in full.

For all Customers except non-residential > 5000 kW, a security deposit required by Hydro One shall be waived on receipt by Hydro One from the Customer, of a satisfactory credit check from TransUnion, Equifax or D&B credit reporting agencies. The decision as to whether the credit check is satisfactory is within Hydro One's sole discretion.

Good Payment History Criteria

A Customer is deemed to have a good payment history unless, during the relevant time period specified below, the Customer has:

- received more than one disconnection notice from Hydro One;
- has more than one cheque given to Hydro One by the Customer returned for insufficient funds;
- has more than one pre-authorized payment to Hydro One returned for insufficient funds; or
- a Disconnect/Collect Trip has occurred.

If any of the preceding events occur due to an error by Hydro One, the Customer's good payment history shall not be affected.

Relevant time periods for establishing a good payment history are the most recent period of time, with at least some of the time occurring in the previous 24 months.

Relevant Time Period

In order for Hydro One to waive or refund a security deposit, good payment history criteria must be maintained by the Customer for the following time periods:

Residential Customer: one year's Good Payment History

Non-residential Customer < 50 kW: five years' Good Payment History

Non-residential Customer > 50 kW: seven years' Good Payment History

Non-residential Customer > 5000 kW rate class: after seven years' Good Payment History only 50 per cent of the security deposit held will be returned. The balance of the security deposit will be retained by Hydro One until closure of the account.

Security deposits shall not be applied to active account arrears and shall not constitute payment of an outstanding account, in whole or part. If Hydro One is in possession of a cash security deposit when the account is terminated, the deposit plus accrued interest, or applicable portion thereof, shall be returned to the Customer through a credit applied to the final bill or a cheque, at Hydro One's discretion. Hydro One will return any excess deposit amount to the Customer directly and within six (6) weeks after account closure. Non-cash security will be applied after the final bill due date, if full payment is not received from the Customer.

A security deposit requested by Hydro One may also be waived or decreased if the Customer provides a reference letter that confirms good payment history from another electricity or natural gas utility in Canada, where the customer was previously a customer. The letter must indicate good payment history for at least 12 months if the Customer has less than 50 kW demand, or seven years if the Customer has a demand equal to or greater than 50 kW demand. Some of this time must have occurred within the previous 24 months.

If a security deposit amount is applied due to a poor payment history, neither a satisfactory utility reference nor credit check will be accepted to waive the deposit. Only maintenance of a good payment history will allow for refund of the deposit. If good payment history is not maintained, Hydro One will not accept another utility reference letter. Utility reference letters are valid for a one-year period.

H. Enforcement where security deposit not paid

Payment of security deposits identified as a condition of service or continuing service will be enforced through collection activities for amounts due, up to and including disconnection of electrical service. (See Section 2.2 of these Conditions of Service.)

I. Security from Embedded Distributors

Embedded Distributors shall post security deposits with Hydro One if a good payment history is not maintained for seven years. Deposits will be calculated according to the following:

<u>Maximum Security Deposit Amount. Wholesale Market Participant:</u>
Security Deposit amount will be calculated based on average monthly non-competitive electricity costs billed by Hydro One, multiplied by the Billing Cycle Factor of 2.5.

<u>Maximum Security Deposit Amount. Not a Wholesale Market Participant</u>
Security deposit amount will be calculated based on Billing Cycle Factor of 2.5 multiplied by the average monthly non-competitive electricity costs plus competitive electricity costs, using the average monthly consumption and cost of energy used by the IESO for the purpose of determining prudential support obligations for Distributors.

<u>Security Deposit Reductions for Good Payment History</u>
Hydro One will reduce the security deposit amount required from an Embedded Distributor based on the following good payment history time periods listed below:

(i) 25 per cent reduction for 2 years;
(ii) 50 per cent reduction for 3 years;
(iii) 75 per cent reduction for 5 years; and
(iv) 100 per cent reduction for 7 years.

Where a security deposit has been reduced for good credit rating (see D, non-residential Demand Billed) it will be further reduced if good payment history periods outlined above are met.

<u>Review and Adjustment of Security</u>

Hydro One shall review security deposit amounts on a periodic basis to determine whether:

(i) a portion of the security deposit is to be returned to the customer based on the number of years of good payment history demonstrated; or

(ii) the security deposit amount is to be adjusted based on a recalculation of the maximum security deposit amount.

J. Acceptable Forms of Security

Hydro One shall accept security deposits in the form of cash or cheque, or automatically renewing, irrevocable letter of credit from a bank as defined in the *Bank Act*, or a combination thereof, at the discretion of the Customer.

2.4.4. Billing

In this Section 2.4.4, references to monthly, bi-monthly, quarterly, and annually are notional and approximate time periods only. They are not to be construed as calendar-based time periods.

A. Billing Frequency

Depending on Rate classification and service size, Customers are billed on a monthly, bimonthly, or quarterly frequency.

B. Low Use Billing Suspension Credit

Billing suspension of any account may be granted for low use farm and general service with less than 2,500 kWh per year that was connected prior to January 1, 1996. The Customer must sign an agreement annually. The suspension is for either a four-month or six-month period, and the Customer will be credited in an amount equal to the monthly service charge multiplied by the number of months suspended. A charge equal to the suspension credit will be applied if the Customer exceeds the limit of 2,500 kWh per year or takes power during the identified period of suspension. In addition to the charge, the Customer will be billed for the kWh consumed in excess of 2,500 kWh per year.

C. Use of Estimates

In months where a bill is issued but no reading is obtained, Hydro One will estimate energy and demand in order to determine billing quantities. The estimate is based on historical usage for the premise, or a predetermined quantity if there is no historical usage information available.

Customers may avoid receiving bills based on estimated meter readings if they provide Customer-obtained meter reads that pass validation checks and are provided according to processes and timing established by Hydro One for billing purposes.

D. Pro-ration of Accounts

Accounts will be pro-rated where the bill to a Customer is for a period shorter or longer than the standard billing period or where rates have been revised effective on a date not coincident with the Customer's billing or meter reading date.

E. Budget Billing Plan

A budget billing plan is available to all Standard Supply Service Customers and retailer-enrolled Customers on Distributor Consolidated billing. To help smooth electricity costs over the year, the plan bills an equal portion of the previous year's charges per bill period and then reconciles the balance owing in the anniversary month. Periodic adjustments may be made to the regular budget bill amount due to Rate or usage changes.

The budget billing plan is not available to Customers who are demand-billed or whose meters are read monthly.

F. Billing Errors: Over and Under Billing

Where a billing error, from any cause, has resulted in a Customer or Retailer being overbilled, and where Measurement Canada has not become involved in the dispute, Hydro One will credit the Customer or Retailer with the amount erroneously billed, for up to a six-year (6-year) period. Where the billing error is not the result of Hydro One's standard billing practices (i.e. estimated meter reads), Hydro One will pay interest on the amount credited at the same rate of interest as paid on security deposits (section 2.4.3).

Where a billing error, from any cause, has resulted in a Customer or Retailer being underbilled, and where Measurement Canada has not become involved in the dispute, the Customer or Retailer shall pay to Hydro One the amount that was not previously billed. In the case of an individual Customer who is not responsible for the error, the allowable period of time for which the Customer may be charged is two (2) years for residential customers and six (6) years for all other customers. For instances of wilful damage, the resulting time period is the duration of the defect, where records are available.

For either situation, where Measurement Canada is involved in instances of checking meter registration accuracy, Measurement Canada will issue a decision. Hydro One or the Customer who initiated the dispute investigation both have the option to appeal the decision and follow Measurement Canada's appeal process.

G. Transformer Loss Allowance

A transformer loss allowance is applicable to Customers, excluding Embedded Distributors and Direct Customers, requiring a billing adjustment for transformer losses as a result of being metered on the primary side of a transformer. The OEB-approved transformer loss allowance is as set out in the Rate schedules available at **www.HydroOneNetworks.com**.

H. Customer-Supplied Transformation Allowance

Customer-supplied transformation allowance is applicable to Standard Customers and Sub-transmission Customers who are demand-billed and providing their own transformers. The OEB-approved Customer-supplied transformation allowance is as set out in the Rate schedules available at **www.HydroOneNetworks.com**.

I. Annual Monitoring of Electricity Usage

For energy only metered non-residential customers, annual consumption will be monitored to identify services that have grown beyond 150,000 kilowatt-hours annually and require a demand meter to be installed.

For demand metered customers, measured demand is monitored during the calendar year to determine whether the account should be reclassified for billing purposes. The review occurs in the first quarter of the year, with the measurement period being January 1 through December 31 of previous year and average monthly demand is calculated based on the measurements taken for bills issued within that time period.

Reclassification of an account, with no retroactive adjustment, will occur effective the next scheduled bill after the annual review, if the average monthly demand over the calendar year crosses the 50 kW threshold for demand billing, or the 5000 kW threshold between General Service, Sub-transmission Customers or “T” class customers and Direct Customers or Large Users.

Alternatively, where a demand metered customer requests Hydro One to do a review, the calculation will be based on the average monthly demand over the most recent 12 month period and the account will be reclassified, as appropriate, effective the next scheduled bill following the review.

J. Billing Determinants for Demand Customers

Hydro One establishes billing determinants for demand customers at the greater of 100 per cent of kW and 90 per cent of kVA where kVA metering is installed. When a Customer’s power factor is known to be less than 90 per cent, a kVA meter or other equivalent electronic meter shall be used for measuring and billing.

2.4.5. Payments and Overdue Account Interest Charges

A. Payment Options

Customers may pay their electricity bills using any of the following methods: cheque or money order mailed with the remittance stub portion of the bill to Hydro One at the address on the stub; in person at most Canadian financial institutions; through automated banking machines, telephone banking or Internet bill payment services offered through the Customer's financial institution. All payments must be in Canadian dollars.

Hydro One also offers a pre-authorized payment option.

B. Late Payment Charges

Bills are due on the billing date. A late payment charge is applied and shall be paid by the Customer if payment is not received within twenty-one (21) days of the billing date. Hydro One's late payment charge is 1.5% per month, compounded monthly (19.56% per year). Late payments are calculated from the billing date to the date the next bill is issued. The late payment charge of 1.5% is applied to the outstanding balance. If partial payment is made within twenty-one (21) days of the billing date, the late payment charge will apply only to the amount outstanding after deducting the partial payment. Late payment charges will be added to the Customer's next bill.

2.5. Customer Information

A. Retail Settlement Code Requirements

Hydro One shall provide current and historical usage information to Customers and retailers in accordance with Chapter 11 of the Retail Settlement Code.

Customers with remotely read Interval Meters shall have access to meter usage data in accordance with Section 2.3.7.3 or over the Internet after having obtained a password from Hydro One for secure access.

Current Usage Data

Customers with cumulative volume, demand and non-remotely read Interval Meters shall receive their current usage data on their electricity bill from Hydro One.

Customers with remotely read or non-remotely read Interval Meters shall have access to meter usage data in accordance with the Read Only Access agreement to be executed by Hydro One and the Customer and in accordance with the standards set out in the Retail Settlement Code. Key provisions of the Read Only Access Agreement are described in Appendix “A” to these Conditions of Service.

Hydro One will provide access to a Customer’s meter or meter information under the following conditions:

(i) Hydro One will select the access windows it requires to read the meter;
(ii) if Hydro One’s access to the meter is hindered or a Customer’s access to the meter corrupts usage information, Hydro One may suspend a Customer’s right to access until any outstanding problems are resolved;
(iii) the Customer shall pay the reasonable cost of any software, hardware and other services required for a Customer to obtain direct access to meter information. This may include installation of a secondary meter access system;
(iv) the Customer shall bear any cost incurred by Hydro One to correct problems caused by a Customer’s direct access to the meter;
(v) if the Customer assigns his or her right to direct meter access to a Retailer or third party, the Customer shall be responsible for the actions of the assigned party.

Meter information generated by Smart Meters will not be accessible for Customers until Hydro One elects to implement time-of-use pricing and will not be accessible for Retailers until the OEB declares smart meters as MIST Meters.

Historical Information

Provision of Customer-specific information to retailers through the Electronic Business Transaction (EBT) system shall be provided at no charge. Requests to deliver data directly to Retailers and Customers, if not delivered through the EBT System, shall be honoured twice a year, at no direct charge to a Retailer or Customer. Additional requests shall also be honoured, but Hydro One may, at its discretion, charge a reasonable fee for such additional requests. A request is considered to be data delivered to a single address.

Hydro One will provide a Customer with at least 12 months, where available, of historical usage information, information about the Customer’s meter configuration, and payment information (“Historical Information”). The Historical Information can be released to the Customer or any third party designated by the Customer, subject to the following:

(i) if the third party is a Retailer, the Customer has provided the Retailer with written authorization for the release; or

(ii) if the third party is someone other than a Retailer, the Customer shall have provided Hydro One with written authorization for the release.

B. Protection of Individual Privacy and Consumer Information

(i) Privacy Legislation and the Licence

Hydro One is subject to provincial and federal privacy legislation that contains specific restrictions concerning the collection, use and disclosure of Personal Information.

In addition, the Licence prohibits Hydro One from disclosing information regarding a Customer to any other party without the written consent of the Customer, except where such information is required to be disclosed:

(a) to comply with any legislative or regulatory requirements, including the conditions of the Licence;

(b) for billing, settlement or market operation purposes;

(c) for law enforcement purposes; or

(d) to a debt collection agency for the processing of past due accounts of the Customer.

The Licence permits Hydro One to disclose information regarding a Customer where the information has been sufficiently aggregated such that the Customer's particular information cannot reasonably be identified.

(ii) Hydro One's Collection, Use and Disclosure of Customer Information

Hydro One collects information about its Customers, including Personal Information (collectively, "Customer Information"), primarily directly from its Customers, whether verbally, in writing or via the www.hydroone.com website; however, it may also collect from other sources, including credit bureaus or personal references. This information collected is primarily:

- information establishing identity (for example: name, address, phone number, date of birth, etc.);
- information related to the provision of electricity and/or distribution services by Hydro One and other electricity distributors; and
- information about financial behaviour, such as payment history and creditworthiness.

Hydro One collects the information described above for the following purposes:

(a) to establish and maintain responsible commercial relations and operations, including for purposes of billing and debt collection and for assessing Customer credit history from time to time to determine whether Hydro One requires a security deposit;

(b) to understand Customer needs and eligibility for products and services;
(c) to recommend particular products and services to meet a Customer's needs;
(d) to develop, enhance, market or provide electricity products and services;
(e) to manage and develop Hydro One's businesses and operations;
(f) to meet legal and regulatory requirements; and
(g) to provide Customers with information about the electricity market and rates.

Hydro One does not trade or sell Customer Information to others. Hydro One shall not use or disclose Customer Information for purposes other than those for which it was collected, except with the Customer's consent or as required by law.

The information will be used and disclosed internally within Hydro One by and among staff members (for example, its customer care staff and its internal auditors) that need the information in the performance of their duties and where the use and disclosure is necessary and proper in the discharge of Hydro One's business.

In some instances, Customer Information will be shared with third party service providers who perform services on Hydro One's behalf, such as customer service, outage management, data storage, data cleansing and the like. These third party service providers are given only the information necessary to perform those services that Hydro One has contracted them to provide. Additionally, they are prohibited from storing, analyzing or using that information for purposes other than the services they have been contracted to provide. Hydro One uses contractual means to require such service providers to protect Customer Information from loss, theft and unauthorized access, use, disclosure and otherwise in a manner consistent with the privacy policy and practices established by Hydro One. In the event our service provider is located outside of Canada, the service provider is bound by, and Personal Information may be disclosed in accordance with, the laws of the jurisdiction in which the service provider is located.

In order to measure performance and develop service improvements, Hydro One may disclose Customer information to third party service providers for the purpose of conducting surveys on Hydro One's behalf. The providers are bound by strict confidentiality contracts to use the information for the sole purpose of the survey. Customers may choose not to have their information released by Hydro One to a service provider for survey purposes, by contacting 1-888-664-9376.

(iii) Access to Personal Information

Hydro One retains Personal Information only as long as necessary for the fulfillment of the purposes described in this Section.

Customers may obtain access to their Personal Information held by Hydro One at any time and review its content and accuracy, and have it amended as appropriate.

However, access may be restricted as permitted or required by law. Customers can request access by contacting 1-888-664-9376.

Further information about Hydro One's practices and procedures concerning the collection, use and disclosure of Personal Information can be found in Hydro One's Privacy Code (available at www.HydroOneNetworks.com).

SECTION 3 CUSTOMER CLASS SPECIFIC

3.1 Residential and Farm

Under Section 79 of the *Ontario Energy Board Act* and associated regulations, qualifying year-round residences and farms are eligible to receive rural or remote electricity rate protection. The monthly service charge amount for eligible Customers is reduced by the applicable rural or remote electricity rate protection.

A. Residential-Year-Round

This Rate classification is applied to a Customer's main place of abode and may include additional buildings served through the same meter, provided they are not rental income units. To be classified as year-round residential, all of the following criteria must be met:

(i) the property must be the Customer's principal residence as defined in the *Income Tax Act*, and the Customer must state that fact in writing;
(ii) the Customer must live in this residence for at least four (4) days of the week for eight (8) months of the year and the Customer does not reside anywhere else for more than three (3) days a week during eight (8) months of the year;
(iii) the address of this residence must appear on the Customer's driver's licence and credit card invoices and as the Customer's mailing address on the Customer's electricity bill and property tax bill, etc.; and
(iv) Customers who are eligible to vote in Provincial or Federal elections must be enumerated for voting purposes at the address of this residence.

Multi-unit residential establishments such as apartment buildings supplied through one service (bulk metered) normally shall be classified as Industrial Commercial General Service; however, up to four residential units may, at Hydro One's discretion, be classified as Residential-Year-Round.

A.1 Residential UR2

Customers classified as Residential UR2 are year-round residences in an urban density zone or Farm Single Phase Energy Billed Customers in an Urban Density Zone.

A.2 Residential R1

Customers classified as Residential R1 are year-round residences in a High Density Zone.

A.3 Residential R2

Customers classified as Residential R2 are year-round residences in a normal density zone.

A.4 Seasonal Residential R3

This Rate classification includes any residential service not meeting the residential-year-round criteria. As such, the seasonal residential class includes cottages, chalets, and camps. Customers classified as Seasonal Residential R3 are residences that have seasonal occupancy in High Density Zone.

A.5 Seasonal Residential R4

This Rate classification includes any residential service not meeting the residential-year-round criteria. As such, the seasonal residential class includes cottages, chalets, and camps. Customers classified as Seasonal Residential R4 are residences that have seasonal occupancy in Normal Density Zone.

A.6 Residential (Acquired Local Distribution Companies)

All service supplied to single-family dwelling units for domestic or household purpose shall be classified as residential service. Multi-unit residential establishments such as apartment buildings supplied through one service (bulk metered) will normally be classified as general service, but, at Hydro One's discretion, up to four residential units may be classified as residential.

Where electricity service is provided to combined residential and business (including agricultural usage) and the wiring does not provide for separate metering, the classification shall be at the discretion of Hydro One, based on such considerations as the estimated predominant consumption.

B. Farm

This Rate classification is applicable to properties actively engaged in agricultural production as defined by Statistics Canada. Services to year-round pumping stations or other ancillary services remote from the main farm shall also be classed as farm. The Farm Service Rate classification does not include tree, sod, or pet farms.

B.1. Farm Single Phase F1

Single Phase F1 Farm Customers are actively engaged in agricultural production in areas other than Urban Density Zones.

B.2. Farm Three Phase F3

Three Phase F3 Farm Customers are actively engaged in agricultural production in areas other than Urban Density Zones.

C. Low Use Secondary Service

Applicable to separately metered services that were connected prior to January 1, 1996, and located on the same contiguous property as the main or primary service, supplied from the same transformer, with the same owner and consuming less than the threshold levels specified in the following table. The distribution basic monthly service charge is not applied.

Primary Service Classification	Low Use Secondary Service Classification	Secondary Service Annual Usage Threshold
R1 R2	R3, R4 G2, F (non-RRP)	<1500 kWh/ year
R3 R4	R3, R4 G2, F (non-RRP)	<500 kWh/year
G F	R3, R4 G2, F (non-RRP)	<2500 kWh/year

D. Connection and Upgrade Charges

A Residential, Seasonal Residential or Farm Customer who makes a written request for a Connection and whose building lies along Hydro One's existing distribution lines shall pay Hydro One Connection charges in accordance with Section 2.1.1.

A Residential, Seasonal Residential or Farm Customer who makes a written request for a Connection and whose building is within Hydro One's service area shall pay Hydro One Connection charges in accordance with Section 2.1.2.

A Residential, Seasonal Residential or Farm Customer who requests an upgrade in connection assets at its premises shall pay the net cost of upgrading the connection assets that is in excess of the cost of supplying distribution transformation or metering. The cost of modifications to the Distribution System due to the upgraded Connection will be in accordance with Section 2.1.2.

E. Ownership Demarcation Point and Operational Demarcation Point

For Secondary Services wholly-owned and maintained by Hydro One, the Ownership Demarcation Point and the Operational Demarcation Point shall be located at:

(i) the top of the Customer's service entrance stack for overhead connections;
(ii) the line side of the Customer's meter base for underground connections; and
(iii) the metering point for a central-metered service.

For Secondary Services wholly owned and maintained by the Customer, the Ownership Demarcation Point and the Operational Demarcation Point is the secondary connection at the transformer or the service bus.

Maintenance of the portion of the Secondary Service owned by Hydro One includes repair and like-for-like replacement of a wire or cable that has failed irreparably. The Customer is responsible for all civil work, supports, vegetation and landscaping associated with any such repair or replacement of the portion of Secondary Service owned by Hydro One.

For Primary Service Residential and Farm Customers, the Ownership Demarcation Point shall be located at the primary live line clamp or line switch.

Where the Customer has ownership of a primary disconnecting device, this device shall be the Operational Demarcation Point, which shall be under the operating control of Hydro One.

F. Customer-Supplied Secondary Wire

The Customer shall install, own, and maintain the secondary conductor under any of the following conditions:

(i) conductor terminations are inside the Customer's building;
(ii) conductor is installed beyond the service entrance;
(iii) conductor is connected to a Primary Service; or
(iv) conductor is a non-standard installation.

G. Residential, Seasonal Residential and Farm Single Phase F1 Customers

Voltage

For residential, seasonal residential and Farm Single Phase F1 Customers, the nominal supply voltage shall be 120/240 Volt single-phase.

Metering

To accommodate Hydro One's meter installation, the Customer shall make provision as follows:

(i) Where the rating of a Customer's main disconnecting device does not exceed 200 A, the Customer shall provide a 120/240 V, 200 A, single phase 4-jaw outdoor meter socket connected on the line side of the main disconnecting device.

(ii) Where the rating of a Customer's main disconnecting device does not exceed 400 A, the Customer shall provide an outdoor combination meter socket and metering transformer enclosure connected on the line side of the main disconnecting device and equipped with:

- 120/240 V, 10 Amp – 5-jaw meter socket with automatic circuit-closing device; and
- 400 Amp revenue-metering current transformer.

The meter installation shall be installed in a location acceptable to Hydro One.

For metering installed on poles, the pole will be installed, owned and maintained by the Customer.

H. Farm Three Phase F3 Customers

Voltage

For Farm Three Phase F3 Customers, the nominal supply voltage shall be 120/208 volts 4 wire or 347/600 volts 4 wire.

Metering

To accommodate Hydro One's meter installation, the Customer shall provide acceptable equipment in accordance with one of the following arrangements, as determined by Hydro One:

(i) 208/120 V, 200 A, 3-phase 7-jaw meter socket connected on the load side of the main disconnecting device; or

(ii) 600/347 V, 200 A, 3-phase 7-jaw indoor meter socket with an insulated neutral jaw, and connected on the load side of the main disconnecting device.

(iii) The meter installation shall be installed in a location that is acceptable to Hydro One.

(iv) Metering for 347/600 V, 3 phase four wire circuits that only have 1 metering point per service entrance shall use transformer rated metering using 3 CTs and 3 PTs.

(v) Metering for 347/600 V, 3 phase four wire circuits that have more than 1 metering point per service entrance may use self contained metering up to 200 A on the load side of the customer's service entrance, in conformity with the requirements of the Electrical Safety Code.

3.2. Industrial Commercial

These Rate classifications are applicable to any service that does not fit the description of the year-round residential, seasonal residential or farm classes. Generally, it is composed of commercial, industrial, educational, administrative, auxiliary and government type services. It includes combination-type services where a variety of uses are made of the service by the owner of one property, and all multiple services except residential with up to four units.

A. Industrial Commercial General Service

These Rate classifications are applicable for Industrial Commercial customers not directly supplied by the Sub-transmission System.

A.1. Industrial Commercial General Service, Urban Density UG2

This Rate classification is applicable to Single or Three Phase Industrial Commercial General Service or Farm Customers located in an Urban Density Zone.

A.2. Industrial Commercial General Service, Single Phase G1

This Rate classification is applicable to Industrial Commercial General Service Single Phase Customers that are not located in an Urban Density Zone.

A.3. Industrial Commercial General Service, Three Phase G3

This Rate classification is applicable to Industrial Commercial General Service Three Phase Customers not located in an Urban Density Zone.

A.4. Lighting

This Rate classification is applicable to street lighting and unmetered sentinel lights.

B. Industrial Commercial Sub-transmission or T-Class

This Rate classification is applicable to Industrial Commercial Customers supplied directly from the Sub-transmission System.

C. General Service (Acquired Local Distribution Companies)

All service supplied to premises other than those classified as residential, lighting or large use shall be classified as general service.

D. Low Use Secondary Service

Applicable to separately metered services that were connected prior to January 1, 1996, and located on the same contiguous property as the main or primary service, supplied from the same transformer, with the same owner and consuming less than the threshold levels specified in the following table. The distribution basic monthly service charge is not applied.

Primary Service Classification	Low Use Secondary Service Classification	Secondary Service Annual Usage Threshold
R1 R2	R3, R4 G2, F (non-RRP)	<1500 kWh/ year
R3 R4	R3, R4 G2, F (non-RRP)	<500 kWh/year
G F	R3, R4 G2, F (non-RRP)	<2500 kWh/year

E. Large Use (Acquired Local Distribution Companies)

Individual Customers whose monthly measured maximum demand (kW) averaged over the most recent 12 consecutive months is equal or greater than 5,000 kW shall be classified as a large use Customer.

F. Connection and Upgrade Charges

A General Service Customer who makes a written request for a Connection and whose building lies along Hydro One's existing distribution lines shall pay Hydro One Connection charges in accordance with Section 2.1.1.

A General Service Customer who makes a written request for a Connection and whose building is within Hydro One's service area shall pay Connection charges in accordance with Section 2.1.2.

A General Service Customer who requests an upgrade in connection assets at its premises shall pay Hydro One the net cost of upgrading the connection assets that is in excess of the cost of supplying distribution transformation or metering. The Customer shall enter into a Connection and Cost Recovery Agreement with Hydro One. The cost of modifications to the Distribution System, due to the upgraded Connection, will be in accordance with Section 2.1.2.

G. Ownership Demarcation Point and Operational Demarcation Point

For Secondary Service General Service Customers, the Ownership Demarcation Point and Operational Demarcation Point shall be located as follows:

(i) where the Customer's conductors emerge from the service head or mast on overhead Secondary Services, or at the secondary terminal (spade) of the transformer, or at the secondary connection pedestal located at the property line, as determined by Hydro One at the Customer's location; or
(ii) on underground Secondary Services, at the secondary terminal (spade) of the transformer.

For Primary Service General Service Customers, the Ownership Demarcation Point shall be located at the primary live line clamp or line switch.

Where the Customer has ownership of a primary disconnecting device, this device shall be the Operational Demarcation Point, which shall be under the operating control of Hydro One.

H. Voltage

For Secondary Service General Service Customers, Hydro One supplies electricity at the following nominal voltages and phases, where available:

(i) 347/600Y Volts 3-phase 4 wire;
(ii) 120/208Y Volts 3 phase 4 wire; or
(iii) 120/240 Volts 1-phase.

The Customer shall consult with Hydro One early to confirm availability of specific voltages within the Hydro One Distribution System.

For Primary Service General Service Customers, Hydro One supplies electricity at the following nominal voltages and phases, where available:

(a) 44,000 Volts – 3 Phase 3 Wire;
(b) 16,000/27,600 Volts – 3 Phase 4 Wire;
(c) 14,400/25,000 Volts – 3 Phase 4 Wire;
(d) 8,000/13,800 Volts – 3 Phase 4 Wire;
(e) 4,800/8,320 Volts – 3 Phase 4 Wire; or
(f) 2,140/4,160 Volts – 3 Phase 4 Wire

I. Metering

Metering Equipment

To accommodate Hydro One's meter installation, the Customer shall provide acceptable equipment in accordance with one of the following arrangements, as determined by Hydro One:

Self-Contained Metering Up to 200 A

A self-contained meter installation at low voltage where the rating of the Customer's main disconnecting device does not exceed 200 A shall be provided with:

(i) 120/240 V, 200 A, 1-phase 4-jaw outdoor meter socket connected on the line side of the main disconnecting device;
(ii) 208/120 V, 200 A, 1-phase 5-jaw indoor meter socket connected on the load side of the main disconnecting device;
(iii) 208/120 V, 200 A, 3-phase 7-jaw meter socket connected on load side of the main disconnecting device; or
(iv) 600/347 V, 200 A, 3-phase 7-jaw indoor meter socket with an insulated neutral jaw, and connected on the load side of the main disconnecting device; and
(v) metering for any 3 phase secondary voltages other than those specified should use transformer rated metering.

120/240 V, 400 A

A General Service single-phase transformer-type meter installation at 120/240 V where the rating of the Customer's main disconnecting device ranges from greater than 200A up to 400 A shall be provided with:

(i) 120/240 V, 10 A, 5-jaw meter socket connected on the line side of the main disconnecting device with an automatic circuit-closing device;
(ii) indoor instrument transformer enclosure; and
(iii) 19 mm conduit from the instrument transformer enclosure to the meter socket.

Three-Phase Less than 200 kW

A three-phase transformer-type meter installation that is not equipped with interval meters and where the monthly average peak demand during a calendar year is forecasted by Hydro One not to exceed 200 kW shall be provided with:

(i) an acceptable outdoor meter enclosure;
(ii) an indoor instrument transformer enclosure; and
(iii) 25 mm conduit from the instrument transformer enclosure to the meter enclosure.

Three-Phase Greater than 200 kW

A transformer-type meter installation where the monthly average peak demand during a calendar year is forecasted by Hydro One to exceed 200 kW and where the rating of the Customer's main disconnecting device does not exceed 3000 A at low voltage shall have an interval meter and shall be provided with:

(i) an acceptable meter enclosure;
(ii) an indoor instrument transformer enclosure;
(iii) 31 mm of conduit from the instrument transformer enclosure to the meter enclosure; and
(iv) a voice grade direct access telephone line that is active 24 hours every day, seven days per week, and protected by a 13 mm conduit from the telephone entrance equipment into the meter enclosure.

Instrument Transformer Enclosure

A Customer who requires a transformer-type meter installation shall provide a metal instrument transformer enclosure that is:

(i) equipped with a hinged door, provision for securing of the transformers to the enclosure, and padlock hasp or other means of rendering the enclosure inaccessible to unauthorized persons;
(ii) connected on the load side of the main disconnecting device;
(iii) sized as follows:

- 120 Volt single phase service: Over 200 Amperes up to and including 400 Amperes - 1.0 m x 1.0 m x 0.3 m (36" x 36" x 12"); Over 400 Amperes - 1.2 m x 1.2m x 0.3m (48" x 48" x 12")
- 120/208 Volt three phase four wire service: Over 200 Amperes up to and including 600 Amperes - 1.2 m x 1.2 m x 0.3 m (48" x 48" x 2")
- 347/600 Volt three phase four wire services: Over 200 Amperes up to and including 600 Amperes - 1.2 m x 1.2 m x 0.3 m (48" x 48" x 12")

  Where a cabinet is required for meters only, the dimensions will be 0.61 m x 0.412 m x 0.257 m (24" x 16.2" x 10.1")
- 347/600 V, 3 phase four wire circuits that only have 1 metering point per service entrance shall use transformer rated metering using 3 CTs and 3 PTs; and

(iv) provided with one of the following meter loop arrangements - Spare conductors not less than 450 mm in length, equipped with connectors supplied and terminated by the Customer at each bar-type current transformer connection point, or three-phase conductors installed through ring-type current transformers, or other acceptable provision for connection of current transformers.

Multi-Occupancy Metering

The meter installation for a multiple occupancy structure where the Customer requires individual meters and where the rating of the main disconnecting device exceeds 400 A shall satisfy the following requirements:

(i) Meters shall be installed in a central service room with access as per Section 1.7.1 Space and access.

(ii) The central service room shall be separated from the remainder of the building by an approved fire separation.

(iii) Any splitter trough cover shall be hinged to open downward and equipped with provision for padlock and seal.

(iv) A full-sized neutral supply conductor shall be extended from any splitter trough to each meter socket.

(v) The conductors to each meter shall be provided with a separate sub-service box.

(vi) Sub-service boxes shall be identified with an approved address or unit number and the same number shall identify the service panel inside the unit.

(vii) Metering for 347/600 V, 3 phase four wire circuits that have more than 1 metering point per service entrance may use self contained metering up to 200A on the loadside of the Customer's service entrance in conformity with the requirements of the Electrical Safety Code.

3.3. Direct Customers

This Rate classification is applicable to Direct Customers, who may or may not be Wholesale Market Participants.

A. Connection and Upgrade Charges

A Direct Customer who makes a written request for a Connection and whose building lies along Hydro One's existing distribution lines shall pay Hydro One Connection charges in accordance with Section 2.1.1.

A Direct Customer who makes a written request for a Connection and whose building is within Hydro One's service area shall pay Connection charges in accordance with Section 2.1.2.

A Direct Customer who requests an upgrade in connection assets at its premises shall pay Hydro One the net cost of upgrading the connection assets that is in excess of the cost of supplying metering. The Customer may be required to enter into a Connection and Cost Recovery Agreement with Hydro One. The cost of modifications to the Distribution System, due to the upgraded Connection, will be in accordance with Section 2.1.2.

B. Ownership Demarcation Point and Operational Demarcation Point

For Direct Customers, the Ownership Demarcation Point and Operational Demarcation Point shall be:

a) located at the primary live line clamp or line switch, or

b) where the Customer has ownership of a primary disconnecting device, this device shall be the Operational Demarcation Point, which shall be under the operating control of Hydro One, or

c) as specified in the Connection Agreement.

C. Voltage

The Customer shall consult with Hydro One early to confirm availability of specific voltages within the Hydro One Distribution System.

For Direct Customers, Hydro One supplies electricity at the following nominal voltages and phases, where available:

(i) 44,000 Volts – 3 Phase 4 Wire;
(ii) 16,000/27,600 Volts – 3 Phase 4 Wire;
(iii) 14,400/25,000 Volts – 3 Phase 4 Wire; or
(iv) 8,000/13,800 Volts – 3 Phase 4 Wire.

D. Metering

For Direct Customers, metering shall be specified in the Connection Agreement.

3.4. Embedded Distributors

This Rate classification is applicable to Embedded Distributors, who may or may not be Wholesale Market Participants.

The reliability of supply and the voltage level at the Delivery Point from the Distribution System to an Embedded Distributor's distribution system shall be as good as or better than what is provided to Hydro One's other distribution Customers.

The Embedded Distributor shall provide load forecasts or any other information related to the Embedded Distributor's system load to Hydro One, as determined and required by Hydro One. Hydro One shall not require any information from another Distributor unless it is required for the safe and reliable operation of either the Distribution System or to meet the obligations contained in the Licence.

An Embedded Distributor shall notify Hydro One when the former has received a formal connection impact assessment request from anyone wishing to connect an Embedded Generations Facility within the former's service area.

Hydro One will make every reasonable effort to respond promptly to another Distributor's written request for a Connection to the Distribution System and shall comply with all of the requirements of Connection as identified in section 6.3 of the Distribution System Code.

The Embedded Distributor seeking a Connection shall pay all costs of consultations, preparation of estimates, system impact studies and design. The Connection costs, costs of system modifications and of commissioning and testing necessary to connect the Distributor as well as all ongoing administration, settlement and maintenance costs will be included in the DCF calculation. The Distributor will provide a load forecast acceptable to Hydro One, which will be used in the determination of the distribution revenues collected over the revenue horizon. Any shortfall calculated by the DCF calculation shall be paid by the Distributor seeking the Connection.

The Embedded Distributor may be required to sign a Connection and Cost Recovery Agreement with Hydro One.

A. Connection and Upgrade Charges

An Embedded Distributor who makes a written request for a Connection shall pay Connection charges in accordance with Section 2.1.2.

An Embedded Distributor who requests an upgrade in connection assets at its premises shall pay Hydro One the net cost of upgrading the connection assets that is in excess of the cost of supplying distribution transformation or metering. The Customer shall enter into a Connection and Cost Recovery Agreement. The cost of modifications to the Distribution System, due to the upgraded Connection, will be in accordance with Section 2.1.2.

B. Ownership Demarcation Point and Operational Demarcation Point

For an Embedded Distributor, the Ownership Demarcation Point and the Operational Demarcation Point shall be specified in the Operating Schedule of the Connection Agreement.

C. Voltage

The Embedded Distributor shall consult with Hydro One early to confirm availability of specific voltages within the Hydro One Distribution System.

For Embedded Distributor, Hydro One supplies electricity at the following nominal voltages and phases, where available:

(i) 44,000 Volts – 3 Phase 4 Wire;
(ii) 16,000/27,600 Volts – 3 Phase 4 Wire;
(iii) 14,400/25,000 Volts – 3 Phase 4 Wire; or
(iv) 8,000/13,800 Volts – 3 Phase 4 Wire.

D. Metering

For Embedded Distributors, metering shall be specified in the Connection Agreement.

3.5. Embedded Generation Facilities

The process and time line associated with connecting an Embedded Generation Facility to the Distribution System (< 50 kV) can be found in the Distribution System Code at the Ontario Energy Board web site (www.oeb.gov.on.ca). The Distribution System Code also identifies the size categories for these Generation Facilities. The categories are outlined below:

Embedded Generation Facility Classification	Name-Plate Rated Capacity
Micro	≤ 10 kW
Small	(a) ≤ 500 kW connected on distribution system voltage < 15 kV (b) ≤ 1 MW connected on distribution system voltage ≥ 15 kV
Mid-Sized	(a) ≤10 MW but > 500 kW connected on distribution system voltage < 15 kV (b) > 1 MW but ≤ 10 MW connected on distribution system voltage ≥ 15 kV
Large	> 10 MW

Hydro One requires all Customers with Generation Facilities connected to the Distribution System and all Generators wishing to connect to the Distribution System to execute a Connection Agreement in the applicable form prescribed in Appendix "E" of the *Distribution System Code* and/or such other agreements as may be reasonably required by Hydro One in the circumstances as described in Appendix "E" of the *Distribution System Code* as "Other Potential Contracts".

Generators with Embedded Generation Facilities connected to the Distribution System prior to the date of these Conditions of Service shall, subject to any agreement to the contrary between the Generator and Hydro One, execute a Connection Agreement with Hydro One within a reasonable period of time. During the time when such an agreement is not yet in place, the Generator will be deemed to have an implied contract with Hydro One. The terms of the implied contract are these Conditions of Service, the Electricity Distribution Rate Handbook, the Hydro One rate schedules, the Licence and the Distribution System Code.

In accordance with Section 2.2 of these Conditions of Service, Hydro One may disconnect any Generator that does not execute a Connection Agreement.

Hydro One shall not allow connections of Embedded Generation Facilities to the Distribution System in a manner that may adversely affect power quality, reliability or the safety of Hydro One's personnel or Customers.

The Generator shall be responsible for all costs associated with Hydro One performing studies, developing and implementing plans for risk mitigation that are to the satisfaction of Hydro One.

If an existing Generator proposes to materially change the mode of operation, the installed capacity and /or the protective devices, the Generator must submit the information required for reassessment of the impact of the operation of the Embedded Generation Facility prior to making such changes.

A. General Technical Information Requirements & Connection Impact Assessment (CIA)

All Generators shall provide Hydro One with the documentation specified in the Application for Connection of Generating Facilities to ensure that the Distribution System is adequately protected from potential damage or increased operating costs resulting from the connection of the Embedded Generation Facility.

The potential impacts on Hydro One's distribution system and any required mitigation measures as a result of proposed Embedded Generation Facilities with a proposed name-plate rated capacity greater than 500 kW will be determined with a Connection Impact Assessment. The cost of completing the CIA will be paid by the Generator. There may be circumstances where the threshold requiring a CIA is less than 500 kW. More information regarding the CIA process and associated costs can be obtained at Hydro One's website:

http://www.hydroonenetworks.com/en/customers/generators/generation_connections/distribution/default.asp

Generators connected to the Distribution System prior to the date of these Conditions of Service shall have the technical information required in the application and assessment process on file and provide the information to Hydro One upon request.

B. Interface Protection and Isolating Devices

The Generator shall provide an interface protection for their Embedded Generation Facility that minimizes the frequency and severity of disturbances on the Distribution System and the impact to the reliability and power quality of service to other Customers. Embedded Generation Facilities must also meet the technical requirements as identified in the document "Technical Requirements for Generators Connecting to Hydro One's Distribution System." Additional requirements may be necessary to address unique situations.

The Generator shall provide, install and maintain a disconnecting device at the connection point with the Distribution System for the purpose of isolating the Embedded Generation Facility in case of Emergency and for work protection. The disconnecting device shall be installed in accordance with the Electrical Safety Code.

C. Metering for Embedded Generation Facilities

Metering Installations – Installed after July 14, 2000

The metering shall be installed at the Ownership Demarcation Point of the Connection of the Embedded Generation Facility to the Distribution System. If this is not practical, Hydro One shall apply loss factors to the generation output in accordance with the loss factors applied for Retail settlements and billing. The Operational Demarcation Point for an Embedded Generation Facility is the primary live line clamp or lines switch that is installed on or at Hydro One's Distribution line.

The Generator shall install metering in accordance with the Distribution System Code, Hydro One's standard metering requirements, and Hydro One's policy for embedded generator metering, NOP-041, located at www.HydroOneNetworks.com. The Generator shall provide Hydro One with the technical details of the Meter Installation.

Metering Installations – Installed Prior to July 14, 2000

Where there is an existing Meter Installation for an Embedded Generation Facility, the Generator shall pay the cost of upgrades required for the Meter Installation to be in accordance with Hydro One's standard metering requirements by no later than the meter seal expiry date.

Embedded Generation Facilities that receive energy (e.g. for station use or backup supply) shall be placed in the appropriate Rate class and billed for the energy consumed.

D. Transformers

Any step-up transformation equipment required to step-up the Embedded Generation Facility's output voltage to the primary voltage of Hydro One's Distribution line shall be supplied, installed, owned and maintained by the Generator.

Customers connected to the Distribution System that wish to connect an Embedded Generation Facility to the Hydro One distribution system may be permitted at Hydro One's sole discretion to be connected through Hydro One's existing distribution transformer, provided the net reverse power flow through the transformer is within the reverse flow limit established by Hydro One. The transformation supplied by Hydro One for such Customers, dependent upon the rate class of the Customer, is subject to the limitations noted in Section 2.1 and is sized solely upon the expected load to be supplied at the Customer's premise. The cost of any incremental transformation and associated impacts on the Hydro One distribution system shall be paid by the Customer.

E. Maintenance Schedules

The Generator must implement and adhere to a regular scheduled maintenance plan to assure both Hydro One and the Generator that the connection devices, protection and control systems are maintained in good working order. The provisions of said maintenance plan are to be listed in the Connection Agreement. The Generator must conduct a re-verification at least every 48 months (or as specified in the Connection Agreement) and provide a written report to Hydro One signed by professional licensed engineer. A verification report of maintenance activities including the operation of devices shall be retained by the Generator and shall be provided to Hydro One upon request.

Hydro One, in its sole discretion, may require the Generator to permit Hydro One to witness the re-verification of any protections that could adversely affect the Distribution System. The Generator shall pay for the re-verification and provide Hydro One a copy of the report giving the results of the re-verification of the protections.

F. Reporting Requirements

All Embedded Generation Facilities over 100kVA shall report any significant event to Hydro One within five business days. The Connection Agreement may include a list of events deemed significant and provide a standard report format.

The Generator shall keep a written log of the operation of the Embedded Generation Facility's protections that result in the tripping of the facility's interrupting devices. On request, the Generator must provide a copy of the log to Hydro One. The log shall contain, at a minimum, the following information:

(i) date and time of event/operation of protections;
(ii) which relay or protection feature of the relay initiated the trip;
(iii) conditions and unit output at the time of the trip that may be related to the operation (e.g. lightning, outage of feeder, etc.).

G. Capital Contribution

When Hydro One is required to add new Hydro One Facilities and Equipment, alter existing Hydro One Facilities and Equipment, or increase the capacity of the Distribution System to connect a new Embedded Generation Facility (an "Expansion"), Hydro One will perform an economic evaluation to determine the

Generator's required capital contribution for the equipment, labour and ongoing maintenance costs of the Expansion (the "Expansion Costs"). Hydro One will use the Discounted Cash Flow Model and assume that future revenue will be zero.

H. Compliance

All Embedded Generation Facility equipment connected, operating or procured before July 14, 2000, is deemed to be in compliance with Hydro One's performance requirements except for the requirements of the Electrical Safety Authority and isolating device requirements identified in section 3.5.2.

Hydro One may require that the equipment deemed compliant above be brought into actual compliance with Hydro One's performance requirements within a timeframe established by Hydro One, but not to exceed 12 months, where, in Hydro One's sole opinion, there is:

(i) a material deterioration of the Distribution System reliability resulting from the performance of the Embedded Generation Facility equipment;
(ii) material negative impacts on the power quality of an existing or a new Customer resulting from the performance of the equipment at the Embedded Generation Facility; or
(iii) a material increase in Generating capacity at the site where the equipment deemed compliant is located.

I. Disconnection of Embedded Generation Facility

Hydro One has the right to disconnect an Embedded Generation Facility from its Distribution System where, where in the sole opinion of Hydro One, any of the following conditions, exist:

(i) there is a material deterioration of the Distribution System reliability resulting from the performance of the Embedded Generator's equipment;
(ii) there is a material negative impact on the quality of power of an existing or a new Customer resulting from the performance of the equipment at the Embedded Generation Facility;
(iii) the Embedded Generator has failed to re-verify the protection and control systems every 48 months or as specified in the Connection Agreement or failed to submit the report within 30 days;
(iv) the Embedded Generator's report of the re-verification of the protection and control systems shows deficiencies that are unacceptable to Hydro One;
(v) the Embedded Generator has made material changes in the capacity and /or the mode of operation of the Generation Facility, and the

impact to the Distribution System is deemed unacceptable to Hydro One;

(vi) the Embedded Generator has failed to meet any technical requirements, including those identified in the document "Technical Requirements for Generators Connecting to Hydro One's Distribution System."; or

(vii) the Embedded Generator has failed to provide any documentation as specified in the application and assessment process upon request.

3.6. Embedded Wholesale Market Participant

An Embedded Wholesale Market Participant is a Customer who is registered as a Wholesale Market Participant with the IESO and whose facility is not directly connected to the IESO Controlled Grid but is connected to the Distribution System. All Embedded Wholesale Market Participants within the service jurisdiction of Hydro One, once approved by the IESO, shall inform Hydro One in writing of their approved status 60 days prior to their participation in the IESO-administered market.

A Connection Agreement, including an operating schedule, will be required between an Embedded Wholesale Market Participant and Hydro One.

An Embedded Wholesale Market Participant will be responsible for the ownership, installation and maintenance of the meter and contracting the services of a Registered Meter Service Provider. Responsibility for an existing Meter Installation will transfer from Hydro One to the Embedded Wholesale Market Participant on the meter seal expiry date.

3.7. Embedded Distributor

Refer to Section 3.4 of these Conditions of Service.

3.8. Unmetered Connections

There are certain instances where Connections can be provided without metering. These loads are generally small in size and consistent in magnitude of load. Hydro One reserves the right to review all cases and may require that a meter be installed at its sole discretion.

Services that can be unmetered include cable TV amplifiers, telephone switching devices, phone booths, bus shelters, rail way crossing signals, traffic signals, and other small fixed loads. Only loads of less than 5 kW can be set up as unmetered. The Customer shall provide detailed manufacturer information and documentation with regard to electrical demand or consumption of the proposed unmetered load.

A completed load study acceptable to Hydro One may be required for determination of load and hours of usage.

At Hydro One's discretion, an agreement may be required between the Customer and Hydro One that identifies the Customer's obligations and responsibilities in notifying Hydro One of changes to existing equipment or new equipment and Connections added to the Distribution System by the Customer.

For installations on Hydro One-owned poles, Hydro One must approve the method of attachment and location of installations and the owner must enter into a Joint Use Agreement.

The billing of unmetered Connections will be based on estimated usage.

All unmetered Connections fall under the Industrial Commercial, Industrial Commercial General Service or Lighting Rate classifications.

Unmetered Connections may also include the following:

3.8.1. Street Lighting

This section pertains to the distribution and supply of electrical energy for street lighting. Street lights are devices owned by or operated for the road authority and/or the municipal corporation.

The energy consumption for street lights is estimated based on Hydro One's profile for street lighting load, which provides the amount of time each month that the street lights are operating. The energy charge is based on installed load.

Street lighting plant, facilities, or equipment owned by the Customer are subject to Electrical Safety Authority requirements.

Charges related to the connection of Street Lighting shall be paid by the Customer, at time and material rates.

Streetlights attached on Hydro One's line poles will require the owner to enter into an agreement to use such poles. The location and method of attachment is subject to Hydro One approval. Hydro One will make the electrical service connection of all streetlights to the Distribution System. The normal service voltage will be 120/240 volts, single-phase, three-wire.

The Customer will provide the secondary conductor to the supply point. Hydro One will install and connect the service conductor at the supply point.

3.8.2. Decorative Lighting

This section pertains to the distribution and supply of electrical energy for decorative street lighting installations. Such installations could be lighting for festive occasions or streetscaping. These are privately owned and maintained and subject to Electrical Safety Authority and Hydro One service conditions.

This section does not apply to street lighting that is owned by or operated by the road authority and/or the municipal corporation.

Hydro One shall determine if metering is required on a case-by-case basis with respect to the demand, load profile, location, accessibility, duration of the Connection, and municipal agreement.

The nominal service voltage will be 120/240 volts, single phase.

The method and location of the supply will vary and will be established for each application through consultation with Hydro One.

Charges for part time or decorative seasonal lighting include an energy charge calculated at dollars/kWh/month. Minimum billing will be for one month (Dollars per kWh x # of fixtures x kWh).

At Hydro One's discretion, an agreement may be required between the Customer and Hydro One that identifies the Customer's obligations and responsibilities in notifying Hydro One of new equipment and connections added to the Distribution System by the Customer.

3.8.3. Cablevision Power Supplies

This section pertains to the distribution and supply of electrical energy for cablevision power units. The standard service with no accessories (heaters or air conditioners, etc.) can be unmetered. A completed load study will be required, otherwise the account will be set up on full name plate rating. Energy consumption will be based on connected wattage on the line side power supply and based on twenty-four hours of use.

Power units that have additional accessories such as heaters or air conditioners, etc. shall require metering.

Each power supply will be set up as an individual account.

The service voltage will be 120 volts, single phase, two wire, maximum 15 amp.

The method and location of supply will vary and will be established for each application through consultation with Hydro One.

3.8.4. Traffic Signals

This section pertains to the distribution and supply of electrical energy for traffic signals and crosswalks. These are the devices owned and maintained by the road authority and/or the municipal corporation.

The service may be unmetered for small intersections while larger loads will be metered. Energy consumption will be based on the connected wattage and the calculated hours of use.

The service voltage will be 120/240 volts, single phase, three wire.

The method and location of the supply will vary and will be established for each application through consultation with Hydro One.

The Customer will provide the secondary conductor to the supply point. Hydro One will install and connect the service conductor at the supply point.

SECTION 4 GLOSSARY OF TERMS

“Acquired Local Distribution Company” means a distribution company or a distribution system acquired by Hydro One since April 1, 1999. “Affiliate Relationships Code” means the code, issued by the OEB and in effect at the relevant time, which among other things, establishes the standards and conditions for the interaction between electricity distributors or transmitters and their respective affiliated companies;

“Applicable Laws” means any and all applicable laws, including environmental laws, statutes, codes, licensing requirements, treaties, directives, rules, regulations, protocols, policies, by-laws, orders, injunctions, rulings, awards, judgments, or decree or any requirements or decision or agreement with or by any government or governmental department, commission, board, court authority or agency;

“Basic Connection” means a Connection of a Building that Lies Along that can be connected without requiring an Expansion;

“Billing Cycle Factor” means a factor applied to a bill amount in order to normalize to the length of the bill period plus forty-five (45) days for the purposes of calculating security deposit requirements, i.e., a monthly bill is adjusted by a Billing Cycle Factor of 2.5, a bi-monthly bill is adjusted by a Billing Cycle Factor of 1.75 and a quarterly bill is adjusted by a Billing Cycle Factor of 1.5;

“Bi-monthly Billing” means a notional and approximate sixty day (60) period for a billing cycle, not necessarily aligned with calendar months;

“Building that Lies Along” means a Customer property or parcel of land that is directly adjacent to or abuts onto the public road allowance where Hydro One has Hydro One Facilities and Equipment of the appropriate voltage and capacity;

“Common Line” means that portion of a line or private property that is owned by Hydro One and is used to serve more than one Customer;

“Complex Metering Installation” means a metering installation where instrument transformers, test blocks, recorders, pulse duplicators and multiple meters may be employed;

“Connection” means the process of installing and activating connection assets in order to distribute electricity to a Customer;

“Connection Agreement” means the agreement entered into between Hydro One and a person whose Customer Equipment is or is to be connected to the Distribution System that delineates the conditions of the Connection and delivery of electricity to or from that Connection;

"Connection and Cost Recovery Agreement" or "Connection Cost Recovery Agreement" means an agreement entered into between Hydro One and a person connected to its Distribution System that describes the work to be performed by Hydro One in connecting the Customer, the cost of same, any required capital contributions and/or revenue guarantees;

"Customer" means a person that has contracted for or intends to contract for connection of a building or an Embedded Generation Facility. This includes developers of residential or commercial subdivisions and Embedded Distributors;

"Customer Equipment" means all electrical and mechanical equipment used by the Customer that only supplies the Customer's home or business and does not include any Hydro One Facilities and Equipment;

"Demand Billed Customer" means a demand metered non-residential Customer with average monthly peak demand greater than 50 kW over the most recent calendar year that is read monthly and billed on kW demand as well as kWh energy;

"Demand Meter" means a meter that measures a Customer's peak usage during a specified period of time;

"Direct Customer" means a Customer other than a Large User or an Embedded Distributor, whose monthly measured maximum demand averaged over the most recent calendar year or whose forecasted monthly average demand over twelve consecutive months is equal to or greater than 5000 kW;

"Disconnect" or "Disconnection" means a deactivation of connection assets that results in cessation of Distribution Services to a Customer;

"Disconnect/Collect Trip" is a visit to a Customer's premises by an employee or agent of Hydro One to demand payment of an outstanding amount or to shut off or limit distribution of electricity to the Customer failing payment;

"Distribute" or "Distribution" with respect to electricity, means to convey electricity at voltages of 50 kV or less;

"Distribution Losses" means energy losses that result from the interaction of intrinsic characteristics of the distribution network such as electrical resistance with network voltages and current flows;

"Distribution Loss Factor" means the factor(s) by which metered loads must be multiplied such that when summed it equals the total measured load at the supply point(s) to the Distribution System;

"Distribution Services" means services related to the distribution of electricity and the services the OEB has required Distributors to carry out, for which a charge or

Rate has been approved by the OEB under Section 78 of the *Ontario Energy Board Act*;

"Distribution Standards" means Hydro One's distribution standards;

"Distribution System" means Hydro One's system for distributing electricity, and includes any structures, equipment or other things used for that purpose. The Distribution System is composed of the main system capable of distributing electricity to many Customers and the connection assets used to connect a Customer to the main Distribution System;

"Distribution System Code" means the code, issued by the OEB, and in effect at the relevant time, which, among other things, establishes the obligations of a Distributor with respect to the services and terms of service to be offered to Customers and Retailers and provides minimum technical operating standards of distribution systems;

"Distributor" means a person who owns or operates a distribution system;

"Distributor Consolidated Billing" is as described in the Retail Settlement Code;

"Electricity Act" means the *Electricity Act, 1998*, being Schedule A to the *Energy Competition Act*, S.O. 1998, c. 15, as amended;

"Electricity Distribution Rate Handbook" means the document issued by the OEB that outlines the regulatory mechanisms that will be applied in the setting of Distributor's Rates;

"Electrical Safety Authority" or "ESA" means the person or body designated under the regulations made pursuant to the *Electricity Act* as the Electrical Safety Authority;

"*Electrical Safety Code*" means the code referred to in O. Reg. 164/99, as amended;

"Electricity System" means the integrated power system and all facilities connected to that system;

"Embedded Distributor" or "Embedded LDC" means a Distributor that is provided electricity from the Distribution System;

"Embedded Generator" means a Generator whose Generation Facility is connected to the Distribution System;

"Embedded Generation Facility" means a Generation Facility which is not directly connected to the IESO-Controlled Grid but instead is connected to the Distribution System;

"Emergency" means any abnormal system condition that requires remedial action to prevent or limit loss of a Distribution System or supply of electricity that could adversely affect the reliability of the Electricity System;

"Emergency Backup Generation Facility" means a generation facility that has a transfer switch that isolates it from the Distribution System;

"Energy Only Customer" means any Customer with average monthly peak demand of 50 kW or less over the most recent calendar year that is billed for electricity service on kWh energy only;

"Expansion" is a situation in which Hydro One needs to construct new facilities to its Distribution System or increase the capacity of existing Hydro One Facilities and Equipment in order to be able to connect a specific Customer;

"Force Majeure Event" shall be deemed to be a cause reasonably beyond the control of the party whose inability as aforesaid is involved such as, but without limitation to, strike, lockout or other labour dispute of that party's employees, damage or destruction by the elements, accident to the works of that party, fire explosion, war on the Queen's enemies, legal act of the public authorities, insurrection, Act of God or inability to obtain essential services or to transport materials, products or equipment because of the effect of similar causes on that party's suppliers or carriers;

"Four-Quadrant Interval Meter" means an Interval Meter that records power injected into the Distribution System and the amount of electricity consumed by the Customer;

"General Service" means the Rate classification applicable to any service that does not fit the description of the year-round residential, seasonal residential or farm classes. Generally, it is composed of commercial, industrial, educational, administrative, auxiliary and government type services. It includes combination type services where a variety of uses are made of the service by the owner of one property, and all multiple services except residential with up to four units.

"Generate" or "Generating", with respect to electricity, means to produce electricity or provide ancillary services, other than ancillary services provided by a transmitter or distributor through the operation of a transmission or distribution system;

"Generation Facility" means a facility for Generating electricity or providing ancillary services, other than ancillary services provided by a transmitter or Distributor through the operation of a transmission or distribution system, and includes any structures, equipment or other things used for that purpose;

"Generator" means a person who owns or operates a Generation Facility;

"Good Utility Practice" means any of the practices, methods and acts engaged in or approved by a significant portion of the electric utility industry in North America during the relevant time period, or any of the practices, methods and acts which in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good practices, reliability, safety, and expedition. Good Utility Practice is not intended to be limited to the optimum practice, method, or act to the exclusion of all others, but rather to be acceptable practices, methods, or acts generally accepted in North America;

"High Density Zone" means an area containing 100 or more Customers with a line density of at least 15 Customers per kilometre. All classes of Customers are included in the density count;

"Hydro One Facilities and Equipment" means Hydro One's meters, wires, poles, cables, transformers, any other structures, equipment, all other appliances and equipment or other things used for distributing electricity;

"IESO" means the Independent Electricity System Operator established under the *Electricity Act*;

"IESO Controlled Grid" means the transmission systems with respect to which, pursuant to agreements, the IESO has the authority to direct operation;

"Interval Meter" means a meter that measures and records electricity use on an hourly or sub-hourly basis;

"Large Embedded Generation Facility" means an Embedded Generation Facility with a name-plate capacity of more than 10 MW;

"Large User" means an individual Customer in the service area of an Acquired Local Distribution Company whose monthly measured maximum demand (kW) averaged over the most recent calendar year or whose forecasted monthly average demand over twelve consecutive months is equal to or greater than 5000kW;

"Load Displacement" means in relation to a Generation Facility that is connected on the Customer side of the Ownership Demarcation Point, that the output of the Generation Facility is used or intended to be used exclusively for the Customer's own consumption;

"Load Limiter" is a device that will limit the amount of power delivered to **a** premise. Load interrupters are also used to limit the amount of power delivered. The load limiting devices are typically used during collection activity;

"Load Transfer" means a network supply point of one distributor that is supplied through the distribution network of another distributor and where this supply point is not considered a wholesale supply or bulk sale point;

"Load Transfer Customer" means a Customer that is provided Distribution Services through a Load Transfer;

"Market Participant" means a person who is authorized by the Market Rules to participate in the IESO-administered markets or to cause or permit electricity to be conveyed into, through or out of the IESO-controlled grid;

"Market Rules" means the rules made under Section 32 of the *Electricity Act*;

"Measurement Canada" means the Special Operating Agency established in August 1996 by the *Electricity and Gas Inspection Act* (Canada);

"Meter Installation" means the meter and, if so equipped, the instrument transformers, wiring, test links, fuses, lamps, loss of potential alarms, data recorders, telecommunication equipment and spin-off data facilities installed to measure power past a meter point, provide remote access to the metered data and monitor the condition of the installed equipment;

"Metering Services" means installation, testing, reading, and maintenance of meters;

"Micro-Embedded Generation Facility" means an Embedded Generation Facility with a name-plate rated capacity of 10 kW or less;

"Mid-Sized Embedded Generation Facility" means an Embedded Generation Facility with a name-plate rated capacity of 10 MW or less and:

(a) more than 500 kW in the case of a facility connected to a less than 15 kV line; and
(b) more than 1 MW in the case of a facility connected to a 15 kV or greater line;

"MIST" refers to "Metering inside the Settlement Timeframe";

"MIST Meter" means an Interval Meter from which data is obtained and validated within a designated settlement timeframe;

"Monthly Billing" means a notional and approximate 30-day period for a billing cycle, not a calendar month;

"MOST" refers to "Metering Outside the Settlement Timeframe";

"MOST Meter" means an Interval Meter from which data is only available outside of the designated settlement timeframe;

"Multiple Residential Properties" means a property, which provides separate living accommodation for two or more families. It does not include properties used for short-term occupancy such as hotels, motels, etc.;

"Normal Density Zone" means an area other than an Urban or High Density Zone;

"OEB" means the Ontario Energy Board;

"Ontario Energy Board Act" means the *Ontario Energy Board Act, 1998*, being Schedule B to the *Energy Competition Act*, S.O. 1998. c. 15, as amended;

"Operational Demarcation Point" means the physical location at which Hydro One's responsibility for operational control of distribution equipment, including Connection assets ends at the Customer;

"Ownership Demarcation Point" means the physical location at which Hydro One's ownership of distribution equipment, including Connection assets ends at the Customer;

"Personal Information" means any factual or subjective information, recorded or not, about an identifiable individual and this includes information in any form such as: age, name, ID numbers, income, ethnic origin, or blood type, opinions, evaluations, comments, social status, or disciplinary actions. Personal information does not include the name, title, business address or telephone of an employee of an organization.

"Point of Supply", with respect to an Embedded Generation Facility, means the Connection point where electricity produced by the Embedded Generation Facility is injected into the Distribution System;

"Present Value" means the current value of a future amount of money;

"Primary Metered Service" means a Connection whose meter point is located on the primary side of a distribution transformer;

"Primary Service" means a Connection directly to Hydro One's primary facilities. The Customer owns all conductors, supports and civil works located on its property;

"Private Property" means any property owned by a Customer or a third party and does not include any public street or highway;

"Public Holidays" mean the days designated by Hydro One from time to time. Until otherwise designated, the Public Holidays are: New Year's Day, Labour Day, Good Friday, Thanksgiving Day, Easter Monday, Christmas Day, Victoria Day, Boxing Day, Canada (Dominion) Day, and the Civic Holiday (as celebrated in Metropolitan Toronto);

"Qualified Contractor" means a contractor qualified to deal with electrical hazards in accordance with the requirements of the Occupational Health & Safety Act, (Ontario) as amended and all applicable regulations thereto including, Construction Projects – O. Reg. 213/91;

"Quarterly Billing" means a notional and approximate 90-day period for a billing cycle, not necessarily aligned with calendar months;

"Rate" means any rate, charge or other consideration, and includes a penalty for late payment;

"Refund Administration Service" means the service offered prior to the Distribution System Code coming into force to new Customers requiring an Expansion for Connection to the Distribution System, as such Customers were required to pay all costs of the Expansion. For a fee, Hydro One monitored new Connections to the line, to collect from any new Customers connecting to the original Expansion a fair share of the original costs and to administer a refund to the original or contributor or the present property owner. This service was provided in 5-year terms and could be renewed for additional 5-year terms upon additional payments of the fee. Customers who did not opt for a Refund Administration Service were not eligible for rebates if new Customers were added to the original expansion. Refund Administration Service is no longer offered to new Customers requiring Expansions for Connection.

"Registered Meter Service Provider" means a Person that provides, installs, commissions, registers, maintains, repairs, replaces, inspects and tests Metering Installations and is approved and registered by Measurement Canada and the IESO;

"Retail", with respect to electricity means,

a) to sell or offer to sell electricity to a Customer;

b) to act as agent or broker for a Retailer with respect to the sale or offering for sale of electricity; or

c) to act or offer to act as an agent or broker for a Customer with respect to the sale or offering for sale of electricity;

"Retail Settlement Code" means the code issued by the OEB and in effect at the relevant time, which, among other things, establishes a Distributor's obligations and responsibilities associated with financial settlement among Retailers and Customer and provides for tracking and facilitating Customer transfers among competitive Retailers;

"Retailer" means a person who Retails electricity;

"Retailer Consolidated Billing" is as described in the Retail Settlement Code;

"Secondary Metered Service" means a Connection whose meter point is located on the secondary side of a distribution transformer;

"Secondary Service" means a Connection to the low voltage side of Hydro One's transformer located on the Distribution System. Hydro One may own the conductor and the Standard Customer always owns all supports and civil works on the Customer's property;

"Service Transfer Request" is as described in the Retail Settlement Code;

"Single Phase" means a system that supplies a single alternating current electricity supply;

"Small Embedded Generation Facility" means an Embedded Generation Facility which is not a Micro-Embedded Generation Facility with a name-plate rated capacity of 500 kW or less in the case of a facility Connected to a less than 15 kV line and 1 MW or less in the case of facility connected to a 15 kV or greater line;

"Standard Customer" means any Customer who is not a Sub-transmission Customer, Large User, Direct Customer, Embedded Distributor or an Embedded Generator;

"Standard Supply Service" means the service approved by the OEB and in effect at the relevant time, which, among other things, establishes the minimum conditions that a Distributor must meet in carrying out its obligations to sell electricity under Section 29 of the *Electricity Act*;

"Standard Supply Service Code" means the code, issued by the OEB, and in effect at the relevant time, which, among other things, sets the minimum conditions that a Distributor must meet in carrying out its obligation to sell electricity under Section 29 of the *Electricity Act* unless otherwise stated in its licence;

"Sub-transmission Customer" or T-Class Customer – means an individual Customer that is typically served from Hydro One's sub-transmission system whose monthly measured maximum demand (kW) averaged over the most recent calendar year, or whose forecasted monthly average demand over twelve consecutive months is less than 5000 kW;

"Sub-transmission Service" means a service related to the Distribution of electricity supplied at voltages above 13 kV, 3 wire but less than 50 kV, 3 wire for which a charge or Rate has been approved by the OEB;

"Sub-transmission System" means a system related to the Distribution of electricity supplied at voltages above 13 kV, 3 wire but less than 50 kV, 3 wire;

"Three Phase" means a system having three distinct alternating currents 120 degrees between each phase;

"Total Losses" means the sum of Distribution Losses and Unaccounted for Energy;

"Unaccounted for Energy" means all energy losses that cannot be attributed to Distribution Losses. These include measurement error, errors in estimates of Distribution Losses and, energy theft and non-attributable billing errors;

"Unmetered Loads" means electricity consumption that is not metered and is billed based on estimated usage;

"Urban Density Zone" means an area containing 3,000 or more Customers with a line density of at least 60 Customers per kilometre. All classes of Customers are included in the density count;

"Utilization Voltage" means the highest voltage at which a Customer uses or distributes power on the Customer's property;

"Validating, Estimating and Editing" or "VEE" means the process used to validate, estimate and edit raw metering data to produce final metering data or to replicate missing metering data for settlement purposes;

"Wholesale Market Participant", means a person that sells or purchases electricity or ancillary services through the IESO administered markets.

Appendix A

A. <u>Description of Certain Agreements</u>

I. Connection and Cost Recovery Agreement

Section 2.1.7C of the Conditions of Service describes the Customers that are required to enter into a Connection and Cost Recovery Agreement (the "CCRA") with Hydro One. Key provisions in the CCRA are:

- a description of the work to be performed by Hydro One including specifications such as capacity and voltage range and work to be performed by the Customer;
- final Ownership Demarcation Point for Connection;
- requirement that Customer obtain all necessary approvals for the construction and Connection, including ESA approval, except where specifically noted that Hydro One is obligated to obtain the approval;
- property requirements, e.g. easements;
- requirement that both parties perform their work in accordance with Good Utility Practice, in compliance with the Conditions of Service, the Distribution System Code, all Applicable Laws and using duly qualified and experienced people;
- an estimate of the cost (plus applicable taxes) of the work to be performed by Hydro One;
- capital contribution requirements (if any) and associated payment schedule;
- annual revenue requirements to be met by Customer including financial and non-financial default conditions;
- true-up methodology and applicability for capital contribution and revenue guarantee(s) to reflect the difference between the actual cost and the estimate;
- Customer may be required to furnish security satisfactory to Hydro One, including deposit;
- liability to each other limited to damages that arise directly out of the wilful misconduct or negligence in meeting their respective obligations under the CCRA;
- deferral, cancellation or termination clauses that the Customer pays Hydro One for the cost of the work performed to date and the cost associated with the winding up of the work; and
- a requirement to execute certain other agreements before the actual Connection is made, e.g. a Connection Agreement.

II. Customer Service Contract

Key provisions of the Customer Service Contract are:

- a description of the work to be performed by Hydro One including specifications such as capacity and voltage range and work to be performed by the Customer;
- final Ownership Demarcation Point for Connection;

- requirement that Customer obtain all necessary approvals for the construction and Connection, including ESA approval, except where specifically noted that Hydro One is obligated to obtain the approval;
- property requirements, e.g. easements;
- requirement that both parties perform their work in accordance with Good Utility Practice, in compliance with the Conditions of Service, the Distribution System Code, all Applicable Laws and using duly qualified and experienced people;
- an estimate of the cost (plus applicable taxes) of the work to be performed by Hydro One;
- a requirement that the Customer reimburses Hydro One for costs and expenses in certain circumstances, e.g. where the Customer changed the condition of the Service Location or the Electrical System;
- Hydro One and the Customer liable for damages only that arise directly out of the wilful misconduct or negligence and HONI's total liability is limited to the aggregate amounts paid for the Work by the Customer to the date of such negligent act or wilful misconduct.

III. Subdivision Agreement

Developers shall execute a Subdivision Agreement in respect of the Connection of a subdivision to the Distribution System. Key provisions of the Subdivision Agreement are:

- a description of the work to be performed by Hydro One, including inspection of Developer's contractor's work;
- detailed description of the work to be performed by the Developer;
- requirement that Developer obtain all necessary approvals for the construction and Connection, including ESA approval, except where specifically noted that Hydro One is obligated to obtain the approval;
- property requirements, e.g. easements;
- an estimate of the cost (plus applicable taxes) of the work to be performed by Hydro One;
- security deposit and capital contribution requirements;
- requirement that Developer provide evidence of Developer's proposed contractor's previous experience and satisfactory performance prior to contractor beginning the installation of the Electrical Distribution System;
- obligation to transfer Electrical Distribution System and the Line Extension constructed by the Developer to Hydro One free and clear for one dollar;
- Developer required to warrant the Electrical Distribution System and the Line Extension constructed by the Developer to be free from defects for two (2) years following energization and must provide a letter of credit to secure these obligations;
- Hydro One's liability limited to damages that arise directly out of the wilful misconduct or negligence of Hydro One; and
- Developer to maintain certain specified types of insurance with minimum limits during term of the Subdivision Agreement.

IV. Connection Agreements (Embedded Distributor, Sub-transmission Customer, Large User, Direct Customer or Standard Customer):

Subsection 2.1.7E(i) of the Conditions of Service describes the Customers required to enter into a Connection Agreement with Hydro One. Hydro One's form of the Distribution Connection Agreement sets out the terms upon which Hydro One has agreed to offer and the Customer has agreed to accept connection service. Key provisions and requirements of Hydro One's form of Connection Agreement are:

- Terms, conditions and obligations of the parties as prescribed under the Distribution System Code;
- lists all necessary contact names and telephone numbers of both parties to ensure proper communication;
- the demarcation of the Ownership Demarcation Point and the Operational Demarcation Point as between Hydro One and the Customer;
- description of the language and procedures to be used for communications between the parties in normal and emergency situations;
- technical description of the Customer's installed protection equipment;
- the single line diagram provided by the Customer that identifies the interface of the Customer's facilities with the Distribution System;
- the description of the metering information;
- the tariff applications by supply point as well as payment requirements;
- the levels of maintenance and testing to be performed by both parties;
- the circumstances under which the Customer can be disconnected from the Distribution System for financial or non-financial defaults;
- the specific technical requirements applicable for a particular type of Customer:
    1. Load Customers: includes Hydro One's requirements with respect to disconnection devices, system design and protection, metering and grounding, capacity of each connection point, motor size and starting and operating requirements; and
    2. Embedded LDCs: includes Hydro One's requirements with respect to disconnection devices, protection and coordination and metering as well as the data to be provided by the Embedded LDC when making requests for additional supply, capacity of each embedded connection point, requirements for load forecast information to be provided by Embedded LDC for each connection point for use in supply planning studies, and may include specific thresholds for embedded load connections, e.g. load/motor sizes, for system impact assessment studies;
- performance requirements for various power quality items such as voltage variations, unbalances, voltage and current harmonics;
- for most Customers, description of metering, instrument transformer, meter programming and meter communications requirements as well as specification of site specific losses; and
- the name of the Customer's Registered Meter Service Provider.

V. Read Only Access Agreement To Interval Meters

If a Customer who is not a Wholesale Market Participant requires remote electronic access to their interval meter recorders, the Customer must execute a Read Only Access Agreement ("ROA"). The ROA allows Customers to have remote electronic access to their interval meter recorders for the purposes of obtaining kilowatt hour and kilovar hour billing meter quantities. Key provisions of the ROA Agreement are:

- Customer is permitted to use, at its expense, only software and communications protocols that have been specifically approved by Hydro One;
- Customer access is limited to daily interrogations, within a time frame specified by Hydro One;
- Hydro One does not provide assistance for reading or interpretation of Metering Information; and
- Customer may have only one third party, who has been approved by Hydro One, to have remote access to the metering data on its behalf.

VI. Access Agreements

Customers requiring ongoing access to Hydro One Facilities and Equipment to operate or maintain Distribution equipment including wholesale revenue metering must enter into an Access Agreement. Key provisions of an Access Agreement are:

- requirement to comply with Hydro One's security protocol and Access Policy and Procedures;
- requirement to provide a list of employees, temporary employees, agents, subcontractors and licencees (the "Customer Personnel") requiring access;
- Customer responsible for ensuring that Customer Personnel have adequate Electrical Safety Awareness Training;
- Customer required to use the contact number provided by Hydro One to enter and exit Distribution facility;
- describes the limitations on access within operational areas within the Distribution facility; and
- Customer is responsible for any and all losses to persons (including death) including Customer personnel or property when accessing the specified Hydro One Facilities and Equipment.

B. <u>How to Obtain Copies of the Above-Referenced Agreements</u>

To obtain a copy of any of the above-referenced agreements, please contact Hydro One during its normal business hours: Monday to Friday from 7:30 am to 8 pm. E.T. at 1-888-664-9376 to be directed to the appropriate Distribution Planner.